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Entities with oil and gas producing activities with conforming changes as of July 1, 2011; Audit and accounting guide

American Institute of Certified Public Accountants. Entities With Oil and Gas Producing Activities Task Force

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AUDIT & ACCOUNTING GUIDE

Entities With Oil and Gas Producing Activities

JULY 1, 2011

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AUDIT & ACCOUNTING GUIDE

Entities With Oil and Gas Producing Activities

With conforming changes as of

July 1, 2011

This edition of the AICPA Audit Guide *Entities With Oil and Gas Producing Activities*, which was originally issued in 2010, 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. The schedule of changes identifies all changes made in this edition of the guide. The changes do *not* include all those that might be considered necessary if the guide was subjected to a comprehensive review and revision.

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Preface

About AICPA Audit and Accounting Guides

This AICPA Audit and Accounting Guide has been developed by the AICPA Entities With Oil and Gas Producing Activities Task Force to assist management in the preparation of their financial statements in conformity with accounting principles generally accepted in the United States of America (U.S. GAAP) and to assist auditors in auditing and reporting on such financial statements.

The financial accounting and reporting guidance contained in this guide, when developed by the original task force or committee, was approved by the affirmative vote of at least two-thirds of the members of the Accounting Standards Executive Committee (AcSEC), now the Financial Reporting Executive Committee (FinREC). FinREC is the senior technical body of the AICPA authorized to speak for the AICPA in the areas of financial accounting and reporting. Conforming updates made to the financial accounting and reporting guidance contained in this guide in years subsequent to the original development are reviewed by select FinREC members, among other reviewers, when applicable.

This guide does the following:

- Identifies certain requirements set forth in the Financial Accounting Standards Board (FASB) *Accounting Standards Codification*™ (ASC).
- Describes FinREC's understanding of prevalent or sole industry practice concerning certain issues. In addition, this guide may indicate that FinREC expresses a preference for the prevalent or sole industry practice, or it may indicate that FinREC expresses a preference for another practice that is not the prevalent or sole industry practice; alternatively, FinREC may express no view on the matter.
- Identifies certain other, but not necessarily all, industry practices concerning certain accounting issues without expressing FinREC's views on them.
- Provides guidance that has been supported by FinREC on the accounting, reporting, or disclosure treatment of transactions or events that are not set forth in FASB ASC.

Accounting guidance for nongovernmental entities included in an AICPA Audit and Accounting Guide is a source of nonauthoritative accounting guidance. As discussed later in this preface, FASB ASC is the authoritative source of U.S. accounting and reporting standards for nongovernmental entities, in addition to guidance issued by the Securities and Exchange Commission (SEC). Accounting guidance for governmental entities included in an AICPA Audit and Accounting Guide is a source of authoritative accounting guidance described in category (b) of the hierarchy of generally accepted accounting principles (GAAP) for state and local governmental entities and has been cleared by the Governmental Accounting Standards Board. AICPA members should be prepared to justify departures from GAAP as discussed in Rule 203, *Accounting Principles* (AICPA, *Professional Standards*, ET sec. 203 par. .01).

Auditing guidance included in an AICPA Audit and Accounting Guide is recognized as an interpretive publication pursuant to AU section 150, *Generally*

Accepted Auditing Standards (AICPA, *Professional Standards*). 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.

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Guidance Considered in This Edition

This edition of the guide has been modified by the AICPA staff to include certain changes necessary due to the issuance of authoritative guidance since the guide was originally issued. Authoritative guidance issued through July 1, 2011, has been considered in the development of this edition of the guide. Authoritative guidance discussed in the text of the guide (as differentiated from the temporary footnotes, which are denoted by a symbol rather than a number) is effective for entities with fiscal years ending on or before July 1, 2011. Authoritative guidance discussed only in temporary footnotes is not yet effective as of July 1, 2011, for entities with fiscal years ending after that same date. This includes relevant guidance issued up to and including the following:

- FASB Accounting Standards Update (ASU) No. 2011-05, *Comprehensive Income (Topic 220): Presentation of Comprehensive Income*
- SAS No. 121, *Revised Applicability of Statement on Auditing Standards No. 100*, Interim Financial Reporting (AICPA, *Professional Standards*, AU sec. 722 par. .05)
- Interpretation No. 19, "Financial Statements Prepared in Conformity With International Financial Reporting Standards as Issued by the International Accounting Standards Board," of AU section 508, *Reports on Audited Financial Statements* (AICPA, *Professional Standards*, AU sec. 9508 par. .93–.97)
- Revised interpretations issued through July 1, 2011, including Interpretation Nos. 1–4 of AU section 325, *Communicating Internal Control Related Matters Identified in an Audit* (AICPA, *Professional Standards*, AU sec. 9325 par. .01–.13)
- Statement of Position 09-1, *Performing Agreed-Upon Procedures Engagements That Address the Completeness, Accuracy, or Consistency of XBRL-Tagged Data* (AICPA, *Technical Practice Aids*, AUD sec. 14,440)
- Public Company Accounting Oversight Board (PCAOB) Auditing Standard No. 15, *Audit Evidence* (AICPA, *PCAOB Standards and Related Rules*, Auditing Standards)

Users of this guide should consider guidance issued subsequent to those items listed previously to determine their effect on entities covered by this guide. In determining the applicability of recently issued guidance, its effective date should also be considered.

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

Applicability of U.S. GAAP and PCAOB Standards

Audits of the financial statements of *nonissuers* (those entities not subject to the Sarbanes-Oxley Act of 2002 or the rules of the SEC—that is, private entities, generally speaking) are conducted in accordance with generally accepted auditing standards (GAAS) as issued by the ASB, the senior technical committee of the AICPA with the authority to promulgate auditing standards for nonissuers. The ASB develops and issues standards in the form of SASs through a due process that includes deliberation in meetings open to the public, public exposure of proposed SASs, and a formal vote. The SASs and their related interpretations are codified in the AICPA's *Professional Standards*. Paragraph .03 of AU section 150 establishes that an AICPA member's failure to follow ASB standards for audits of nonissuers is a violation of Rule 202, *Compliance with standards* (AICPA, *Professional Standards*, ET sec. 202 par. .01) of the AICPA Code of Professional Conduct.

Audits of the financial statements of *issuers*, as defined by the SEC (those entities subject to the Sarbanes-Oxley Act of 2002 or the rules of the SEC—that is, public entities, generally speaking), are conducted in accordance with standards established by the PCAOB, a private sector, nonprofit corporation created by the Sarbanes-Oxley Act of 2002 to oversee the audits of issuers. The SEC has oversight authority over the PCAOB, including the approval of its rules, standards, and budget.

For audits of a nonissuer, in accordance with both GAAS and PCAOB standards, Interpretation No. 18, "Reference to PCAOB Standards in an Audit Report on a Nonissuer," of AU section 508 (AICPA, *Professional Standards*, AU sec. 9508 par. .89–.92) provides reporting guidance applicable to such engagements.

References to Professional Standards

In citing GAAS and their related interpretations, references use section numbers within the codification of currently effective SASs and not the original statement number, as appropriate. For example, SAS No. 54, *Illegal Acts by Clients*, is referred to as AU section 317, *Illegal Acts by Clients* (AICPA, *Professional Standards*). In those sections of the guides that refer to specific auditing standards of the PCAOB, references are made to the AICPA's *PCAOB Standards and Related Rules* publication.

FASB ASC

Overview

Released on July 1, 2009, FASB ASC is a major restructuring of accounting and reporting standards designed to simplify user access to all authoritative U.S. GAAP by topically organizing the authoritative literature. FASB ASC disassembled and reassembled thousands of nongovernmental accounting pronouncements (including those of FASB, the Emerging Issues Task Force, and the AICPA) to organize them under approximately 90 topics.

FASB ASC also includes relevant portions of authoritative content issued by the SEC, as well as selected SEC staff interpretations and administrative guidance issued by the SEC; however, FASB ASC is not the official source of SEC guidance and does not contain the entire population of SEC rules, regulations, interpretive releases, and SEC staff guidance. Moreover, FASB ASC does not include governmental accounting standards.

FASB published a notice to constituents that explains the scope, structure, and usage of consistent terminology of FASB ASC. Constituents are encouraged to read this notice to constituents because it answers many common questions about FASB ASC. FASB ASC, and its related notice to constituents, can be accessed at http://asc.fasb.org/home and are also offered by certain third party licensees, including the AICPA. FASB ASC is offered by FASB at no charge in a Basic View and for an annual fee in a Professional View.

Issuance of Amendments to FASB ASC

Amendments to FASB ASC are now issued through ASUs and serve only to update FASB ASC. FASB does not consider the ASUs authoritative in their own right; such amendments become authoritative when they are incorporated into FASB ASC.

The ASUs issued are in the form of ASU No. 20YY-XX, in which "YY" is the last two digits of the year and "XX" is the sequential number for each update.

For example, ASU No. 2011-01 is the first update in the calendar year 2011. The ASUs include the amendments to FASB ASC and an appendix of FASB ASC update instructions. ASUs also provide background information about the amendments and explain the basis for the board's decisions.

Pending Content in FASB ASC

Amendments to FASB ASC issued in the form of ASUs (or other authoritative accounting guidance issued prior to the release date of FASB ASC) that are not fully effective, or became effective within the last six months, for all entities or transactions within its scope are reflected as "Pending Content" in FASB ASC. This pending content is shown in text boxes below the paragraphs being amended in FASB ASC and includes links to the transition information. The pending content boxes are meant to provide users with information about how a paragraph will change when new guidance becomes authoritative. When an amended paragraph becomes fully effective, the outdated guidance will be removed, and the amended paragraph will remain without the pending content box. FASB will keep any outdated guidance in the applicable archive section of FASB ASC for historical purposes.

Because not all entities have the same fiscal year ends, and certain guidance may be effective on different dates for public and nonpublic entities, the pending content will apply to different entities at different times. As such, pending content will remain in place within FASB ASC until the "roll-off" date. Generally, the roll-off date is six months following the latest fiscal year end for which the original guidance being amended or superseded by the pending content could be applied as specified by the transition guidance. For example, assume an ASU has an effective date for fiscal years beginning after November 15, 2010. The latest possible fiscal year end of an entity still eligible to apply the original guidance being amended or superseded by the pending content would begin November 15, 2010, and end November 14, 2011. Accordingly, the roll-off date would be May 14, 2012.

Entities cannot disregard the pending content boxes. Instead, all entities must review the transition guidance to determine if and when the pending content is applicable to them. This audit and accounting guide identifies pending content where applicable. As explained in the section of the preface "Guidance Considered in This Edition," pending content discussed in the text of the guide (as differentiated from the temporary footnotes, which are denoted by a symbol rather than a number) is effective for entities with fiscal years *ending* on or before July 1, 2011. Pending content discussed only in temporary footnotes is not yet effective as of July 1, 2011, for entities with fiscal years ending after that same date.

New AICPA.org Website

The AICPA encourages you to visit the new website at www.aicpa.org. It was launched in 2010 and provides significantly enhanced functionality and content critical to the success of AICPA members and other constituents. Certain content on the AICPA's website referenced in this guide may be restricted to AICPA members only.

Select Recent Developments Significant to Readers of This Guide

Summary of Significant Differences Between the PCAOB and AICPA Risk Assessment Standards

On August 5, 2010, the PCAOB issued Release No. 2010-004, *Auditing Standards Related to the Auditor's Assessment of and Response to Risk and Related Amendments to PCAOB Standards* (AICPA, *PCAOB Standards and Related Rules*, Select PCAOB Releases). This release includes eight auditing standards (collectively referred to as the "PCAOB Risk Assessment Standards") as adopted by the PCAOB. The eight standards, which were approved by the SEC on December 23, 2010, are as follows:

1. Auditing Standard No. 8, *Audit Risk*
2. Auditing Standard No. 9, *Audit Planning*
3. Auditing Standard No. 10, *Supervision of the Audit Engagement*
4. Auditing Standard No. 11, *Consideration of Materiality in Planning and Performing an Audit*
5. Auditing Standard No. 12, *Identifying and Assessing Risks of Material Misstatement*
6. Auditing Standard No. 13, *The Auditor's Responses to the Risks of Material Misstatement*
7. Auditing Standard No. 14, *Evaluating Audit Results*
8. Auditing Standard No. 15

The release also includes conforming amendments to other interim standards related to the PCAOB Risk Assessment Standards. The effective date of the PCAOB Risk Assessment Standards is for audits of financial statements of issuers with fiscal periods beginning on or after December 15, 2010.

In general, the PCAOB Risk Assessment Standards are consistent with the AICPA SASs related to risk assessment (the "AICPA Risk Assessment Standards"). Where differences exist, they are primarily due to the PCAOB

a. addressing audits of financial statements in conjunction with audits of effectiveness of internal control (often referred to as "Integrated Audits"). The AICPA Risk Assessment Standards only address audits of financial statements.

b. presenting content in standards different than the AICPA Risk Assessment Standards. For example, the PCAOB

   i. incorporated fraud risk assessment procedures into the PCAOB Risk Assessment Standards,

   ii. created Auditing Standard No. 10 to separately address supervision of the audit engagement,

   iii. created Auditing Standard No. 14 to separately address the evaluation of audit results, and

   iv. moved content related to other audit areas such as analytical review procedures and audits of group financial statements.

The PCAOB Risk Assessment Standards are not as voluminous as the AICPA Risk Assessment Standards because the PCAOB standards do not contain as much application guidance as does the AICPA Risk Assessment Standards. Appendix 11 of the release contains a more detailed comparison of the differences between the PCAOB Risk Assessment Standards and the AICPA Risk Assessment Standards.

ASB's Clarity Project

To address concerns over the clarity, length, and complexity of its standards, the ASB has made a significant effort to clarify the SASs. The ASB established clarity drafting conventions and undertook redrafting all of its SASs in accordance with those conventions, which include the following:

- Establishing objectives for each clarified SAS
- Including a definitions section, where relevant, in each clarified SAS
- Separating requirements from application and other explanatory material
- Numbering application and other explanatory material paragraphs using an A- prefix and presenting them in a separate section that follows the requirements section
- Using formatting techniques, such as bulleted lists, to enhance readability
- Including, when appropriate, special considerations relevant to audits of smaller, less complex entities within the text of the clarified SAS
- Including, when appropriate, special considerations relevant to audits of governmental entities within the text of the clarified SAS

In order to address practice issues timely, SAS Nos. 117–120 have already been issued in the clarity format and are already effective. SAS No. 122, *Statement on Auditing Standards: Clarification and Recodification* (AICPA, *Professional Standards*), was issued in October 2011. SAS No. 122 contains 39 clarified SASs and recodifies and supersedes all outstanding SASs through No. 121 except

- SAS No. 51, *Reporting on Financial Statements Prepared for Use in Other Countries* (AICPA, *Professional Standards*, AU sec. 534);
- SAS No. 59, *The Auditor's Consideration of an Entity's Ability to Continue as a Going Concern*, as amended (AICPA, *Professional Standards*, AU sec. 341);
- SAS No. 65, *The Auditor's Consideration of the Internal Audit Function in an Audit of Financial Statements* (AICPA, *Professional Standards*, AU sec. 322);
- SAS No. 87, *Restricting the Use of an Auditor's Report* (AICPA, *Professional Standards*, AU sec. 532);
- SAS Nos. 117–120

In addition, SAS No. 122 withdraws SAS No. 26, *Association With Financial Statements*, as amended (AICPA, *Professional Standards*).

SAS No. 122 contains "AU-C" section numbers instead of "AU" section numbers. "AU-C" is a temporary identifier to avoid confusion with references to existing

"AU" sections, which remain effective through 2013 in AICPA *Professional Standards*. The "AU-C" identifier will revert to "AU" in 2014, by which time SAS No. 122 becomes fully effective for all engagements.

SAS No. 122 recodifies the AU section numbers as designated by SAS Nos. 1–121. AU-C section numbers for clarified SASs based on equivalent International Standards on Auditing (ISAs) are the same as the equivalent ISA numbers. AU-C section numbers for clarified SASs with no equivalent ISAs have been assigned new numbers. The ASB believes that this recodification structure will aid firms and practitioners that use both ISAs and GAAS.

As noted previously, SAS Nos. 59, 65, and 87 are currently being redrafted and will be issued as separate SASs when finalized. In the interim, SAS No. 122 redesignates these SASs as follows and reissues the sections with conforming changes necessary due to the issuance of SAS No. 122:

- SAS No. 59 has been codified as AU-C section 570, *The Auditor's Consideration of an Entity's Ability to Continue as a Going Concern* (AICPA, *Professional Standards*).
- SAS No. 65 has been codified as AU-C section 610, *The Auditor's Consideration of the Internal Audit Function in an Audit of Financial Statements* (AICPA, *Professional Standards*).
- SAS No. 87 has been codified as AU-C section 905, *Restricting the Use of an Auditor's Report* (AICPA, *Professional Standards*).

As part of the Clarity Project, SAS No. 123, *Omnibus Statement on Auditing Standards—2011*, and SAS No. 124, *Financial Statements Prepared in Accordance With a Financial Reporting Framework Generally Accepted in Another Country* (AICPA, *Professional Standards*), were issued in October 2011 along with SAS No. 122. SAS No. 123 conforms SAS No. 117, *Compliance Audits* (AICPA, *Professional Standards*), and SAS No. 118, *Other Information in Documents Containing Audited Financial Statements* (AICPA, *Professional Standards*), to SAS No. 122 and addresses other changes necessitated by the Clarity Project. SAS No. 124 supersedes and recodifies SAS No. 51.

SAS Nos. 122–124 will be effective for audits of financial statements for periods ending on or after December 15, 2012. Refer to individual AU-C sections for specific effective date language.

All auditing interpretations corresponding to a SAS have been considered in the development of a clarified SAS and incorporated accordingly, and have been withdrawn by the ASB except for certain interpretations that the ASB has retained and revised to reflect the issuance of SAS No. 122. The effective date of the revised interpretations aligns with the effective date of the corresponding clarified SAS.

AICPA Audit and Accounting guides, as well as other AICPA publications, will be conformed to reflect the new standards resulting from the Clarity Project as appropriate based on the effective dates.

International Financial Reporting Standards

International Financial Reporting Standards (IFRSs) consist of accounting standards and interpretations developed and issued by the International Accounting Standards Board (IASB), a London-based independent accounting standard-setting body.

IASB began operations in 2001, when it succeeded the International Accounting Standards Committee (IASC). IASC was formed in 1973, soon after the formation of FASB. In 2001, when the IASB replaced the IASC, a new, independent oversight body, the IASC Foundation, was created to appoint the members of the IASB and oversee its due process. The IASC Foundation's oversight role is very similar to that of the Financial Accounting Foundation (FAF) in its capacity as the oversight body of FASB.

The term *IFRSs* has both a narrow and a broad meaning. Narrowly, IFRSs refer to the new numbered series of pronouncements issued by the IASB, as differentiated from IASs issued by its predecessor, the IASC. More broadly, however, IFRSs refer to the entire body of authoritative IASB pronouncements, including those issued by the IASC and their respective interpretive bodies. Therefore, the authoritative IFRSs literature, in its broadest sense, includes the following:

- Standards, whether labeled IFRSs or IASs
- Interpretations, whether issued by the IFRS Interpretations Committee (the interpretive body of the IFRS Foundation), the International Financial Reporting Interpretations Committee (IFRIC, predecessor to the IFRS Interpretations Committee), or the Standing Interpretations Committee (SIC, the predecessor to IFRIC)
- IFRS framework

As of March 31, 2010, IFRIC formally changed its name to the IFRS Interpretations Committee and on July 1, 2010, the IASC Foundation formally changed its name to the IFRS Foundation.

The preface to the IFRS 2010 bound volume states that IFRSs are designed to apply to the general purpose financial statements and other financial reporting of all profit-oriented entities including commercial, industrial, and financial entities regardless of legal form or organization. Included within the scope of profit-oriented entities are mutual insurance entities and other mutual cooperative entities providing dividends or other economic benefits to their owners, members, or participants.

IFRSs are not designed to apply to not-for-profit entities or those in the public sector, but these entities may find IFRSs appropriate in accounting for their activities. In contrast, U.S. GAAP is designed to apply to all nongovernmental entities, including not-for-profit entities, and includes specific guidance for not-for-profit entities, development stage entities, limited liability entities, and personal financial statements.

The AICPA Governing Council voted in May 2008 to recognize the IASB as an accounting body for purposes of establishing international financial accounting and reporting principles. This amendment to appendix A of Rule 202 and Rule 203 of the AICPA's Code of Professional Conduct gives AICPA members the option to use IFRSs as an alternative to U.S. GAAP. As a result, private entities in the United States can prepare their financial statements in accordance with U.S. GAAP as promulgated by FASB; an other comprehensive basis of accounting, such as cash- or tax-basis; or IFRSs, among others. However, domestic issuers are currently required to follow U.S. GAAP and rules and regulations of the SEC. In contrast, foreign private issuers may present their financial statements in accordance with IFRSs as issued by the IASB without a reconciliation to U.S. GAAP, or in accordance with non-IFRS home-country GAAP reconciled to U.S. GAAP as permitted by Form 20-F.

The growing acceptance of IFRSs as a basis for U.S. financial reporting could represent a fundamental change for the U.S. accounting profession. Acceptance of a single set of high quality accounting standards for worldwide use by public companies has been gaining momentum around the globe for the past few years. See appendix C of this guide for a discerning look at the status of convergence with IFRSs in the United States and the important issues that accounting professionals need to consider now.

Private Company Financial Reporting

The Blue Ribbon Panel on Private Company Financial Reporting was established in December 2009 and was sponsored by the AICPA, FAF, and the National Association of State Boards of Accountancy. This panel was formed to consider how U.S. accounting standards can best meet the needs of users of private company financial statements. Members of the panel represented a cross-section of financial reporting constituencies, including lenders, investors, owners, preparers, and auditors. In January 2011, the Blue Ribbon Panel concluded its work with the submission of a report of its recommendations to FAF.

On October 4, 2011, FAF released a proposal on creating a new Private Company Standards Improvement Council (PCSIC). The proposal is in response to FAF's outreach to stakeholders and the report of the Blue Ribbon Panel on standard setting for private companies. A major recommendation of the panel was for FAF to establish an independent board that would set differences in U.S. GAAP, where warranted, to make financial reporting more relevant and less complex for private companies and their financial statement users. However, FAF's proposal does not provide for an authoritative standard-setting body. The PCSIC's decisions would need to be ratified by FASB, making the PCSIC essentially a continuation of past efforts that did not result in meaningful change.

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Chapter 1

Overview of the 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 is helpful. The following discussion is intended to be basic, and the interested reader is encouraged to refer to other available sources, as necessary.

Development of the Oil Industry

1.02 The first commercial oil drilling venture occurred near Titusville, Pennsylvania, in 1859. A steam powered, cable tool drilling rig, which lifted and dropped a heavy piece of metal to pound a hole into the earth, was used to drill a 59-foot well, which yielded 5 barrels of oil per day. At that time, the price of crude oil was about $10 per barrel. This well set off a boom of sorts, and the cable tool drilling rig was used to drill other wells in the area. Oil soon sold for about $0.10 per barrel because of the dramatic increase in supply.

1.03 In the 1850s and early 1860s, oil was used chiefly as fuel for lamps. 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, requiring (*a*) wooden barrels (each with a capacity of 42 gallons, which is the present measurement of a barrel of crude oil); (*b*) horse-drawn wagons; (*c*) river barges; and (*d*) the railroads. The first pipeline, completed in the 1860s, was made of wood and was less than 1,000 feet long.

1.04 One of the first persons to rise to power in this infant industry was John D. Rockefeller. In 1870, Rockefeller merged his firm with four others to form the Standard Oil Company. During the 1880s, Standard Oil dominated the global production industry and 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 because of federal and state antitrust legislation that had been enacted as a response to its size.

1.05 The U.S. oil industry began exploration internationally (the Middle East, South America, Africa, and the Far East) in the 1920s as a result of increased demand. However, the East Texas oil field discovery of 1930 ultimately created an oil surplus that caused entities to cut back foreign operations. During and after World War II, the worldwide demand again increased, and enormous capital investments were made to develop the Persian Gulf area, other Middle East countries, Africa, South America, and the Far East.

1.06 In 1960, the Organization of Petroleum Exporting Countries (OPEC) was formed by five countries. The original founding members were Iran, Iraq, Kuwait, Saudi Arabia, and Venezuela. Since that time, OPEC membership and influence has continued to increase. The 2010 membership is shown in the following table:

Country	*Year Joined*	*Country*	*Year Joined*
Algeria	1969	Libya	1962
Angola	2007	Nigeria	1971
Ecuador	2007	Qatar	1961
Iran	1960	Saudi Arabia	1960
Iraq	1960	United Arab Emirates	1967
Kuwait	1960	Venezuela	1960

For many years, the United States was recognized as holding more oil and gas reserves within its borders than any other nation. However, that position has changed significantly since the creation of OPEC. The members of OPEC have controlled a substantial portion of the world's oil reserves, production, and excess productive capacity and, as a result, OPEC has been able to exercise a great deal of control over oil prices by decreasing or increasing the output of member nations through a production quota system.

1.07 Although large oil reserves have been discovered in Africa, Russia and the former Soviet states, the Gulf of Mexico, and the North Sea, OPEC members continue to have significant influence over the world oil market.

Development of the Natural Gas Industry

1.08 Natural gas demand increased significantly in the United States in the 1960s and has continued to increase, facilitated by improved transportation systems. In the United States, electricity generation, the growth of the petrochemical industry (which produces plastics and synthetics), and the heating of buildings create the primary demand for natural gas.

1.09 The use of natural gas has continued to grow throughout the world, although the lack of pipelines has impeded growth of production and consumption of natural gas in many areas of the world. One of the primary issues facing the international natural gas industry is that many of the largest discoveries are in countries that are remote from the primary consuming markets in North America, Europe, and Japan, as well as the growing markets in China and India. Efforts to resolve this issue have been made through the development of improved techniques for liquefying natural gas and transporting the resulting liquids, with liquefied natural gas playing a more critical role in worldwide supply and demand balance.

Prices for Oil and Gas

1.10 One of the most important factors in the development of the industry has been changes in oil and gas prices. The Arab oil embargo of 1973 focused public attention on the industry, largely because of its effect on previously stable prices. In 1973, before the embargo, the average barrel of crude oil sold for about $3. By December 1973, crude oil prices had risen to over $11 per barrel. In the United States, oil prices were placed under federal government control in late 1973. By 1977, nearly half the oil used by the United States was imported.

1.11 In 1979, the Iranian revolution resulted in a sharp increase in oil prices to $42 per barrel. In late 1979, the U.S. government announced "phased decontrol" of oil prices, and in January 1981, all price controls on crude oil were lifted. Natural gas prices continued to be subject to controls created by the Natural Gas Policy Act of 1978, but initial deregulation of gas prices began on January 1, 1985, with complete deregulation occurring on January 1, 2003.

1.12 By the early 1980s, the price for a barrel of oil ranged from $30 to $40 (and sometimes higher), but prices declined in the mid-1980s in the face of a world oil surplus. These fluctuations were further complicated by the U.S. government's earlier price controls that designated different prices for different grades of oil and created a complex pricing structure. As a result, producing entities 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. In the decades of the 1990s and 2000s, crude oil prices have fluctuated from a low of $13 per barrel to a high well in excess of $100 per barrel. Natural gas prices also have fluctuated significantly, ranging from a low of about $1 per million British thermal units (MMBTUs) in 1992 to more than $15 per MMBTUs in late 2005. Since that date, natural gas prices have continued to fluctuate.

Recent Developments in the Oil and Gas Industry

1.13 *Increase in demand.* For a number of years, countries like China and India have seen double-digit demand growth and are expected to continue growing at a high pace. The rapid economic expansion in much of the world, including China and India, has led to increased demands for energy and changes in the competition for new hydrocarbon resources. In particular, China and India are actively pursuing opportunities in their geographic region, as well as in Africa and South America.

1.14 The decline in traditional sources of natural gas in Western Europe, together with Russia's significant oil and gas reserves, have led to an increased dependence in Western Europe on the supply of hydrocarbons (especially gas) from Russia.

1.15 *Problems with supply of hydrocarbons.* In recent years, the global crude oil market supply has seen a number of disruptions. These include war and security issues in the Middle East (particularly Iran and Iraq) and political issues in Russia, the newer republics of the former Soviet Union, Nigeria, and Venezuela. These factors, combined with a weaker dollar (global oil trade is primarily dollar based), have driven oil prices significantly higher in recent years.

1.16 *New opportunities—offshore drilling.* Although offshore wells were drilled before 1900, including the use of piers and pilings in the Baku region of Azerbaijan in the Caspian Sea and piers extending into the Pacific Ocean in California, significant technological advancements have occurred in recent years. Such technology allows wells to be drilled in water depths greater than 9,000 feet and over 175 miles from shore. In more recent times, companies have invested billions of dollars in deep water drilling projects off the coasts of Africa, Brazil, the U.S. Gulf of Mexico, and the North Sea. Africa remains a bright spot for hydrocarbon opportunities. Offshore West Africa has been one of the most active areas in the world for new discoveries and significant projects. The oil discoveries have been sizeable, and the offshore operating conditions have been relatively mild and, due to the distance from the shore, somewhat insulated from the political and security unrest that occurs in onshore areas.

1.17 *Further development of offshore technologies.* Offshore drilling and production technology has advanced at a steady pace. For many decades, offshore oil and gas operations were restricted primarily to platforms affixed to the seafloor, with some limited use of subsea wells tied back to those platforms. Platform costs increase rapidly with water depth, but floating platform concepts, such as tension leg platforms and spars, have been used successfully in water depths up to 5,300 feet. Deepwater discoveries are now being developed with subsea wells in water depths up to 9,000 feet, with production being piped either to floating production, storage, and offloading tankers; central production hubs serving multiple fields; or directly to shore.

1.18 *Alternative sources of hydrocarbons.* As markets and producers have reacted to imbalances in demand and supply, the perceived need for alternative sources of energy also has boosted the prospects for alternative production techniques and technology. As a result, resources produced from oil sands, oil shales, coal, and several improved recovery techniques have become more important sources of hydrocarbons in recent years. Activities to extract these alternative or nontraditional resources are now considered to be oil and gas producing activities under the new oil and gas reporting requirements of the Securities and Exchange Commission (SEC) and, therefore, hydrocarbons extracted from oil sands, shales, coal beds, and other nonrenewable natural resources, which are intended to be upgraded into synthetic oil or gas, are now deemed to be oil and gas reserves. The previous SEC rules excluded such resources from the definition of *oil and gas reserves*.

1.19 *Modernization of oil and gas reporting.* On December 31, 2008, the SEC issued Final Rule No. 33-8995, *Modernization of Oil and Gas Reporting,* adopting revisions to oil and gas reporting requirements and disclosures that existed in Regulation S-K under the Securities Act of 1933 and in Regulation S-X under the Securities Exchange Act of 1934. The Final Rule also eliminated Industry Guide 2 and incorporated certain of these disclosure requirements in Subpart 1200 of Regulation S-K. Compliance with the SEC reporting requirements contained in Final Rule No. 33-8995 is required for registration statements filed on or after January 1, 2010, and for annual reports on Forms 10-K and 20-F for fiscal years ending on or after December 31, 2009, with early adoption not permitted. On January 6, 2010, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2010-03, *Extractive Activities—Oil and Gas (Topic 932): Oil and Gas Reserve Estimation and Disclosures*. ASU No. 2010-03 includes changes to accounting and disclosure requirements that are consistent with SEC Final Rule 33-8995. This guide reflects the new guidance.

Origin and Accumulation of Oil and Gas

1.20 An oil or gas reservoir is often erroneously viewed as a large cave containing liquids or gas beneath the earth, like a subterranean pond. In reality, an oil or gas reservoir is porous rock capable of containing oil, gas, or water in the microscopic pore spaces of the rock. For an oil or gas reservoir 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 filled with pores (having porosity) so the oil, gas, or both, can collect.
- The rock's pores must be interconnected (having permeability) so the oil or gas can move or migrate.
- There must be a trap that will cause the oil or gas to collect and prevent the hydrocarbons from moving upward.

1.21 Oil and gas 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 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 porous and permeable reservoir beds.

1.22 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 impermeable and rarely hold movable oil and gas in significant quantities. The oil and gas normally move from the source rock into more porous rocks; they then migrate upward through the porous rocks until reaching a structural closure or an impermeable barrier. These closures and barriers are called *traps*, and they cause oil and gas to accumulate into a pool or field.

1.23 Oil and gas traps may be classified in several different ways. One commonly used system for classifying traps is based on the one of two ways in which they were formed: (*a*) structural traps and (*b*) stratigraphic traps.

1.24 Structural traps formed by vertical or horizontal movement, or both, in the earth's crust, are the most important sources of hydrocarbons. A common structural trap is the anticline, which has been the most productive type of structure for oil and gas production. An anticline is a dome usually formed by upthrusts from below. Anticlines containing oil and gas are covered by an impervious cap rock layer. Oil, gas, and water migrate upward through porous layers until they reach the cap rock and are trapped.

1.25 Another structural trap of special importance as a source of oil and gas is the fault. Faults are created by shifts in the earth's crust that cause a porous strata containing hydrocarbons to shift and break so that a strata on one side of the fault is higher than the strata on the other side of the break. At the fault line, the strata containing hydrocarbons is sealed off by an impervious layer, trapping the oil, gas, and water.

1.26 A third common form of a structural trap is the salt dome. In these structures, a nonporous salt bed pushes upward and pierces porous strata, causing an uplifting of the strata and faults along the sides of the dome. Also, some of the impervious overriding formations are merely bent, creating anticlines at the top of the domes. Both faults and anticlines are excellent traps for hydrocarbons.

1.27 Another common structural trap is an unconformity or truncation trap, in which a portion of reservoir strata has been eroded away and replaced with impermeable sediments to form a trap. Different forms of truncation are involved in the large oil fields in Saudi Arabia and the Prudhoe Bay field in Alaska.

1.28 Stratigraphic traps are created by abrupt changes in the porosity of the strata. Areas of strata containing oil and gas may be cut off by irregular dispositions of sand and shale or changes in the rocks in the strata, causing the oil and gas to be trapped.

Oil and Gas Reserves

1.29 The discovery and preparation for production of oil and gas reserves is the primary objective of exploration and development activities. In addition, reserve information is critical to an oil and gas producer's financial statements.

1.30 Historically, only reserves classified as proved were disclosed in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP) and the disclosure requirements of the SEC. However, for internal purposes, entities generally also identify unproved categories. The most common additional categories are known as *probable* and *possible reserves*. In connection with the SEC reporting requirements contained in Final Rule No. 33-8995, probable and possible reserves are now permitted (although not required) to be disclosed outside of the financial statements in filings with the SEC.

1.31 Reserve determinations have a significant effect on an entity's results of operations and financial position because they are used in the calculation of the amortization of capitalized costs, the assessment of impairments, and the estimation of the timing of settlements of asset retirement obligations. U.S. GAAP generally requires that only proved reserves be used for accounting purposes (such as the amortization of capitalized costs.) However, probable and possible reserves are used (after adjusting for the risk of uncertainty of existence) in evaluating impairment of oil and gas properties for entities following the successful efforts method of accounting. Such reserves also are used in the determination of the fair value of assets in acquisition and disposition transactions.

The SEC's Definition of *Proved Reserves*

1.32 The current definition of *proved reserves* used by the SEC is found in Final Rule 33-8995. This definition is the only definition currently acceptable under both the successful efforts method and the full cost method of accounting when preparing financial statements and disclosures in accordance with U.S. GAAP.

1.33 The current and previous definitions of *proved reserves* are similar in that determination of proved reserves is based on whether the estimated oil and gas quantities are reasonably certain to be recoverable under existing economic and operating conditions. The concept of reasonable certainty of recovery under existing economic and operating conditions is subject to many interpretations and judgments, including, but not limited to, having the necessary transportation infrastructure; the existence of a market or market arrangements, or both; sufficient resources to fund development costs; and other criteria, each of which would need to be addressed. The inability of an entity to demonstrate that these criteria are reasonably certain to occur may affect its ability to recognize proved reserves.

1.34 However, certain key differences exist between the current and previous definitions of *proved reserves*, including the following:

- Previously, the SEC required that the economic recoverability assessment of proved reserves be based on prices on the last day of the fiscal year. However, in Final Rule No. 33-8995, the SEC requires that a 12-month average price be used to determine reserves (including proved reserves), calculated as the unweighted arithmetic average of the first day of the month price for each month within the company's 12-month period prior to the end of the reporting period, unless prices are affected by contractual arrangements, as defined.

- The previous definition of *oil and gas producing activities* explicitly excluded sources of oil and gas from nontraditional sources, such as the extraction of hydrocarbons from shales, tar sands, or coal. Under Final Rule No. 33-8995, the definition of *oil and gas producing activities* includes the extraction of nontraditional resources, such as bitumen extracted from oil sands and hydrocarbons extracted from coal beds and shales, which are intended to be upgraded into synthetic oil or gas.

- The previous definition of *proved oil and gas reserves* limited the ability to use certain technologies developed in recent years to support the determination of the quantities of proved reserves. However, under Final Rule No. 33-8995, the use of new reliable technologies is allowed to establish proved, probable, and possible reserve estimates. *Reliable technology* is defined as technology (including computational methods) that has been field tested and has demonstrated consistency and repeatability in the formation being evaluated or in an analogous formation.

Additional SEC staff guidance related to the determination of reserves can be found on the SEC's website at www.sec.gov/divisions/corpfin/guidance/oilandgas-interp.htm. This guidance is in the form of Compliance and Disclosure Interpretations (C&DIs) on the oil and gas rule of the SEC. These C&DIs comprise the interpretations of the SEC's Division of Corporation Finance.

The SEC reporting requirements contained in Final Rule No. 33-8995 also can be found on the SEC's website at www.sec.gov/rules/final/2008/33-8995.pdf.

1.35 Historically, proved reserves were classified as either *proved developed reserves* or *proved undeveloped reserves*, as defined in Rule 4-10(a) of Regulation S-X. Under the SEC reporting requirements contained in Final Rule No. 33-8995, proved, probable, and possible reserves can be classified as *developed* and *undeveloped*, in accordance with the following definitions:

- *Developed oil and gas reserves* are reserves of any category that can be expected to be recovered
  - — through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well and
  - — through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

- *Undeveloped oil and gas reserves* are reserves of any category that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

The definitions of *developed* and *undeveloped reserves* are generally similar to the previous definitions, although the classification of *developed* and *undeveloped* now applies to all reserve categories, not just proved reserves.

1.36 The SEC definition of *undeveloped oil and gas reserves* includes the following provision: "Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time."

In addition, the disclosures required under Item 1203 of Subpart 1200 of Regulation S-K require disclosure for proved undeveloped reserves, including the reasons why material amounts of proved undeveloped reserves have remained undeveloped for five years or more after disclosure as proved undeveloped reserves. See the "SEC Disclosures—Subpart 1200 of Regulation S-K" section of chapter 4, "Successful Efforts Method and General Accounting for Oil and Gas Activities," for further information regarding disclosure requirements. Additional guidance related to the definition of *undeveloped oil and gas reserves* has been provided by the SEC in Section 131 of its C&DIs. In particular, question 131.03 provides guidance regarding the SEC's views about the "specific circumstances" that would justify a time period longer than five years to begin development of proved undeveloped reserves.

The Society of Petroleum Engineers' Definitions of *Reserves*

1.37 In March 2007, the Society of Petroleum Engineers (SPE), the World Petroleum Council, the American Association of Petroleum Geologists, and the Society of Petroleum Evaluation Engineers announced a new framework for determining oil and gas resources: the Petroleum Resources Management System (PRMS). The PRMS provides a definition for *proved reserves*, as well as other resource categories, such as *probable* and *possible reserves*. The PRMS definitions are not acceptable for use in the preparation of financial statements in accordance with U.S. GAAP; however, entities may utilize them for internal purposes. The PRMS defines *proved reserves* as

> those quantities of petroleum, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

1.38 Historically, although the PRMS and SEC definitions of *proved reserves* were consistent across many areas, certain differences did exist between the two sets of definitions. The SEC definitions provided in Final Rule No. 33-8995 were significantly influenced by the PRMS and have eliminated some of these historical differences. However, differences do remain, including the fact that proved reserves under the PRMS are determined based on management's "defined" economic and operating conditions (that is, management's own pricing assumptions) as opposed to the "existing" economic and operating conditions required by the SEC (that is, historical 12-month average). Many companies still use the PRMS definition in their own internal reserves analyses.

1.39 For further information, readers can refer to the 2007 PRMS on the SPE's website at www.spe.org/spe-site/spe/spe/industry/reserves/Petroleum_Resources_Management_System_2007.pdf.

Determination of Reserves

1.40 Reserve estimates are prepared by persons with the requisite specialized knowledge and experience to estimate oil and gas reserve quantities, such as petroleum reservoir engineers and geologists. The reserve estimators may either be employees of the oil and gas entity or consulting engineers. When reserve estimates are prepared by employees of the entity, consulting engineers will often be hired to audit or review the estimates.

1.41 The assumptions that may vary include fixed or escalated prices, different price and cost scenarios, different development scenarios, probability based or deterministic methods of reserves estimates, and so on.

1.42 Reserve estimates or studies are widely used in managerial decisions. They also are used in financial statement information or supplemental disclosures to the financial statements. The most common uses are the following:

- A basis for computing the depreciation, depletion, and amortization rates used
- A basis to assign capitalized costs to oil and gas properties
- Disclosure of proved reserve quantities and discounted present value of future net cash flows information about a producing entity's proved reserves, in accordance with U.S. GAAP for publicly traded entities
- A basis for preparing cost ceiling test calculations for entities following the full cost method of accounting
- Undiscounted and discounted cash flow calculations for asset impairment purposes for entities following the successful efforts method of accounting

1.43 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 entity based on well log and formation core data, drill stem tests, and other available information.

1.44 Oil and gas entities should revise reserve estimates at least annually or whenever an indication of the need for revision exists, such as significant differences in actual production versus earlier estimates, changes in ownership, or significant decreases in cash flows.

1.45 The following is only a part of the supply of information that 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

1.46 The methods used to estimate recoverable reserves vary with the amount and nature of the preceding information that is available. Estimates of the reserve quantities that are economically recoverable are made for internal use. Estimates for internal use may be based on estimated selling prices, development costs, and production costs; however, those used for financial reporting purposes are required to be based on historical prices and production costs, as required by the SEC.

1.47 *Precision of estimates*. According to the SPE, the reliability of reserve information is affected considerably by several factors. It is important to note that reserve information is imprecise because of the inherent uncertainties in, and the limited nature of, the data upon which the reserve estimate 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. The persons estimating reserve information make numerous judgments based solely on their educational background, training, and experience. The extent and significance of the judgments to be made are, in themselves, sufficient to render reserve information inherently imprecise.

Operations in the Upstream Petroleum Industry

1.48 Financial statements of an oil and gas producing entity will include many transactions and accounts not commonly found in other types of economic enterprises. This is a result of the unique nature of the principal assets—oil and gas reserves—and the ways in which these reserves are acquired, developed, and produced. The high risks and high costs of acquiring, developing, and producing oil and gas and the unique nature of the ownership rights result in unique contractual relationships between oil and gas producing entities and owners of mineral rights. Chapter 2, "Primary Business Activities of the Industry," provides fundamental information about the most important contracts and operations encountered in the United States. Some of the most important contracts frequently encountered in petroleum activities in other countries are discussed in greater detail in chapter 6, "Accounting for International Oil and Gas Activities."

1.49 Operating activities in the oil and gas industry are commonly divided into the following categories: upstream activities and midstream and downstream activities. Upstream activities, which are the subject of this guide, may be broadly described as the following:

- Acquiring mineral rights
- Exploring for oil and gas
- Drilling wells and installing production equipment
- Lifting the oil, gas, and water from the wells to the surface

- Separating the oil, gas, and water sufficiently to prepare the hydrocarbons for transport to pipelines or oil refineries

Midstream and downstream activities include the following:

- Transporting the petroleum from the producing wells to the processing plants and refineries
- Refining and processing activities necessary to produce marketable products, such as natural gas, gasoline, and petrochemicals
- Transporting, distributing, and storing the refined products
- Marketing activities, which get the refined products, natural gas liquids, and natural gas into the hands of consumers

The activities involved in transporting the petroleum to processing plants and refineries are generally referred to as *midstream activities*, and the other activities are generally referred to as *downstream activities*.

1.50 Entities engaged in both upstream and downstream activities are referred to as *vertically integrated entities*, with the largest of these integrated entities often referred to as *majors*. A common term used in the industry to describe entities solely or primarily engaged in upstream activities is *independents*.

1.51 Within the petroleum industry, there have been continuing changes in entity structures and identities. Throughout the industry, mergers and acquisitions occur at all size levels. These transactions are entered into in order to acquire reserves, gain efficiencies, reduce costs, and gain operations in new areas.

1.52 The accounting and auditing principles and procedures related to refining activities, most gas processing activities, petrochemical operations, distribution, storage, and retail marketing activities are similar to those applicable to other manufacturing and marketing activities. As a result, this guide deals almost solely with accounting for, and reporting on, upstream activities, with only limited discussion of other related industry activities.

Oil Sands

1.53 Beginning in the late 1990s and early 2000s, the industry began to partner with joint venture partners in Canada in order to develop oil sand deposits. Potentially, oil sand projects can have a productive life that covers multiple decades. Many of these nonconventional operations involve the production of bitumen, which is transported from the mining operation via pipeline to an upgrader or directly to a refinery that processes heavy oil. An upgrader processes the bitumen into a lighter degree of synthetic crude oil that can be sold to the marketplace as is or further refined and converted into an array of refined products. Bitumen is a tar-like form of crude petroleum that is so viscous that it must be heated before it will flow.

1.54 The production techniques used to extract bitumen can be a mixture of nonconventional production techniques (referred to as *truck and shovel* or *surface mining* operations) and conventional drilling techniques, such as steam assisted gravity drainage (SAGD or in-situ operations). The surface mining operations can be used to recover only a certain percentage of the total resource volume. Conventional drilling techniques, such as SAGD, are applied in order to produce the resource volumes that are located on deeper horizons and not available for the mining type of production. Historically, oil and gas entities have accounted for and disclosed truck and shovel operations as mining activities and SAGD operations as oil and gas producing activities.

1.55 The accounting guidance for nonconventional production has been outside the scope of FASB *Accounting Standards Codification* (ASC) 932, *Extractive Activities—Oil and Gas*, due to truck and shovel operations being viewed as a mining operation; however, accounting for SAGD operations has been covered by FASB ASC 932 because this technique involves the removal of resource volumes via a drilling operation. In Final Rule No. 33-8995, the definition of *oil and gas reserves* includes reserves related to either type of operation as long as the resources are intended to be processed into synthetic oil or gas. FASB ASC 932 has also been updated by ASU No. 2010-03 to reflect the inclusion of these activities within its scope.

Sources of Capital and Organizational Structure of Oil and Gas Entities

1.56 Oil and gas producing entities require large 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.

1.57 In the past, oil and gas entities, 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 entities for exploration rights to undeveloped properties, increased risks related to exploration and development of oil and gas properties, as well as rising acquisition and development costs, have resulted in entities turning more frequently to other sources of funds.

1.58 Oil and gas entities use a variety of ownership arrangements for sharing risks. These arrangements may be in the form of undivided interests, unincorporated entities (joint ventures), corporations, limited liability companies, partnerships, and others. The oil and gas entity determines the appropriate method to account for these varied ownership arrangements. This involves determining whether consolidation, equity method accounting, cost basis accounting, or proportional consolidation are applicable, based on the specific facts and circumstances. See chapter 3, "Accounting for Common Oil and Gas Ownership Arrangements," of this guide for a discussion of accounting for common oil and gas arrangements.

Joint Interest Arrangements

1.59 Entities often enter into arrangements with others as a means of raising or sharing capital. This can be done by creating joint operations, often in the form of joint ventures or partnerships, and is often accomplished by transferring a portion of the working interest to other parties. Depending on the attractiveness of the property and the owner's willingness to dilute its interest, a portion of the costs of a property may be financed in this manner. An example is a carried interest arrangement, in which one party agrees to incur all the costs to develop and operate a property but maintains the right to recapture its costs or a defined greater amount from the proceeds of production. Such arrangements in which parties bear disproportionate costs are often referred to as *promotes*. See chapter 2 of this guide for information regarding joint interest arrangements.

Limited Partnerships

1.60 Oil and gas operators may organize limited partnerships.[1] These legal entity partnerships are commonly called *oil and gas funds* or *oil and gas programs*. Limited partnerships may be 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. Limited partnerships are often 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.

1.61 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 entity analyzes the substance of the transaction and the details of the partnership agreement to determine the proper accounting treatment. Methods for special allocation of profits and costs for tax purposes may be inappropriate for financial reporting purposes.

1.62 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, 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 partnerships that are issuers, which are required to be prepared on the basis of U.S. GAAP.

Royalty Trusts

1.63 SEC *Codification of Staff Accounting Bulletins* Topic 12(E), "Financial Statements of Royalty Trusts," addresses the reporting requirements for royalty trusts, which file financial statements with the SEC. A royalty trust is typically created by a company conveying a net profits interest in certain of its oil and gas properties to the newly created trust. The trust then distributes trust units to its unitholders. The trust is a passive entity, which is prohibited from entering into or engaging in any business or commercial activity of any kind and from acquiring any oil and gas lease, royalty, or other mineral interest. The function of the trust is to serve as an agent to distribute the income from the net profits interest. The amount to be periodically distributed to the unitholders is defined in the trust agreement and is typically determined based on the cash received from the net profits interest less expenses of the trustee.

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[1] For guidance on earnings per unit calculations for master limited partnerships with incentive distribution rights, refer to the "Master Limited Partnerships" subsections of Financial Accounting Standards Board *Accounting Standards Codification* 260-10.

Royalty trusts typically report their earnings on the basis of cash distributions to unitholders. The net profits interest paid to the trust for any month is based on production from a preceding month; therefore, the method of accounting followed by the trust is different from the accrual accounting method that would have been followed by the creating company.

1.64 SEC *Codification of Staff Accounting Bulletins* Topic 12(E) states that the SEC staff will accept a statement of distributable income, which reflects the amounts to be distributed for the period under the terms of the trust agreement in lieu of a statement of income prepared under generally accepted accounting principles (GAAP). SEC *Codification of Staff Accounting Bulletins* Topic 12(E) further states that this position is due to the SEC staff's belief that the item of primary importance to the reader of the financial statements of the royalty trust is the amount of the cash distributions to the unitholders for the period reported. Should there be any change in the nature of the trust's operations due to revisions in the tax laws or other factors, the SEC staff's interpretation would be reexamined. In cases in which this presentation is used, a note to the financial statements should disclose the method used in determining distributable income and should also describe how distributable income, as reported, differs from income determined on the basis of GAAP.

Other Sources of Capital

1.65 Quite common are various forms of production payment and net profit interest transactions, whereby an investor advances funds to be repaid from future production. See the "Frequently Encountered Transactions for Transferring Mineral Interests" section in chapter 2 for further discussion of these types of arrangements.

History of Accounting for Oil and Gas Producing Activities

1.66 Two accounting methods are acceptable for use by oil and gas producers: the successful efforts method and the full cost method. The accounting requirements for these two methods are discussed in separate chapters of this guide. In addition, appendix A, "Summary of the Successful Efforts and Full Cost Methods of Accounting," of this guide provides a high level comparison of the two methods. The following discussion summarizes the development of U.S. GAAP for oil and gas entities.

1.67 Prior to the mid-1950s, most oil and gas entities 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 that became popular with small, newly formed entities because it allowed for the deferral of costs until successful exploration produced offsetting revenue. By 1970, almost half of the public oil and gas producing entities were using a form of the full cost method.

1.68 In 1969, the AICPA called for the elimination of the full cost method and recommended that the successful efforts method be the only acceptable method. The Accounting 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 disbanded in 1973 before the committee completed its charge.

1.69 In December 1977, FASB issued guidance that required a form of successful efforts accounting as the uniform method for all enterprises engaged in oil and gas producing activities.

1.70 The SEC called for public hearings in August 1978 before adopting FASB Statement No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies*, as the authoritative standard of accounting and reporting for oil and gas producing entities filing reports with the SEC. Because of the strong opposition voiced at those hearings, the SEC issued Accounting Series Release (ASR) No. 253, *Adoption of Requirements for Financial Accounting and Reporting Practices for Oil and Gas Producing Activities*. ASR No. 253

- adopted the form of successful efforts accounting and the disclosures prescribed by FASB.
- indicated the SEC's intention to develop a form of the full cost accounting method as an acceptable alternative for SEC reporting purposes (ASR No. 258, *Oil and Gas Producers—Full Cost Accounting Practices*).
- concluded that both the full cost and successful efforts methods of accounting, based on historical costs, fail to provide sufficient information on the financial position and operating results of oil and gas producing entities 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.)
- adopted rules that require financial statement disclosure of certain financial and operating data, regardless of the method of accounting followed.

1.71 In ASR No. 257, *Requirements for Financial Accounting and Reporting Practices for Oil and Gas Producing Activities*, and ASR No. 258, the SEC released its final rules for successful efforts and full cost accounting. As a result, entities under SEC jurisdiction could follow either the full cost method prescribed in Section 406.01.c of ASR No. 258 or the successful efforts method prescribed in Section 406.01.b of ASR No. 253, as modified by Section 406 of ASR No. 257, which is a method identical to that contained in FASB's guidance.

1.72 In response to the SEC's issuance of ASR No. 253, FASB issued additional guidance that suspended most of the provisions of its successful efforts accounting guidance for an indefinite period. However, some provisions of the successful efforts accounting guidance, including the accounting for deferred income taxes and some aspects of property conveyances and disclosure requirements, were retained and became effective. Thus, entities that report to the SEC may follow either accounting method. Nonpublic entities have no prescribed method of accounting for oil and gas producing entities. However, the Financial Reporting Executive Committee (FinREC) believes that nonpublic entities engaged in oil and gas producing activities should apply either the successful efforts method established by FASB or the full cost method established by the SEC because these are the only comprehensive methods of accounting developed for oil and gas producing entities. FinREC also recommends that any nonpublic entity that chooses to follow a method that varies from one of these methods should disclose in the notes to its financial statements any differences between the accounting policies it follows and those established by FASB or the SEC relating to oil and gas producing activities.

1.73 In November 1982, FASB issued guidance establishing disclosures to be made about oil and gas producing activities for publicly traded enterprises when presenting a complete set of annual financial statements. The SEC generally adopted these disclosure standards in Section 406.02 of Financial Reporting Release No. 9, *Supplemental Disclosures in Oil and Gas Producing Activities*.

1.74 The SEC reporting requirements contained in Final Rule No. 33-8995 revised the disclosure requirements for oil and gas reserves, in addition to changing the definition and requirements related to the determination of the quantities of oil and gas reserves. The SEC reporting requirements contained in Final Rule No. 33-8995 also changed certain accounting requirements under the full cost method of accounting for oil and gas activities. On January 6, 2010, FASB issued ASU No. 2010-03. ASU No. 2010-03 includes changes to accounting and disclosure requirements that are consistent with SEC Final Rule 33-8995.

1.75 For purposes of this guide, *successful efforts* refers to the accounting method specified in FASB ASC 932-360, and *full cost* refers to the accounting method specified in Rule 4-10(c) of Regulation S-X.

International Standards of Accounting for Oil and Gas

1.76 The International Accounting Standards Board (IASB) has established an accounting framework alternative that includes International Accounting Standards, International Financial Reporting Standards (IFRSs), and interpretations. The accounting framework established by the IASB does not have comprehensive accounting standards that would specifically address accounting for extractive industries, including oil and gas activities. IFRS 6, *Exploration for and Evaluation of Mineral Resources*, addresses accounting for the exploration stage of oil and gas and mining activities. Other operations and transactions related to oil and gas activities should follow the overall accounting framework established by the IASB. Further development of accounting standards under IFRSs is in progress. The IASB has initiated an extractive activities research project, which is expected to address the matters related to accounting and financial reporting of reserves and resources in the extractive industries, as well as other extractive industry accounting issues.

1.77 Currently, oil and gas companies preparing financial statements under IFRSs as issued by the IASB may adopt accounting policies different from those under U.S. GAAP as long as the accounting policies follow the overall accounting framework of the IFRSs.[2] However, entities that file reports with the SEC continue to provide disclosures required by FASB ASC 932-235-50. For further information, refer to the IASB website at www.iasb.org.

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[2] The Securities and Exchange Commission reporting requirements contained in Final Rule No. 33-8995, *Modernization of Oil and Gas Reporting*, revised Form 20-F to incorporate Subpart 1200 of Regulation S-K, with respect to oil and gas disclosures, and delete appendix A of item 4.D in Form 20-F (which previously required significantly less oil and gas reserves disclosure for foreign private issuers versus domestic filers).

Chapter 2

Primary Business Activities of the Industry

Acquisition of Mineral Interests

2.01 In the United States, the rights to minerals underlying private lands were initially held by the land surface owners. Ownership of both the surface and mineral rights in a tract is called a *fee interest in the property*. The federal government and state governments almost always possess title to all minerals underlying the surface acreages they own. Similarly, Indian tribes generally own the minerals underlying their lands. States bordering on the oceans and gulfs own mineral rights within specified distances from the shore, and those distances vary by state. The federal government owns the mineral rights beyond the offshore areas owned by the state governments and up to the international waters line.

2.02 An owner of the fee interest in a tract of land may sell all or part of the mineral rights but retain ownership of the surface. More commonly, the fee interest owner will sell the surface rights but retain ownership of the underlying minerals.

2.03 Most commonly, an oil and gas entity does not acquire a fee interest but acquires rights to drill wells and produce minerals through lease contracts, often referred to as *lease agreements*.

2.04 It is normal in oil and gas operations to have ownerships of individual properties and varying types of ownership interests. This variety of ownership interests has developed in response to the need to share risks, take advantage of tax opportunities, and raise the large amounts of necessary capital.

2.05 A lease contract grants a working interest in the property to the lessee. The lessee's rights and obligations include bearing most of the costs associated with drilling and equipping wells and producing the oil and gas that is found.

2.06 The working interest owner usually obtains a lease from a mineral rights owner(s), either through an in-house landman or an independent lease broker. The landman or broker researches public records to verify the legal owners of the mineral interest in the property and may obtain legal title opinions, although in some instances, the title work will not be performed until shortly before drilling commences. The landman or broker then finds the mineral owners and negotiates the lease terms on an individual basis with them. An upfront payment to the mineral owner made to obtain the lease is called a *lease bonus* and is discussed subsequently.

2.07 In some situations, the owner of the property will have sold the surface rights but retained ownership of the mineral rights. In these cases, the lessee initially negotiates with the mineral rights owner(s) and, at some point, also negotiates with the surface owner(s). Generally, the surface owner cannot prevent drilling and producing operations from being carried out on the property, although negotiations for drill sites, surface damages, and rights-of-way may be necessary. This may involve payments to the landowner for damages to property, use of areas needed for drilling and producing operations, and other negotiated issues.

2.08 Oil and gas 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, also are awarded by bidding. Leases on federally owned properties located onshore may be awarded through lease application systems with a standard fee.

2.09 As discussed in the subsequent section "Basic Concepts of Prospecting and Exploration Activities," some exploration activities may precede the acquisition of mineral rights.

Important Provisions in Lease Contracts

2.10 The most important provisions commonly found in oil and gas leases are explained briefly in the following paragraphs. A standard lease agreement, prepared by the American Association of Professional Landmen, is often adapted to fit particular circumstances. The provisions of oil and gas leases include important information relevant to the accounting for these arrangements.

2.11 The basic provisions in leases are generally similar, but each lease may contain unique provisions because the parties may add, delete, or modify provisions. These nonstandard provisions can have significant implications, particularly with respect to the payment of lease royalties to the lessor. Also, the parties may pool adjacent leases to form a tract large enough to cover a field or reservoir. In those cases, production from a single well may be subject to multiple leases with different terms.

2.12 *Lease bonus*. The *lease bonus* is the cash or other consideration paid to the lessor by the lessee in return for the lessor granting the lessee rights to explore for minerals, drill wells, and extract any minerals found. The bonus is normally computed on a per acre basis and may range from a few dollars per acre in *wildcat locations* (locations not near formations known to contain oil or gas deposits) to several thousand dollars per acre for locations near producing wells.

2.13 *Primary term and drilling obligation*. The maximum period of time allowed for the lessee to commence drilling a well on the property covered in the lease contract is referred to as the *primary term*, which is usually 2–5 years. The primary term of properties located in close proximity to producing wells may be as short as 1 year; however, the primary term of properties located in remote areas far from producing wells may be as long as 10 years. If drilling has not begun within the primary term, the lease contract automatically terminates unless the parties agree on an extension. The lessee usually has to make a specified payment to the lessor to keep the lease in force beyond the primary term.

2.14 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.

2.15 If the lessee wishes to retain a property for which the primary term is about to expire but on which drilling has not begun, an extension of the original lease may be agreed to by all 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 also may be taken by a third party in expectation of the expiration of the existing lease.

2.16 *Delay rentals*. The payment made to defer drilling activities for each additional year after the first year during the primary term is called a *delay rental*. The amount of the annual delay rental is much smaller than the lease bonus. Like the bonus, the farther from existing production the lease is located, the lower the delay rental. If delay rentals are not paid on or before the due date, the lease contract lapses.

2.17 *Fixed or mandatory rentals*. In addition to the usual delay rentals typically included in contracts, some contracts may include additional fixed or mandatory rental payments that are payable without regard to whether drilling has begun or production has been established. In effect, these payments are deferred bonuses paid on an installment basis.

2.18 *Lessor's royalty interest*. Typically, the lessor retains a royalty interest in the properties being leased. This entitles the lessor to receive, free and clear of all exploration, development, and production costs, a specified portion of the oil and gas produced (or, now more commonly, a specified portion of the value of such production) less (*a*) the related state severance or production taxes and (*b*) certain costs necessary to get the product into a marketable condition. Occasionally, the royalty interest may bear certain other specific costs. The royalty interest created by the lease contract is referred to as the *basic royalty interest*. Historically, the basic royalty interest has been one-eighth of the value of the mineral produced and sold, but it may vary. Many lease contracts on properties near producing areas now call for up to a one-fourth or greater basic royalty.

2.19 *Compensatory royalties*. The payment made by the lessees to royalty owners as compensation for lost income during periods when the entity has not fulfilled its drilling and production obligations (for example, failure to follow an agreed-upon development plan for the property or failure to drill an offset well within a specified time if a productive well is drilled within a specified distance on an adjoining property).

2.20 *Other costs related to development delays*. After mineral rights have been acquired through a lease, several years may elapse before drilling begins. Economic or market conditions may delay development. During that period, the lessee may have to pay specified expenses related to the property.

2.21 *Shut-in royalties*. Most lease contracts provide for *shut-in royalties*, which are payments by the operator to the royalty owner if a successful well has been drilled but production has not begun within a specified time after completion of the well. The lease contract also may call for shut-in royalties to be paid on producing wells from which production has been temporarily suspended. Shut-ins frequently occur on properties containing gas and may be caused by reduced prices, the absence of a market, working over the well, a lack of transportation, or the necessity to obtain permission from a governmental unit. Shut-in payments may or may not be recoverable by the operator out of royalties accruing to the royalty owner from production subsequent to the shut-in period.

2.22 *Guaranteed or minimum royalties*. For properties with a high probability of being productive, the mineral owner may be able to negotiate a specified minimum royalty payment each month or year for a specified period.

Guaranteed payments may or may not be subject to offset against future royalties payable to the royalty owner.

2.23 *Production holds lease*. Once a successful well has been drilled and commercial production has begun, the lease remains in effect for as long as there is production without extended and indefinite interruption. In some cases, the lease specifies that the production be commercial (profitable), but other leases are silent regarding commercial production. If production ceases, the operator acts in good faith to resume the extraction of oil or gas within a reasonable time, or the contract terminates. (Reasonable time may be specified in the lease contract.)

2.24 *Offset clause*. A common provision, called an *offset* or *drainage clause*, specifies that the lessee drill leaseline offset wells to prevent drainage of oil or gas to a nearby tract (usually adjoining) if a well is drilled within a specified distance of the boundary of the property involved in the lease. Often, the contract states that the offset well is necessary when a prudent operator would drill the offset well under similar circumstances.

2.25 *Surface damages*. Provisions are frequently incorporated in a mineral lease to define what damages to the surface overlying the minerals, resulting from drilling and production activities, are paid by the lessee and which damages are not reimbursable.

2.26 *Continuous drilling clause*. Once production has been established, some leases specify that additional wells be drilled within a certain time to continue to hold the remaining acreage under the lease that is not associated with the producing well.

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

2.28 The typical lease contract is likely to contain a variety of other provisions designed to identify the rights and obligations of the parties, based on the nature and peculiarities of the individual operating environment, such as limitations on drill site locations and the location of pipelines to remove produced oil and gas from the property.

Frequently Encountered Transactions for Transferring Mineral Interests

2.29 *Purchase or sale of working interest*. Oil and gas producers frequently purchase from other producers working interests in leases that may or may not have been developed. The acquisition may involve the sale and transfer to the purchaser of all rights and obligations of the original working interest owner for cash consideration. This transaction would be referred to simply as a *purchase and sale of the working interest*. The transaction would not affect the interests of the royalty holder.

2.30 In addition to outright sales or purchases of working interests, oil and gas producing entities frequently engage in transactions that involve all or part of the working interest in a property and also create nonoperating interests that may be retained by the entity or "carved out" of the working interest and transferred to the other party. Transactions of this type may be entered into as a means of financing drilling and development by the working interest owner.

2.31 A working interest in a property also may be purchased, subject to retention of an overriding royalty interest (ORRI) by the transferor. An ORRI is almost identical to a basic royalty interest, except it is "carved out" of the working interest created by the original lease. This transaction has no effect on the original lessor's royalty interest. Like a royalty interest, an ORRI bears little or no costs.

2.32 A *net revenue interest* (NRI) or *net profit interest* (NPI) is an interest in production created from the working interest and measured by a certain percentage of revenues or net profits (as defined in the contract) from the operations of the property.

2.33 An NRI owner is entitled to a specific share of production. The NRI may be different from the net working interest owned by the lessee. The NRI owner may or may not have any cost obligations.

2.34 An NPI owner is entitled to a specific share of profits from the property. It is particularly important that net profit and the costs used to calculate it are carefully defined in the contract. The costs may include both capital and operating costs. As in the case of overriding royalties, the NPI may be "carved out" of the working interest and transferred to another party or may result from the transfer of the working interest to a new owner, with the NPI being retained by the former working interest owner.

2.35 The sum of the interests in both revenue and costs will obviously total 100 percent. However, because the various royalty owners will often not share in the costs consistent with their share of revenues, the working interest owners will generally incur a greater share of the costs than revenue interests. This difference is often called the *lease burden*.

2.36 *Production payments*. A production payment entitles its owner to receive a specified fractional share of the working interest's share of gross production until a specified amount of production (called a *volumetric production payment* [VPP]) or a specified amount of cash has been recovered. Less frequently, the life of the production payment may be expressed in terms of a specified period of time. The production payment may be "carved out" of the working interest and "sold" separately, or it may be retained by the seller when the working interest is transferred to a new owner.

2.37 The terms *NRI*, *NPI*, and *VPP* are widely used by industry participants; however, they may have different meanings when applied to different contracts. The form and substance of these transactions are important to the determination of the proper accounting treatment. Depending on the terms, these transactions can be accounted for as loans, prepaid commodity sales, the sale of a mineral interest with revenue deferred, or an outright sale. No specific accounting guidance related to many of these types of agreements exists. However, the accounting for certain forms of these agreements is described in the "Conveyances" section of chapter 4, "Successful Efforts Method and General Accounting for Oil and Gas Activities."

2.38 A number of other contracts and special interests in the production from an oil and gas lease may be created, often as part of a plan to finance development activities. Some of the other contracts creating mineral interests are described throughout this guide.

Documents and Files Relating to Mineral Interests

2.39 The lessee usually maintains a prospect file or a lease (land) file, or both, for each property. These files include a copy of the lease contract, the survey or other legal description of the property, and the title opinions. As the prospect is developed, additional documents, such as authorizations for expenditures (AFEs), division orders to allocate revenue to the different interest owners, purchase contracts (if applicable), operating agreements, regulatory permits, and producer status certifications, are added to the lease file. This file is an important source of information for accountants and auditors.

2.40 *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. 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, assets, and liabilities. Liabilities are only several in nature. 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.

2.41 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 nonoperating parties and provides for billings, advance of funds, payment schedules, audits, and other matters. The accounting provisions in joint operating agreements usually follow a model provision devised by the Council of Petroleum Accountants Societies. 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.

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

2.43 Most large oil and gas entities, as well as many smaller entities, act as operators on a number of the oil and gas properties in which they have an interest. It is important to note, however, that nearly all entities will be nonoperators, with respect to a portion of their properties. In addition, the extent to which nonoperators take an active role in the operation of properties varies in practice. In many instances, the nonoperator maintains full accountability for activities on the properties, including advance authorization of capital expenditures through the AFE 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 may receive only a summary report of activity.

2.44 *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 nonoperators would be precluded from conducting a subsequent audit, and all transactions billed would be considered correct.

2.45 Joint interest audits are normally conducted by the nonoperators' internal auditors or independent auditors hired by the nonoperators. The purpose and, therefore, the scope of joint interest audits are significantly different from that of audits 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 no generally recognized joint interest audit standards are in existence.

2.46 *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. A regular *division order* is an agreement among the purchaser of production and all the various owners of interest in the property. This agreement includes (*a*) the legal description of the property; (*b*) the owners of interest in the property; (*c*) the interest owned by each; and (*d*) 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. By signing the division order, each owner represents ownership to be as stated, authorizes the purchaser to receive production from the property and 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.

2.47 In the event that an owner of an 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 a title opinion, execution of the division order, or litigation to resolve a dispute over ownership of an interest.

Basic Concepts of Prospecting and Exploration Activities

2.48 The purpose of geological and geophysical (G&G) exploration is to obtain information about subsurface geological conditions that can be used in assessing the probability that oil or gas exists in commercial quantities. Typically, this process involves first identifying large areas that have characteristics indicating that underground structures or stratigraphic variations that are conducive to the trapping of oil and gas exist. (This initial search for areas that warrant further exploration is often referred to as *prospecting*.)

2.49 The second step is to carry out detailed tests on areas identified in the broad survey as potentially containing mineral deposits to determine the likelihood that minerals exist in sufficient quantities to justify drilling. This more detailed work is referred to as *exploration*. For the sake of simplifying the discussion, both of these activities are frequently grouped together and called *exploration activities*.

2.50 *Geological exploration* involves scientific studies focused primarily on the earth's crust and examines the materials and life forms in the crust since its origin. Analysis of the chemical content of the earth's surface is a prime example of geological studies.

2.51 *Geophysical exploration* studies examine the earth's surface using quantitative and physical methods, such as seismography (bouncing sound waves off the surface and underlying strata and measuring the pattern and strength of their reflections in order to get a "picture" of the underlying minerals and formations).

Prospecting and Exploring for Potential Hydrocarbon-Bearing Structures

2.52 At one time, prospecting principally involved visible sightings of surface accumulations of oil that had seeped from the formations. Later, the primary technique used in locating potential petroleum-bearing structures in many areas was surface geological mapping to define the structural features expressed in the rock outcrops that indicated an oil and gas trap likely would be present in the subsurface.

2.53 Today, many methods are being used to carry out prospecting work on projects covering thousands of square miles, including aerial photography, plane-based imaging radar, satellite imaging radar, and U.S. government Landsat satellite infrared images. In addition, as discussed subsequently, various seismic methods are now widely used in prospecting and exploration activities.

2.54 Aerial photographs can be taken of large areas; however, aerial photography is very expensive, and the photographs do not always provide high quality pictures of the surface.

2.55 As the name suggests, plane-based imaging radar involves the transmission of high frequency electronic waves by a radar transmitter located in a plane. Similarly, satellite imaging involves high frequency electronic waves sent out by a radar transmitter located in a satellite. In both instances, the waves are reflected from the earth's surface, and some of them return to the radar receiver, resulting in an image of the topography of the area. The returned waves provide useful information, but the image resolution is low.

2.56 Oil and gas entities are now making wide use of the data provided by Landsat satellites owned and operated by the U.S. government. Landsat was designed for mapping and crop forecasting. It uses infrared transmission bands that permit geologists to identify various deposits frequently associated with mineral deposits and areas that likely do not have mineral deposits. The cost of data provided by Landsat is much less per square mile than the cost of aerial photography or imaging radar, and the data is easily obtained.

2.57 The examination of structures identified by prospecting utilizes many of the techniques and tools, especially seismic work, initially used in locating the structure. Seismic testing involves sending energy waves or sound waves into the earth and recording their reflections to indicate the type, size, shape, and depth of the subsurface rock. The use of seismic analysis has greatly increased the ability to assess the likelihood that a formation contains adequate recoverable hydrocarbons to be commercially recoverable and substantially reduced the percent of drilled wells that result in "dry holes."

2.58 Early seismic surveys utilized relatively wide spaced lines of data that were processed and used as two-dimensional cross sections of subsurface data. Advances in computer processing and memory storage in the 1980s allowed seismic data between the data points to be interpreted and manipulated so that a high resolution cross section could be generated anywhere within the seismic survey boundaries. Such three-dimension (3D) seismic allows entities to better understand the reservoirs and target the wells.

2.59 *Four dimension seismic* is a process in which subsequent 3D surveys are performed to track the movement of fluids in producing reservoirs. In some instances, the surveys are performed utilizing permanently located seismic receivers (geophones) above the reservoir. Four dimension seismic is a reservoir surveillance tool and is not applicable for exploratory drilling.

Other Significant Aspects of Exploration Activities

2.60 Some large entities maintain exploration departments or establish exploration subsidiaries that own or lease G&G equipment and employ exploration crews and scientists. Most entities, both large and small, contract with exploration and oil industry service entities to carry out their exploration.

2.61 In some cases, the entities may acquire nonproprietary seismic survey data from the service entities, which collect and process such data. The entities also may join together to collect data in the area that interests two or more of the entities.

2.62 If an outside contractor is used to perform exploration activities, the contract normally contains detailed provisions about (*a*) the area to be covered; (*b*) the nature of work to be performed; (*c*) the period in which the exploration is to be carried out; (*d*) the nature of reports to be made; and (*e*) rules for insuring security of data, as well as other provisions.

2.63 For control purposes, exploration is undertaken on a project basis. A *project area* is usually the maximum area that can be efficiently explored under a coordinated exploration program. This may involve a preliminary reconnaissance of the project area using magnetometers, gravitometers, aerial photography, and surface geology to define areas that look promising (leads) for oil and gas accumulations and for which more intensive exploration through seismic shooting or core drilling is justified. Detailed exploration is then conducted on the leads to determine more specific prospective areas for drilling (prospects).

2.64 Some exploration can be conducted without direct access to privately owned land surfaces. As previously observed, 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 public roads and railroads cut through hills. However, to gain access to private land, the operator secures permission from landowners. This transaction infrequently involves a rights to explore only contract, which permits the operator to conduct exploration on the property but does not provide for the subsequent leasing of acreage. Permission also may 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 agreement 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).

2.65 Holders of mineral properties may make payments to other operators who are drilling wells on nearby properties in exchange for the other operator providing geological data, including samples from wells it has 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 a specified depth. In other cases, the transaction involves a *dry hole contribution*, which is a contribution to be made only if the well being drilled does not produce commercial reserves. If the well is a producer, no contribution is made.

2.66 Basic G&G data, such as seismograph tests and aerial photographs of most areas of the United States, may be purchased at a relatively low cost. However, more detailed and current data is not as readily available from commercial sources.

Drilling and Development

2.67 Once the seismic, other data, or both have been analyzed and the leases acquired, the entity determines the exact spot for drilling. A well drilled to look for oil or gas in a strata not known to contain proved oil and gas reserves is called an *exploratory well*. 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*.

2.68 Before a well can be drilled, a drilling permit is obtained from the appropriate state or federal regulatory agency. Many political units, such as counties or cities, also may impose restrictions on drilling activities. Some typical procedures performed prior to drilling are as follows:

- Proof of financial assurance, involving either a bond from an insurance entity or letter of credit from a bank.
- Filing an application to drill, showing specific details of the location, goals of the well, lease name, plans to protect fresh water sources, and much more other detailed information.
- Providing the specific location of other wells (and perhaps other planned wells) in the area. Although spacing guidelines differ, a common spacing guideline is that no more than 1 well per 40 acres is allowed for oil wells, and no more than 1 well per 640 acres is allowed for gas wells.
- Payment of a drilling fee.

2.69 For offshore wells, even greater information is provided, especially information about environmental aspects (pollution control and environmental protection). Industry organizations, such as the American Petroleum Institute (API), accumulate and make available up-to-date information about governmental regulations. Readers may refer to the API website at www.api.org for additional information.

2.70 Although most wells drilled by oil and gas operators are intended to find and extract oil, gas, or both, some wells are drilled solely to obtain geological information (stratigraphic test wells) or to facilitate production from other wells (gas or water injection wells).

2.71 In the early years of the industry and into the 1930s, cable tool rigs were the dominant drilling equipment. Cable tool rigs used a pulley at the top of the derrick tower to repeatedly raise a heavy steel tool, which was then dropped, pounding a hole into the earth.

2.72 Since that time, rotary drilling has been, by far, the most prevalent method of drilling wells. *Rotary drilling*, as the name implies, involves the application of a rotating motion to a drill bit to bore a hole into the earth. Drilling fluid (mud) is continually circulated into and out of the hole during drilling to flush the cuttings from the hole as it is drilled, cool the bit, and control the subsurface pressures.

2.73 Although well bores are normally planned to be drilled vertically, it is often necessary or advantageous to drill at an angle, especially in offshore operations. Typically, the well is begun as a vertical well, but is subsequently deviated at an angle. Directional drilling makes it possible to drill a number of wells from the same surface location, but directional drilling also has other applications. Wells may be drilled from the shoreline and deflected to reach a reservoir offshore or when surface constraints (buildings, waterways, and the like) do not allow the placement of the rig. *Horizontal drilling* is a type of directional drilling in which the departure of the well bore from vertical exceeds 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

2.74 Entities that perform drilling operations (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.

2.75 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 drill only a few feet per day because of hard rock or other problems, the drilling contractor bears the economic risk.

2.76 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, and 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.

2.77 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 associated with drilling costs. Turnkey contracts usually specify completing a well to a certain point, such as to a casing point; to completion; to tanks; or the like.

Completing the Well or Plugging and Abandoning the Well

2.78 Once the well has been drilled to total depth, the operator and other working interest owners evaluate the evidence to determine whether the costs of completion can be justified. This decision point is often referred to as the *casing point*. Generally, the well will be completed if the expected revenues from that well and any other associated wells exceed the incremental completion costs and the expected operating expenses of the reserves to be recovered. If the well is deemed to not contain adequate reserves to more than cover the costs to complete the well and the future production costs, it will likely be declared a "dry hole" and will be abandoned.

2.79 If the well is abandoned, state laws and regulations usually specify that the operator remove any equipment, fill the hole or otherwise plug it, and clean up the drilling area. Reports are filed with the regulatory agency reporting the details of the abandonment work and environmental remediation carried out.

2.80 In completing the well, the first step, especially in wells with high formation pressures, is to set casing and cement it into the hole, sealing off the producing formation. Cement also is used to block off fresh water-bearing formations to protect them from contamination and also to prevent cave-ins. The next step is to perforate the casing and cement so the oil and gas in the formation can enter the well bore. This is typically done by lowering a perforation gun to the oil or gas-bearing formation and shooting bullets through the casing and cement. Also, projectiles may be fired through the casing and cement, or a jet or rocket charge may be used. Other techniques also are available. Depending on the permeability of the formation, it also may be necessary to fracture or acidize the formation to obtain the desired flow of oil and gas.

2.81 Completion of the well also involves the installation of equipment. The specific equipment installed depends on the nature of the well; whether oil or gas, or both, are produced; the availability of pipelines; and other factors. Natural gas is under high pressure and, thus, flows through the production tubing to the surface. Oil also may be under high pressure and, as a result, may flow to the surface without assistance. However, many oil wells do not have adequate pressure to force the oil to the surface, even at the time they are completed, so lifting pumps are installed. Almost all oil wells, even those that originally have high pressures, ultimately have lifting equipment installed as their natural pressure is reduced.

2.82 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 specify that wells be plugged, all facilities and equipment removed, and the terrain restored to specified conditions.

Developing the Reservoir

2.83 Normally, a single well is not sufficient to fully develop a reservoir. Additional wells usually increase the ultimate quantity of oil or gas that can be economically extracted from the reservoir. They also affect the timing of the extraction and, thus, the present value of the income stream. Although the presence of an oil and gas reservoir is established through the drilling of the discovery well, the discovery well may not establish whether the property has sufficient potential reserves to warrant the further expenditures necessary for complete development. Core samples, pressure tests, flow tests and rates, fluid analyses, and other geological data are used in deciding whether to continue with development of the reservoir.

2.84 Reservoir development also includes building platforms, laying gathering pipelines, installing processing plants, and completing interconnections to the main pipeline systems or tanks.

The Regulatory Environment

2.85 Various regulatory agencies issue regulations concerning well spacing limitations and 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 are 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 regulatory agency. If a well is completed, various types of information, including production, are 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. Outside the United States, the regulatory reporting environment may be significantly different.

Production

2.86 After a well is completed, the production phase begins. In the case of gas wells, the pressure in the reservoir is usually sufficient for the gas to expand into the well bore when the well is opened and flow to the surface. Oil wells, however, may initially be flowing wells, or they may need mechanical equipment that provides artificial lift to raise the oil to the surface.

2.87 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 (*a*) measure the oil's temperature, gravity, and volume; (*b*) drain off basic sediment and water (BS&W); and (*c*) run the oil from the tank into the pipeline. The well area normally has all the equipment necessary to separate oil, gas, and water, as well as 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 is 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.

2.88 At this point, the liquid is likely to contain a certain amount of water, which is removed before the oil is sold. The liquid may be heated by passing it through a continuous type of heater, known as a *heater-treater*, which heats the oil and water mixture and separates the water from the oil.

2.89 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. The bottom of the tank has a drain for draining the BS&W.

2.90 When the tank is full or at another predetermined time, the oil is delivered (run) 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 that only oil in a particular tank is entering the pipeline entity's lines.

2.91 The oil delivered is measured by gauging the height of the oil in the tank before and after delivery. The oil also is tested at this time to determine its gravity or density, temperature, and 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 are recorded on the run ticket and are used in converting to net barrels delivered. It is the responsibility of the lease operator to witness the gauging and testing of the oil done by the gauger and to be sure that the measurements are correct.

2.92 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 separation facilities at the lease to remove the liquids, which are similar to crude oil, before the gas is turned into the pipeline.

2.93 Settlement is usually made monthly for purchases of the oil and gas. The purchaser may be responsible for withholding production taxes or severance taxes or, alternatively, may need to obtain a withholding exemption certificate from the seller. Production tax and severance tax regulations vary from state to state. They may be based on the quantity of production, the value of production, or a combination of quantity and value.

Workovers

2.94 Occasionally, it is necessary to workover a well. *Workovers* are remedial operations that are sometimes necessary to maintain maximum oil producing rates. For example, when a well begins to produce an excessive amount of salt water, a workover rig, which is very similar to a drilling rig but somewhat smaller, is moved onto the well, and remedial operations are conducted.

2.95 As another example, when there is more than one producing interval in the well bore and a lower zone has been depleted, a plug-back (often referred to as a *recompletion*) to a higher zone is in order. The plug-back can be accomplished with a cement plug in the casing or a *bridge plug*, which is a mechanical device that can be set in the casing to effectively seal off the casing below the point at which the bridge plug is set.

Enhanced Recovery Methods

2.96 Primary oil production operations seldom recover more than half of the oil originally in place in a reservoir. *Primary recovery* is the production of oil resulting from the reservoir's natural drive mechanism (water, dissolved gas, gravity, or gas cap drive), which causes the reservoir contents to flow into the well bore. The fluids may move to the surface because of the reservoir pressure, or it may be necessary to use a pump to lift the oil to the surface. When production rates from primary recovery methods are no longer satisfactory, enhanced recovery techniques may be used to attain maximum production of the reserves, if reservoir characteristics and economics are favorable. *Enhanced recovery* is the production resulting from an artificial reservoir drive, such as water flooding, chemical injection, gas injection, enriched gas and miscible injection, *thermal stimulation* (heating the oil in the reservoir by injecting hot water or steam into the reservoir), or *in situ combustion* (injection of air and starting of a fire in the reservoir). All of these cause the reservoir contents to flow into the well bore. If the first artificial drive mechanism (called a *secondary recovery technique*) ceases to perform, one of the other methods may be used. The production resulting from the second (or subsequent) new driver mechanism is called *tertiary recovery*.

2.97 Many types of production stimulation techniques have been developed to enhance the recovery of hydrocarbons from the formations. Such techniques have allowed vast resources of previously uneconomical oil and gas to be produced. One of the most significant techniques used by the industry is fracturing. This technique involves pumping a mixture of fluid and sand down into the producing formation at pressures sufficient to actually crack, or fracture, the reservoir rock. The fluid carries the sand out into the fractures, and the sand-filled crack provides an easier path for oil and gas to flow back to the well bore. Although this fracture technique has been used by the industry for over 50 years, continual technological developments in the technique have resulted in more sophisticated and effective fracture treatments. Although some reservoirs do not respond well to such treatment, this technique is critical for many of the tight gas or unconventional reservoirs that are currently being drilled.

Chapter 3

Accounting for Common Oil and Gas Ownership Arrangements

Ownership Arrangements

3.01 The "Sources of Capital and Organizational Structure of Oil and Gas Entities" section of chapter 1, "Overview of the Industry," of this guide discusses the variety of ownership arrangements used by oil and gas producing entities to share risks and raise capital. The determination of the appropriate accounting method for these organizational structures can often be complex and involves determining whether consolidation, equity method accounting, cost basis accounting, or proportionate consolidation are applicable, based on the specific facts and circumstances. This chapter discusses various considerations related to some organizational structures commonly used in the industry and summarizes certain literature that is important to consider when assessing the accounting for these arrangements.

Ownership Arrangements—Mineral Interests

Undivided Interests

3.02 In the majority of arrangements, especially in the United States, ownership of oil and gas is through a *mineral interest*, which is an economic interest in underground minerals. Under these arrangements, each party holds an individual interest in the asset and is proportionately liable for any liabilities. Also, such arrangements do not involve a separate legal entity. As a result, these arrangements are accounted for following the concept of an undivided interest whereby each party reflects its proportionate share of the underlying assets, liabilities, revenues, and expenses. This type of accounting also is typically applied to arrangements in extractive activities (that is, exploration and production [E&P]) in which the ownership interest is in the form of an undivided interest, such as concessions, production sharing contracts, and similar arrangements, and no separate legal entity exists. The accounting treatment in these situations is as discussed in Financial Accounting Standards Board (FASB) *Accounting Standards Codification* (ASC) 323-30-25-1, FASB ASC 810-10-45-14, and FASB ASC 932-810-45-1.

Other Arrangements

3.03 When a separate entity has been formed to own the oil and gas activities, the evaluation about the appropriate accounting model may be more complex. An investor entity evaluates the accounting for ownership of an interest in an investee entity using different accounting literature than if it owned an undivided interest. When a separate entity exists, an investor entity should first determine that it is not required to consolidate the investee before applying another method of accounting for its investment (for example, equity method or cost method accounting). In evaluating whether to consolidate an investee, an investor should first apply the guidance in the "Variable Interest Entities" subsections of FASB ASC 810-10 (previously FASB Interpretation No. 46[R], *Consolidation of Variable Interest Entities [revised December 2003]—an* *interpretation of ARB No. 51*) to determine whether the entity is a variable interest entity (VIE). The guidance in the "Variable Interest Entities" subsections of FASB ASC 810-10 is applicable to any type of legal entity (for example, a corporation, limited liability company [LLC], or partnership).

3.04 If the investee is excluded from the scope of the "Variable Interest Entities" subsections of FASB ASC 810-10 or is determined not to be a VIE, then an evaluation should be performed using what is commonly referred to as the *voting interest model* to determine whether the investor has a controlling financial interest in the investee. The usual condition for a controlling financial interest under this model is ownership of a majority voting interest. The voting interest model is addressed in the "General" subsections of FASB ASC 810-10. Both of these models are discussed further subsequently.

Accounting Models

Variable Interest Model ("Variable Interest Entities" subsections of FASB ASC 810-10)

3.05 Under the variable interest model as prescribed by the "Variable Interest Entities" subsections of FASB ASC 810-10, an entity is considered a VIE if (1) the entity's equity is insufficient to permit the entity to finance its activities without additional subordinated financial support, (2) at-risk investors in the entity's accounting principles generally accepted in the United States of America equity do not control the entity through the power to direct the activities that most significantly impact the entity's economic performance or do not participate fully in the entity's economic risks and rewards, or (3) the entity was established with nonsubstantive voting interests.

If the entity is a VIE, a determination should be made regarding which party, if any, is the *primary beneficiary* (that is, the party that is required to consolidate the VIE). The primary beneficiary generally is the enterprise that has a variable interest or interests that provides the enterprise with both

a. the power to direct the activities that most significantly impact the VIE's economic performance and

b. the obligation to absorb losses of the VIE that could potentially be significant to the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE.

If an entity is determined not to be the primary beneficiary but holds a significant variable interest in a VIE, certain disclosures are required. If the entity is not a VIE, then the entity should be evaluated for consolidation under the voting interest model.

Voting Interest Model

3.06 Under the voting interest model, the type of entity will be one of the factors used to evaluate the appropriate literature to apply. Immediately following is a discussion of specific considerations related to LLCs and partnerships. Following that is a discussion of general guidance on the consolidation, equity, and cost methods. Numerous interpretations of accounting principles generally accepted in the United States of America (U.S. GAAP) may be relevant. Some of these are discussed subsequently. However, this discussion is a general overview, and all relevant authoritative literature should be considered in making these assessments.

Special Considerations

LLCs

3.07 LLCs have characteristics of both corporations and partnerships but are dissimilar to them in some respects. Paragraphs 3–4 of FASB ASC 272-10-05 provide guidance on the characteristics of an LLC that might indicate if the entity is akin to a corporation or partnership. An investment in an LLC that maintains a specific ownership account for each investor, similar to a partnership capital account structure, is viewed as similar to an investment in a limited partnership for purposes of applying the equity method accounting literature. Absent specific ownership accounts, an LLC is viewed as being similar to a corporation, whereas LLCs that have specific ownership accounts are considered similar to unincorporated entities for purposes of applying equity method guidance. For purposes of applying the consolidation accounting literature under the voting interest model, LLCs with governing provisions that are the functional equivalent of a limited partnership are evaluated in the same manner as limited partnerships, based on the provisions in FASB ASC 810-20. LLCs with governing provisions that are not the functional equivalent of a limited partnership are evaluated for consolidation in the same manner as corporations under the voting interest model.

Partnerships[1]

3.08 No authoritative literature broadly addresses the accounting for partnerships. In practice, the guidance primarily in FASB ASC 970-323 is applied by analogy to partnerships that are not real estate ventures.

3.09 The most common types of partnerships are general and limited partnerships. Both of these types of partnerships are defined in the FASB ASC glossary. FASB ASC 810-20 provides guidance to determine whether a general partner has control over a limited partnership. The general partner is presumed to have control and should consolidate a limited partnership, regardless of the extent of its ownership interest in the limited partnership unless the limited partners have either (*a*) the substantive ability to dissolve (liquidate) the limited partnership or otherwise remove the general partner without cause, or (*b*) substantive participating rights.

3.10 According to the FASB ASC glossary, the rights underlying the limited partners' ability to dissolve (liquidate) the limited partnership or otherwise remove the general partners are collectively referred to as *kick-out rights*.

3.11 The characteristics of substantive kick-out rights generally include the rights that can be exercised by a limited partner or a vote of a simple majority of the limited partners and the ability of the limited partners to exercise those rights if they choose to do so (that is, no significant barriers to exercise the rights exist). The substantive participating rights referred to in the preceding paragraph generally refer to the limited partners' ability to effectively participate in significant decisions that would be expected to be made in the ordinary course of the limited partnership's business. Each of the matters is discussed in more detail in FASB ASC 810-20. Note that the analysis of how

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[1] For guidance on earnings per unit calculations for master limited partnerships with incentive distribution rights, refer to the "Master Limited Partnerships" subsections of Financial Accounting Standards Board (FASB) *Accounting Standards Codification* (ASC) 260-10.

kick-out rights and participating rights affect the primary beneficiary analysis under the "Variable Interest Entities" subsections of FASB ASC 810-10 differs from the analysis of whether the presumption of control by the general partner of a limited partnership is overcome by the existence of kick-out rights or participating rights under the guidance applicable to entities other than VIEs in FASB ASC 810, *Consolidation*.

3.12 In many instances, especially in many oil and gas master limited partnerships, the presumption of control by the general partner is not overcome. As a result, in those cases, the general partner should consolidate the limited partnership under the voting interest model. However, if the limited partners have substantive kick-out rights or substantive participating rights, as previously described, the general partner should account for its investment in the limited partnership using the equity method of accounting. This guidance does not apply to entities that are VIEs under the "Variable Interest Entities" subsections of FASB ASC 810-10. FASB ASC 323-30-25-1, FASB ASC 810-10-45-14, and FASB ASC 932-810-45-1 provide accounting guidance for certain partnerships accounted for under the equity method, as discussed subsequently.

General Guidance on the Consolidation, Equity, and Cost Methods

Consolidation Method

3.13 If the investee is not covered by the guidance in the "Variable Interest Entities" subsections of FASB ASC 810-10, the investor in the entity should evaluate whether it controls the entity based on voting interests. The following discussion provides general guidance on the application of the consolidation, equity, and cost methods for oil and gas producing entities. Certain special considerations related to these methods for LLCs and partnerships are discussed in the previous section.

3.14 Consolidation principles included in the "General" subsections of FASB ASC 810-10 should be referred to in making the assessment. The usual condition for a controlling financial interest is ownership of over 50 percent of the outstanding voting shares. *Control* is defined in Section 210.1-02(g) of Regulation S-X as "the possession, direct or indirect, of the power to direct or cause the direction of the management and policies of a person, whether through the ownership of voting shares, by contract, or otherwise." The concept of having control by contract or otherwise also is discussed in the "Consolidation of Entities Controlled by Contract" subsections of FASB ASC 810-10. Note that arrangements within the scope of the "Consolidation of Entities Controlled by Contract" subsections of FASB ASC 810-10 are usually evaluated for consolidation under the variable interest model because the arrangement causes the at-risk investors in the entity's U.S. GAAP equity to lack the ability through their equity interests to control the entity or participate fully in the entity's economic risks and rewards.

3.15 When evaluating whether consolidation is appropriate, the investor who holds the majority voting interest also needs to determine whether the rights of the other owners are of the level that prohibits the control by such investor. This guidance is provided in FASB ASC 810-10-15 and FASB ASC 810-10-25, which provides a framework to evaluate whether the minority shareholder has protective or participating rights. Generally, participating rights held by the minority shareholder give the minority shareholder the right to participate in decisions that occur as part of the ordinary course of the investee's business and are significant factors in directing and carrying out the activities of the business. Specifically, the majority shareholder must have the minority shareholder's approval to take certain actions. If the majority shareholder concludes that the minority shareholder has substantive participating rights, the majority shareholder should not consolidate. Clearly, this evaluation should be based on the specific facts and circumstances.

Equity Method

3.16 If the investor is not required to consolidate the investee under either the variable interest or voting interest consolidation models, then the investor should evaluate whether equity method or cost method accounting is appropriate. Equity method accounting is described in FASB ASC 323, *Investments—Equity Method and Joint Ventures*. The general condition for equity method accounting is that the investor has the ability to exercise significant influence over the operating and financial policies of the investee. FASB ASC 323-30 provides guidance on accounting for investments in unincorporated entities.

3.17 Pro rata consolidation often is used for investments in unincorporated entities if the entity is involved in only extractive activities. FASB ASC 323-30-25-1, FASB ASC 810-10-45-14, and FASB ASC 932-810-45-1 provide guidance on accounting for an investment in an unincorporated entity that does not meet the criteria for consolidation. This guidance states that a proportionate gross financial statement presentation (commonly referred to as *pro rata consolidation*) is appropriate for an investment in an unincorporated legal entity accounted for under the equity method only if the investee is in either the construction industry or an extractive industry. For purposes of this guidance, an investee is in an extractive industry only if its activities are limited to the extraction of mineral resources (such as oil and gas E&P) and do not involve related activities, such as refining, marketing, or transporting extracted mineral resources. Accordingly, if the investee has activities other than E&P, the investor does not follow pro rata consolidation. Investments in a corporation or an LLC functioning like a corporation are not presented using pro rata consolidation under the guidance in FASB ASC 323-30-25-1, FASB ASC 810-10-45-14, and FASB ASC 932-810-45-1.

3.18 For investments in corporate entities, an investor typically looks to the rights inherent in the common stock ownership. Paragraphs 1–19 of FASB ASC 323-10-15 provide accounting guidance for investors when determining whether to apply the equity method of accounting, including the definition of *significant influence*, which is provided in paragraphs 6–11.

3.19 The FASB ASC glossary defines *in-substance common stock* as an investment in an entity that has risk and reward characteristics that are substantially similar to that entity's common stock. In making this determination, an investor should perform a qualitative analysis considering three characteristics: subordination, risks and rewards of ownership, and obligation to transfer value. Each of these characteristics is discussed in more detail in FASB ASC 323-10-15-13.

3.20 FASB ASC 323-10-15-8 indicates that there is a presumption that, in the absence of predominant evidence to the contrary, the investor in a corporation has the ability to exercise significant influence over an investee when it owns (directly or indirectly) 20 percent or more of the voting stock of the investee. However, FASB ASC 323-10-15-6 indicates that it is possible for an investor to have the ability to exercise significant influence even in situations in which ownership in a corporation is below 20 percent, such as through representation on the board of directors; by participation in policy making processes of the investee; by material intraentity transactions; by interchange of managerial personnel; or in other ways, such as technological dependence. FASB ASC 323-10-15-10 sets forth indicators, which are not all-inclusive, of situations in which an investor may be unable to exercise significant influence over the operating and financial policies of the investee. FASB ASC 323-10-15-10 also indicates that when evaluating whether equity method accounting is appropriate, all facts and circumstances should be evaluated.

3.21 The equity method of accounting also may apply to, among other investments, an investment in a limited partnership (including an LLC functioning as a limited partnership). In the Securities and Exchange Commission (SEC) Staff Announcement "Accounting for Limited Partnership Investments,"[2] the SEC staff indicated that the guidance provided in Statement of Position 78-9, *Accounting for Investments in Real Estate Ventures* (which has been codified primarily in FASB ASC 970-323), should be applied to ownership interests in all limited partnerships, regardless of whether such partnerships are involved in real estate ventures. Accordingly, under this guidance, a limited partner investor should use the equity method unless the investment is so minor (that is, no more than a 3 percent to 5 percent interest in the partnership) that the limited partner may have virtually no influence over the partnership operating and financial policies. The Financial Reporting Executive Committee believes that this guidance also is appropriate for investors that are not SEC registrants.

Cost Method

3.22 If the investor concludes that consolidation of the investee is not required under either the variable interest or voting interest consolidation models and the investor is not required to apply the equity method of accounting, the cost method, for which accounting guidance is provided in FASB ASC 325-20 should be used unless it is determined that the investment should be accounted for under FASB ASC 320, *Investments—Debt and Equity Securities*, or the "Fair Value Option" subsections of FASB ASC 825, *Financial Instruments*.

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[2] Securities and Exchange Commission (SEC) Staff Announcement "Accounting for Limited Partnership Investments" is codified in FASB ASC 323-30-S99-1. This authoritative document, issued by the SEC, is included for reference in FASB ASC to increase the utility of FASB ASC for public companies. Readers should consult FASB's notice to constituents for important discussion about standards issued by the SEC that have been included in FASB ASC. Readers should also consult the SEC's interpretive guidance *Commission Guidance Regarding the Financial Accounting Standards Board's Accounting Standards Codification* at www.sec.gov/rules/interp/2009/33-9062a.pdf.

Chapter 4

Successful Efforts Method and General Accounting for Oil and Gas Activities

General

4.01 Successful efforts and full cost are the two basic methods of accounting for oil and gas exploration and producing activities. Normally, an entity with significant acquisition and exploratory activities will incur geological and geophysical (G&G) costs and costs to drill exploratory wells. Under the successful efforts method, acquisition costs are capitalized. Exploration costs, such as G&G costs and costs of unsuccessful exploratory wells (dry holes), as well as delay rentals, are expensed. The costs of drilling development wells, including unsuccessful development wells, are capitalized. Under the full cost method, all of these costs are capitalized and charged to expense through depletion as the oil and gas in the cost center is produced. Thus, successful efforts entities tend to have lower earnings and equity in their early stages and relatively lower charges to depreciation, depletion, and amortization (DD&A) in later periods. Conversely, under similar circumstances, the full cost method will generally provide higher earnings and equity initially, with higher DD&A charges in future periods. It is evident that the accounting method chosen can substantially influence the financial position and income statements of an oil and gas exploration and production (E&P) entity.

4.02 The successful efforts method is prescribed by the Financial Accounting Standards Board (FASB) and is set forth in FASB *Accounting Standards Codification* (ASC) 932, *Extractive Activities—Oil and Gas*.

4.03 Successful efforts accounting generally provides the following:

- 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.
- Exploration costs, other than exploration drilling costs, should be charged to expense when incurred. These costs include G&G costs, costs of carrying and retaining unproved properties, and dry hole and bottom hole contributions.
- 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.
- The costs of drilling development wells, including unsuccessful development wells, should be capitalized.
- Internal acquisition, development, and exploration costs may be capitalized if directly related to acquisition, development, or exploration activities that are capitalizable under the successful efforts method. Indirect internal costs should be expensed.

- Production (or lifting) costs, together with the amortization of the capitalized acquisition, exploration, and development costs, become the cost of oil and gas produced.
- Capitalized costs are accumulated on a property-by-property basis or on the basis of some reasonable aggregation of properties with a common geological structural feature or stratigraphic condition, such as a field or reservoir.
- Capitalized acquisition costs associated with proved properties should be amortized on the unit of production method using total proved oil and gas reserves. Exploration and development costs that qualify for capitalization should be amortized on the unit of production method using proved developed oil and gas reserves.
- Capitalized costs for unproved properties are subject to an impairment test, as set forth in FASB ASC 932-360-35. Capitalized costs for proved properties are tested for impairment, as set forth in paragraphs 15–49 of FASB ASC 360-10-35.
- In accordance with FASB ASC 410, *Asset Retirement and Environmental Obligations*, asset retirement costs recorded upon initial recognition of an asset retirement obligation (ARO) become part of the carrying amount of the related oil and gas property and are amortized using a systematic and rational method over the useful life of the property. Asset retirement costs are typically associated with development costs and, accordingly, would be amortized using the unit of production method over proved developed oil and gas reserves.

4.04 Rule 4-10 of the Securities and Exchange Commission's (SEC's) Regulation S-X establishes the requirement for public entities to follow either the form of successful efforts method of accounting set forth in FASB Statement No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies* (which has been codified in FASB ASC 932), or the full cost method of accounting set forth in Rule 4-10(c) of Regulation S-X.

4.05 FASB ASC 932-360-25 expresses a preference for the successful efforts method. Therefore, a change from full cost to successful efforts is generally considered to be preferable. For companies subject to the filing requirements of the SEC, a change from the successful efforts method to the full cost method requires justification of the change and that the company's independent accountants file a preferability letter with the SEC.

4.06 Therefore, nonpublic entities are not required to follow either the successful efforts method or the full cost method of accounting. However, the Financial Reporting Executive Committee (FinREC) of the AICPA believes that nonpublic entities engaged in oil and gas producing activities should apply either the successful efforts method set forth in FASB ASC 932 or the full cost method set forth in Rule 4-10(c) of Regulation S-X because these are the only two comprehensive methods of accounting developed for oil and gas producing entities. FinREC also believes that any nonpublic entity that chooses to follow a method that varies from one of these two methods should disclose in the notes to its financial statements any differences between the accounting policies it follows and those established by FASB or the SEC relating to oil and gas producing activities.

4.07 A nonpublic entity that previously applied an alternative accounting method should apply FASB ASC 250, *Accounting Changes and Error Corrections*, if it changes its method of accounting to a preferable method for oil and gas activities, as established by either FASB or the SEC.

4.08 This chapter primarily addresses the successful efforts method provided in FASB ASC 932. Certain sections of this chapter (generally beginning with the "Accounting for Production" section) address other accounting guidance that is applicable to entities applying the successful efforts method and critical to oil and gas producing entities. Much of the guidance in these areas also is applicable to entities applying the full cost method. However, chapter 5, "Full Cost Method of Accounting for Oil and Gas Activities," provides additional guidance that is specific to the full cost method.

Accounting for Acquisition, Exploration, and Development Costs

Acquisition Costs

4.09 Acquisition costs associated with the acquisition of leases[1] are capitalized when incurred. These consist of costs incurred in obtaining a mineral interest or right in a property, such as a lease, concession, license, production sharing agreement, or other type of agreement granting such rights. In addition, options to lease, brokers' fees, recording fees, legal costs, and other similar costs related to activities in acquiring property interests are capitalized.

Exploration Costs

4.10 Exploration costs incurred in G&G activities are commonly referred to as *G&G costs*. G&G costs include costs of topographical and G&G 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 unproved properties, dry hole and bottom hole contributions, costs of drilling and equipping exploratory wells, and costs of drilling exploratory-type stratigraphic test wells.

4.11 G&G costs incurred in exploratory activities; costs of carrying and retaining unproved properties, such as delay rentals, ad valorem taxes on unproved properties, legal costs for title defense, and 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 has found proved reserves. If it is determined the well has not found proved reserves, the capitalized costs, net of any salvage value, are charged to expense.

4.12 FASB ASC 932-360-25-18 sets forth certain indicators (discussed in the following paragraphs) to consider when evaluating whether suspended exploratory well costs should continue to be capitalized and stipulates the required financial statement disclosures for suspended exploratory well costs.

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[1] Oil and gas leases are not included in the scope of Financial Accounting Standards Board (FASB) *Accounting Standards Codification* (ASC) 840, *Leases*. FASB ASC 840-10-15-15 indicates that "[t]his Topic does not apply to lease agreements concerning the rights to explore for or to exploit natural resources such as oil, gas, minerals, timber, precious metals, or other natural resources."

4.13 All costs related to drilling an exploratory well are capitalized pending determination of whether the well has found proved reserves.

4.14 In some cases, according to FASB ASC 932-360-35-18, an exploratory well or an exploratory-type stratigraphic test well may have found reserves, but those reserves cannot be classified as proved when drilling is completed. Costs related to these wells are referred to as *suspended well costs*. In those cases, FASB ASC 932-360-35-18 also states that the capitalized drilling costs should continue to be capitalized when (1) the well has found a sufficient quantity of reserves to justify its completion as a producing well, and (2) the entity is making sufficient progress assessing the reserves and the economic and operating viability of the project.

4.15 If either of the preceding criteria is not met, the exploratory well or exploratory-type stratigraphic test well is assumed impaired, and its cost, net of any salvage value, is charged to expense.

4.16 According to FASB ASC 932-360-35-19, long delays in the assessment or development plan (whether anticipated or unexpected) may raise doubts about whether an entity is making sufficient progress to continue the capitalization of costs related to an exploratory well or exploratory-type stratigraphic test well. FASB ASC 932-360-35-20 indicates that if an entity has not engaged in substantial activities to assess the reserves or the development of the project in a reasonable period of time after the drilling of the well is completed or activities have been suspended, any capitalized costs associated with that well should be expensed, net of any salvage value. After a reasonable period of time, the planning of future activities without engaging in substantial activities is not sufficient to continue the capitalization of exploratory well or exploratory-type stratigraphic test well costs. However, brief interruptions in the activities necessary to assess the reserves or the project or other delays resulting from governmental or other third party evaluation of a proposed project, do not require capitalized exploratory well or exploratory-type stratigraphic test well costs to be expensed.

4.17 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 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, in accordance with FASB ASC 932-360-40-10.

Development Costs

4.18 Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering, and storing the oil and gas are capitalized. All costs incurred to drill and equip development wells, development-type stratigraphic test wells, and service wells are development costs and are capitalized, whether the well is successful or dry.

4.19 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.

4.20 FASB ASC 932-720-25-1 discusses certain exploration costs that are to be expensed as incurred. Included in these costs are G&G costs incurred in exploration activities. FASB ASC 932 does not address G&G costs in the context of development activities.

4.21 However, in recent years, entities have begun to use G&G methods to perform functions related to the development of oil and gas properties, such as the determination of the location for development wells. As a result, these entities have assessed the appropriate treatment of these costs.

4.22 According to FASB ASC 932-360-25-13, *development costs* include costs to "prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites."

4.23 Oil and gas entities generally consider G&G costs incurred related to activities that are consistent with the definition of *development costs* and specific to a proved property, to be development costs that are capitalized under FASB ASC 932. In some cases, G&G activities, such as seismic shoots, may cover an area larger than the area that has been determined to be proved. If so, only the costs related to the area covered by proved reserves should be treated as development costs, with the remainder treated as exploratory G&G.

Interest Capitalization

4.24 Capitalized costs of each property represent the company's assets. Drilling and development costs and leasehold costs represent qualifying assets for the purposes of applying FASB ASC 835-20. Interest costs should be capitalized, provided activities that are necessary to get the asset ready for its intended use are in progress. When a property is ready for production to commence, the capitalized costs of that property are considered to be in the earnings activities of the entity and are no longer assets qualifying for interest capitalization. Capitalized interest is attached to the qualifying costs on which the interest was computed and is amortized or tested for impairment in the same manner as those costs.

Amortization of Capitalized Costs

4.25 Capitalized costs are accumulated on a property-by-property basis or on the basis of some reasonable aggregation of properties with a common geological structural feature or stratigraphic condition, such as a field or reservoir. The accumulated costs of the cost center then provide a means whereby capitalized costs can be collected and amortized.

4.26 Under successful efforts accounting, DD&A is based on the unit of production method in which (*a*) amortization of acquisition costs of proved properties is based on total estimated units of proved (both developed and undeveloped) reserves, and (*b*) amortization of all other costs generally is based on total estimated units of proved developed reserves. Depreciation, as well as operating costs of support equipment and facilities used in oil and gas producing operations, should be classified as exploration, development, or production costs, based on the nature or use of such equipment and facilities. In some cases, support equipment and facilities provide service to more than one field and may be depreciated on a straight line method rather than the unit of production method.

4.27 The amortization rate is computed using current period production divided by reserves at the beginning of the period. Often, beginning of the period reserves are determined by adding reserves estimated at the end of the period to current period production. Unit of production amortization rates are revised at least once a year or more often if there is an indication of the need for revision. Changes in amortization rates are made prospectively as changes in estimates. For entities subject to the reporting requirements of the SEC, when reserve quantities are revised, the SEC staff will not object to reflecting the revision as of the beginning of the quarter that has not been reported, for purposes of calculating DD&A. However, taking the reserve revisions back to earlier quarters that have already been reported is not appropriate. Companies should treat this as a policy election, which should be consistently applied.

4.28 Future development costs are not considered when computing the DD&A rate under successful efforts accounting.

4.29 If significant development costs (such as for 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 these development costs in determining the DD&A rate until the additional development wells have been drilled. Similarly, it is appropriate to exclude the proved developed reserves produced only after significant additional development costs are incurred (such as for improved recovery systems) in computing the DD&A rate.

4.30 Estimated residual salvage values should be taken into account in determining the DD&A rate.

4.31 When a property contains both oil and gas reserves, the units of oil and gas used to compute DD&A are converted to a common unit of measure on the basis of their relative energy content (commonly six thousand cubic feet of gas for one barrel of oil) unless (*a*) 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 (*b*) if oil or gas clearly dominates both the reserves and current production, in which case the DD&A rate may be computed on the basis of the dominant mineral only.

Impairment Tests for Capitalized Costs

4.32 Separate impairment tests should be performed for unproved properties, pursuant to FASB ASC 932, and proved properties, pursuant to the "Impairment or Disposal of Long-Lived Assets" subsections of FASB ASC 360-10.

Unproved Properties

4.33 Unproved properties are assessed periodically to determine whether they have been impaired. A property may be considered impaired if, for example, a dry hole has been drilled on a portion of the lease or in close proximity, and the entity has no intention of further drilling on the property. Also, as the expiration of the lease term approaches and the entity has not begun drilling on the property or nearby properties, the possibility of partial or total impairment of the property increases.

4.34 If a property is found to be impaired, an impairment allowance is provided, and a loss is recognized in the income statement. For entities subject to the reporting requirements of the SEC, the SEC has indicated "[i]f future net cash flows are used to evaluate unproved properties for impairment, registrants should risk adjust any unproved (sometimes referred to as probable or possible) reserves *before* estimating future cash flows associated with those resources."[2]

4.35 Individually significant unproved properties are assessed for impairment on a property-by-property basis. The provision for impairment for individually insignificant unproved properties may be determined by amortizing those properties in the aggregate, or by groups, on the basis of the entity's experience 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.

4.36 Properties are classified as unproved until proved reserves are discovered on the property. For properties that have been impaired on an individual basis, the net amount (acquisition cost minus any valuation allowance) is reclassified to a proved property classification if the property is later determined to have proved reserves. For properties that have been impaired on a group basis, the gross acquisition cost is reclassified to the proved classification.

4.37 For properties assessed on either an individual or aggregate basis, if the property is surrendered or the lease expires without identifying proved reserves, the cost of the property is charged against the impairment allowance to the extent impairment has been recognized. Any remaining cost is charged to the income statement.

Proved Properties

4.38 The "Impairment or Disposal of Long-Lived Assets" subsections of FASB ASC 360-10 address financial accounting and reporting for the impairment of long-lived assets and long-lived assets to be disposed, including (for entities following the successful efforts method) the costs of an entity's wells and related equipment and facilities and the costs of the related proved properties. FASB ASC 360-10-35-21 indicates that a long-lived asset (asset group) to be held and used by an entity should be tested for recoverability whenever events or changes in circumstances indicate that the carrying amount of the asset may not be recoverable.

4.39 The FASB ASC glossary defines *impairment* as the condition that exists when the carrying amount of a long-lived asset (asset group) exceeds its fair value. According to FASB ASC 360-10-35-17, 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. The carrying amount of a long-lived asset (asset group) to be held and used is not recoverable if it exceeds the sum of the undiscounted net cash flows expected to result from the use and eventual disposition of the asset (asset group). That assessment should be based on the carrying amount of the asset (asset group) at the date it is tested for recoverability. An impairment loss should be measured as the amount by which the carrying amount of a long-lived asset (asset group) exceeds its fair value.

4.40 Typically, the evaluation of oil and gas producing properties is on a field-by-field basis or by a logical grouping of assets if a significant shared infrastructure (for example, a platform) exists. The undiscounted net future

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[2] Securities and Exchange Commission (SEC) *Division of Corporation Finance: Frequently Requested Accounting and Financial Reporting Interpretations and Guidance* issued March 31, 2001.

cash flows (cash inflows less associated cash outflows) are based on total proved and risk adjusted probable and possible reserves, which are based on economic producibility using management's best estimate of prices and costs. Future prices should be in nominal dollars (adjusted for expected inflation) and should reflect management's best estimates. Future cost projections should include future capital expenditures and development and operating costs.

4.41 The estimated future cash flows associated with settling AROs that have been accrued on the balance sheet are excluded from the cash flows used to test the asset for recoverability because the estimated asset retirement cost has already been included in the related asset balance. The exclusion of the cash outflows in the cash flow calculation avoids "double counting" this cost in the determination of an impairment.

Conveyances

4.42 The oil and gas industry is capital intensive and usually associated with considerable risks. These characteristics, along with the depleting, nonregenerative nature of its most significant asset—hydrocarbon reserves—require entities to continually expand their exploration efforts and capital commitments. Oil and gas entities desiring to spread the risks and generate the funds necessary to explore and develop properties 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 interests, 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.

4.43 Mineral property conveyances and related transactions should be recorded based on the substance of the transactions, such as sales, borrowings, exchanges of nonmonetary assets, poolings of assets in joint undertakings, or some combination thereof. Because the types of conveyances vary widely, are generally complex, and often do not fit exactly within the accounting literature, a thorough understanding of the transaction is necessary to reach a proper conclusion. In addition, the form of conveyance may have significant tax consequences.

4.44 According to FASB ASC 810-10-40-3A, the deconsolidation and derecognition guidance in FASB ASC 810-10-40 does not apply to a subsidiary that is a business if it is a conveyance of oil and gas mineral rights. For guidance on conveyances of oil and gas mineral rights and related transactions, entities should refer to FASB ASC 932-360.

4.45 FASB ASC 932-360-40, FASB ASC 932-470-25, and FASB ASC 932-360-55 provide guidance on conveyances and other types of similar transactions.

4.46 FASB ASC 932-360-40-9 provides that gain or loss should be recognized if a conveyance is not one of the types described in paragraphs 7–8 of FASB ASC 932-360-40, unless there are other aspects of the transaction that would prohibit such recognition under accounting principles applicable to entities in general. Paragraphs 8–14 of FASB ASC 932-360-55 provide specific accounting guidance for certain forms of conveyance transactions for which gain recognition is prohibited.

4.47 FASB ASC 932-360-40-7 provides that no gain or loss should be recognized at the time of the conveyance 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.

4.48 Furthermore, according to FASB ASC 932-360-40-8, no gain should be recognized at the time of the conveyance of part of an interest owned if (*a*) substantial uncertainty exists about recovery of the costs applicable to the retained interest, or (*b*) the seller has a substantial obligation for future performance, such as an obligation to drill a well or operate the property, without proportional reimbursement for that portion of the drilling or operating costs applicable to the interest sold.

4.49 FASB ASC 932-470-25-1 states that certain types of conveyance transactions are, in substance, borrowings repayable in cash or its equivalent and should be accounted for as borrowings. These transactions are commonly referred to as *production payments*, and examples are provided in FASB ASC 932-360-55.

4.50 In another type of production payment that is discussed in FASB ASC 932-360-55-2, the seller's obligation is not expressed in monetary terms but rather as an obligation to deliver to the purchaser, free and clear of operating expenses, a specified quantity of oil or gas from a specified share of future production. FASB ASC 932-360-55-2 further states that this type of production payment arrangement should be accounted for as a sale of a mineral interest for which gain should not be recognized because the seller has a substantial obligation for future performance. The seller should account for the funds received as unearned revenue to be recognized as the oil or gas is delivered.

4.51 Entities that enter into volumetric production payments also should consider the guidance in paragraphs 15–24 of FASB ASC 815-15-55, which provides guidance on volumetric production payments for which the quantity of the commodity that will be delivered is reliably determinable.

Accounting for Production

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

Revenue

4.53 Revenue from sales of oil and gas should be recognized when title passes to the customers, the price is determinable, and collectability is reasonably assured. Revenues are recorded net of royalties, discounts, and allowances, as applicable. For convenience, some entities record revenue on a cash basis throughout the period, which requires an accrual adjustment at the end of the period under accounting principles generally accepted in the United States of America.

4.54 In the oil and gas industry, taxes are assessed by various governmental authorities and include sales, use, excise, and value added taxes. The characteristics of how these different types of taxes are calculated, remitted to the governmental authority, and administered are numerous and varied.

4.55 As discussed in paragraphs 3–4 of FASB ASC 605-45-50, the presentation of taxes in the income statement can be reflected on either a gross basis (included in revenues and costs) or a net basis (netted against revenues). The determination of presentation is an accounting policy decision that should be disclosed in the financial statements. In addition, for any such taxes reported on a gross basis, the entity should disclose the amounts, if significant. In addition, for SEC reporting companies, Rule 5-03 of Regulation S-X requires that the amount of excise taxes be shown on the face of the income statement (parenthetically or otherwise) if such taxes are included in revenues and are equal to 1 percent or more of the total.

4.56 Producers of oil and gas usually incur gathering, shipping, and handling costs from the production point, generally the field, to the point of processing or sale. Producers may charge customers for shipping and handling separately from the oil and gas and in amounts that exceed the related costs incurred. Shipping costs generally comprise payments to third party shippers but also may be costs incurred directly by the producer.

4.57 The FASB ASC glossary defines *handling costs* as costs incurred to store, move, and prepare the products for shipment. Generally, handling costs are incurred from the point the product is removed from finished goods inventory to the point the product is provided to the shipper and often include an allocation of internal overhead. As set forth in FASB ASC 605-45-45-20, all amounts billed to a customer in a sale transaction related to shipping and handling, if any, represent revenues earned for the goods provided and should be classified as revenue.

4.58 The classification of shipping and handling costs incurred by the entity (for example, within cost of sales) is an accounting policy decision that should be disclosed in the financial statements. If shipping and handling costs are significant and not included in cost of sales (that is, if the costs are accounted for together or separately on other income statement line items), an entity should disclose both the amount(s) of such costs and the line item(s) on the income statement that includes the costs.

4.59 When an entity has an interest in properties with other producers, it may not take its proportionate share of the oil and gas as such oil and gas is produced, resulting in the need to ultimately balance production according to each owner's interest in the properties. In these cases, revenue from oil and gas production is recognized either (*a*) on the basis of the entity's net working interest (entitlement method) or (*b*) on the basis of all crude oil and natural gas sold to the entity's purchasers and customers, regardless of whether the sales are proportionate to its ownership in the property (sales method). When the entitlement method is used to recognize revenue, to the extent that a party has under- or overlifted its share of production, a receivable is established for an underlift position, and a payable is established for an overlift position. When the sales method of revenue recognition is used, no receivable or payable is recorded unless a party has taken more than its estimated total field entitlement. In that case, a liability is recorded by the party that has overtaken its share of estimated total field entitlement, with the liability being limited to the value of the volumes taken in excess of estimated total field entitlement.

4.60 For entities that use the entitlement method for revenue recognition, an under- or overlift position could be valued in a number of different ways, based on the commodity involved, the entity's accounting policy, and the joint operating agreement. For crude oil imbalances, the receivable and payable are valued at production costs, market value (less selling expenses if a receivable), or the actual sales proceeds received by the overtaken party. Because judgment is involved, it is important to understand how the joint operating agreement addresses the settlement of under- and overlift positions.

4.61 The SEC staff has not taken a position on which method of accounting is preferable. However, for gas imbalances, the SEC staff has indicated that for those entities using the entitlement method, the receivable or liability should be valued using the lower of (*a*) the price in effect at the time of production; (*b*) the current market value; or (*c*) if a contract is in hand, the contract price. Receivables should be measured net of selling expenses.

4.62 The method of accounting for imbalances should be disclosed. The SEC states that registrants should use one method of accounting consistently for all significant gas imbalances. The SEC also states that if insufficient gas volumes are available to offset imbalances, the overtaker should record the liability for the amount of shortfall in reserves valued at current market prices unless a different price is specified in the contract, in which case, the contract price may be used.

4.63 For the sale of gas, entities record revenue based on an estimate of the volumes delivered at the agreed-upon price and then adjust revenue in subsequent periods based on the data received from the purchaser that reflects actual volumes received. Generally, proceeds from gas production are received from one to three months after the actual delivery has occurred. Thus, it is usually necessary to estimate gas revenue based on prior months' production volumes and current lease operating data, such as meter readings, in order to prepare financial statements on a timely basis. Revenue associated with liquefied natural gas, liquefied petroleum gas, gas-to-liquids, and products from other emerging technologies should be analyzed to ensure appropriate recognition policies are in place.

Inventory

4.64 Inventory generally consists of produced oil and gas, as well as material and supplies used in the operations. Oil may be stored in tanks at the production site; however, gas may be stored at facilities closer to the actual end market or pipeline facilities. Inventory and oil and gas in storage at the end of the accounting period are recorded at the lesser of cost or market in the financial statements.

4.65 The "Purchases and Sales of Inventory with the Same Counterparty" subsection of FASB ASC 845-10-15 provides that a purchase and sale of inventory with the same counterparty should be combined and viewed as a single exchange transaction if the transactions were entered into in contemplation of one another (and the transaction is not accounted for as a derivative under FASB ASC 815, *Derivatives and Hedging*). FASB ASC 845-10-25-4 provides that the following factors may indicate that a purchase transaction and a sales transaction were entered into in contemplation of one another: (*a*) a specific legal right of offset of obligations exists between counterparties involved in inventory purchase and sales transactions; (*b*) inventory purchase and sales transactions with the same counterparty are entered into simultaneously; (*c*) inventory purchase and sales transactions were entered into at terms that were off-market when the arrangement was agreed to between counterparties;

and (*d*) relative certainty exists that reciprocal inventory transactions with the same counterparty will occur.

4.66 For example, for an integrated oil and gas entity, its production may not be convenient or of suitable quality for efficient processing at its refinery. It may then swap its production at one location with another producer to receive production from the counterparty at a location closer to its refinery or a grade of crude oil more efficiently refined in its facility.

4.67 Such a transaction described in the preceding paragraph should be accounted for at fair value, as set forth in FASB ASC 845-10-30-15, if fair value is determinable within reasonable limits and the transaction has commercial substance, as discussed in FASB ASC 845-10-30-4.

Operating Expenses

4.68 Mineral lease operating expenses are charged to expense; examples include supply vessel costs, helicopter charges, personnel wages, fuel or electricity for operating equipment, subsurface and surface maintenance, insurance, ad valorem taxes, producing-well overhead, salt water disposal, fracturing, acidizing, and workovers to maintain production. One exception to this occurs when a well has multiple productive zones. After the initial completion zone has been depleted, the well may be recompleted to one of the remaining behind-pipe zones. The portion of the expenditures allocable to the recompletion should be accounted for as development or exploratory costs.

4.69 The operator of the property is periodically reimbursed by the other working interest owners for certain overhead costs incurred. In the United States, this reimbursement is often termed a *Council of Petroleum Accountants Societies reimbursement*. Under the successful efforts method of accounting, these reimbursements are typically recorded as an offset to the same financial statement account as the related expense, which would generally be lease operating expense or general and administrative expense.

4.70 Some entities view these reimbursements to be within the scope of FASB ASC 605-45-45-23 and record the reimbursement as revenue in the income statement.

Asset Retirements, Environmental Liabilities, Abandonments, Involuntary Conversions, and Expropriations

AROs

4.71 FASB ASC 410-20 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) normal operation of a long-lived asset, except for certain obligations of lessees.

4.72 In accordance with FASB ASC 410-20-25-4, an entity should recognize the fair value of a liability for an ARO 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 ARO is incurred, the liability should be recognized when a reasonable estimate of fair value can be made. In accordance with FASB ASC 410-20-50-2, if the fair value of an ARO cannot be reasonably estimated, that fact and the reasons therefore should be disclosed.

4.73 As stated in FASB ASC 410-20-25-5, upon initial recognition of a liability for an ARO, an entity should capitalize an asset retirement cost by increasing the carrying amount of the related long-lived asset by the same amount as the liability. According to FASB ASC 410-20-35-2, an entity should subsequently allocate that asset retirement cost to expense using a systematic and rational method over its useful life.

4.74 The estimated residual values should be taken into account in determining amortization and depreciation rates but not in estimating the amount of the obligation.

4.75 FASB ASC 410-20-15-2 provides that a legal obligation to perform an asset retirement activity that is conditional on a future event is within the scope of the "General" subsections of FASB ASC 410-20-15. FASB ASC 410-20-25-7 indicates that the fair value of a liability for the conditional ARO should be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made.

4.76 Uncertainty surrounding the timing and method of settlement that may be conditional on events occurring in the future should be factored into the measurement of the liability, rather than affecting the recognition of the liability.

Environmental Liabilities

4.77 The primary authoritative literature governing accounting for environmental remediation costs not in the scope of the "General" subsections of FASB ASC 410-30 is contained in FASB ASC 450, *Contingencies*. The "General" subsections of FASB ASC 410-30 provide accounting guidance with respect to environmental remediation liabilities that relate to pollution arising from some past act. Also, paragraphs 1–18 of FASB ASC 360-10-55 address whether the costs of future site restoration or closure (environmental exit costs) that may be incurred if a long-lived asset is sold, abandoned, or ceases operations should be included as part of testing a long-lived asset for recoverability.

Abandonments

4.78 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. Regulations, legal statutes, or contractual provisions may stipulate that wells be plugged, facilities and equipment removed, and the terrain or subsea surface restored to specified or predrilling conditions.

4.79 Normally, no gain or loss is recognized 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 abandoned or retired asset is presumed to be fully amortized, and its cost is charged against the accumulated DD&A. Only when the last well ceases to produce and the entire property is abandoned is gain or loss recognized. A gain or loss can occur, for example, if the actual proceeds received for the salvage value of the equipment exceed or are below the estimated salvage value that had been considered in determining depletion. 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.

Involuntary Conversions

4.80 No differences from accounting principles generally accepted in the United States of America (U.S. GAAP) exist between oil and gas entities and entities in general regarding the accounting for involuntary conversions, such as damage resulting from hurricanes, explosions, or other recurring catastrophic events.[3] Potential losses from the impairment of long-lived assets should be assessed based on the guidance in the "Impairment or Disposal of Long-Lived Assets" subsections of FASB ASC 360-10, and liabilities for loss accruals should be assessed based on the guidance in FASB ASC 450. This is consistent with the guidance provided in FASB ASC 605-40.

4.81 The "General" subsections of FASB ASC 605-40 clarify the accounting for conversions of nonmonetary assets (such as property and equipment) to monetary assets (such as insurance proceeds), even if the entity reinvests the proceeds in replacement property.

4.82 Insurance recoveries related to natural disasters, and other similar events, should be recorded up to the amount of related recognized losses when deemed probable, as defined in FASB ASC 450.

4.83 Any remaining insurance recovery should be treated as a gain contingency and recognized when realized.

4.84 FASB ASC 410-30-35-9 further states that a rebuttable presumption exists that realization of the claim is not probable if the recovery or claim is the subject of litigation.

4.85 Under FASB ASC 450-30-25-1, a gain (that is, a recovery in excess of a loss not yet recognized in the financial statements or an amount recovered in excess of a loss recognized in the financial statements) should not be recognized until any contingencies related to the insurance claim have been resolved. These recoveries will often take two forms: those related to involuntary conversions and those related to business interruption. The accounting for involuntary conversions is addressed in the "General" subsections of FASB ASC 605-40, which generally requires the recognition of a gain or loss when a nonmonetary asset is involuntarily converted to monetary assets, even though an entity reinvests or is obligated to reinvest the monetary assets in replacement of nonmonetary assets. The income statement classification of business interruption insurance recoveries is addressed in FASB ASC 225-30-45. FASB ASC 225-30-45-1 provides that an entity may choose how to classify business interruption insurance recoveries in the statement of operations, as long as that classification is not contrary to existing U.S. GAAP.

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[3] The AICPA Technical Questions and Answers (TIS) section 5400.05, "Accounting and Disclosures Guidance for Losses From Natural Disasters—Nongovernmental Entities" (AICPA, *Technical Practice Aids*), indicates that losses from natural disasters are not viewed as extraordinary items. TIS section 5400.05 includes additional guidance related to the accounting for events common to natural disasters.

Expropriations

4.86 Oil and gas entities have had assets expropriated or "nationalized" by governments. FASB ASC 450-20-55-9 addresses the accounting when a threat of expropriation of assets exists. This guidance requires that the assessment be made to determine whether any related compensation will be less than the carrying amount of the assets. If so, an impairment should be recognized. If it is not possible to estimate the loss, then the contingency should be disclosed.

Lease Arrangements

4.87 Service and equipment arrangements are commonplace in the industry. For a variety of reasons, including increasing commodity prices and the relative scarcity of both onshore and offshore drilling rigs (and the personnel necessary to operate them), entities engaged in oil and gas exploration and development activities are increasingly contracting with service providers for drilling services on a multiyear basis. In some cases, the contractual arrangements explicitly identify the rig to be used to fulfill the drilling services. In other cases, however, the drilling rig to be used to fulfill the arrangement is not explicitly identified but is implicitly specified because it is not feasible for the drilling service provider to fulfill the arrangement with any equipment other than a particular, specific drilling rig. Other types of long-term contracts that may contain leases include contracts for the use of pipelines and storage facilities. FASB ASC 840-10-15 provides guidance for determining if such contractual arrangements, which have an underlying property, plant, and equipment component, contain an embedded lease that is within the scope of FASB ASC 840, *Leases*.

4.88 As stated in FASB ASC 840-10-15-4, FASB ASC 840 does not address whether an undivided interest or a pro rata portion of property, plant, or equipment could be the subject of a lease. If parties governed by a joint venture agreement accounted for as an undivided interest under FASB ASC 323-30 enter into a lease for equipment, the contract should be assessed to determine the legal obligations of the parties in order to determine the appropriate accounting and disclosures for the joint venture partners.

Discontinued Operations and Asset Held for Sale Considerations

4.89 The FASB ASC glossary defines a *component of an entity* as comprising operations and cash flows that can be clearly distinguished, operationally and for financial reporting purposes, from the rest of the entity. A component of an entity may be a reportable segment or an operating segment, a reporting unit, a subsidiary, or an asset group.

4.90 Entities following the successful efforts method of accounting should assess the criteria for reporting discontinued operations for a disposition to determine if the disposed asset or asset group is a component of the entity.

4.91 The results of operations of a component of an entity that either has been disposed or is classified as held for sale under the requirements of FASB ASC 360-10-45-9 should be reported in discontinued operations, in accordance with FASB ASC 205-20-45-3, if (*a*) the operations and cash flows of the component 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.

4.92 For oil and gas entities, a component is generally assessed in the same manner as the amortization base for DD&A and for measuring impairment under the "Impairment or Disposal of Long-Lived Assets" subsections of FASB ASC 360-10. The determination of a component involves significant judgment.

4.93 FASB ASC 205-20-55 provides additional guidance to determine whether (1) an entity has significant continuing involvement in the operations of the component, and (2) cash flows of the component have been or will be eliminated from the ongoing operations of the entity. The application of this guidance involves considerable judgment. Example 5 in paragraphs 57–58 of FASB ASC 205-20-55 provides guidance for oil and gas entities. A rebuttable presumption exists that the continued sale of a commodity by the ongoing entity in an active market should be considered a migration of customers and, therefore, the cash flows of a disposed entity have not been entirely eliminated.

4.94 For purposes of this issue, the FASB ASC glossary defines *commodity* as a product whose units are interchangeable, traded on an active market where customers are not readily identifiable, and immediately marketable at quoted prices.

4.95 This guidance limits the disposals that result in treatment as discontinued operations for oil and gas entities.

Goodwill and Business Combinations

4.96 It has become more common to recognize goodwill related to acquisitions in the oil and gas industry. For acquisitions of operations with oil and gas or mineral properties for which no other substantial business activities exist, it would generally be expected that substantially all of the value of the acquired entity not attributed to the tangible and identifiable intangible assets is derived from the value of the mineral or oil and gas reserves acquired. However, if an excess purchase price is clearly indicated by all reasonable valuations of the oil and gas or mineral properties and other net tangible and intangible assets, recognition of goodwill is appropriate for acquisitions that are determined to be a business.

4.97 FASB ASC 805-10-55-4 states that a business consists of inputs and processes applied to those inputs that have the ability to create outputs. Although businesses usually have outputs, outputs are not required for an integrated set to qualify as a business. The three elements of a business are defined as follows:

- *a.* *Input*. Any economic resource that creates, or has the ability to create, outputs when one or more processes are applied to it. Examples include long-lived assets (including intangible assets or rights to use long-lived assets), intellectual property, the ability to obtain access to necessary materials or rights, and employees.
- *b.* *Process*. Any system, standard, protocol, convention, or rule that, when applied to an input or inputs, creates or has the ability to create outputs. Examples include strategic management processes, operational processes, and resource management processes. These processes typically are documented, but an organized workforce having the necessary skills and experience following rules and

conventions may provide the necessary processes that are capable of being applied to inputs to create outputs. Accounting, billing, payroll, and other administrative systems typically are not processes used to create outputs.

c. *Output.* The result of inputs and processes applied to those inputs that provide or have the ability to provide a return in the form of dividends, lower costs, or other economic benefits directly to investors or other owners, members, or participants.

4.98 The determination about whether an acquisition of oil and gas properties is a business, as defined in FASB ASC 805-10-55-4, requires significant judgment based on the facts. Additional information that is useful to this determination is included in paragraphs 5–9 of FASB ASC 805-10-55.

4.99 The acquisition of a mineral interest in an unproven nonproducing property is generally an asset acquisition. In this situation, the mineral interest would potentially represent an input, but the acquisition does not include processes or outputs. In situations in which the acquisition includes processes, the acquirer should consider whether those processes would be substantial enough to lead to a conclusion that the acquisition is a business given the lack of any outputs. In most cases, this would not be the case.

4.100 The acquisition of a mineral interest in a proved property with oil and gas production activities that are already in place would generally be considered a business combination. Employees are not required to be a part of the acquired assets to be a business combination. In this example, the acquired property has inputs, processes (development activities), and outputs (production revenues); therefore, it is generally viewed as a business combination.

4.101 FASB ASC 350, *Intangibles—Goodwill and Other*, establishes accounting and reporting standards for goodwill and other intangible assets, once recognized.

Derivative Commodity Contracts

4.102 FASB ASC 815 establishes accounting and reporting standards for hedging activities and derivative instruments, including certain derivative instruments embedded in host contracts (collectively referred to as *embedded derivatives*). It requires that an entity recognize all derivative contracts as either assets or liabilities in the statement of financial position and measure those instruments at fair value, except those that meet the scope exception for normal purchases and sales in paragraphs 40–51 of FASB ASC 815-10-15.

4.103 If certain conditions are met, a derivative contract 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, a recognized asset or liability, an unrecognized firm commitment, an available-for-sale security, or a foreign currency-denominated forecasted transaction.

4.104 The accounting for changes in the fair value of a derivative contract (that is, gains and losses) depends on the intended use of the derivative and the resulting designation. FASB ASC 815 provides guidance regarding accounting and reporting issues related to derivative instruments and hedging activities.

4.105 Derivative commodity contracts include swaps and option contracts linked to oil or natural gas, as well as similar forwards and futures and combinations of the preceding. Oil and gas producers are significantly affected by FASB ASC 815. For derivative contracts that qualify, the designation of the contracts as accounting hedges is elective.

4.106 An oil and gas producer utilizes derivative commodity contracts for a variety of business purposes, including hedging an entity's exposure to a decline in prices for produced oil and natural gas. An oil and gas producer's exploration and development program or debt service requirements may be dependent on receiving a minimum price for produced oil and gas.

4.107 An example of an economic hedge of variability in future cash flows would be an option that gives the entity the right but not the obligation to sell a specified quantity of crude oil at a specified price for a specified period. This put option contract would normally cash settle, with the entity receiving proceeds if the current market price for the crude oil was less than the specified strike price in the derivative option contract. The proceeds received from the settlement of the cash settled put option contract plus the proceeds received from the sale of the actual physical production would result in the entity receiving a higher price than the current market price, resulting in an economic hedge of the exposure to variability of oil prices. If the current market price exceeds the strike price in the put option, the oil producing entity would receive no payment, and the option contract would expire at the end of the specified period. This type of option contract would result in the payment of a premium for the option. In an effort to minimize or eliminate premium payments, oil and gas producing entities may combine option contracts into a "costless collar," which combines the purchased put option previously described and a sold call option. This gives the other party to the option the right to receive a payment from the oil producing entity if the current market price of oil is greater than the strike price of the call option for the specified production period. Depending on the specific terms of the sold call options, the premium received for selling the call option would offset the premium paid for the purchased put option, thus creating the "costless collar." The combination of options contracts has many variations, but the value of all is based on crude oil and natural gas prices.

4.108 Another common example of derivative commodity contracts would be a price swap contract. A natural gas producing entity may sell its southern Louisiana produced gas under a gas sales contract that pays a variable price that is based on the index price of gas sold at the Henry Hub marketing point in Erath, Louisiana. The gas producing entity would prefer to receive a fixed price for its gas production. Through a gas price swap contract, the entity could swap the variable Henry Hub index price for a fixed price for certain quantities of produced gas for certain production periods. This gas price swap contract would result in payments to the producing entity if the specified fixed price in the swap contract was greater than the Henry Hub index price. Alternatively, the contract would require payments to the counterparty to the contract if the Henry Hub index price was greater than the swap contract fixed price. Proceeds from selling actual production under the variable price physical gas sales contract and payments to or from the counterparty under the terms of the price swap contract would result in the gas producing entity receiving the fixed price for the quantity specified in the price swap contract for the specified production periods.

4.109 Other examples of derivative commodity contracts include *futures contracts*, which are defined by the FASB ASC glossary as a standard and transferable form of contract that binds the seller to deliver to the bearer a standard amount and grade of commodity to a specific location at a specified time. They usually include a schedule of premiums and discounts for quality verification.

4.110 Futures contracts are exchange traded and standardized regarding quantity, quality, and location of the commodity being sold, and the performance of the parties to the futures contract is guaranteed by the exchange. A well established market exists for crude oil, natural gas, and other hydrocarbon-derived futures contracts. *Commodity forward contracts* are contracts to buy or sell a commodity at a specified date in the future for a price agreed to at inception of the contract. Commodity forward contracts are private agreements that are not exchange traded and contain counterparty performance risk; they may not be standardized regarding quantity and quality.

4.111 Physical contract purchase and sale agreements put in place on a day-to-day basis are within the scope of the accounting rules for commodity derivative contracts. Paragraphs 40–51 of FASB ASC 815-10-15 provide an exception to derivatives fair value accounting for qualifying contracts that are appropriately designated as normal purchases and normal sales. This exception is an election that may be made, but is not a requirement. *Normal purchases and normal sales* are contracts that provide for the purchase or sale of something other than a financial instrument or derivative instrument that will be delivered in quantities expected to be used or sold by a reporting entity over a reasonable period in the normal course of business. An oil and gas producing entity should assess whether a forward contract for the sale of crude oil or natural gas at a fixed price meets the normal sales exemption from derivative contract accounting. An oil or gas sales contract for which the price received is a variable price would not normally have intrinsic fair value.

4.112 If it is probable at inception, and throughout the term of the individual contract, that the contract will not settle net and will result in physical delivery, then the contract may be accounted for under the normal purchase and normal sale exception in paragraphs 40–51 of FASB ASC 815-10-15. Net settlement of contracts that are designated as normal purchases and normal sales results in reconsideration of whether similar contracts continue to meet the normal purchase and normal sale exception. FASB ASC 815-10-15 provides guidance on derivative contract accounting relating to the application of the normal purchases and normal sales exception.

Fair Value Measurements*

4.113 FASB ASC 820, *Fair Value Measurement*, defines *fair value*, establishes a framework for measuring fair value (which refers to certain valuation

* In May 2011, FASB issued Accounting Standards Update (ASU) No. 2011-04, *Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs*. According to FASB, the objective of this update is to improve the comparability of fair value measurements presented and disclosed in financial statements prepared in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP) and International Financial Reporting Standards (IFRSs), by changing the wording used to describe many of the requirements in U.S. GAAP for measuring fair value and disclosing information about fair value measurements. The amendments include those that clarify FASB's intent about the application of existing fair value measurement and disclosure requirements and

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concepts and practices), and requires certain disclosures about fair value measurements. The following paragraphs summarize certain provisions of FASB ASC 820 but are not intended as a substitute for reviewing FASB ASC 820 in its entirety.

Definition of *Fair Value*

4.114 The FASB ASC glossary 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. FASB ASC 820-10-35-5 states that a fair value measurement assumes that the transaction to sell the asset or transfer the liability either 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. The FASB ASC glossary 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. The principal market (and thus, market participants) should be considered from the perspective of the reporting entity, thereby allowing for differences between and among entities with different activities.

4.115 FASB ASC 820-10-35-3 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, FASB ASC 820-10-30-3 explains that, in many cases, 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 at initial recognition. In determining whether a transaction price represents the fair value of the asset or liability at initial recognition, the reporting entity shall consider facts specific to the transaction and the asset or liability.

4.116 Paragraphs 7–8 of FASB ASC 820-10-35 provide that the price should not be adjusted for transaction costs. However, 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) its principal (or most advantageous) market.

Application to Assets

4.117 FASB ASC 820-10-35-10 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

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(footnote continued)

those that change a particular principle or requirement for measuring fair value or for disclosing information about fair value measurements. ASU No. 2011-04, which is to be applied prospectively, is effective for public entities during interim and annual periods beginning after December 15, 2011 (early application is not permitted). For nonpublic entities, the amendments are effective for annual periods beginning after December 15, 2011. Nonpublic entities may early implement during interim periods beginning after December 15, 2011.

determined based on the use of the asset by market participants, even if the intended use of the asset by the reporting entity is different.

4.118 FASB ASC 820-10-35-10 provides that the highest and best use for an asset is established by one of two 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. The highest and best use of the asset is in-exchange if the asset would provide maximum value to market participants principally on a stand-alone basis. For example, value in-exchange might be appropriate for a financial asset. According to paragraphs 12–13 of FASB ASC 820-10-35, 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. An asset's value in-exchange is determined based on the price that would be received in a current transaction to sell the asset stand-alone.

Application to Liabilities

4.119 According to FASB ASC 820-10-35-16, a fair value measurement assumes that both (1) the liability is transferred to a market participant at the measurement date (the liability to the counterparty continues; it is not settled), and (2) the nonperformance risk relating to that liability is the same before and after its transfer. Paragraphs 16A–16G of FASB ASC 820-10-35 provide guidance on techniques for measuring the fair value of liabilities in circumstances in which a quoted price in an active market for the identical liability is not available.

4.120 Paragraphs 17–18 of FASB ASC 820-10-35 provide that a fair value measurement for a liability should reflect 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.

4.121 Paragraphs 65–76 of FASB ASC 820-10-55 provide implementation guidance on measuring the fair value of liabilities.

Valuation Techniques

4.122 Paragraphs 24–35 of FASB ASC 820-10-35 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, 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.

4.123 FASB ASC 820-10-35-24 states that 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 (for example, as might be the case when valuing a reporting unit), and the respective indications of fair value should be evaluated and weighted, as appropriate, considering the reasonableness of the range indicated by those results. Example 3 in paragraphs 35–41 of FASB ASC 820-10-55 illustrates 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.

4.124 As explained in paragraphs 25–26 of FASB ASC 820-10-35, valuation techniques used to measure fair value should be consistently applied. However, a change in a valuation technique or its application (for example, a change in its weighting when multiple valuation techniques are used) is appropriate if the change results in a measurement that is equally or more representative of fair value in the circumstances. That might be the case if, for example, new markets develop, new information becomes available, information previously used is no longer available, or valuation techniques improve. Such a change would be accounted for as a change in accounting estimate in accordance with the provisions of FASB ASC 250.

Present Value Techniques

4.125 Paragraphs 4–20 of FASB ASC 820-10-55 provide guidance on present value techniques. Those paragraphs neither prescribe the use of one specific present value technique nor limit the use of present value techniques to the three techniques discussed therein. They say that a fair value measurement of an asset or liability using present value techniques should capture the following elements from the perspective of market participants as of the measurement date: an estimate of future cash flows; expectations about possible variations in the amount or timing, or both, of the cash flows; the time value of money; the price for bearing the uncertainty inherent in the cash flows (risk premium); other case-specific factors that would be considered by market participants; and, in the case of a liability, the nonperformance risk relating to that liability, including the reporting entity's (obligor's) own credit risk.

The Fair Value Hierarchy*

4.126 FASB ASC 820-10-35-51D emphasizes that fair value is a market-based measurement, not an entity-specific measurement. Therefore, as stated in FASB ASC 820-10-35-9, a fair value measurement should be determined

* See footnote * in the heading above paragraph 4.113.

based on the assumptions that market participants would use in pricing the asset or liability (referred to as *inputs*). Paragraphs 37–58 of FASB ASC 820-10-35 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). According to FASB ASC 820-10-35-36, valuation techniques used to measure fair value should maximize the use of relevant observable inputs and minimize the use of unobservable inputs.

4.127 FASB ASC 820-10-35-58 provides guidance on classification within the fair value hierarchy of a fair value measurement of an investment within the scope of paragraphs 4–5 of FASB ASC 820-10-15 that is measured at net asset value per share (or its equivalent, for example, member units or an ownership interest in partners' capital to which a proportionate share of net assets is attributed).

Fair Value Disclosures[†,*]

4.128 FASB ASC 820-10-50 discusses the disclosures required for assets and liabilities measured at fair value. "Pending Content" in paragraphs 1 and 2 of FASB ASC 820-10-50 explains that the reporting entity should disclose information that enables users of its financial statements to assess both (*a*) for assets and liabilities 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 valuation techniques and the inputs used to develop those measurements, and (*b*) for recurring fair value measurements using significant unobservable inputs (level 3), the effect of the measurements on earnings for the period. For both recurring and nonrecurring measurements using level 2 or level 3 inputs, a description of the valuation technique (or multiple valuation techniques) used, and the inputs used should be disclosed.

4.129 Paragraphs 1–32 of FASB ASC 825-10-50 provide financial instrument disclosures required in the notes to the financial statements. FASB ASC 825-10-50-2A provides that for interim reporting periods, the disclosure requirements in FASB ASC 825-10-50 applies to all entities but is optional for those entities that do not meet the definition of a *publicly traded company*. Furthermore, the FASB ASC glossary defines a publicly traded company.

4.130 FASB ASC 825-10-50-3 indicates that for annual reporting periods, the disclosure requirements in FASB ASC 825-10-50 applies to all entities but is optional for an entity that meets the following criteria:

a. The entity is a nonpublic entity.

[†] In January 2010, FASB issued ASU No. 2010-06, *Fair Value Measurements and Disclosures (Topic 820): Improving Disclosures about Fair Value Measurements*. ASU No. 2010-06 established new disclosure requirements regarding significant transfers in and out of levels 1 and 2 of the fair value hierarchy and activity in level 3 fair value measurements. The amendments in this ASU became effective for interim and annual reporting periods beginning after December 15, 2009, except for the disclosures in the level 3 fair value measurement roll forward. Those disclosures are effective for fiscal years beginning after December 15, 2010, and for interim periods within those fiscal years. Examples related to the guidance in this ASU were added to FASB ASC 820-10-55.

[*] See footnote * in the heading above paragraph 4.113.

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 ASC 815 other than commitments related to the origination of the mortgage loans to be held for sale during the reporting period.

4.131 FASB ASC 825-10-50-10 indicates that an entity should disclose all of the following:

a. Either in the body of the financial statements or in the accompanying notes, the fair value of financial instruments for which it is practicable to estimate that value

b. The method(s) and significant assumptions used to estimate the fair value of financial instruments

c. A description of the changes in the method(s) and significant assumptions used to estimate the fair value of financial instruments, if any, during the period

For financial instruments recognized at fair value in the statement of financial position, the disclosure requirements of FASB ASC 820 also apply.

Disclosure Requirements for Oil and Gas Entities[‡]

General

4.132 The purpose of this section is to provide a high level overview of certain disclosures that are unique or significant to oil and gas producing entities. This section does not include every disclosure required by the referenced literature or all disclosures that are required of oil and gas producing entities.

[‡] On July 21, 2010, the president signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act). Section 1504, *Disclosure of Payments By Resource Extraction Issuers*, of the Dodd-Frank Act amends Section 13 of the Securities Exchange Act of 1934 (*Commerce and Trade, U.S. Code* Title 15, Section 78m) to require a resource extraction issuer to include in its annual report (and also submit in an interactive data format) information relating to any payment made by the resource extraction issuer, a subsidiary of the resource extraction issuer, or an entity under the control of the resource extraction issuer to a foreign government or the U.S. Federal Government for the purpose of the commercial development of oil, natural gas, or minerals, including (*a*) the type and total amount of such payments made for each project of the resource extraction issuer relating to the commercial development of oil, natural gas, or minerals, and (*b*) the type and total amount of such payments made to each government.

Section 1504 of the Dodd-Frank Act indicates that *commercial development of oil, natural gas, or minerals* includes exploration, extraction, processing, export, and other significant actions relating to oil, natural gas, or minerals, or the acquisition of a license for any such activity, as determined by the SEC. Section 1504 of the Dodd-Frank Act also indicates that the term *payment* means a payment that is made to further the commercial development of oil, natural gas, or minerals, and is not de *minimis*, including taxes, royalties, fees (including license fees), production entitlements, bonuses, and other material benefits, that the SEC, consistent with the guidelines of the Extractive Industries Transparency Initiative (to the extent practicable), determines are part of the commonly recognized revenue stream for the commercial development of oil, natural gas, or minerals.

Section 1504 of the Dodd-Frank Act can be found at www.sec.gov/about/laws/wallstreetreform-cpa.pdf.

On December 15, 2010, the SEC issued Proposed Rule No. 34-63549, *Disclosure Payments by Resource Extraction Issuers*, for public comment. Proposed Rule No. 34-63549 can be found at www.sec.gov/rules/proposed/2010/34-63549.pdf. Additional information on this proposed rule, including discussion of the proposed disclosure requirements and comment letters received by the SEC, can also be found at www.sec.gov/news/press/2010/2010-247.htm. Readers are encouraged to monitor the SEC's website at www.sec.gov/index.htm for the latest developments on this rulemaking project.

Refer to the applicable literature and accounting standards for the complete requirements.

4.133 The following sections describe the disclosure requirements for oil and gas entities based on SEC Final Rule No. 33-8995, *Modernization of Oil and Gas Reporting*, and FASB ASC 932.

4.134 Some of the more significant disclosures required for oil and gas producing entities are based on the requirements of FASB ASC 932 and FASB ASC 835, *Interest*; Rule 4-10 of Regulation S-X; Items 1201–1208 of Subpart 1200 of Regulation S-K.[4] Other disclosure guidance is included in Financial Reporting Policies 406, "Oil and Gas Producing Activities," and SEC's *Codification of Staff Accounting Bulletins* Topic No. 2(D), "Financial Statements of Oil and Gas Exchange Offers," and Topic No. 12, "Oil and Gas Producing Activities."

4.135 In general, specific oil and gas disclosures relate to the following:

- Accounting policies and other accounting disclosures specific to the industry
- Disclosures required by FASB ASC 932
- Additional disclosures for entities following the full cost method of accounting
- Disclosures required by Final Rule No. 33-8995 (Financial Reporting Release No. 78)
- Disclosures relevant to SEC exchange offers

Accounting Policy Disclosures

4.136 Typical accounting policy disclosures required of both public and nonpublic oil and gas producing entities are provided subsequently. Certain of these disclosures would only be applicable to entities following the successful efforts method of accounting. In addition, certain other disclosures required only for entities following the full cost method of accounting are included in chapter 5 of this guide. (This list is not intended to include all possible required policy disclosures.)

- Accounting method followed for costs incurred in oil and gas producing activities, which is either the full cost method or successful efforts method (FASB ASC 932), including the policy for capitalization of acquisition, exploration, and development costs and the policy for capitalization of internal costs associated with E&P activities (Rule 4-10 of Regulation S-X).
- The manner of disposing of capitalized costs (FASB ASC 932), which includes accounting for DD&A and accounting for disposition of oil and gas properties.
- Accounting policy for AROs (FASB ASC 410-20).

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[4] Upon issuance of Final Rule No. 33-8995, *Modernization of Oil and Gas Reporting*, the SEC adopted amendments to Rule 4-10 of Regulation S-X and Item 102 of Regulation S-K. Certain disclosures previously included in SEC Industry Guide No. 2, "Disclosure of Oil and Gas Operations," of Regulation S-K were eliminated and replaced by a new Subpart 1200, including Items 1201–1208. In addition, Form 20-F was revised to incorporate Subpart 1200, with respect to oil and gas disclosures, and appendix A of Item 4D in Form 20-F was deleted. Refer to paragraphs 4.149–.153 for further details on the amendments to Regulation S-K.

- Accounting policy for gas sales (sales method versus entitlement method) and accounting for the gas imbalances under the entitlement method (FASB ASC 235, *Notes to Financial Statements*, and FASB ASC 932). Although oil sales are not referenced in this literature, some entities apply the same method for gas sales to oil sales.

- Accounting policy for buy and sell transactions (FASB ASC 845, *Nonmonetary Transactions*).

Suspended Well Disclosures

Annual Disclosures

4.137 Under FASB ASC 932-235-50-1B, entities following the successful efforts method of accounting are required to disclose the accounting policy related to the evaluation of capitalized exploratory well costs. Disclosures required by FASB ASC 932-235-50-1B include the following:

a. Amount of capitalized exploratory well costs that is pending the determination of proved reserves and changes in those capitalized exploratory well costs resulting from the following:

   i. Additions to capitalized exploratory well costs that are pending the determination of proved reserves.

   ii. Capitalized exploratory well costs that were reclassified to wells, equipment, and facilities based on the determination of proved reserves.

   iii. Capitalized exploratory well costs that were charged to expense.

   This disclosure should not include amounts that were capitalized and subsequently expensed in the same annual period.

b. Amount of exploratory well costs that have been capitalized for a period greater than one year after the completion of drilling at the most recent balance sheet date and aging of those amounts by year and the number of projects to which those costs relate.

c. For exploratory well costs that continue to be capitalized for more than one year after the completion of drilling at the most recent balance sheet date, an entity should describe (i) the projects and activities that it has undertaken to evaluate the reserves and the projects that it has undertaken to date in order to evaluate the reserves and the projects and (ii) the remaining activities required to classify the associated reserves as proved.

Interim Disclosures

4.138 The preceding annual disclosures are not routinely required in interim financial statements. Interim disclosures should include significant changes from the information presented in the most recent annual financial statements and any impairments of capitalized exploratory well costs that were capitalized for a period greater than one year.

FASB ASC 932 Disclosures

Annual Disclosures

4.139 Under FASB ASC 932, publicly traded entities with significant oil and gas activities should disclose certain unaudited supplemental information in complete sets of annual financial statements. Although certain of these disclosures are only required for public entities, nonpublic entities also often include these disclosures in their financial reporting. Refer to the FASB ASC glossary for definitions of the terms *publicly traded entity* and *nonpublic entity*.

4.140 An entity is regarded as having significant oil and gas producing activities if it satisfies certain criteria, applied separately, for each year for which a complete set of annual financial statements is presented. The criteria are provided in the FASB ASC glossary term *significant oil and gas producing activities*.

4.141 FASB ASC 932-235-55 contains implementation guidance and illustrations that are an integral part of FASB ASC 932-235 and present formats that may be used to disclose certain information required by FASB ASC 932-235.

4.142 Disclosures required by FASB ASC 932-235 include the following:

a. Net quantities of an entity's interests in proved oil and gas reserves, proved developed oil and gas reserves, and proved undeveloped oil and gas reserves of each of the following as of the beginning and the end of the year:

   i. Crude oil, including condensate and natural gas liquids. (If significant, the reserve quantity information should be disclosed separately for natural gas liquids)

   ii. Natural gas

   iii. Synthetic oil

   iv. Synthetic gas

   v. Other nonrenewable natural resources that are intended to be upgraded into synthetic oil and gas

   Net quantities of reserves include those relating to the entity's operating and nonoperating interests in properties. Quantities of reserves relating to royalty interests owned should be included in net quantities if the necessary information is available to the entity; if reserves relating to royalty interests owned are not included because the information is unavailable, that fact, and the entity's share of oil and gas produced for those royalty interests, should be disclosed for the year. Net quantities should not include reserves relating to interests of others in properties owned by the entity.

b. Changes in the net quantities of an entity's proved reserves of oil and gas during the year. Changes should be presented by the following categories:

   i. Revisions of previous estimates

   ii. Improved recovery

   iii. Purchases of minerals in place

   iv. Extensions and discoveries, which include

(1) extension of the proved acreage of previously discovered (old) reservoirs through additional drilling in periods subsequent to discovery, and

(2) discovery of new fields with proved reserves or of new reservoirs of proved reserves in old fields.

v. Production

vi. Sales of minerals in place

c. If an entity's proved reserves of oil and of gas are located entirely within its home country, that fact should be disclosed. The disclosures of net quantities of reserves of oil and gas and changes in them should be presented in the aggregate, and separately, by geographic area in which significant reserves are located.

Any one of the following may constitute a geographic area, as appropriate for meaningful disclosure in the circumstances:

i. An individual country

ii. A group of countries within a continent

iii. A continent

In determining whether reserves are significant

i. an entity should consider all facts and circumstances and not solely the quantity of reserves.

ii. at a minimum, net quantities of reserves should be presented in the aggregate and separately by geographic area and for each country containing 15 percent or more of an entity's proved reserves, expressed on an oil-equivalent-barrels basis.

Reserves should include an entity's proportionate share of reserves of equity method investees.

d. Quantities of oil or gas subject to purchase under long-term supply, purchase, or similar agreements and contracts, including such agreements with governments or authorities as of the end of the year, and the net quantity of oil or gas received under the agreements during the year should be separately disclosed if the entity participates in the operation of the properties in which the oil or gas is located or otherwise serves as the producer of those reserves, as opposed, for example, to being an independent purchaser, broker, dealer, or importer.

e. FASB ASC 932-235 also requires that the entity's share in the proved oil and gas reserves quantities; capitalized costs; and capitalized costs incurred in property acquisition, exploration, and development activities of the entity's equity method investees be presented separately from the consolidated disclosures.

f. Aggregate capitalized costs relating to an entity's oil and gas producing activities and the aggregate related DD&A and valuation allowances as of the end of each year, including the following:

i. Separate disclosures of capitalized costs for the following asset categories, or a combination of these categories, often may be appropriate: mineral interests in properties, including unproved and proved properties; wells and related equipment and facilities; support equipment and facilities used in oil and gas producing activities; and uncompleted wells, equipment, and facilities.

ii. Significant capitalized costs of unproved properties should be separately reported. Capitalized costs of support equipment and facilities may be disclosed separately or included, as appropriate, with capitalized costs of proved and unproved properties.

g. Costs incurred in property acquisition, exploration, and development activities for each year, including the following:

i. Each of the following types of costs for the year should be disclosed regardless of whether such costs are capitalized or expensed: property acquisition costs, exploration costs, and development costs.

ii. The preceding costs should be disclosed separately for each of the geographic areas for which reserve quantities are disclosed.

h. Results of operations for oil and gas producing activities for each year, including the following:

i. An entity should disclose historical results of operations for oil and gas producing activities by major geographic area. If oil and gas producing activities represent substantially all of the business activities and the activities are located substantially in a single geographic area, additional information is not required if that information is provided elsewhere in the financial statements.

ii. The results of operations for oil and gas producing activities should be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed. The following information relating to those activities should be presented: revenues; production (lifting) costs; exploration expenses; DD&A and valuation provisions; income tax expenses; and results of operations for oil and gas producing activities (excluding corporate overhead and interest costs). An entity should separately disclose amounts for (1) its consolidated entities and (2) the entity's share of equity method investees except that it may present a combined total for its total results of operations.

iii. Revenues related to sales to unaffiliated entities and sales or transfers to the entity's other operations (for example, refineries or chemical plants) should be disclosed separately. Revenues include sales to unaffiliated entities attributable to net working interests, royalty interests, oil payment interests, and net profits interests of the reporting entity.

iv. Sales or transfers to other operations of the entity should be based on market prices, determined at the point of delivery from the producing unit (prices equivalent to those that could be obtained in an arm's-length transaction).

v. Production or severance taxes should not be deducted in determining gross revenues but should be included as part of production costs. Royalty payments and net profits disbursements should be excluded from gross revenues.

vi. Income taxes should be computed using the statutory tax rate for the period, applied to revenues less production (lifting) costs, exploration expenses, DD&A, and valuation provisions.

i. Standardized measure of discounted future net cash flows relating to an entity's interests in both (*a*) proved oil and gas reserves and (*b*) oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves, should be disclosed as of year-end and the aggregate change in the standardized measure of discounted future net cash flows for the year, including the following:

i. The following information should be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed: future cash inflows (computed by applying prices used to estimate the entity's proved reserves to the year-end quantities of those reserves), future development and production costs, future income tax expenses, future net cash flows, discount, and standardized measure of discounted future net cash flows.

ii. For changes in the standardized measure of discounted future net cash flows, the following, if significant, should be shown separately, with an appropriate explanation of significant changes: net change in sales and transfer prices and in production (lifting) costs related to future production; changes in estimated future development costs; sales and transfers of oil and gas produced during the period; net change due to extensions, discoveries, and improved recovery; net change due to purchases and sales of minerals in place; net change due to revisions in quantity estimates; previously estimated development costs incurred during the period; accretion of discount; other—unspecified; and net change in income taxes.

iii. The preceding information should be separately disclosed for both consolidated subsidiaries and for the entity's share of equity method investees. The entity is also permitted to disclose a total of these amounts.

4.143 The list of disclosures referred to previously is not all-inclusive. Refer to FASB ASC 932 for comprehensive disclosure requirements.

Interim Disclosures

4.144 FASB ASC 932 requires that interim financial statements include information about a major discovery or other favorable or adverse event that causes a significant change from the most recent annual supplemental disclosures concerning oil and gas reserves.

Other Disclosure Matters

4.145 The SEC's website includes guidance related to the treatment of the statement of cash flows for exploratory disbursements by entities following the successful efforts method. This guidance states that cash expenditures for exploratory wells are investing activities, but cash expenditures for exploratory G&G are operating activities. For more information, see *Division of Corporation Finance: Frequently Requested Accounting and Financial Reporting Interpretations and Guidance* at www.sec.gov/divisions/corpfin/guidance/cfactfaq.htm.

Additional Disclosures for Entities Following the Full Cost Method of Accounting

4.146 Refer to chapter 5 of this guide for discussion of additional disclosures for entities following the full cost method of accounting.

SEC Disclosures—Subpart 1200 of Regulation S-K

4.147 For public entities with material oil and gas operations, the SEC requires certain additional nonfinancial disclosures to be included in the securities registration statements and annual reports on Form 10-K filed with the SEC. The SEC's Final Rule No. 33-8995 disclosure requirements are included in a new Subpart 1200 of Regulation S-K.

4.148 For each of the last three fiscal years, disclosure of the following is required:

- Production related information, including (*a*) volumetric production data and (*b*) average sales price and production cost per unit (separately for oil and natural gas). The disclosure must be made by geographic area[5] and for each country or field containing 15 percent or more of the registrant's proved reserves. In addition, because Final Rule No. 33-8995 requires the disclosure of reserves of other end products aside from oil and gas, such as bitumen, disclosure of production, transfer price, and production cost information is also required for such products.

  Under the SEC reporting requirements contained in Final Rule No. 33-8995, these disclosure requirements have been codified in Item 1204 of Regulation S-K.

- Total net productive and dry wells drilled, broken down by exploratory wells and development wells drilled and appropriate geographic area.

  Under Final Rule No. 33-8995, these disclosures have been codified in Item 1205 of Regulation S-K.

4.149 For the current date or end of the latest fiscal year, disclosure of the following is required:

- Total gross and net productive oil and gas wells

[5] The definition of *geographic area* in the SEC reporting requirements contained in Final Rule No. 33-8995 is substantially consistent with the definition provided in FASB ASC 932-235-50-6 requiring disclosure, as applicable, by individual country, by group of countries within a continent, or by continent. However, the SEC reporting requirements include specific percentage thresholds to the geographic breakdowns of reserve estimates and production.

- Total gross and net developed acreage by major geographic area
- Total gross and net undeveloped acreage by appropriate geographic area and, if material, minimum remaining terms of leases and concessions

  Under Final Rule No. 33-8995, the preceding disclosures have been codified in Item 1208 of Regulation S-K.

- Number of wells in progress (gross and net), waterfloods, pressure maintenance operations, and any other related operations of material importance as of current period end and by appropriate geographic area

  Under Final Rule No. 33-8995, the preceding disclosures have been codified in Item 1206 of Regulation S-K.

- Information about obligations to provide fixed quantities of oil and gas in the future under existing contracts

  Under Final Rule No. 33-8995, the preceding disclosures on delivery commitments have been codified in Item 1207 of Regulation S-K.

4.150 The disclosures included under Subpart 1200 of Regulation S-K in Final Rule No. 33-8995 have to be included in the documents filed under the Securities Act of 1933 and the Securities Exchange Act of 1934 if oil and gas operations are material for the entity. However, limited partnerships and joint ventures engaged in oil and gas operations, as well as companies exempted under paragraphs 1–2 of FASB ASC 932-235-50 and the criteria within the FASB ASC glossary term *significant oil- and gas-producing activities*, do not have to provide such disclosures.

4.151 Other disclosures required in the new Subpart 1200 of Regulation S-K include the following:

- A tabular summary of oil and gas reserves at fiscal year-end by geographic area. Disclosure of reserves should be by product type, such as oil, natural gas, synthetic oil, synthetic gas, and other nonrenewable natural resource products that are intended to be upgraded into synthetic oil and gas (Item 1202[a][1]-[4]).
- A general discussion of the technologies used to establish reserves estimates from material properties (Item 1202[a][6]).
- Disclosure of the internal controls the registrant uses in its reserves estimation effort, together with disclosure of the qualifications of the technical person primarily responsible for overseeing the preparation of the reserves estimates and, if one is conducted by a third party, a reserves audit (Item 1202[a][7]).
- The filing of the report of a third party if the company represents that its estimates of reserves were prepared or audited by a third party, together with additional disclosures related to the third party report and conclusions contained therein (Item 1202[a][8]).
- An optional reserves sensitivity analysis. Under this optional disclosure, an entity is permitted to disclose estimated reserves for each product type based on different price and cost criteria. If this disclosure is made, the related price and cost assumptions also should be disclosed (Item 1202[b]).

- Disclosures for proved undeveloped reserves, including the reasons why material amounts of proved undeveloped reserves have remained undeveloped for five years or more after disclosure as proved undeveloped reserves (Item 1203).

Exchange Offer Disclosures

4.152 In accordance with question 1 of SEC *Codification of Staff Accounting Bulletins* Topic No. 2(D), full disclosure of reserve data and related information is required for all entities in exchange offers. The SEC also indicated in Topic No. 2(D) that when an exchange is accounted for as a purchase, it will consider, on a case-by-case basis, granting exemptions from (*a*) the disclosure requirements for year-to-year reconciliations of reserve quantities and (*b*) the requirements for a summary of oil and gas producing activities and a summary of changes in the net present value of reserves.

4.153 The SEC also requires pro forma reserves information to be presented with the exchange offer. Although the requirement for pro forma reserves information is explicitly required only for exchange offers, the SEC has typically considered this information to be required by Article 11 of Regulation S-X and has requested pro forma reserves for all significant acquisitions, regardless of whether they are filed under SEC Form S-4.

Chapter 5

Full Cost Method of Accounting for Oil and Gas Activities

General

5.01 The full cost method is prescribed by the Securities and Exchange Commission (SEC) and is principally set forth in Rule 4-10(c) of Regulation S-X and interpreted through the periodic issuance of Staff Accounting Bulletins (SABs) and other communications by the SEC staff. Entities not subject to SEC regulation (that is, nonpublic entities) also may apply the full cost method.

5.02 Full cost method accounting generally provides the following:

- All costs incurred in exploring for, acquiring, and developing oil and gas reserves are capitalized, regardless of whether the results of specific costs are successful.
- Capitalized costs are accumulated in a cost center for each country in which operations are conducted.
- Capitalized costs of all evaluated properties (including costs of unsuccessful drilling efforts) in each cost center are amortized on the unit-of-production method using total proved reserves for that cost center.
- Capitalized costs in each cost center are subject to a ceiling test and cannot exceed the present value (using a 10 percent discount factor) of estimated future net revenues computed by applying current prices[1] to estimated future production of proved oil and gas reserves as of the balance sheet date, less estimated future expenditures (based on current costs) to be incurred to develop and produce the reserves.
- Conveyances (sales) of oil and gas properties are accounted for as an adjustment of capitalized costs, with no gain or loss recognized, unless the adjustment would significantly alter the relationship between capitalized costs and proved oil and gas reserves attributable to a cost center.

5.03 The other generally accepted method of accounting for oil and gas activities is the successful efforts method. This method is described in chapter 4, "Successful Efforts Method and General Accounting for Oil and Gas Activities," of this guide, which also includes a description of accounting matters common to both methods.

5.04 Full cost accounting generally provides for capitalizing (within a cost center) all costs incurred in exploring for, acquiring, and developing oil and gas

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[1] Under the Securities and Exchange Commission (SEC) reporting requirements contained in Final Rule No. 33-8995, *Modernization of Oil and Gas Reporting*, the term *current prices* is defined as the historical 12-month average price calculated as the average of the first day of the month price for each month within the 12-month period prior to the reporting date. Under previous guidance, application of current prices for purposes of the full cost ceiling test was interpreted as single day, year-end prices. See further discussion of SEC reporting requirements in chapter 1, "Overview of the Industry," of this guide.

reserves, regardless of whether the results of specific costs are successful. Thus, even the costs of abandoned leaseholds and unsuccessful drilling efforts are capitalized. 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 oil and gas reserves. Thus, all costs incurred in acquiring mineral rights, in drilling, and in exploration activities, along with all carrying costs of unevaluated properties in the cost center, are treated as the cost of that center. The costs capitalized in a cost center are then amortized and charged to expense, subject to a quarterly ceiling test.

5.05 Cost centers are established on a country-by-country basis.

5.06 A reporting entity that follows the full cost method should apply that method to all of its operations and the operations of its subsidiaries (except that registrants may give effect to differences arising from the ratemaking process for rate-regulated cost of service companies). Although conformity of accounting methods between a reporting entity and its equity investees may be desirable, it may not be practicable and, thus, is not required. However, if a reporting entity proportionately consolidates its ownership interests in accordance with the guidance in Financial Accounting Standards Board (FASB) *Accounting Standards Codification* (ASC) 323-30, it is necessary to present these interests on the same basis of accounting as the reporting entity.

Accounting for Acquisition, Exploration, and Development Costs

5.07 All costs associated with property acquisition, exploration, and development activities are capitalized within the appropriate cost center. Internal costs that are capitalized are limited to those costs that can be directly identified with acquisition, exploration, and development activities undertaken by the reporting entity for its own account and do not include any costs related to production, general corporate overhead, or similar activities.

Capitalization of Interest

5.08 Interest costs also should be capitalized under FASB ASC 835, *Interest*. Assets that qualify for interest capitalization are the following:

a. Those unusually significant investments in unproved properties and major development projects that are not being currently depreciated, depleted, or amortized

b. Significant properties and projects in cost centers with no production, provided that exploration and development activities on such assets are in progress

Amortization of Capitalized Costs

5.09 Capitalized costs within a cost center are amortized on the unit-of-production basis using proved oil and gas reserves. Costs to be amortized include (*a*) all net capitalized costs, other than the cost of excludable properties (excluded costs) described subsequently; (*b*) the estimated future expenditures (based on current costs) to be incurred in developing proved reserves; and (*c*) the estimated dismantlement and abandonment costs, net of estimated salvage values, that have not yet been recorded as asset retirement costs. SEC *Codification of Staff Accounting Bulletins* Topic 12(D)(4), "Interaction of FASB ASC Subtopic 410-20 *Asset Retirement and Environmental Obligations—Asset Retirement Obligations* and the Full Cost Rules," addresses the application of FASB Statement No. 143, *Accounting for Asset Retirement Obligations* (which has been codified in FASB ASC 410, *Asset Retirement and Environmental Obligations*), to the calculation of depreciation, depletion, and amortization (DD&A) and the ceiling test for entities using the full cost method.

5.10 Generally, amortization of capitalized costs of oil and gas assets is computed on the basis of physical units, with oil and gas converted to a common unit of measure on the basis of their approximate relative energy content (commonly six thousand cubic feet of gas for one barrel of oil).

5.11 Rule 4-10 of Regulation S-X allows an alternative method of amortization based on units of revenue, if determined to be appropriate. Under this method, amortization is computed on the basis of current gross revenues from production in relation to future gross revenues, based on current prices (including consideration of changes in existing prices provided by contractual arrangements) from estimated production of proved oil and gas reserves. SEC *Codification of Staff Accounting Bulletins* Topic 12(F), "Gross Revenue Method of Amortizing Capitalized Costs," indicates that the use of this method may be more appropriate when oil and gas sales prices are disproportionate to their relative energy content, such as when prices are regulated. In this case, the unit of production method would result in an improper matching of the costs of oil and gas production against the related revenue received.

5.12 Amortization computations are made on a consolidated basis for a cost center, including investees accounted for on a proportionate consolidation basis. Investees accounted for on the equity method are treated separately.

5.13 To the extent that estimated dismantlement and abandonment costs, net of estimated salvage values, have not been included as capitalized costs in the base for computing DD&A because they have not yet been capitalized as asset retirement costs under FASB ASC 410, an estimate of such costs should be included in the base for computing DD&A. Entities should estimate the amount of dismantlement and abandonment costs that will be incurred as a result of future development activities on proved reserves and include those amounts in the costs to be amortized.

5.14 The amortization rate that is applied to the costs to be amortized is computed using current period production divided by reserves at the beginning of the period. Often, beginning of the period reserves are determined by adding current period production to the reserves estimated at the end of the period. Unit of production amortization rates are revised at least once a year, or more often, if there is an indication of the need for revision. Changes in amortization rates are made prospectively as changes in estimates. For entities subject to the reporting requirements of the SEC, when reserve quantities are revised, the SEC staff will not object to reflecting the revision as of the beginning of the quarter that has not been reported, for purposes of calculating DD&A. However, taking the reserve revisions back to earlier quarters that have already been reported is not appropriate. Entities should treat this as a policy election, which should be consistently applied.

Excluded Costs

5.15 The cost of investments in unevaluated, unproved properties and major development projects are excluded from capitalized costs to be amortized. However, costs associated with unevaluated or untested sites on proved properties are not excluded from the ceiling test.

5.16 With respect to costs directly associated with the acquisition and evaluation of unproved properties, such costs are excluded from the amortization computation until it is determined whether proved reserves can be assigned to the properties, subject to the following conditions:

a. Until such a determination is made, the properties are assessed at least annually to ascertain whether impairment has occurred. Unevaluated properties whose costs are individually significant are assessed individually. If 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. Impairment may be estimated by applying factors based on historical experience and other data, such as primary lease terms of the properties, average holding periods of unproved properties, and geographic and geologic data, to groupings of individually insignificant properties and projects. The amount of impairment assessed under either of these methods is added to the costs to be amortized.

b. Drilling costs associated with an exploratory dry hole are included in the amortization base immediately upon determination that the well is dry.

c. If geological and geophysical (G&G) costs, including seismic costs, cannot be directly associated with specific unevaluated properties, they are included in the amortization base as incurred. Upon complete evaluation of a property, the total remaining excluded cost (net of any impairment) is included in the full cost amortization base.

5.17 With respect to costs incurred in connection with major development projects expected to entail significant costs to ascertain the quantities of proved reserves attributable to the properties under development (for example, the installation of an offshore drilling platform from which development wells are to be drilled, the installation of improved recovery programs, and similar major projects undertaken in the expectation of significant additions to proved reserves), the amounts that may be excluded are applicable portions of (1) the costs that relate to the major development project that have not previously been included in the amortization base and (2) the estimated future expenditures associated with the development project. The excluded portion of any common costs associated with the development project should be based, as is most appropriate in the circumstances, on a comparison of either (*a*) existing proved reserves to total proved reserves expected to be established upon completion of the project or (*b*) the number of wells to which proved reserves have been assigned and the total number of wells expected to be drilled. Such costs may be excluded from costs to be amortized until the earlier determination of whether additional reserves are proved or impairment occurs.

5.18 Previously excluded costs and the proved reserves related to such costs, if any, are transferred into the amortization base on an ongoing (well-by-well or property-by-property) basis as the project is evaluated and proved reserves are established or impairment is determined. Once proved reserves are established, justification no longer exists for continued exclusion from the full cost amortization base, even if other factors prevent immediate production or marketing.

Impairment Tests for Capitalized Costs

Cost Center Ceiling Test

5.19 For entities using the full cost method of accounting, capitalized costs are not subject to impairment analysis under the "Impairment or Disposal of Long-Lived Assets" subsections of FASB ASC 360-10. As described more fully in Rule 4-10(c)(4) of Regulation S-X and SEC *Codification of Staff Accounting Bulletins* Topic 12(D), capitalized costs are subject to an impairment test known as a *ceiling test*. For each cost center, capitalized costs, less accumulated amortization and related deferred income taxes, cannot exceed an amount (the cost center ceiling) equal to the sum of the following:

a. The present value of estimated future net revenues computed by applying current prices[2] of oil and gas reserves (with consideration of price changes only to the extent provided by contractual arrangements) 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 properties not being amortized (the preceding excluded properties); plus

c. The lower of cost or estimated fair value of unproven properties included in the costs being amortized; less

d. Income tax effects related to differences between the book and tax basis of the excluded properties and unproven properties included in the amortization base

5.20 As mentioned in paragraph 5.19, the present value of estimated future net revenues that is computed to determine the cost center ceiling should be based on current prices and may only give consideration of price changes to the extent provided by contractual arrangements that existed at period-end. Such contractual arrangements would include those related to physical sales of an entity's production. An entity also should consider derivative contracts if, prior to the balance sheet date, an entity enters into certain qualifying hedging arrangements for a portion of its future natural gas and oil production. In this case, the entity should use the hedge adjusted prices in calculating the current price of the quantities of its future production of oil and gas reserves covered by the hedges as of the reported balance sheet date. These arrangements qualify as cash flow hedges under the provisions of FASB ASC 815, *Derivatives and Hedging*, and should be documented, designated, and accounted for as such

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[2] Under the SEC reporting requirements contained in Final Rule No. 33-8995, the term *current prices* is defined as the historical 12-month average price. Previously, the application of current prices for purposes of the full cost ceiling test was interpreted as single day, year-end prices.

under the criteria of FASB ASC 815. Refer to the "Disclosure Requirements" section of this chapter for certain disclosure requirements related to the effects of hedges on the ceiling test for entities following the full cost method. Also, refer to the "Derivative Commodity Contracts" section in chapter 4 of this guide for details of typical derivative instruments and transactions used by oil and gas entities.

5.21 The future cash outflows associated with settling asset retirement obligations (AROs) that have been accrued on the balance sheet should be excluded from the computation of the present value of estimated future net revenues for purposes of the full cost ceiling calculation. However, the estimated future cash outflows related to properties with proved undeveloped reserves for which AROs have not been accrued on the balance sheet should be included in the computation.

5.22 If unamortized costs capitalized within a cost center, less related deferred income taxes, exceed the cost center ceiling, the excess is charged to expense and separately disclosed during the period in which the excess occurs. Amounts thus identified to be written off cannot be reinstated for any subsequent increase in the cost center ceiling.

5.23 In certain circumstances, an impairment may be indicated by the ceiling test calculation shortly after an entity has made a major purchase of proved properties. For example, this can occur when the period-end current prices of oil and gas are lower than the estimated forward prices used by the entity to negotiate the purchase price of the properties. To the extent that the excess carrying value relates to the purchased reserves and a public entity believes the fair value of the properties in a cost center clearly exceeds the unamortized costs, a public entity may request a temporary exemption of the full cost ceiling limitation from the SEC staff. Registrants requesting an exemption should demonstrate that the additional value exists beyond reasonable doubt. See SEC *Codification of Staff Accounting Bulletins* Topic 12(D)(3)(a), "Exemptions for Purchased Properties." Although the SEC regulations do not directly apply to private entities, these entities should consider this guidance.

5.24 SEC *Codification of Staff Accounting Bulletins* Topic 12(D)(3)(c), "Effect of Subsequent Events on the Computation of the Limitation on Capitalized Costs," provides guidance on the effect of a certain subsequent event on the ceiling test. In the situation described, subsequent to year-end but before the date of the auditors' report on the entity's financial statements, additional reserves are proved up on properties owned at year-end. The present value of future net revenues from the additional reserves may be sufficiently large that the ceiling would more than cover the costs if the full cost ceiling limitation were recomputed giving effect to these additional reserves as of period-end. In this instance, the entity can elect to consider these additional reserves in the ceiling test, with certain disclosures. If taken into consideration, this may reduce or eliminate the impairment. The AICPA Financial Reporting Executive Committee (FinREC) understands that the SEC staff views the decision to assess these subsequent events in the ceiling test as an option that may or may not be elected at each period-end. In periods when it is elected, it should be applied in a consistent manner.

5.25 The proving up of additional reserves on properties owned at year-end indicates that the capitalized costs were not, in fact, impaired at year-end. However, for purposes of the revised computation of the ceiling, the net book costs capitalized as of year-end should be increased by (*a*) the amount of any additional costs incurred subsequent to year-end to prove the additional reserves or (*b*) any related costs previously excluded from amortization.

5.26 Although the fact pattern described herein relates to annual periods, the guidance on the effects of subsequent events applies equally to interim period calculations of the ceiling limitation. The date selected for the ceiling recomputation should be consistent from period to period and bear a logical relationship to the filing date of the affected financial statements. For example, it is logical that an oil and gas producing entity that chooses to consider a subsequent event should consistently make whatever recalculations are necessary at the date the auditors are completing their interim reviews.

5.27 The financial statements should disclose that capitalized costs exceeded the limitation thereon at period-end and should explain why the excess was not charged against earnings. In addition, supplemental disclosures of estimated proved reserve quantities and related future net revenues and costs should not give effect to the reserves proved up or the cost incurred after year-end. However, such quantities and amounts may be disclosed separately with appropriate explanations.

5.28 Oil and gas reserves related to properties acquired after year-end would not justify avoiding a write-off indicated as of year-end. Similarly, the effects of cash flow hedging arrangements entered into after year-end cannot be factored into the calculation of the ceiling limitation at year-end. Such acquisitions and financial arrangements do not confirm situations existing at year-end.

Applications Involving a New Country

5.29 Under the full cost method, costs of property acquisition, exploration, and development are accumulated in a country-specific cost center and subjected to a quarterly impairment (ceiling) test, as previously discussed. If an entity using the full cost method conducts activities in a country in which it has not previously conducted exploration activities (a new country) and, therefore, has not recognized any proved reserves in that new country, the following issues arise in the application of the ceiling test:

- *Issue no. 1*. For entities using the full cost method that are assessing exploration opportunities in a new country, can G&G costs incurred prior to the acquisition of a property interest (initial G&G costs) be added back to the ceiling limitation, consistent with the treatment of such costs when associated with an owned unevaluated property interest?
- *Issue no. 2*. Once a property interest is acquired, if dry hole costs are incurred prior to determination of proved reserves (initial dry hole costs), can such costs be deferred pending completion of other planned exploratory drilling activity in the new cost center?

5.30 Issue no. 1 relates to a situation in which an oil and gas entity incurs G&G costs pursuant to an exploration plan prior to acquiring any property interests in a new country. Rule 4-10(c)(3)(ii)(A)(3) of Regulation S-X states that "[i]f geological and geophysical costs cannot be directly associated with specific unevaluated properties, they shall be included in the amortization base as incurred." As a result, it would be consistent with Rule 4-10 to subject initial G&G costs to the ceiling limitation test, which would result in immediate impairment. This treatment differs from that for G&G costs directly associated with specific owned unevaluated properties, which are added back to the ceiling limitation until the property is fully evaluated.

5.31 In regard to issue no. 2, Rule 4-10 requires that costs associated with a specific property be included in the amortization base, subject to the ceiling limitation test, when evaluation of the property is complete, including the drilling of a dry hole. Pursuant to an exploration plan, an oil and gas entity entering a new country may drill one or more dry holes before it has discovered any proved reserves. In a situation in which an entity has plans to continue exploration activity in the new country, a determination needs to be made about whether the dry hole costs should be subjected to the ceiling limitation test.

5.32 In the case of initial dry hole costs incurred, impairment would be indicated by the ceiling test, even though the entity has not abandoned its exploration plans for that new country. Some may consider the impairment of these costs under these circumstances to be inconsistent with the underlying premise of full cost accounting, which is that all of the costs incurred in the exploration for oil and gas reserves, including costs related to unsuccessful activities, are necessary in order to find oil and gas reserves.

5.33 If these costs were impaired, the potential exists to eventually record proved reserves with little or no capitalized costs. For example, if an entity entered into a program in a new country to drill five wells and only the fifth well recovered oil and gas reserves, some may consider that the cost to obtain the proved reserves (and the related cost center depletion rate) should reflect the costs of the first four wells.

5.34 The authoritative guidance for the full cost method provided in Rule 4-10 of Regulation S-X, and the related interpretive guidance provided by the SEC, does not address this issue. Because no accounting guidance exists for an entity to apply when assessing whether continued capitalization is appropriate, significant judgment is necessary.

5.35 An entity should consider the guidance included in Rule 4-10 with respect to the accounting treatment for exploration activities as well as the concepts underlying the full cost accounting method to determine whether immediate application of the ceiling limitation test or potential deferral of the ceiling test is appropriate.

Accounting for Production

5.36 Refer to chapter 4 of this guide for details of accounting for production, including accounting for revenue, inventory, and operating expenses.

Asset Retirements, Environmental Liabilities, Abandonments, Involuntary Conversions, and Expropriations

Abandonment of Unevaluated (Unproved) Properties

5.37 Abandonments of oil and gas properties that had not previously been evaluated and, therefore, are included in the full cost center are accounted for as adjustments of capitalized costs (that is, the cost of abandoned properties should be charged to the full cost center and amortized, subject to the limitation on capitalized costs).

Revisions and Settlements of AROs

5.38 FASB ASC 410-20-35-8 states that changes resulting from revisions to the timing or amount of the original estimate of undiscounted cash flows should be recognized as an increase or decrease in the carrying amount of the liability for an ARO and the related asset retirement cost capitalized as part of the related long-lived asset. Upward revisions in the amount of undiscounted estimated cash flows should be discounted using the current credit-adjusted risk-free rate. Downward revisions in the amount of undiscounted estimated cash flows should be discounted using the credit-adjusted risk-free rate that existed when the original liability was recognized.

5.39 Under FASB ASC 410, when an ARO is settled using internal resources, a gain or loss typically is recognized when settlement occurs. If an entity's estimates of future costs prove accurate and the costs incurred are consistent with the costs a third party would incur, any gain or loss equals the normal profit margin and market risk premium that was assumed in measuring the fair value of the liability.

5.40 However, under the full cost rules, recognizing gains (or losses) for contractual services performed in connection with properties owned is prohibited by Rule 4-10(c)(6)(iv) of Regulation S-X. Further, Rule 4-10(c)(6)(i) of Regulation S-X prohibits gains or losses on the sale or abandonment of properties unless the event is considered significant. Separately recognizing the gains and losses related to the profit margin resulting from the settlement of AROs of abandoned properties using internal resources would present inconsistencies with costs remaining in the full cost pool that are related to the abandoned properties (for example, salvage value, remaining unamortized costs, and so on).

5.41 The authoritative guidance for the full cost method provided in Rule 4-10 of Regulation S-X and the related interpretive guidance provided by the SEC does not provide guidance regarding the accounting for these transactions under the full cost rules and, therefore, the SEC has not provided a view with respect to the discussion that follows. Regarding the accounting for these transactions, according to FinREC, it is acceptable to either recognize gain or loss on these transactions consistent with the guidance in FASB ASC 410 or to treat the implied gain or loss as an adjustment to the full cost pool consistent with the guidance in Rule 4-10(c) of Regulation S-X.

5.42 Refer to chapter 4 of this guide for a general discussion related to the accounting for asset retirements, abandonments, involuntary conversions, and expropriations.

Fair Value Measurements

5.43 Refer to chapter 4 of this guide for a general discussion related to fair value measurements.

Lease Arrangements

5.44 Refer to chapter 4 of this guide for details of the accounting for lease arrangements.

Conveyances

5.45 Rule 4-10 of Regulation S-X adopts the conveyance accounting requirements in FASB Statement No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies* (which has been codified in FASB ASC 932, *Extractive Activities—Oil and Gas*), for all oil and gas entities, with certain modifications for entities applying the full cost method. See chapter 4 of this guide for general guidance regarding accounting for conveyances, and see the following discussion for certain guidance specific to the full cost method.

5.46 Sales of oil and gas properties, regardless of whether they are currently amortized, are accounted for as an adjustment of capitalized costs, with no gain or loss recognized, unless such adjustment would significantly alter the relationship between capitalized costs and proved oil and gas reserves attributable to a cost center. For instance, a significant alteration would not ordinarily be expected to occur for sales involving less than 25 percent of the reserve quantities of a given cost center.

5.47 Although expected to occur infrequently, a significant alteration of the relationship between capitalized costs and proved reserves also could occur for sales of less than 25 percent of the reserve quantities if there were substantial economic differences between the properties sold and those retained. Significant judgment is required to determine whether an adjustment to capitalized costs would result in a significant alteration.

5.48 If it is determined that a gain or loss should be recognized on such a sale, total capitalized costs within the cost center are allocated between the reserves sold and reserves retained. The allocation of capitalized costs should be made on the same basis used to compute amortization unless there are substantial economic differences between the properties sold and those retained, in which case capitalized costs should be allocated on the basis of the relative fair values of the properties.

Discontinued Operations

5.49 Under the "Impairment or Disposal of Long-Lived Assets" subsections of FASB ASC 360-10 and FASB ASC 205-20, the sale of an oil and gas property qualifies for discontinued operations reporting under certain circumstances for entities applying the successful efforts method. For entities applying the full cost method, FinREC believes that a *component of an entity*, which, according to the FASB ASC glossary, comprises operations and cash flows that can be clearly distinguished, operationally and for financial reporting purposes, from the rest of the entity and may be a reportable segment or an operating segment, a reporting unit, a subsidiary, or an asset group, would be an individual cost center and, therefore, discontinued operations reporting would not be appropriate unless the entire cost center was disposed. If an entire cost center is disposed, reporting as discontinued operations would be appropriate if the other criteria in the "Impairment or Disposal of Long-Lived Assets" subsections of FASB ASC 360-10 and FASB ASC 205-20 were met.

Goodwill

5.50 Refer to the "Goodwill and Business Combinations" section in chapter 4 of this guide for specifics of goodwill accounting in business combinations by oil and gas entities.

Goodwill—Property Disposals

5.51 FASB ASC 350-20-35-52 states that when a portion of a reporting unit that constitutes a business is disposed of, goodwill associated with that business shall be included in the carrying amount of the business in determining the gain or loss on disposal. Determining when the disposition of oil and gas properties constitutes a business can be a complicated assessment that requires significant judgment. Refer to the "Goodwill and Business Combinations" section of chapter 4 for further discussion regarding the assessment of whether an oil and gas operation represents a business.

5.52 As discussed in paragraph 5.46, Rule 4-10 of Regulation S-X generally precludes recognizing gains or losses when a full cost entity sells oil and gas properties unless such disposition involves more than 25 percent of the proved reserves attributed to the cost center. Further, Rule 4-10(c) of Regulation S-X or the SABs do not contemplate goodwill (either its creation or disposition) in any manner. Accordingly, diversity in practice has developed when full cost entities dispose of oil and gas properties constituting a business that represent less than 25 percent of the proved reserves in a cost center.

5.53 Some preparers and auditors believe that FASB ASC 350-20-35-52 requires a full cost entity to calculate the goodwill associated with dispositions of properties that constitute a business. Given that Rule 4-10 of Regulation S-X precludes recognition of gain or loss for dispositions involving less than 25 percent of the proved reserves attributed to the cost center, these preparers and auditors believe that the amount of goodwill determined to be allocable to the disposition should be netted against the proceeds from the disposition in calculating the amount of the adjustment to the cost center. The disposition may also represent a triggering event that requires the remaining goodwill to be evaluated for impairment. Based on discussions with the SEC staff in April 2010, the SEC staff expressed their concurrence with this view and indicated that they believed it is preferable to a policy of not allocating a portion of the goodwill to the disposed business, as discussed subsequently.

5.54 Given that Rule 4-10 of Regulation S-X is silent on the subject of goodwill, some preparers and auditors believe that full cost entities are not required to allocate goodwill for dispositions representing less than 25 percent of the proved reserves of a cost center. Instead they consider such an occurrence a triggering event that requires goodwill to be evaluated for impairment. Entities that use this accounting policy point to a February 2005 letter from the SEC Division of Corporation Finance as confirmation for their policy. (The letter has been moved to the Division's Archives[3] on the SEC's website because the staff believes the topics addressed in this letter have been superseded by subsequently issued U.S. generally accepted accounting principles or are otherwise no longer relevant.) As noted in paragraph 5.53, the SEC staff has indicated that an accounting policy of allocating goodwill to a disposition constituting a business is preferable to an accounting policy of not allocating goodwill to such a disposition. However, if an entity has historically maintained an accounting policy of not allocating goodwill based upon the February 2005 SEC letter, the SEC staff will not take exception to such a policy. To the extent that a full cost entity is establishing a policy for the first time in regard to goodwill and the

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[3] This letter can be found on the SEC'S website at www.sec.gov/divisions/corpfin/guidance/oilgas021105.htm.

disposition of properties constituting a business, the SEC staff believes that the policy described in paragraph 5.53 is preferable.

5.55 An allocated portion of goodwill should be included in the gain or loss calculation when a disposition of properties constitutes a business and represents more than 25 percent of proved reserves of a cost center.

Other Matters

Management Fees and Other Income

5.56 Per Rule 4-10(c)(6)(iv) of Regulation S-X, no income should be recognized in connection with contractual services performed (for example, drilling, well service, equipment supply services, and so on) in connection with properties in which the registrant or an affiliate holds an ownership or other economic interest, except as follows:

a. When the registrant acquires an interest in the properties in connection with the service contract, income may be recognized to the extent the cash consideration received exceeds the related contract costs plus the registrant's share of costs incurred and estimated to be incurred in connection with the properties. For purposes of applying this rule, ownership interests acquired within one year of the date of such a contract are considered to be acquired in connection with the service. The amount of any guarantees or similar arrangements undertaken as part of this contract should be considered as part of the costs related to the properties, for purposes of applying this rule.

b. When the registrant acquires an interest in the properties at least one year before the date of the service contract through transactions unrelated to the service contract and that interest is unaffected by the service contract, income from such contract may be recognized, subject to the general provisions for elimination of intercompany profit under U.S. generally accepted accounting principles.

c. Notwithstanding the provisions of the preceding (*a*) and (*b*), no income may be recognized for contractual services performed on behalf of investors in oil and gas producing activities managed by the registrant or an affiliate. Furthermore, no income may be recognized for contractual services to the extent that the consideration received for such services represents an interest in the underlying property.

d. Any income not recognized as a result of these rules would be credited to the full cost center and recognized through a lower amortization provision as reserves are produced.

According to Financial Reporting Release No. 17, *Oil and Gas Producers—Full Cost Accounting Practices*, this guidance does not distinguish between proved producing properties and unproved properties. The prohibition on income recognition applies to all properties. The rule's general prohibition of income recognition reflected the SEC's view that current recognition of income for services rendered in connection with an owned property would be inconsistent with the full cost concept under which income is recognized only as reserves are produced. The SEC indicated that income should be recognized only to the extent that it exceeds an entity's costs in connection with the contract and the properties, except for the limited circumstances. Accordingly, registrants should treat management and service fees (including Council of Petroleum Accountants Societies [COPAS] fee reimbursements) as a reimbursement of costs by offsetting the costs incurred to provide the services, with any excess of fees over costs credited to the full cost center and recognized through lower cost amortization only as production occurs.

Commodity Derivative Activities

5.57 Refer to the "Derivative Commodity Contracts" section in chapter 4 of this guide for details of typical derivative instruments and transactions used by oil and gas entities.

Disclosure Requirements

5.58 Refer to the "Disclosure Requirements for Oil and Gas Entities" section in chapter 4 of this guide for general disclosure requirements for oil and gas producing entities.

Additional Disclosure Requirements for Full Cost Entities

5.59 Pursuant to Rule 4-10(c)(7) of Regulation S-X, reporting entities that follow the full cost method of accounting should make certain special disclosures, including the following:

- For each cost center for each year that an income statement is required, disclose the total amount of amortization expense (either per equivalent physical unit of production, if amortization is computed on the basis of physical units, or per dollar of gross revenue from production if amortization is computed on the basis of gross revenue).
- State separately on the face of the balance sheet the aggregate of the capitalized costs of unproved properties and major development projects that are excluded from the capitalized costs being amortized, in accordance with Rule 4-10(c)(3)(ii) of Regulation S-X. Provide a description in the notes to the financial statements of the current status of the significant properties or projects involved, including the anticipated timing of the inclusion of the costs in the amortization computation. Present a table that shows, by category of cost, (*a*) the total costs excluded as of the most recent fiscal year and (*b*) the amounts of such excluded costs incurred (i) in each of the three most recent fiscal years and (ii) in the aggregate for any earlier fiscal years in which the costs were incurred. In the case of significant development projects and capitalized interest, categories of cost to be disclosed include acquisition costs, exploration costs, and development.

5.60 In addition, pursuant to Rule 4-10(c)(4)(ii) of Regulation S-X, any impairment charge recorded based on the ceiling test should be separately disclosed. If an indicated impairment is not recorded because of certain subsequent events, as described in SEC *Codification of Staff Accounting Bulletins* Topic 12(D)(3)(c), then disclosure should be made to explain why the impairment was not recorded.

5.61 In SEC *Codification of Staff Accounting Bulletins* Topic 12(D)(3)(b), "Use of Cash Flow Hedges in the Computation of the Limitation on Capitalized Costs," the SEC staff suggested that 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 FASB ASC 275, *Risks and Uncertainties*. The SEC staff indicated that paragraph .14 of Statement of Position 94-6, *Disclosure of Certain Significant Risks and Uncertainties* (which has been codified in FASB ASC 275-10-50-9), 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.

Chapter 6

Accounting for International Oil and Gas Activities

Overview

6.01 The world's increasing appetite for oil and natural gas has resulted in oil and gas entities widening their search for hydrocarbon resources well beyond the national borders of their home country. For example, a leading entity headquartered in the United States that prepares its consolidated financial statements in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP) reported that more than 70 percent of its crude oil and liquids proved reserves and proved reserves of its equity investee entities were located outside the United States, and more than 65 percent of such reserves were located outside of North America.

6.02 Operating in different countries subjects oil and gas entities to different legal systems than in the United States. Rights and obligations under these different systems should be carefully understood because exploration, development, exploitation, and production economics can be significantly affected. Outside the United States, hydrocarbon resources are commonly owned by the government on behalf of the country and not by private citizens or businesses.

6.03 Additionally, operating in developing countries of the world subjects oil and gas entities to additional business risks, such as (*a*) political, economic, and regulatory risks; (*b*) foreign currency risks; and (*c*) information and communication risks. Although these risks are better understood as entities gain operating experience in specific countries, changing governments can pass sweeping new laws and institute new regulatory regimes that can quickly change the landscape in which businesses operate. Information and communication risks relate to pertinent information that should be identified, captured, and communicated in a form and time frame that enables a business to achieve its objectives. These risks are often exacerbated by the geographical distances between field operations and accounting operations and by differences between knowledge of U.S. GAAP and financial reporting practices of accountants located in the host country and those located in the United States.

6.04 Although the accounting methods required under U.S. GAAP are the same for both U.S. and international operations, as previously mentioned, the contractual arrangements encountered internationally often differ from the arrangements that exist in the United States. In addition, the successful efforts and full cost methods were developed before these contractual arrangements had become widely used and, therefore, do not specifically address these arrangements. This chapter discusses certain aspects of commonly encountered contractual arrangements in international areas and discusses how the provisions of these arrangements may affect how the entity accounts for these operations and determines its reserves.

International Contractual Arrangements

6.05 One of the most significant accounting issues for oil and gas entities operating internationally is properly determining the sharing of the prospective value and actual value of oil and gas produced from within the host country. The host country's share of the value can be in many different forms, such as acreage or block bonuses, production royalties, carried arrangements, profit sharing, taxes and fees, and infrastructure developments. Proper accounting for international oil and gas operations requires a thorough understanding of the terms of the contractual arrangements in order to identify the rights and obligations of the oil and gas entity. These rights and obligations translate into assets, liabilities, revenues, and costs for accounting purposes.[*]

6.06 International contractual arrangements, also known as *fiscal systems*, have many different terms and variations but generally are classed as (*a*) concessions, (*b*) production sharing contracts, or (*c*) service contracts.

Concessions

6.07 Concessions are similar to leases in the United States. The entity typically has rights to the discovered reserves through the terms of the concession. Title to oil and gas produced rests with the concession participants, but the host government's share of the operation is determined by bonuses, royalties, carried interests, and taxation, which is similar to the U.S. government's share of operations on federal leases.

Production Sharing Contracts

6.08 Production sharing contracts (PSCs) are the most common contractual arrangements in oil and gas producing countries of the world. The other contracting party is often a government agency or a government-owned entity

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[*] On July 21, 2010, the president signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act). Section 1504, *Disclosure of Payments By Resource Extraction Issuers*, of the Dodd-Frank Act amends Section 13 of the Securities Exchange Act of 1934 (*Commerce and Trade, U.S. Code* Title 15, Section 78m) to require a resource extraction issuer to include in its annual report (and also submit in an interactive data format) information relating to any payment made by the resource extraction issuer, a subsidiary of the resource extraction issuer, or an entity under the control of the resource extraction issuer to a foreign government or the U.S. Federal Government for the purpose of the commercial development of oil, natural gas, or minerals, including (*a*) the type and total amount of such payments made for each project of the resource extraction issuer relating to the commercial development of oil, natural gas, or minerals, and (*b*) the type and total amount of such payments made to each government.

Section 1504 of the Dodd-Frank Act indicates that *commercial development of oil, natural gas, or minerals* includes exploration, extraction, processing, export, and other significant actions relating to oil, natural gas, or minerals, or the acquisition of a license for any such activity, as determined by the Securities and Exchange Commission (SEC). Section 1504 of the Dodd-Frank Act also indicates that the term *payment* means a payment that is made to further the commercial development of oil, natural gas, or minerals, and is not de *minimis*, including taxes, royalties, fees (including license fees), production entitlements, bonuses, and other material benefits, that the SEC, consistent with the guidelines of the Extractive Industries Transparency Initiative (to the extent practicable), determines are part of the commonly recognized revenue stream for the commercial development of oil, natural gas, or minerals.

Section 1504 of the Dodd-Frank Act can be found at www.sec.gov/about/laws/wallstreetreform-cpa.pdf.

On December 15, 2010, the SEC issued Proposed Rule No. 34-63549, *Disclosure Payments by Resource Extraction Issuers*, for public comment. Proposed Rule No. 34-63549 can be found at www.sec.gov/rules/proposed/2010/34-63549.pdf. Additional information on this proposed rule, including discussion of the proposed disclosure requirements and comment letters received by the SEC, can also be found at www.sec.gov/news/press/2010/2010-247.htm. Readers are encouraged to monitor the SEC's website at www.sec.gov/index.htm for the latest developments on this rulemaking project.

(GOE) designated by the host country's energy ministry. The terms of PSCs will vary between countries and even within the same country. A PSC includes provisions that specify the sharing of costs (both exploration and development) and the value attributed to any production.

6.09 Commonly, the oil and gas entity bears all costs of exploration. If proved reserves are discovered, the GOE has the right to participate, often as the majority working interest owner, and normally pays its share of development and operating costs. The PSC includes provisions specifying the manner in which the oil and gas entity recovers its exploration and development costs. PSCs have many contractual variations about how costs are recouped by the oil and gas entity. Cost recovery is normally accomplished through *cost recovery oil*, which is production allocated to the oil and gas entity to recover a specified type or amount of costs. Sometimes, it is unclear whether certain costs are eligible for cost recovery, and the host country government may reject or disallow certain costs. The oil and gas entity's share of production after recovery of cumulative costs or costs incurred or allocated to a specific period is known as *profit oil*. Understanding the terms and conditions about how and when costs are recovered through cost recovery oil and when an oil and gas entity is entitled to profit oil is key to accounting for PSCs. The determination of cost recovery oil and profit oil are critical factors in determining whether proved reserves exist and how they are to be allocated between the parties.

Service Contracts

6.10 Service contracts are another type of contractual arrangement being encountered more often by oil companies. Service contracts are risk service contracts or nonrisk service contracts. In a risk service contract, the oil and gas entity accepts the exploration, development, exploitation, and production risks and pays the related costs. For accepting the risks, the oil and gas entity receives a fee for recovery of costs and profits, normally payable in production. The fees may be based on a variety of production related factors, such as incremental production over a previous period or incremental production over a baseline quantity. The fees also may include a form of incentive fee after cumulative production exceeds some predetermined quantity.

6.11 Nonrisk or "pure" service contracts are arrangements whereby the oil and gas entity provides services in the form of exploration, development, and production activities. The host country or GOE pays a fee covering costs incurred by the oil and gas entity plus profits. In these arrangements, the GOE retains the operational risks and pays the oil and gas entity for its specialized skills or knowledge, normally in cash. Thus, the oil and gas entity acts as a contractor or consultant providing services, rather than in its usual role as a producer of hydrocarbons. Nonrisk service contracts are less prevalent than risk service contracts.

Other Arrangements

6.12 Other types of fiscal arrangements that have been encountered include technical assistance contracts and rate of return contracts. These types of arrangements contain aspects of PSCs or service contracts. They should be evaluated based on the terms of the contracts to determine the appropriate accounting treatment.

6.13 Understanding the nature of the oil and gas entity's international activities and the terms and conditions of international contractual arrangements is necessary to determine the appropriate accounting under generally accepted accounting principles. Activities under PSCs and risk service contracts are generally viewed as oil and gas producing activities. However, activities performed under nonrisk service contracts are not likely to meet the Securities and Exchange Commission's (SEC's) definition of oil and gas producing activities. Key factors are whether (*a*) the oil and gas entity is at risk for performance, (*b*) the contract results in payment to the oil and gas entity in cash or in kind, and (*c*) the entity receives the title to the hydrocarbons produced.

6.14 International oil and gas producing activities are conducted in many different legal forms, including partnerships, joint ventures, corporations, or undivided interests in the oil and gas properties. Partnership interests are typically general partnership interests, but host country laws may increase or decrease the legal obligations of general partners. Determining the accounting treatment for these entities can be complex. Refer to the discussion in chapter 3, "Accounting for Common Oil and Gas Ownership Arrangements," of this guide for further information.

Royalty, Production Taxes, and Income Taxes

6.15 As previously mentioned, the terms and provisions of international contractual arrangements should be closely evaluated to determine the appropriate accounting treatment. One key area relates to amounts paid in cash or in kind to the host government and whether such amounts constitute a royalty, production tax, or income tax, including situations in which the income tax is paid on behalf of the oil and gas entity. The following summarizes several different arrangements that might exist; however, no common theme fits every international contractual arrangement, and the final conclusion should be based on the specific terms and provisions of the contract.

6.16 In some situations, it may be difficult to determine whether an arrangement represents a royalty, a production tax, or an income tax. The following discussion summarizes the characteristics of each and provides some factors to consider when determining how to assess the terms and provisions of a PSC in this area.

Royalty

6.17 A *royalty* is the right to a share of oil and gas production free from cost and can be paid with oil and gas in kind or in cash. A royalty interest is considered a nonoperating interest and is included within the definition of *properties* in the Financial Accounting Standards Board (FASB) *Accounting Standards Codification* (ASC) glossary. A nonoperating interest held by others should not be reflected in either the financial results or the proved reserve quantities of the entity's oil and gas activities. The amounts paid for royalties, whether in kind or in cash, should be excluded from revenues. If the royalty is paid in cash, the related volumes should be determined by dividing the amount paid by the price of the overall volumes sold. For example, if the total sales volumes were 1,000 barrels, the price was $40 per barrel (total revenue of $40,000), and the royalty was $4,000, then the related royalty volumes would be 100 barrels ($4,000/$40). These volumes should be excluded from the entity's sales volume for purposes of calculating depreciation, depletion, and amortization, and the same approach should be applied to determine the proved reserves attributable to the royalty interest. See chapter 2, "Primary Business Activities of the Industry," of this guide for further discussion of royalty interests.

6.18 Factors that may indicate that the arrangement represents a royalty would generally be the opposite of the factors discussed subsequently related to production taxes.

Production Tax

6.19 A *production tax* (sometimes referred to as a *severance tax*) is a tax levied by the government on mineral production based on the value or quantity of production, or both. *Production costs* are defined in FASB ASC 932-360-25-15 as those costs incurred to operate and maintain an entity's wells and related equipment and facilities. Severance taxes are included as a specific example of production costs in FASB ASC 932-360-25-15. FASB ASC 932-235-50-24 indicates that "[p]roduction or severance taxes shall not be deducted in determining gross revenues, but rather shall be included as part of productions costs."

6.20 Some factors that could indicate the amount paid is a production tax and, thus, part of production costs might include, but are not limited to, the following:

- The amount is shared based on each party's ownership interest.
- The amount is remitted to a party (or government component) separate and distinct from the government agency authorizing the contractual arrangement.
- The amount is not considered a nonoperating interest (such as a royalty), upon legal analysis.
- The amount attributable to the oil and gas entity is treated like any other operating expense for local country tax purposes (that is, generally it would be deductible locally) and does not generate a foreign tax credit for U.S. income tax purposes.

Income Tax

6.21 The FASB ASC glossary defines *income tax* as domestic and foreign federal (national), state, and local (including franchise) taxes based on income.

6.22 The host country generally has a defined tax regime. However, if the host country does not have such a tax regime, the payments may, nevertheless, constitute an income tax, subject to FASB ASC 740, *Income Taxes*, to the extent amounts owed are predicated on a concept of income less allowable expenses incurred to generate and earn the income.

6.23 In some situations, the host government may allow settlement of the income tax through delivery of produced volumes instead of cash. The accounting for the income tax should be based on the substance of the arrangement. In situations in which the amount meets the criteria of an income tax and the calculation is expressed in monetary terms, the amount should be included in gross revenue and income tax expense. The oil and gas entity has, in effect, sold the volumes and used the proceeds to settle its income tax liability.

6.24 In other situations, the GOE pays the income tax due by the oil and gas entity on behalf of the oil and gas entity, which is referred to as a *paid on behalf* (POB) *arrangement*. A critical issue related to POB arrangements is whether the arrangement is a tax holiday or an income tax levied on the oil and gas entity. If the oil and gas entity does not have a legal obligation for payment of the tax, the accounting should follow that of a tax holiday. If the amount is considered an income tax, the oil and gas entity should record the POB amount as both revenue and income tax expense.

6.25 FASB ASC 740-10-05-1 establishes standards of financial accounting and reporting for the tax consequences of "[r]evenues, expenses, gains, or losses that are included in taxable income." The FASB ASC glossary defines *taxable income* as "[t]he excess of taxable revenues over tax deductible expenses and exemptions for the year as defined by the governmental taxing authority."

6.26 Thus, if the amount meets the definition of an income tax (that is, it is based on a calculation that considers both income and deductions), it should be treated as an income tax.

6.27 Some other factors that might indicate that the arrangement represents an income tax, include, but are not limited to, the following:

- The international contractual arrangement specifically states the entity is subject to income tax.
- The oil and gas entity is required to file an income tax return.
- The oil and gas entity is legally responsible for the income taxes until relieved of the obligation by payment either by itself or the GOE.
- A clear separation exists between the tax authority and the GOE.
- The amounts paid are creditable, for purposes of U.S. income tax.

6.28 The accounting concepts to be applied to amounts paid or deemed to be paid to the host country's government are not "one size fits all." The specific terms and provisions of the international contractual arrangement should be carefully evaluated.

Reporting International Proved Reserves[1]

6.29 Paragraphs 4–5 of FASB ASC 932-235-50 require the disclosure by an oil and gas entity (that meets the definition of a *publicly traded company*) of its net interest in quantities of proved, proved developed, and proved undeveloped oil and gas reserves and of the changes in the net quantities of proved oil and gas reserves. These disclosures are required in the aggregate and separately for geographic areas, as defined in paragraph 5–6B of FASB ASC 932-235-50. See the "FASB ASC 932 Disclosures" section of chapter 4, "Successful Efforts Method and General Accounting for Oil and Gas Activities," for further information related to these requirements. As mentioned in

[1] The information in this section relates to the reporting of reserves for purposes of compliance with current accounting principles generally accepted in the United States of America (U.S. GAAP) and SEC requirements. See further discussion of these disclosure requirements in chapter 4, "Successful Efforts Method and General Accounting for Oil and Gas Activities," of this guide. Many foreign jurisdictions have specific reserve reporting requirements that differ from those for U.S. GAAP. Entities should determine that reserves reported for international operations under U.S. GAAP are reported using the appropriate guidelines. In addition, the SEC reporting requirements contained in Final Rule No. 33-8995, *Modernization of Oil and Gas Reporting* revise Form 20-F to incorporate Subpart 1200 of Regulation S-K, with respect to oil and gas disclosures, and delete appendix A of Item 4D in Form 20-F, which previously required significantly less oil and gas reserves disclosure for foreign private issuers versus domestic filers.

paragraph 6.13, nonrisk service contracts are not likely to meet the definition of an *oil and gas producing activity*. Consequently, the guidance in FASB ASC 932, *Extractive Activities—Oil and Gas*, would not apply.

6.30 FASB ASC 932-235-50-7 provides that reserve quantities disclosed under the requirements of paragraphs 4–6 of FASB ASC 932-235-50, which are discussed in the preceding paragraph, should not include oil or gas subject to purchase under long-term supply, purchase, or similar agreements and contracts, including such agreements with governments or authorities. However, quantities subject to such agreements with governments or authorities should be separately disclosed if the oil and gas entity participates in the operation of the properties in which the oil and gas is located or otherwise serves as the producer of those reserves. The FASB ASC glossary includes in its definition of *properties* those agreements with foreign governments or authorities under which an entity participates in the operation of the related properties or otherwise serves as producer of the underlying reserves.

6.31 Properties do not include other supply agreements or contracts that represent the right to purchase (versus extract) oil and gas. Entities operating internationally should evaluate their contractual arrangement to determine if they participate in the operation of the properties or otherwise serve as producer.

6.32 Oil and gas entities operating internationally should determine the legal nature of their right to produce the oil and gas, subject to agreements with governments and authorities, in order to properly present their proved reserve quantities and changes to those quantities.

6.33 In general, two methods of determining oil and gas reserves under production sharing arrangements have been utilized by oil and gas entities operating internationally: (*a*) the working interest method, and (*b*) the economic interest method. Under the working interest method, the estimate for total proved reserves is multiplied by the respective working interest held by the oil and gas entity, net of any royalty. Under the economic interest method, the oil and gas entity's share of the cost recovery oil revenue and profit oil revenue is divided by the year-end oil price,[2] which represents the volume entitlement. The lower the oil price, the higher the barrel entitlement and vice versa.

6.34 Reserve volumes determined by various owners should add up to 100 percent of the total field reserves, but that is not always the case using the working interest method. If the reserve volumes calculated under the working interest method are different than the actual entitlement to reserve volumes, the SEC staff prefers the economic interest method, as indicated in the March 2001 guidance of the SEC's Division of Corporation Finance. It is the SEC staff's view that the economic interest method is a closer representation of the actual reserve volume entitlement that can be monetized by an oil and gas entity. Also, the use of the economic interest method avoids violating the prohibition in FASB ASC 932-235-50-4 against reporting reserves relating to interests of others.

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[2] Although not specifically addressed in the SEC reporting requirements contained in Final Rule No. 33-8995, upon adoption of these requirements, the price used to compute an entity's reserves under the economic interest method would be expected to be the 12-month average price required for reserve determinations under this new guidance.

Asset Retirement Obligations in International Operations

6.35 FASB ASC 410, *Asset Retirement and Environmental Obligations*, provides the accounting for dismantlement, restoration, and abandonment costs related to oil and gas properties.

6.36 The legal obligation for dismantlement, restoration, and abandonment costs generally is incurred when a well is drilled or a platform or other equipment is placed in service. Oil and gas entities operating internationally should consider the specific asset retirement obligations (AROs), if any, imposed by the host country. In many PSCs, title to the assets passes to the GOE either after installation (drilling) or at the expiration of the PSC. In cases in which wells are expected to still be producing at that time, it is often not clear which party has the obligation for the asset retirement.

6.37 An area of complexity for AROs of international operations relates to the application of FASB ASC 830, *Foreign Currency Matters*. In particular, differences in practice exist in situations in which the functional currency of the entity differs from the currency in which the ARO is expected to settle. To apply FASB ASC 830, an entity determines whether the ARO is a monetary or nonmonetary item. Some entities consider AROs to be nonmonetary items, based on the FASB ASC glossary term *monetary liability*.

6.38 The FASB ASC glossary defines *monetary liability* as an obligation to pay a sum of money, the amount of which is fixed or determinable, without reference to future prices of specific goods and services.

6.39 Because the extinguishment of an ARO typically includes consideration of technological changes as well as changes in future prices, these entities treat AROs as nonmonetary items and remeasure them at historical rates. Other entities treat these AROs as monetary obligations.

6.40 Two views related to the accounting for AROs as monetary obligations were included in the Emerging Issues Task Force (EITF) *Agenda Committee Report* in May 2005. (The issue was not added to the EITF agenda.) In the draft paper, one view proposed that the change in the ARO due to exchange rate changes should be treated as a foreign currency transaction gain or loss, in accordance with FASB ASC 830-20-35-1. The second view stated that the entire change in the ARO (including that due to exchange rate changes) should be treated as a revision to the original estimate of undiscounted cash flows, pursuant to FASB ASC 410-20-35-8. This treatment results in an adjustment to both the ARO and related long lived asset.

The Foreign Corrupt Practices Act of 1977

6.41 The Foreign Corrupt Practices Act of 1977 (FCPA) was designed to restore confidence in U.S. businesses doing business overseas after several scandals involving bribes to foreign officials, politicians, and political parties. The FCPA contains antibribery provisions and accounting provisions. The antibribery provisions make it unlawful for a U.S. person and certain foreign issuers of securities registered in the United States to make a corrupt payment to a foreign official for the purposes of obtaining or retaining business for or with, or directing business to, a person. Since 1998, the provisions also apply to foreign businesses or persons who perform any act related to a corrupt payment while in the United States. Noncompliance with the antibribery provisions can result in significant fines for corporations and individuals who willfully participate in the bribery of a foreign official. Noncompliance also can result in the loss of foreign tax credits for the jurisdictions in which the related act occurs.

6.42 The accounting provisions require businesses covered by the provisions to make and keep books and records that accurately and fairly reflect the transactions of the business and to devise and maintain an adequate system of internal accounting control. The FCPA also imposes criminal liability for failing to comply with the internal control provisions if a person knowingly circumvents the provisions; fails to implement a system of internal control; or falsifies any books, records, or accounts. Violations of the FCPA may have a direct and material effect on the determination of financial statement amounts or may have an indirect effect on the financial statements. Oil and gas entities operating internationally should specifically develop business controls to ensure compliance with all provisions of the FCPA.[†]

[†] See footnote * for discussion of Section 1504 of the Dodd-Frank Act, which proposes disclosure requirements on resource extraction issuers to include in annual reports (and also submitted in interactive data format) information relating to any payment made by the resource extraction issuer, a subsidiary of the resource extraction issuer, or an entity under the control of the resource extraction issuer to a foreign government or the U.S. Federal Government for the purpose of the commercial development of oil, natural gas, or minerals, including (*a*) the type and total amount of such payments made for each project of the resource extraction issuer relating to the commercial development of oil, natural gas, or minerals, and (*b*) the type and total amount of such payments made to each government.

Chapter 7

Tax Considerations

General

7.01 Taxes represent one of the major costs affecting oil and gas producing entities. An auditor may consider obtaining a general understanding of the principal types of taxes and their impact on the industry when planning and performing an audit of an oil and gas entity's financial statements.

7.02 The discussion in this chapter is intended to be 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. Refer to currently enacted provisions of the Internal Revenue Code (IRC) and regulatory or judicial interpretations for changes that have been made subsequent to the publication of this guide.

7.03 The following sections address certain common income tax issues applicable to oil and gas operations.

Income Taxes

7.04 In general, income taxes affect oil and gas entities in the same manner as they do other types of entities; however, the income tax provisions related to oil and gas operations 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. As a result of this significance and the impact on financial reporting, the auditor should have an understanding of the principal income tax considerations for entities in the industry.

7.05 This chapter contains references to certain classifications of oil and gas entities for U.S. tax purposes. The classification of the entity for tax purposes may have a significant affect on the taxation of the entity. The common classifications and their definitions are as follows:

- An *integrated oil company* is defined as an entity that is not an independent producer because it directly or indirectly engages in significant retailing or refining activities involving oil and gas.
- An *independent producer* is defined as an entity that does not directly, or through a related party, significantly engage in certain specified retailing or refining activities involving oil and gas or products derived therefrom.

The definitions of *integrated oil company*, *independent producer*, and *related party* are generally set forth in Section 613A of the IRC and may vary from those used in general accounting literature and industry publications.

Intangible Drilling and Development Costs

7.06 Intangible drilling and development costs (IDCs) are costs that in themselves have no salvage value and are incurred incidentally to, and are necessary for, the drilling and 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 costs). Tangible items, such as casing and tubing, do not qualify; however, the related cost of installation does qualify. Costs applicable to line pipe and storage tanks and comparable costs, including installation costs, are not considered IDCs because these costs are not related to the drilling and preparation of wells for production. These costs are treated as part of the cost of tangible property.

7.07 A taxpayer may elect to deduct domestic IDCs 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 IDCs. Such election is binding on the taxpayer for subsequent years.

7.08 An integrated oil company may deduct only 70 percent of domestic IDCs in the year paid or incurred. The remaining 30 percent is deducted ratably over 60 months, beginning with the month such costs are paid or incurred.

7.09 A taxpayer owning a working interest in a property may further elect to capitalize all or any portion of its otherwise deductible IDCs for a taxable year and amortize them over a 60-month period. In addition, if a taxpayer is allocated IDC deductions through a partnership, such costs also are subject to an election by the partner to be amortized ratably over a 60-month period. A taxpayer may be inclined to make such elections for various reasons (for example, to minimize or avoid alternative minimum tax payments).

7.10 Generally, any IDC incurred outside the United States is capitalized and amortized ratably over a 10-year period or capitalized to the depletable base of the property and then depleted for tax purposes consistent with other capitalized leasehold costs.

Depletion

7.11 Producers of oil and gas are entitled to a deduction for depletion of capitalized leasehold costs. The costs to be recovered through depletion are those that (*a*) must be capitalized for tax purposes in connection with acquisition of the taxpayer's interest in the property and (*b*) are not recoverable through depreciation (including capitalized IDCs). Such costs may include bonuses paid to a lessor, amounts paid for a royalty interest, capitalized delay rentals, and other types of expenditures related to acquisition of the interest. The proper determination of the applicable property for U.S. income tax purposes is critical to the depletion calculation.

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

7.13 Depletion 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 greater 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.

7.14 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 do not qualify for percentage depletion.

7.15 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 to deduct percentage depletion.

Common Temporary Differences

7.16 Tax laws and financial accounting standards differ in their recognition and measurement of assets, liabilities, equity, revenues, expenses, gains, and losses. As a result, differences between financial and tax accounting arise between (*a*) the amounts of taxable income and pretax financial income for a year and (*b*) the tax bases of assets or liabilities and their reported amounts in the financial statements.

7.17 Many of these types of differences result in taxable or deductible amounts in a future year. Such differences are known as *temporary differences* and are discussed in paragraphs 18–29 of Financial Accounting Standards Board (FASB) *Accounting Standards Codification* (ASC) 740-10-25. Exhibit 7-1 summarizes the most common temporary differences for oil and gas producing entities.

Exhibit 7-1

Common Temporary Differences

Temporary Difference	*Successful Efforts*	*Full Cost*	*Income Tax*
Prospecting costs (preacquisition exploration costs)			
Geological and geophysical (G&G) costs	Expense	Capitalize	Capitalize (Note 1)
Exploration costs (postacquisition)			
Carrying costs of undeveloped properties			
Delay rentals	Expense	Capitalize	Capitalize (Note 2)
Ad valorem taxes	Expense	Capitalize	Expense
Legal costs of title defense	Expense	Capitalize	Capitalize
Direct costs of maintaining land and lease records	Expense	Capitalize	Expense
Costs to prepare well location for drilling exploratory wells and intangible drilling costs			
Proved reserves are found	Capitalize	Capitalize	Expense (Note 4)
No proved reserves are found	Expense	Capitalize	Expense (Note 4)
Dry hole contribution	Expense	Capitalize	Capitalize (Note 3)
Bottom hole contribution	Expense	Capitalize	Capitalize (Note 3)
Intangible drilling and development costs (IDCs) (development wells)	Capitalize	Capitalize	Expense (Note 4)
Disposition of capitalized costs			
Depletion	Expense	Expense	Expense (Note 5)
Abandonments			
A property that is a portion of an amortization base becomes worthless	No loss recognized	No loss recognized	Loss recognized (Note 6)
Book provision for abandonments	Expense	N/A	Nondeductible
Amortization base becomes worthless	Loss recognized	Loss recognized	Loss recognized (Note 6)
Impairment valuation allowances for unproved properties	Expense	N/A	Nondeductible
Conveyances and related transactions	(Note 7)	(Note 7)	(Note 7)

Temporary Difference	*Successful Efforts*	*Full Cost*	*Income Tax*
Sale of part of an interest owned			
Substantial uncertainty exists concerning recovery of costs applicable to retained interest, or seller has substantial obligation for future performance	No gain or loss recognized	No gain or loss recognized	Gain or loss recognized (Note 8)

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 costs were generally capitalized if such costs would be associated with the acquisition of a property; otherwise, they were deducted.
2. Delay rentals generally are capitalized. If the taxpayer can demonstrate that delay rentals were paid with respect to undeveloped properties that the taxpayer does not intend to develop, they may be deductible.
3. Income tax treatment is unsettled. The IRS position is that dry hole and bottom hole contributions should be capitalized (Revenue Ruling 80-153). Many taxpayers continue to contend that all dry hole contributions should be expensed, along with bottom hole contributions, if dry.
4. Taxpayer makes a one-time election to deduct IDCs. Thereafter, independents can deduct 100 percent of IDCs, and integrateds can deduct 70 percent and amortize the remaining 30 percent over 60 months. An annual election is available to all taxpayers to capitalize any 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.
7. 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 (Revenue Ruling 77-176), farm-outs, tax partnerships, and the like.
8. Conveyances of an interest in which the conveyer retains an overriding royalty, net profits interest, or other nonoperating interest are treated as subleases, not sales, for income tax purposes.

Conveyances

7.18 As discussed in chapter 3, "Accounting for Common Oil and Gas Ownership Arrangements," 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 reviewed carefully and the terms and provisions analyzed to determine the appropriate tax treatment.

Accounting for Temporary Differences in Asset Acquisitions

7.19 The determination about whether an acquisition is a business combination or an asset purchase for accounting purposes requires significant judgment and can be complex for oil and gas exploration entities. Refer to the "Goodwill and Business Combinations" section of chapter 4, "Successful

Efforts Method and General Accounting for Oil and Gas Activities," for further discussion of this topic.

7.20 For transactions accounted for as asset acquisitions, any acquired temporary differences should be recorded in accordance with the guidance in sections 25, 35, 45, and 55 of FASB ASC 740-10. Examples of temporary differences in transactions accounted for as asset acquisitions may include acquisitions of oil and gas properties in which the amount paid differs from the tax basis (for example, a taxing authority may allow cost recovery in excess of the cost of oil and gas property); net tax benefits resulting from the purchase of future tax benefits from an independent party not acting as a taxing authority (for example, acquisition of an oil and gas entity with net operating loss carryforwards and no future operations at a price less than the value of the tax attributes); and transactions with governmental entities resulting in a tax benefit (for example, a particular taxing jurisdiction may allow for a step up in basis of oil and gas properties in exchange for a current tax payment).

7.21 As further addressed in FASB ASC 740-10-25-51, an asset purchase in which the amount paid differs from the tax basis requires the use of simultaneous equations to determine book basis and deferred taxes. FASB ASC 740-10-25-52 also addresses the accounting for net tax benefits associated with the purchase of future tax benefits from a third party (other than a government entity acting in its capacity as a taxing authority), and FASB ASC 740-10-25-53 addresses the accounting for transactions between a taxpayer and a government (in its capacity as a taxing authority).

FASB ASC 740-10—Uncertain Tax Positions

7.22 FASB ASC 740-10 clarifies the accounting for uncertain income tax positions. FASB ASC 740-10 prescribes a consistent recognition threshold and measurement criteria, as well as clear guidance for subsequently recognizing, derecognizing, and measuring changes in such tax positions for financial statement purposes. FASB ASC 740-10-50 requires disclosure with respect to the uncertainty in income taxes.

7.23 Some common items that often result in a determination of uncertain tax positions for upstream oil and gas operations include the following:

- Because IDCs are subject to accelerated deduction, the segregation of costs between IDCs and equipment additions can often result in controversy between taxpayers and the IRS, particularly regarding offshore facility costs.
- The rules related to the capitalization or deduction of geological and geophysical costs may be an issue for years prior to the enactment of the new amortization rules, and delay rental deductions also may be a point of contention.
- Although the IRS has issued new guidelines on how to compute reserve volumes for cost depletion purposes and provided a safe harbor method tied to 105 percent of proved reserve quantities determined pursuant to the rules of the Securities and Exchange Commission, the application of these rules still generates scrutiny from IRS engineers.
- Also, in recent years, taxing authorities from around the world have increased their scrutiny of transfer pricing, particularly in the area of the transfer pricing for services.

7.24 Other industry topics that may give rise to liabilities under FASB ASC 740-10 include enhanced oil recovery (EOR) credits, application of the uniform capitalization rules to self-constructed assets, and tax property determinations for depletion and worthless asset purposes.

Net Operating Losses—Valuation Allowances

7.25 Valuation allowances are required for deferred tax assets (for example, net operating losses) that are not more likely than not to be realized. In situations in which a history of cumulative losses in recent years exists, negative evidence is presumed that can be rebutted in only limited instances with offsetting high quality positive evidence. The oil and gas industry prepares estimates of proved reserve volumes that may be used as a source of evidence by oil and gas companies and may be one of several elements utilized to assess the need for a valuation allowance.

Other Common Tax Matters

Ad Valorem and Severance Taxes

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

- Ad valorem and severance taxes are deductible for income tax purposes. Both should be allocated to the appropriate property when calculating net income from the property applicable to determining limitations for percentage depletion.
- Ad valorem and severance taxes are normally applicable at the revenue interest level (versus lease operating expenses applicable at the working interest level).

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

EOR Credit (Section 43)

7.28 For tax years after December 31, 1990, a credit is available for qualifying costs paid or incurred as part of an EOR project. The base for the credit is qualified EOR costs. Qualified costs should be related to a certified, qualified EOR project, and only domestic costs qualify. To qualify, the project should involve the application of various gases, liquids, or other matters specified by Department of Energy regulations, and the taxpayer must own an operating mineral interest in the property. Three types of costs qualify for this credit: IDCs, costs of tangible property, and tertiary injectant costs. Generally, the credit is 15 percent of the qualified costs multiplied by a factor that is based on the 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 phaseout based on the inflation adjusted price of crude oil, such that the credit was not applicable for calendar year taxpayers in 2006–2009.

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

7.29 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 (*a*) $3.00 per barrel for the production of crude oil, and (*b*) $0.50 per 1,000 cubic feet of qualified natural gas production. The maximum amount of production on which the credit can be claimed is 1,095 barrels or barrel equivalents per well. Unused credits can be carried back 5 years. This credit is subject to a phaseout based on the inflation adjusted price of crude oil, such that the credit was not applicable for calendar year taxpayers in 2006–2009.

Deduction for Income Attributable to Domestic Production Activities

7.30 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. For tax years beginning after 2009, when the deduction is fully phased in, the deduction is equal to 9 percent of the lesser of qualified production activities income or taxable income. To determine the deduction, oil related qualified production activities income is reduced by 3 percent of the lesser of (*a*) oil related qualified production activities income, (*b*) qualified production activities income, or (*c*) taxable income. In addition, the deduction allowed generally cannot exceed 50 percent of the amount of W-2 wages paid by the taxpayer during the year and properly allocable to domestic production gross receipts. This deduction is treated as a permanent difference in the accounting principles generally accepted in the United States of America (U.S. GAAP) calculation of income taxes.

International Operations

U.S. Foreign Tax Credit

7.31 A U.S. corporation is subject to current U.S. federal and certain state income taxes on foreign income earned through foreign branch operations and from dividends received (or, in certain cases, deemed received) from foreign controlled and noncontrolled subsidiaries. Generally, the U.S. corporation may elect to claim a credit against its U.S. tax liability for foreign taxes paid or deemed paid in the case of dividends received from foreign subsidiaries owned at least 10 percent or more by the taxpayer.

7.32 The amount of U.S. tax that the U.S. corporation can offset with foreign tax credits is limited to the U.S. tax imposed on net income derived from foreign sources after taking into account U.S. deductions related to foreign income (for example, interest expense). An additional limitation prevents the crediting of foreign oil and gas extraction income taxes against nonextraction income. Finally, the U.S. taxpayer should demonstrate that the foreign levy in question was paid, constitutes a tax and not a payment for a specific economic benefit (that is, a disguised royalty for oil and gas rights), and was imposed on realized net income or in substitution for a generally applicable income tax. The creditability of foreign levies and limitations on utilization of foreign tax credits should be considered when analyzing current and deferred taxes along with related valuation allowances and FASB ASC 740-10 liabilities for uncertain tax positions.

Taxes in Foreign Jurisdictions

Royalty, Production Taxes, and Income Taxes

7.33 International taxation of oil and gas operations may have some unique features, depending on the structure of international contractual arrangements. One such feature is that taxes may be paid with oil and gas in kind or in cash. Another is that income and other taxes may be paid by the oil and gas entity itself or an affiliate of the foreign government that is contractually obligated to pay taxes on behalf of the oil and gas entity. In certain cases, it may be difficult to determine whether an arrangement represents a royalty, a production tax, or an income tax. Refer to chapter 6, "Accounting for International Oil and Gas Activities," of this guide for a discussion of the characterization and effects of international contractual arrangements.

7.34 The income tax element of a production sharing contract (PSC) is typically accounted for under FASB ASC 740-10 (whereas the royalty and government's production share are not). Thus, host country deferred income taxes calculations are required. Even when the foreign income tax is imposed by its terms only on the international oil company's (IOC's) share of "profit oil" (consequently, its share of production for cost recovery is technically not subject to tax), industry convention, nonetheless, treats differences between PSC cost recovery and U.S. GAAP cost recovery as a temporary difference in respect of which deferred tax is recognized.

Tax Holidays

7.35 As an inducement for an IOC to enter into an exploitation license or contract, the foreign government may sometimes grant a tax holiday or agree to assume the IOC's liability to pay taxes. For purposes of the U.S. foreign tax credit, a tax holiday reduces taxes paid and, hence, the foreign tax credit. Also, the reporting entity should forecast and schedule the reversal of temporary differences created during the tax holiday. To the extent temporary differences are forecasted to reverse after expiration of the tax holiday, deferred taxes should be recognized and measured using currently enacted tax rates that would apply to the future periods.

Transfer Pricing—Services

7.36 Under U.S. federal tax transfer pricing rules, a function or activity (that is, a service) undertaken by an entity that provides a benefit to one or more other group entities should result in the recognition of taxable income by the service provider entity equal to an arm's length price for the service in question. An entity's transfer pricing policy will likely be driven not only by the U.S. tax rules but also by other factors, including accounting system capabilities to track activities and their costs, recoverability of intercompany charges for services from partners or under the terms of PSCs, and deductibility for tax purposes of intercompany charges in service recipient jurisdictions. Limitations on the deductibility of such intercompany charges to the service recipient entity often result in permanent differences in the income tax provision calculation that can increase the effective tax rate of a multinational entity.

Foreign Exchange

7.37 Worldwide oil and gas prices are often quoted and executed in U.S. dollars, and in some foreign locations, oilfield service companies and drillers often desire to be paid in dollars rather than local currencies. As a result, oil and gas entities often determine that the U.S. dollar is the functional currency for certain foreign subsidiaries. This may cause significant difficulty in correctly calculating deferred taxes in the local jurisdiction if those taxes need to be paid in local currency. To prepare the calculation, it is necessary to compare the accounting principles generally accepted in the United States of America calculated amounts in local currency with the local currency tax basis balance sheet. After the deferred tax balance has been calculated in local currency, it is remeasured into U.S. dollars, resulting in a foreign exchange transaction gain or loss, which is included in the determination of net income. In addition, a decision should be made by the entity about whether the gain or loss from such remeasurement should be reported as a part of foreign exchange gains and losses or the income tax provision. If reported as part of the income tax provision, the transaction gain or loss should still be included in the aggregate transaction gain or loss for the period that is required to be disclosed by FASB ASC 830-20-45-1.

Chapter 8

Auditing

Overview

8.01 In the United States, two sets of professional auditing standards exist: (*a*) the standards and related rules of the Public Company Accounting Oversight Board (PCAOB), which are applicable to audits of financial statements and internal control over financial reporting (collectively referred to as an *integrated audit*) of issuers (as defined by the Sarbanes-Oxley Act of 2002 [SOX]) and (*b*) the AICPA's Statements on Auditing Standards, which are applicable to audits of nonissuers.[1] When referencing auditing standards in this chapter, references are primarily to the auditing standards as promulgated by the AICPA Auditing Standards Board. These standards were originally adopted by the PCAOB in PCAOB Rule 3200T, *Interim Auditing Standards* (AICPA, *PCAOB Standards and Related Rules*, Select Rules of the Board), on an interim basis and may have been modified through subsequent auditing standards and related rules issued by the PCAOB. When the respective PCAOB auditing standard is more restrictive than the auditing standard promulgated by the AICPA, either through issuance of a new auditing standard or amendment of an existing auditing standard, the nature of the more restrictive PCAOB requirement(s) is presented in a clearly identified and indented paragraph within the existing paragraph.

8.02 In accordance with AU section 150, *Generally Accepted Auditing Standards* (AICPA, *Professional Standards*), an 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 entities with oil and gas producing activities.

8.03 Financial accounting by entities with oil and gas producing activities is unique in many areas and consequently presents challenges for the auditor when determining whether the financial statements are presented in conformity with accounting principles generally accepted in the United States of America (U.S. GAAP) or an other comprehensive basis of accounting (OCBOA). This chapter is intended to provide general guidance on the audit of an entity with oil and gas producing activities. Chapter 9, "Internal Control Considerations," provides additional information related to internal control considerations for certain accounting areas specific to entities with oil and gas producing activities. Auditors should use professional judgment in applying this guidance to develop the specific audit procedures that will meet their particular needs.

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[1] A *nonissuer* is an entity other than an issuer of securities that is registered under Section 12 of the Securities Exchange Act of 1934, or that is required to file reports under Section 15(d) of that act, or that files or has filed a registration statement with the Securities and Exchange Commission (SEC) that has not yet become effective under the Securities Act of 1933, and that has not withdrawn.

Planning Related Auditing Considerations

Objective of an Audit

8.04 The objective of an audit of the financial statements of an entity 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 U.S. GAAP or OCBOA. To accomplish that objective, the 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.

> *Considerations for Audits Performed in Accordance with PCAOB Standards*
>
> The objective of an integrated audit is to express an opinion on whether the entity's financial statements are presented fairly, in all material respects, in conformity with U.S. GAAP and to express an opinion on the effectiveness of the entity's internal control over financial reporting. To form a basis for expressing such an opinion, the auditor must plan and perform the audit to obtain reasonable assurance about whether the entity's internal control over financial reporting are effective as of the date specified in management's assessment.

Audit Planning

8.05 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*), establishes requirements and provides guidance applicable to scoping, planning, and supervision of an audit conducted in accordance with GAAS.

8.06 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 PCAOB Standards*
>
> Paragraph .01 of AU section 311, *Planning and Supervision* (AICPA, *PCAOB Standards and Related Rules*, Interim Standards), 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,* Auditing Standards), regarding planning considerations, in addition to the planning considerations set forth in AU section 311.[2]

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[2] Public Company Accounting Oversight Board (PCAOB) Staff Audit Practice Alert No. 3, *Audit Considerations in the Current Economic Environment* (AICPA, *PCAOB Standards and Related Rules*,

(continued)

Audit Risk

8.07 AU section 312, *Audit Risk and Materiality in Conducting an Audit* (AICPA, *Professional Standards*), 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.

8.08 At the account balance, class of transactions, relevant assertion, or disclosure level, audit risk consists of (*a*) risks of material misstatement (consisting of inherent risk and control risk) and (*b*) detection risk. Paragraph .23 of AU section 312 states that auditors should assess the risks 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.

8.09 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 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.

8.10 Refer to the subsequent section "Additional Considerations for Specific Audit Areas" for discussion of specific risks and audit procedures for entities with oil and gas producing activities.

Planning Materiality

8.11 AU section 312 establishes requirements and provides guidance regarding the auditor's consideration of materiality when performing an audit of financial statements, including the determination of a planning materiality for purposes of establishing the overall audit strategy. Materiality judgments are made in relation to surrounding circumstances and necessarily involve both quantitative and qualitative considerations.

> *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*,

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(footnote continued)

PCAOB Staff Guidance, sec. 400.03), assists auditors in identifying matters related to the current economic environment that might affect audit risk and require additional emphasis. This practice alert is organized into six sections: (1) overall audit considerations; (2) auditing fair value measurements; (3) auditing accounting estimates; (4) auditing the adequacy of disclosures; (5) auditor's consideration of an entity's ability to continue as a going concern; and (5) additional audit considerations for selected financial reporting areas. PCAOB Staff Audit Practice Alerts are not rules of the board, nor have they been approved by the PCAOB.

Interim Standards), 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.

Use of Specialists

8.12 Due to the nature of the oil and gas industry, an entity with oil and gas producing activities often has to use specialists, such as reservoir engineers, geologists, valuation specialists, and environmental consultants. Such specialists may be employees of the entity, or they may be independent consultants or contractors engaged by the entity. In some cases, the auditor may engage a specialist, such as a valuation expert, and use the specialist's work as part of the audit evidence. AU section 336, *Using the Work of a Specialist* (AICPA, *Professional Standards*), establishes requirements and provides guidance for auditors when evaluating the appropriateness of the specialist's work as audit evidence, including specialists engaged by the entity and specialists supporting the audit team. When assessing the appropriateness of the work of a specialist, the auditor should assess the competence and objectivity of specialists engaged by the entity and perform additional procedures to evaluate the appropriateness of the source data used, assumptions and methods used, and their consistency with prior periods, as well as evaluate the results of the specialist's work in the light of the auditor's overall knowledge of the business and of the results of other audit procedures. Footnote 1 to paragraph 5 of Interpretation No. 1, "Supplementary Oil and Gas Reserve Information," of AU section 558A, *Required Supplementary Information* (AICPA, *Professional Standards*, AU sec. 9558A par. .01–.06), refers to the standards prepared by the Society of Petroleum Engineers which, among other things, provides general indications for determining when a reserve estimator is considered to be qualified.

8.13 The most significant area in which an entity with oil and gas producing activities may need to involve specialists relates to the evaluation of oil and gas reserves. Additionally, specialists are often used by an entity with oil and gas producing activities in the following areas:

- Oil and gas asset valuations in connection with business combinations, property acquisitions, or asset impairments
- Fair value of reporting units when assessing impairment of goodwill
- Derivative instrument valuations
- Environmental remediation liabilities
- Insured loss recoveries
- Asset retirement obligations

Use of Assertions in Obtaining Audit Evidence

8.14 Paragraphs .14–.19 of AU section 326, *Audit Evidence* (AICPA, *Professional Standards*), discuss the use of assertions in obtaining audit evidence. In representing that the financial statements are fairly presented in accordance with U.S. 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:

Categories of Assertions

	Description of Assertions		
	Classes of Transactions and Events During the Period	*Account Balances at the End of the Period*	*Presentation and Disclosure*
Occurrence/ Existence	Transactions and events that have been recorded have occurred and pertain to the entity.	Assets, liabilities, and equity interests exist.	Disclosed events and transactions have occurred.
Rights and Obligations	—	The entity holds or controls the rights to assets, and liabilities are the obligations of the entity.	Disclosed events and transactions pertain to the entity.
Completeness	All transactions and events that should have been recorded have been recorded.	All assets, liabilities, and equity interests that should have been recorded have been recorded.	All disclosures that should have been included in the financial statements have been included.
Accuracy/ Valuation and Allocation	Amounts and other data relating to recorded transactions and events have been recorded appropriately.	Assets, liabilities, and equity interests are included in the financial statements at appropriate amounts, and any resulting valuation or allocation adjustments are recorded appropriately.	Financial and other information is disclosed fairly and at appropriate amounts.
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.

8.15 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. Refer to the subsequent sections "Identification of Significant Risks" and "Additional Considerations for Specific Audit Areas" for examples of specific assertions common in an audit of an entity with oil and gas producing activities.

Understanding the Entity, Its Environment, and Assessing the Risks of Material Misstatement*

8.16 AU section 314, *Understanding the Entity and Its Environment and Assessing the Risks of Material Misstatement* (AICPA, *Professional Standards*), establishes requirements and provides guidance for auditors when obtaining an understanding of the entity and its environment, including its internal control. In accordance with AU section 314, auditors (*a*) assess risks of material misstatement of the financial statements, and (*b*) design and perform further audit procedures (tests of controls and substantive tests). 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.

8.17 The auditor's understanding of the entity and its environment consists of an understanding of the following aspects:

- Industry, regulatory, and other external factors
- Nature of the entity
- Objectives and strategies and the related business risks that may result in a material misstatement of the financial statements
- Measurement and review of the entity's financial performance
- Internal control, which includes the selection and application of accounting policies

8.18 AU section 316, *Consideration of Fraud in a Financial Statement Audit* (AICPA, *Professional Standards*), is the primary source of authoritative guidance about an auditor's responsibilities concerning the consideration of fraud in a financial statement audit.

> *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*, Interim Standards), 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*, Interim Standards).

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* In August 2010, the PCAOB issued Release No. 2010-04, *Auditing Standards Related to the Auditor's Assessment of and Response to Risk and Related Amendments to PCAOB Standards* (AICPA, *PCAOB Standards and Related Rules*, Select PCAOB Releases). In Release No. 2010-04, the PCAOB adopted eight auditing standards related to the auditor's assessment of and response to risk that will supersede six of the PCAOB's interim auditing standards and related amendments to PCAOB standards. These standards are effective for audit engagements conducted pursuant to the standards of the PCAOB for fiscal years beginning on or after December 15, 2010. Refer to the preface of this guide for important information about the release and applicability of these standards. Readers can download the entire release, which includes full text of the standards, at http://pcaobus.org/.

8.19 Refer to the sections "Identification of Significant Risks" and "Additional Considerations for Specific Audit Areas" for examples of risks and audit procedures specific to an entity with oil and gas producing activities.[3]

Risk Assessment Procedures

8.20 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*. Paragraph .21 of AU section 326 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. Refer to paragraphs .06–.13 of AU section 326 for additional guidance on risk assessment procedures.

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

- Inquiries of management and others within the entity
- Analytical procedures
- Observation and inspection

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

Industry, Regulatory, and Other External Factors

8.23 Chapters 1–7 of this guide may be useful in obtaining an understanding of the oil and gas industry, regulatory, and other factors affecting risks and audit approach for entities with oil and gas producing activities.

Nature of the Entity and Its Operations

8.24 In accordance with paragraph .26 of AU section 314, the auditor should obtain an understanding of the nature and structure of the entity and its operations, its ownership, governance, the types of investments it is making and plans to make, and how it is financed. The discussion that follows refers to certain aspects of the entity with oil and gas producing activities, which the auditor may consider during the planning process.

8.25 The auditor should consider the entity's method of operation when obtaining an understanding of the entity with oil and gas producing activities and its environment. Responsibilities associated with property operation will vary widely. Among other matters the auditor may consider are the extent of operating responsibilities, the use of partnerships or joint ventures, and related party transactions.

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[3] PCAOB Staff Audit Practice Alert No. 5, *Auditor Considerations Regarding Significant Unusual Transactions* (AICPA, *PCAOB Standards and Related Rules*, PCAOB Staff Guidance, sec. 400.05), provides auditors of issuers with guidance on assessing and responding to the risks of material misstatement of the financial statements due to error or fraud due to significant unusual transactions. PCAOB Staff Audit Practice Alert No. 5 complements Staff Audit Practice Alert No. 3 and compiles relevant requirements from existing PCAOB auditing standards regarding significant unusual transactions. PCAOB Staff Audit Practice Alerts are not rules of the board, nor have they been approved by the PCAOB.

Operator or Nonoperator

8.26 Audit procedures designed to be used in the audit of the financial statements of an entity acting as an operator of properties will likely be different from the audit procedures used in the audit of the financial statements of an entity acting solely as a nonoperator pursuant to a joint operating agreement. Some of the factors an auditor may consider include the following:

- The terms of the joint 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 accurate and prompt billing of costs and expenses to nonoperators, and provide complete and accurate 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. Other factors to consider are that billings received from the operator are properly supported and in compliance with the terms of the operating agreement, and revenues received from the operator are in accordance with the division of interests order.
- Whether or not joint interest audits are periodically performed.

8.27 Operators generally perform more significant accounting functions than nonoperators. The operator will have the responsibility for paying all exploration, development, and operating costs 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, usually once a month.

8.28 An entity with direct investments in oil and gas producing activities generally should maintain its own accounting procedures and controls and accountability for nonoperators' properties. However, in some instances, particularly in which the nonoperator is a passive investor with little or no industry experience, the entity may not have the personnel or procedures to provide adequate oversight over costs and revenues related to nonoperated properties. In these instances, the auditor may consider extending the audit tests to achieve the necessary level of assurance with respect to the recorded amounts.

8.29 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, the nonoperator can request sufficient documentation from the operator to provide the support for the recorded amounts or to enable the necessary adjustments to be made. As an alternative, the auditor may consider visiting the operator and examining directly the accounting records related to the specific properties. However, auditor access to the operator's accounting records will need to be requested by the nonoperator prior to the commencement of the audit. Examples of procedures the auditor may consider performing through requesting additional documentation or visiting the operators' office are as follows:

- Examining third party charges to support joint interest billings (JIB) 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

Ownership Structure

8.30 *Partnerships.* Many companies create limited partnerships by selling limited partner interests in public or private offerings. Often, the limited partnership agreements may require audits of the partnership.

8.31 The terms of the partnership agreement dictate the allocation of costs and revenues to the limited and general partners and often 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 the audit procedures should reflect these considerations.

8.32 *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. Financial Accounting Standards Board (FASB) *Accounting Standards Codification* (ASC) 323-30-25-1, FASB ASC 810-10-14, and FASB ASC 932-810-45-14-1 indicate that pro rata consolidation of the assets, liabilities, revenues, and expenses of unincorporated joint ventures accounted for under the equity method is often used in the oil and gas industry. The auditor may consider reviewing and understanding the structure of unincorporated joint ventures to determine if the entity appropriately accounts for its investment in such joint ventures.

Operations and the Related Business Risks

8.33 *Risk Management*. Risk management is an integral part of the business that the auditor may consider when planning the audit and assessing overall audit risk. Risks faced by the oil and gas industry include, but are not limited to, the following:

- Exploration drilling risk
- Developmental drilling risk
- Production risk
- Inaccurate proved reserve estimates
- Risk of volatile oil and natural gas prices
- Environmental issues and regulations, which could increase costs
- Risks related to international operations
- Risk of susceptibility of assets to natural disasters

8.34 The auditor may consider understanding who is responsible for risk management within the organization and whether the organization has a risk management committee or department. The auditor may consider making inquiries of management regarding the entity's risk management strategy and obtaining the risk management policy. The auditor may consider inquiring of those responsible for risk management about the types of transactions entered into to ensure the transactions are in accordance with the risk management policy. Common forms of risk management include the use of derivative instruments, nontraditional financing arrangements (such as production payments and other forms of property conveyances), joint ventures, and various insurance products. The auditor may consider reviewing the relevant contracts or other documentation of risk management transactions to understand the details of the transaction and to determine if the entity has properly accounted for the transaction. Risk management transactions, and the related accounting, can be very complex.

8.35 Certain audit considerations related to areas associated with risk management, such as derivative activities, are discussed further in the subsequent sections "Additional Considerations for Specific Audit Areas" and "Other Audit Considerations."

8.36 *Other Considerations.* Other items related to property operations that the auditor may consider in the planning of specific audit procedures include various contractual arrangements and operational activities, including the following:

- Agreements for the acquisition of properties including leases, concessions, or other arrangements, particularly lease expiration provisions and requirements for dismantlement, restoration, and abandonment obligations
- Joint operating agreements
- Drilling contracts
- Natural gas gathering and processing contracts
- Oil, gas, and natural gas liquids sales contracts
- Division of interest orders
- Production payments
- Pipeline transportation contracts

Geographical Considerations

8.37 The procedures used by the auditor during an audit of the financial statements of an entity with oil and gas producing activities may be greatly affected by the geographical areas in which the entity operates. For example, if an entity has offshore operations and operations in foreign countries, the auditor may consider the following:

- Different types of property costs associated with offshore, as opposed to onshore, operations
- Regional pricing differences and the availability of markets
- Export and foreign currency regulations
- Risk of hurricanes or other natural disasters prevalent in a geographic location
- Various environmental and other regulatory implications
- Production-sharing contracts with foreign governments

- Tax implications of foreign operations
- Disclosure requirements of foreign operations
- Required approval by foreign governments of transactions, agreements, and contracts in international locations, including changes in political environment
- Transfer pricing agreements for international tax

8.38 *Foreign Corrupt Practices Act of 1977*. The auditor may consider the Foreign Corrupt Practices Act of 1977 (FCPA) when auditing companies with international operations. The FCPA is a U.S. law. The FCPA comprises two components which the auditor may consider: (*a*) Antibribery Provisions (*Commerce and Trade*, *U.S. Code* [USC] Title 15, Sections 78dd-1–78dd-3); and (*b*) Accounting Provisions (*Commerce and Trade*, USC Title 15, Sections 78dd-1–78dd-3). Furthermore, AU section 317, *Illegal Acts by Clients* (AICPA, *Professional Standards*), establishes requirements and guidance regarding the nature and extent of the consideration an auditor should give to the possibility of illegal acts by a client in an audit of financial statements.

8.39 Interpretation No. 2, "Material Weaknesses in Internal Control and the Foreign Corrupt Policies Act," of AU section 317 (AICPA, *Professional Standards*, AU sec. 9317 par. .03–.06) establishes requirements and provides guidance for the auditor. The auditor may consider making inquiries of management to understand if a history exists of actual or alleged violations of the FCPA, management's assessment of risk regarding FCPA violations, and the programs and controls to prevent and detect such violations. Additional discussion of the FCPA can be found in chapter 6, "Accounting for International Oil and Gas Activities," and chapter 9.

Understanding of Internal Control

8.40 Refer to paragraph .41 of AU section 314 for the definition of *internal control* applicable to audits performed under GAAS. Refer to paragraphs .40–.101 of AU section 314 for discussion of the internal control components.

8.41 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.

8.42 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.

8.43 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.

> *Considerations for Audits Performed in Accordance with PCAOB Standards*
>
> When performing an integrated audit of financial statements and internal control over financial reporting, refer to paragraph A5 of PCAOB Auditing Standard No. 5, for the definition of internal control applicable to an audit under PCAOB standards, refer to paragraphs 22–27 of PCAOB Auditing Standard No. 5 for guidance related to assessment of internal control system components, and refer to paragraphs 42–61 of PCAOB Auditing Standard No. 5 for guidance related to testing the design and operating effectiveness of internal control, including nature, timing and extent of tests of controls.

8.44 Chapter 9 of this guide provides further discussion of internal control over financial reporting.

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

Assessing the Risks of Material Misstatement

8.45 Audit risk consists of inherent risk, control risk, and detection risk. The way that an auditor considers these component risks and combines them involves professional judgment and depends on the audit approach. Based on risk assessment procedures performed, the auditor assesses the risks of material misstatement at the financial statements level and at the relevant assertion level related to classes of transactions, account balances, and disclosures. Based on the risk assessment, the auditor determines the nature, timing, and extent of further audit procedures to be performed. Refer to the preceding "Risk Assessment Procedures" section for examples of risks common to entities with oil and gas producing activities. Refer to the subsequent section titled "Additional Considerations for Specific Audit Areas" for examples of audit procedures which the auditor may consider to address specific audit risks.

Identification of Significant Risks

8.46 The auditor should determine which of the risks identified require special audit consideration (such risks are defined as *significant risks*). The determination of significant risks is a matter for the auditor's professional judgment. The auditor should consider inherent risk to determine whether the risk may give rise to potential material misstatement. Refer to paragraphs .45 and .53 of AU section 318, *Performing Audit Procedures in Response to Assessed Risks and Evaluating the Audit Evidence Obtained* (AICPA, *Professional Standards*), for further audit procedures pertaining to significant risks.

8.47 Higher inherent risk may be present in certain financial statement assertions of entities with oil and gas producing activities related to classes of transactions, account balances, and disclosures including the following:

- Occurrence, completeness, accuracy, and cut off for recorded oil and natural gas sales amounts and operating expense amounts including period-end estimates
- Existence, rights and obligations, completeness, and valuation and allocation of proved and unproved oil and natural gas properties
- Existence, rights and obligations, completeness, and valuation of derivative instruments utilized for risk management or trading purposes
- Existence, rights and obligations, completeness, and valuation of current and deferred state, federal, and foreign income tax assets and liabilities, including liabilities for uncertain tax positions
- Existence, rights, completeness, and valuation of amounts due from other working interest owners for costs incurred in joint operations
- Existence, obligations, and completeness of amounts due to other working interest owners and royalty and other interest owners for collected proceeds for oil and natural gas sales

Designing and Performing Further Audit Procedures

8.48 To reduce audit risk to an acceptably low level, the auditor should (*a*) determine overall responses to address the assessed risks of material misstatement at the financial statement level, and (*b*) 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. Refer to AU section 318 for further guidance.

Further Audit Procedures

8.49 Further audit procedures provide important audit evidence to support an audit opinion. These procedures consist of tests of controls and substantive procedures, including tests of details and substantive analytical procedures. 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.

8.50 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. When performing tests of controls, the auditor should obtain audit evidence that controls operate effectively.

8.51 The auditor should design and perform substantive procedures for all relevant assertions related to each material class of transactions, account balance, and disclosure. 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.

8.52 Refer to the subsequent section "Additional Considerations for Specific Audit Areas" for specific examples of audit considerations and related testing procedures for certain transactions and accounts unique to entities with oil and gas producing activities.

Auditing of Estimates

8.53 The nature of the oil and gas industry often requires management to make accounting estimates in the preparation of financial statements. Estimates are based on subjective as well as objective factors and, as a result, judgment is required to estimate an amount at the date of the financial statements. Management's judgment is normally based on its knowledge and experience about past and current events and its assumptions about conditions it expects to exist and courses of action it expects to take.

8.54 The auditor is responsible for evaluating the reasonableness of accounting estimates made by management in the context of the financial statements as a whole. The risks of material misstatement of accounting estimates normally varies with the complexity and subjectivity associated with the process, the availability and reliability of relevant data, the number and significance of assumptions that are made, and the degree of uncertainty associated with the assumptions. An entity's internal control may reduce the likelihood of material misstatements of accounting estimates.

8.55 The auditor's objective when evaluating accounting estimates is to obtain sufficient appropriate audit evidence to provide reasonable assurance that

- all accounting estimates that could be material to the financial statements have been developed.
- those accounting estimates are reasonable in the circumstances.
- the accounting estimates are presented in conformity with applicable accounting principles and are properly disclosed.

8.56 In evaluating reasonableness, the auditor should obtain an understanding of how management developed the estimate. Based on that understanding, the auditor should use one, or a combination of, the following approaches:

- Review and test the process used by management to develop the estimate.
- Develop an independent expectation of the estimate to corroborate the reasonableness of management's estimate.
- Review subsequent events or transactions occurring prior to the date of the auditor's report.

8.57 AU section 342, *Auditing Accounting Estimates* (AICPA, *Professional Standards*), provides requirements and guidance on obtaining and evaluating sufficient appropriate audit evidence to support significant accounting estimates.

8.58 Significant estimates common in the oil and gas sector include the following:

- Oil and gas revenues
- Oil and gas reserves
- Future development costs
- Income taxes
- Asset retirement obligations
- Legal and environmental liabilities

Considerations for Audits Performed in Accordance with PCAOB Standards

When performing an integrated audit of financial statements and internal control over financial reporting, as part of identifying and testing entity-level controls and selecting other controls to test, the auditor should evaluate whether the entity's controls sufficiently address identified risks of material misstatement due to fraud and the risk of management override of other controls.

Evaluating the Sufficiency and Appropriateness of the Audit Evidence Obtained

8.59 AU section 318 provides requirements and guidance related to the auditor's assessment of the sufficiency and appropriateness of audit evidence to support the auditor's conclusions. Paragraph .75 of AU section 318 refers to factors which influence the auditor's judgment about what constitutes sufficient audit evidence.

Considerations for Audits Performed in Accordance with PCAOB Standards

AU section 325, *Communications About Control Deficiencies in an Audit of Financial Statements* (AICPA, *PCAOB Standards and Related Rules*, Interim Standards), states that when performing an integrated audit of financial statements and internal control over financial reporting, when evaluating whether a deficiency exists and whether deficiencies, either individually or in combination with other deficiencies, are material weaknesses, the auditor should follow the direction in paragraphs 62–70 of PCAOB Auditing Standard No. 5.

Management Representations

8.60 AU section 333, *Management Representations* (AICPA, *Professional Standards*), provides requirements and guidance related to obtaining written representations from management.

8.61 The auditor may consider the specific examples of management representations relevant to entities with oil and gas producing activities included in appendix B, "Sample Management Representations for Entities With Oil and Gas Producing Activities," to this guide.

Evaluating Misstatements

8.62 In accordance with AU section 312, 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. The auditor must evaluate the effects of known and likely misstatements that are not corrected by the entity, both individually and in the aggregate, including the effect of misstatements related to prior periods. The auditor should include both quantitative and qualitative factors when evaluating whether the misstatement is material.

Additional Audit Considerations

Consideration of Fraud

8.63 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.

> *Considerations for Audits Performed in Accordance with PCAOB Standards*
>
> Paragraph .01 of AU section 316 (AICPA, *PCAOB Standards and Related Rules*, Interim Standards) 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.

Audit Documentation

8.64 AU section 339, *Audit Documentation* (AICPA, *Professional Standards*), and PCAOB Auditing Standard No. 3, *Audit Documentation* (AICPA, *PCAOB Standards and Related Rules*, Auditing Standards), provide requirements and guidance on the form, content, and extent of audit documentation.

Communication With Those Charged With Governance

8.65 Paragraphs .34–.35 of AU section 380, *The Auditor's Communication With Those Charged With Governance* (AICPA, *Professional Standards*), and AU section 325, *Communicating Internal Control Related Matters Identified in an Audit* (AICPA, *Professional Standards*), establish requirements and provide guidance regarding matters communicated with those charged with governance.

> *Considerations for Audits Performed in Accordance with PCAOB Standards*
>
> The first bullet point before paragraph 1 of AU section 325 states that when performing an integrated audit of financial statements and internal control over financial reporting, refer to paragraphs 78–84 of PCAOB Auditing Standard No. 5 regarding communicating certain matters.

Additional Considerations for Specific Audit Areas

8.66 This section identifies and discusses certain audit considerations and related testing procedures of some of the business functions and accounts unique to entities with oil and gas producing activities. The nature, timing, and extent of audit procedures should be based on the auditor's assessment of the risks of material misstatements at the relevant assertion level. These illustrative procedures are not all inclusive and may be adapted to the specific circumstances of the entity.

Oil and Gas Properties—Acquisition, Exploration, and Development Activities

8.67 In audits of the financial statements of most entities with oil and gas producing activities, the primary focus is most often on the oil and gas properties. More often than not, the inherent risk for assertions about the accumulation and recovery of costs associated with the oil and gas properties is significant. Therefore, evaluating the accumulation and recovery of costs associated with the properties is important to the audit process and to determining whether the financial statements are presented in conformity with U.S. GAAP.

8.68 In auditing the property, plant, and equipment (PP&E) of an entity with oil and gas producing activities, significant audit focus is centered on auditing accounting estimates, including, but not limited to, the following:

- Recoverability of capitalized costs (including proved and unproved properties, suspended wells, and so on)
- Allocation of value between proved and unproved properties at acquisition
- Gain or loss on disposition

Refer to the subsequent paragraphs that discuss some of the accounting estimates related to PP&E. Management's development of such estimates requires significant judgment. The auditor should consider, with an attitude of professional skepticism, both the subjective and objective factors when evaluating the reasonableness of those estimates.

8.69 Following are several areas that deserve special attention in the auditing of oil and gas property and related accounts:

- Property costs
- Conveyances
- Authorization for expenditures
- Acquisition of oil and gas properties
- Physical existence
- Interest capitalization
- Capitalized overhead costs
- Materials and supplies
- Dry hole costs
- Wells in progress
- Workover costs
- Depreciation, depletion, and amortization (DD&A)
- Depreciation of support facilities
- Assessment of proved properties for impairment—full cost
- Assessment of proved properties for impairment—successful efforts
- Assessment of unproved properties for impairment
- Asset retirement obligations

Property Costs

8.70 Joint interest owners share in acquisition, exploration, development, and production costs in accordance with the cost-sharing provisions of the joint operating agreement signed by the joint interest parties. Carried interests (among many other similar arrangements) often cause the sharing of costs to differ from the actual lease ownership. The auditor should obtain an understanding of cost-sharing provisions for each property in order to effectively audit property costs.

Authorization for Expenditure

8.71 An authorization for expenditure (AFE) is prepared for most exploratory and development drilling activities and major projects undertaken by joint interests for cost control purposes. The AFE gives the operator approval to incur specified dollar amounts in accomplishing agreed-upon tasks. The AFE provides information that is important to ensure proper classification of the expenditures as either capital or periodic expense. Examination of joint interest audit reports may provide important information about any potential charges or credits and should be evaluated in accordance with FASB ASC 450, *Contingencies*). Examination of joint ownership audit reports also provides an indication of the quality of an entity's operation of the project.

Acquisitions of Oil and Gas Properties

8.72 Costs associated with the acquisition of oil and gas properties are capitalized when incurred under both the successful efforts method of accounting and the full cost method. Properties are generally acquired as of an effective date, at which time the purchase price is set, although the closing date of the transaction typically takes place at a later date. Ordinarily, the closing date represents the time at which title and risk of loss are transferred and represents the acquisition date for accounting purposes. In testing acquisitions of oil and gas properties, the auditor should examine the recording of activities from the effective date to the closing date to determine that the acquirer recorded the revenues and expenses on the oil and gas properties subsequent to the closing date. The auditor should consider verifying that any revenues generated and expenses incurred between the effective and closing dates are recorded as adjustments to the purchase price in the accounting records of the purchaser.

8.73 In testing the recognition and measurement of oil and gas properties acquired, the auditor may assess the appropriateness of the measurement of proved and unproved properties. Additionally, under the successful efforts method of accounting, the auditor should assess the appropriateness of the measurement of tangible equipment and leasehold costs because these costs are depleted using different rates (proved vs. proved developed), and allocation of costs at the field level.

8.74 Verification of leasehold rights requires a title search, which is 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 entity'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.

8.75 The acquisition of oil and gas properties may be treated differently for accounting and tax purposes (acquisition of an asset vs. acquisition of a business), which sometimes has an impact on the structure of the acquisition as well as on the recognition of deferred taxes related to the properties acquired.

Division of Interest

8.76 Oil and gas exploration and development represents a high risk activity, requiring significant capital investments, which often results in entities sharing the risks by dividing the ownership and related risks among several joint participants. Entities or individuals may own a variety of interests including a royalty interest, working interest, overriding royalty interest, net profits interest, retained interest, carved-out interest, net revenue interest, and so on, all of which are specified in signed division orders. In order to easily process activities with the joint interest parties, entities often set up working interest and revenue interest decks (master files) in their accounting systems, which reflect all interests held by owners for each well within each field. This facilitates the handling and recording of all transactions in which costs and revenues are shared, including oil and gas revenue, joint interest billings, property additions, lease operating expenses, and other similar expenses.

8.77 Given the pervasiveness of the use of working interest and revenue interest percentage information, the auditor should conduct testing to validate the appropriateness and integrity of ownership percentages in the division of interest master files. Additionally, the auditor should obtain audit evidence regarding changes to these ownership percentages over time when conveyance agreements transfer ownership from one party to another. Working interest and net revenue interest percentages are often tested by verifying signed division orders, joint operating agreements, or other such legally binding agreements as well as by testing the entity's internal control in this area.

Interest Capitalization

8.78 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 entity. Auditing interest capitalization includes (*a*) verifying that the assets used for interest capitalization are qualifying assets in accordance with FASB ASC 835-20 and FASB ASC 932-835-25-1, and (*b*) determining that interest capitalized is properly computed.

8.79 The auditor should validate the appropriateness of the capitalization rate being used to ensure it represents the rate applicable to borrowings outstanding during the period, in accordance with FASB ASC 835-20. Additionally, interest cost capitalized in a period shall not exceed interest cost incurred in the period. For those entities following the full cost method of accounting, FASB ASC 932-835-25-1 clarifies that the assets qualifying for capitalization are those "unusually significant investments in unproved properties and major development projects that are not being depreciated, depleted, or amortized currently and significant properties and projects in cost centers with no production, provided that exploration or development activities on such assets are in progress."

Capitalized Overhead Costs

8.80 The nonoperator's auditor should perform procedures (*a*) to test the reasonableness of the allocated charges, and (*b*) to test that the entity was charged for its proper share of the expenses.

8.81 Relative to capitalization of overhead costs, the successful efforts method of accounting only allows the capitalization of such costs that directly relate to oil and gas properties activities already being capitalized. Under the full cost method of accounting, overhead costs incurred by the entity that are directly associated with the exploration, acquisition, and development of oil and gas properties may be capitalized. Under both methods of accounting, the auditor should assess the reasonableness of the capitalization percentages used by the entity for various types of costs (for example, exploration management costs, land department costs) and ensure that general corporate overhead costs are not capitalized.

Dry Hole Costs

8.82 The auditor may substantiate the success or failure of a drilling effort by examining drilling reports from the drilling entity (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.

Suspended Wells

8.83 For entities following the successful efforts method, all relevant facts, circumstances, and management's judgment should be taken into consideration to determine if capitalization of costs is appropriate in accordance with FASB ASC 932-235-50-16 and FASB ASC 932-360-25-18. Generally, information may be obtained from discussions with management and operational personnel, as well as from support for the entity's future drilling plans and ongoing evaluation of each of suspended well.

Wells in Progress

8.84 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 in progress at the end of the period should be expensed if, prior to the financial statements being issued, it is determined that the well has not found proved reserves. The auditor uses all information available in evaluating the status of an exploratory well as of the report date; as such, the determination of a dry hole subsequent to the end of the reporting period, but prior to issuance of financial statements, still results in the expensing of well costs incurred through the end of the reporting period.

Depreciation, Depletion, and Amortization

Successful Efforts Method

8.85 As mentioned previously, the auditor may need to consider allocation between proved and unproved properties, allocation between tangible equipment and leasehold costs, and grouping of properties for DD&A calculation (usually at the field level).

Full Cost Method

8.86 The methods used in computing DD&A under the full cost and successful efforts methods are discussed in the related chapters of this guide. For the full cost method, the auditor may (*a*) determine if all costs excluded from the cost base are properly excludable; (*b*) review the estimated future development costs to determine if they are reasonable; and (*c*) compare the estimated future development costs to the reserve report and determine whether these costs are based on current costs. Under the full cost method, the auditor should determine that the estimated dismantlement and abandonment costs, net of estimated salvage values that have not yet been recorded as asset retirement costs, have been appropriately included in the cost base for purposes of computing the DD&A rate, consistent with FASB ASC 410-20 and Securities and Exchange Commission (SEC) *Codification of Staff Accounting Bulletins* Topic (12)(D)(4), "Interaction of FASB ASC Subtopic 410-20 Asset Retirement and Environmental Obligations and the Full Cost Rules." Depending on the extent of reliance placed on internal control, the auditor may also apply certain analytical procedures to the testing of DD&A, including performing analytical procedures to compare DD&A rates per barrel by field or cost center, as applicable, against prior periods.

Depreciation of Support Equipment and Facilities

8.87 Depreciation of support equipment and facilities used in oil and gas producing activities (such as drilling equipment, vehicles, warehouses, or repair shops) 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 perform audit procedures to determine that depreciation of support equipment is properly allocated based on the nature of the activity.

Impairment

Assessment of Proved Properties for Impairment—Capital Cost Limitations

8.88 The full cost method prescribes a ceiling test for capitalized costs, which is discussed in chapter 5, "Full Cost Method of Accounting for Oil and Gas Activities." The auditor should examine the components of the cost ceiling computation to determine that they are computed in accordance with the prescribed guidelines. These components include:

- present value of estimated future net revenues using a 12-month average price calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions (with consideration for price changes only to the extent provided by contractual arrangements, for example, qualifying cash flow hedges under FASB ASC 815, *Derivatives and Hedging*);
- discount factor used (should be 10 percent);
- proper exclusion of the cost of properties not being amortized;
- income tax effects;
- validation of the net book value of oil and gas properties being assessed for impairment; and so on.

Assessment of Proved Properties for Impairment—Successful Efforts

8.89 Impairment of proved properties for a successful efforts entity is based on the provisions of the impairment and disposal of long-lived assets subsections of FASB ASC 360-10. The auditor should perform audit procedures to test for impairment of long-lived assets. Audit procedures that the auditor should perform, but not be limited to, include those described in the following paragraphs.

8.90 *Asset grouping*. Ensuring the impairment calculation is being conducted at the appropriate asset grouping. Generally, this will be on a field-by-field basis or by logical grouping of assets if a shared infrastructure exists (for example, platform) because the long-lived assets are grouped at the lowest level of identifiable cash flows for purposes of the impairment test.

8.91 *Future net cash flows*. Ensuring that the recoverability test considers future net cash flows on an undiscounted basis consistent with FASB ASC 360-10-35, and if the carrying amount of the long-lived assets is higher than these undiscounted future net cash flows, then ensuring that the entity impairs the asset to its fair value in accordance with FASB ASC 820, *Fair Value Measurement*. It is important to note that the future net cash flows (both undiscounted and discounted) are based on total proved reserves as well as risk-adjusted probable and possible reserves. Additionally, the auditor should validate that future net cash flows for asset retirement obligations have been excluded from the analysis.

8.92 For an entity with oil and gas producing activities, indicators of impairment may include, but not be limited to, the following:

- Significant negative oil and gas reserve revisions.
- Decreases in pricing.
- Accumulation of drilling costs significantly in excess of amounts originally expected.
- Significant increases in DD&A rates.
- Production difficulties.
- The period of time that the entity has the right to explore a lease is expiring in the near future.
- Steeper than anticipated production decline curves, and so on.

Assessment of Unproved Properties for Impairment

8.93 The auditor should assess the reasonableness of the entity's methodology and procedures used for impairment analysis and should consider evaluating the adequacy of the impairment provision in accordance with FASB ASC 932-360-35-11. In evaluating the adequacy of the impairment provision, the auditor may consider using such information as the entity's drilling plans, dry holes drilled in areas near the leases, and lease expiration dates. Such items may represent indicators of impairment of the related unproved properties.

Oil and Gas Property Conveyances

8.94 Due to the capital intensive nature of the industry, conveyances of oil and gas properties are common, and such transactions can vary widely in form and complexity. Chapter 4, "Successful Efforts Method and General Accounting for Oil and Gas Activities," contains a discussion of the various forms of property conveyances and accounting considerations. The auditor should obtain an understanding of the entity's property conveyances during the planning phase of the audit and understand the form of the transaction to evaluate the appropriateness of the entity's accounting for the related conveyance. The form of the property conveyance can significantly affect financial gain or loss recognition and the income tax consequences of the transaction.

8.95 Oil and gas property conveyances can take a variety of forms, including sales, borrowings, exchanges of nonmonetary assets, poolings of interests in joint undertakings, or some combination thereof, each of which may be unique. The auditor should evaluate the accounting treatment of conveyance transactions in accordance with the conveyance provisions of FASB ASC 932, *Extractive Activities—Oil and Gas*, 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 audit of the income tax accrual.

8.96 Accounting for oil and gas property conveyances is complex and should be examined to determine that they are recorded in accordance with the contractual terms, underlying substance, and applicable accounting pronouncements. In evaluating the substance of the transaction, the auditor should consider individually if the production and price risk have been retained by the seller or transferred to the buyer. This analysis is a factor in determining the appropriate accounting treatment. Once the initial accounting impact is determined, the auditor should perform specific tests over application of the conveyance as the production occurs. These tests may be customized to the individual contract, and the auditor should consider testing whether all applicable revenue recognition requirements have been met. The auditor should also examine the likelihood for future obligations that often accompany conveyance transactions and may affect accounting treatment and footnote disclosures.

8.97 The auditor should verify that any revenues generated and expenses incurred between the effective and closing dates of property sale transactions are recorded in the seller's income statement and that appropriate adjustments are made to the purchase price in the accounting records of the seller.

8.98 Divestitures of oil and gas properties may also result in the reporting of discontinued operations. In accordance with the "Impairment and Disposal of Long-Lived Assets" subsections of FASB ASC 360-10, FASB ASC 205-20-50, and FASB ASC 205-20-55, the auditor should ensure that the entity appropriately considered the various criteria and circumstances in this accounting literature for the property to qualify for discontinued operations reporting. Additionally, as mentioned in the chapter 5 of this guide, under the full cost method of accounting, the *component of an entity*, as defined in the FASB ASC glossary, would be an individual cost center and, therefore, the treatment for discontinued operations would only be appropriate when the entire cost center is disposed.

Production

Revenue

8.99 Revenue generally is realized or realizable and earned when all of the following criteria are met:

- Persuasive evidence of an arrangement exists.
- Delivery has occurred or services have been rendered.

- The seller's price to the buyer is fixed or determinable.
- Collectability is reasonably assured.

8.100 Revenues from oil and gas producing activities are typically derived from production. The following items may need to be considered by the auditor in conducting an audit of revenues for an entity with oil and gas producing activities:

- Allocation of interest in oil and gas sales
- Pricing regulations and contractual agreements (including settlement of hedging contracts)
- Revenue accumulation
- Take-or-pay contracts
- Inventory
- Production sharing contracts

8.101 *Allocation of Interest in Oil and Gas Sales.* Oil and gas revenues are allocated in accordance with the division order, joint operating agreement (JOA), or other similar legal documentation, which sets forth the revenue ownership interest of each owner or division of interest. The auditor should test whether the entity recorded its appropriate share of revenue in accordance with its revenue interest in each property. The auditor may agree the division of interest to the appropriate legal documentation and design tests to compare the volumes produced to the volumes sold. The auditor may also determine if the volumes sold are independently measured by the purchaser on a run ticket or other metered statement or a third party (that is, pipeline entity). The receipt of independent third party measurements normally satisfies the revenue recognition requirement that delivery has occurred. Volumetric differences may result from losses on the pipeline. If these differences are significant, the auditor should perform additional tests of these reconciling items. The auditor may also test oil and gas sales volumes by comparing current year sales volumes against current year budgeted production from engineering reports, current year forecasts, historical operating results reported to state or governmental agencies, or other production estimates.

8.102 Due to the timing of the receipt of third party volume measurements, including pipeline statements, and purchase remittance advices for nonoperated properties, entities often accrue between one and three months of revenue at period end. The auditor may analyze the historical differences between accrued and actual revenues and analyze the underlying production utilized in the revenue accrual by corroborating any known production changes with the entity's reserve engineers or operations department.

8.103 The auditor should ensure that the entity has appropriately applied either the entitlements or sales method for sales of gas production. If the entitlements method is used, the auditor may examine the entity's entitlement computation and may perform confirmation procedures[4] to substantiate any production imbalance receivables or payables recorded at the audit date.

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[4] Interpretation No. 1, "Use of Electronic Confirmations," of AU section 330, *The Confirmation Process* (AICPA, *Professional Standards*, AU sec. 9330 par. .01–.08), clarifies, among other matters, that the use of an electronic confirmation process is not precluded by AU section 330. Although no confirmation process with a third party is without some risk of interception or alternation, including the risk that the confirmation respondent will not be the intended respondent, paragraph .05 of AU

(continued)

8.104 The sharing of oil and gas production revenues by joint owners can be affected by a number of different arrangements. For instance, joint interest drilling ventures may 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 generally reverts to their permanent interest in the property. 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 generally entitled to all of the nonconsenting parties' interest in generated revenues until they recover a predetermined percentage of their actual costs incurred. In these instances, the auditor may compare revenue allocation percentages to the respective agreements and calculations or confirm the terms directly with the joint interest owners.

8.105 *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 the realized pricing component of oil and gas revenue, the auditor may compare the realized price received to the executed sales contract. The sales contract will usually state the specific pricing terms, including the relevant index price or fixed price and any differentials or adjustments from the base index. Sales contracts that include specified volume and pricing criteria will generally satisfy the revenue recognition requirements that persuasive evidence of an arrangement exists, and that the seller's price to the buyer is fixed or determinable. If the sales contract price is primarily driven by an index price, the auditor may compare the realized index price to the same index price location as quoted in a third party publication. In certain circumstances the auditor may also confirm significant contract terms directly with the counterparty.

8.106 *Revenue Accumulation.* Entities with oil and gas producing activities generally should accumulate revenue and expense data on a property-by-property basis with each property level revenue transaction linked to a sales or marketing contract and each expense or capital property transaction linked to an invoice and AFE. Financial data on a detail property basis are needed for several reasons, including royalty payments, percentage depletion, and income tax obligations. The auditor may perform tests to determine that detail property data are properly accumulated. These tests may include comparing property level production to third party volume measurements, the realized price for a sale of oil or gas from the property to the pricing mechanism specified in the sales or marketing contract and third party pricing support, and analyzing any differences between the revenue recorded in the accounting records and the amount reported to governmental agencies.

(footnote continued)

section 9330 states that confirmations obtained electronically can be considered to be reliable audit evidence if the auditor is satisfied that (*a*) the electronic confirmation process is secure and properly controlled, (*b*) the information obtained is a direct communication in response to a request, and (*c*) the information is obtained from a third party who is the intended respondent. The interpretation also provides guidance to assist the auditor in assessing the confirmation process.

8.107 *Production Sharing Contracts.* The contract analysis for a production sharing contract (PSC) is a very important procedure in determining how the revenues, assets, and taxes are to be recorded. Such analysis can be complex and, as a result, significant auditor judgment is required. Some of the specific features of PSC arrangements are described in chapter 6 of this guide.

Receivables

8.108 Special consideration may be given to the following areas:

- Joint interest billings
- Joint interest credits
- Oil and gas sales
- Production imbalances
- Cash calls
- Collectability

8.109 *Joint Interest Billings.* The auditor of the operator may confirm the JIB balance as of the audit date with the nonoperating interest owners. However, confirmation of the operator's JIB balance may sometimes be ineffective. The auditor should determine during the planning phase of the audit whether or not the JIB balance will be confirmed at period end. If confirmations are not sent, the auditor should document the rationale for that conclusion. 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 existence and accuracy of the charges supporting the JIB statements, and (*b*) the working interest percentage of the charge allocated to nonoperating interest owners. JIB statements usually include details of the gross charges incurred by the operator and the working interest percentage of the charge allocated to nonoperating interest owners. The auditor may compare a sample of these gross charges to the related invoice and the cash payment. The auditor also may compare the working interest percentage to the working interest percentage in the joint operating agreement or other similar legal documentation. At the audit date, the operator may have incurred and paid operating expenses or capital costs on behalf of the joint owners that have not been billed. The operator generally captures these costs in an accrual for capitalized drilling costs and an accrual for operating expenses. These unbilled obligations also represent JIB receivables that, if not confirmed, may be tested by the auditor. Support for these accruals is often maintained partially by operational personnel, who can corroborate operational status, and accounting personnel, who can corroborate amounts previously billed to nonoperating interest owners.

8.110 *Joint Interest Credits.* Nonoperating parties normally have the right to audit the accounts and records of the operator relating to the specific property 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 in accordance with the gain-contingency provisions of FASB ASC 450. These procedures also apply to the audit of accounts payable of an operating entity in which the operator is subject to issuance of potential joint interest credits. The auditor may examine the results of historical joint interest audits to identify any specific risk areas during the audit planning phase.

8.111 *Oil and Gas Sales.* Oil and gas production sales are generally recorded from run tickets or remittance advices received from purchasers of the production. Due to the timing of the receipt of third party volume measurements, including pipeline statements, and purchase remittance advices for nonoperated properties, companies generally accrue between one and three months of revenue at period end. Such estimates consider production volumes, revenue interests, sales price histories, and appropriate deductions. Often, third party confirmation of those accruals is not possible to obtain because these accruals represent estimates. Instead, the auditor may perform the following procedures:

- Analyze the entity's historical differences between accrued and actual revenues to assess the precision achieved in prior periods.
- Analyze the underlying production estimated in the period end revenue accrual by corroborating any known production changes with the entity's production engineers or operations department.
- Compare accrued production quantities to independent production records, including run tickets or pipeline statements, if available, and compare the oil or gas price utilized in the accrual to the executed sales contract pricing terms and corroborate using independent pricing sources for the corresponding periods accrued.
- Compare the revenue ownership interest used in the accrual to the division order, JOA, or other similar legal documentation, which sets forth the revenue ownership interest of each owner.
- Significant adjustments to the accrual related to production taxes or other items could also be corroborated against independent source data because applicable oil and gas revenue transactions may also be recorded on a cash basis; however, the entity should accrue estimated unreceived production revenues and related production taxes at the financial statement date.

8.112 *Production Imbalances*. Oil and gas production from a property may be sold to purchasers for the benefit of all joint owners of that property. The purchasers 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. When 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 entity can record gas sales using the entitlements method, whereby the entity records revenue based on the production volumes it was entitled to under the division order and either a receivable or payable for the difference. The entity can also record gas sales using the sales method, whereby the entity records revenue only when gas is produced and sold on the owner's behalf. Under the sales method, no receivables or payables are recorded unless the estimated remaining reserves are not sufficient to satisfy the imbalance. In this instance, a receivable is recorded by the underproduced party, whereas the overproduced party records a liability. If the entitlements method is used, the auditor should examine the entity's entitlement computation. The auditor may confirm any production imbalance receivables recorded at the audit date. In addition, the auditor should ensure the entity has disclosed its method of accounting for gas production sales imbalances and the imbalance in terms of units and value, if material.

8.113 *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. In these cases, the operator is entitled to these advances upon proper notification to the nonoperating interest owners. When applicable, the auditor may confirm balances of receivables represented by cash advances. As with the other types of receivables discussed, the auditor may examine cash payments received subsequent to the reporting period as possible evidence supporting the appropriateness of the receivable balance. The auditor should also consider the appropriateness of the classification of the type of expenditure associated with the cash call as expense or capital in nature.

8.114 *Collectability.* Noncollectability of joint interest accounts receivable in the oil and gas industry is mitigated by the remedies available to operators in the event of nonpayment or default by joint interest owners. 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 equal to the amount owed. When 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 net revenues will equal or exceed the uncollected balance. The auditor should inquire from management whether any disputes or potential disallowances exist and perform appropriate audit procedures to determine that the effect of any such dispute is properly reflected or disclosed in the financial statements. Collectability 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.

8.115 Collectability of oil and gas sales is primarily analyzed in a manner similar to that of accrued revenue of other commercial entities. The auditor should examine the difference between the accrued revenue estimate and the actual proceeds received for the accrued volumes to identify counterparties that the auditor may examine for collectability issues. The entity's receivables should be presented at their net realizable value.

Inventory

8.116 Production from offshore platforms is occasionally loaded into floating production storage and offloading vessels. *Liftings* is the name given to the volume of product that is offloaded to a purchaser. Normally, production volumes exceed the volumes lifted, which results in inventory. The auditor should perform tests to determine if liftings recorded occurred in the proper period and that any related inventory is properly recorded.

8.117 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 should perform 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 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 evaluate materials and supplies for obsolescence. When materials and supplies are held for sale, the auditor should test the valuation by performing a lower-of-cost-or-market test.

Operating Expenses

8.118 Two types of expenses are (*a*) workover expense and (*b*) district and warehousing expenses and administrative overhead.

8.119 *Workover Costs.* The auditor should determine the nature of well workover costs and test the classification of the workover charges as capitalized versus expensed. The auditor may accomplish this through assessment of the purpose and objective of the workover as described in the AFE and through discussions with operations personnel. In addition, the auditor may compare actual charges with the AFE (when an AFE has been prepared), to determine if there were any apparent excessive or unauthorized charges.

8.120 *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 should consider procedures (*a*) to test the reasonableness of the allocated charges under the accounting procedures supplement and (*b*) to test that the entity was charged for its proper share of the expenses.

Payables

8.121 Liabilities related to oil and gas producing activities are, in many ways, similar to those of a typical commercial entity. 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
- Borrowings from production purchasers
- Unapplied advances
- Production taxes payable

Joint Interest Payables

8.122 JIBs sent to nonoperating interest owners from operators generally provide little detail about the timing of exploration, development, and production expenditures incurred by the operator. Therefore, these JIBs may not be the only source of information used by nonoperating parties to accrue accounts payable as of the audit date. Nonoperating interest owners accrue these expenditures based on the best available information from the 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 entity's working interest in the related properties, and the completion percentage of each AFE. The nonoperating interest owner's operations department generally should be familiar with these AFEs because most operating agreements require their approval prior to commencement of significant operations. The auditor should consider appropriate audit procedures to substantiate the completeness of the schedule of open AFEs. To accomplish this, the auditor may compare AFE expenditures to the capital budget for operated and nonoperated properties. The auditor may also review the AFE data contained in the AFE schedule with operations personnel for reasonableness. For mature proved developed producing properties, the auditor may analyze the accrual by comparing the accrual to a trend analysis of the actual monthly capital and operating costs incurred. Significant differences should be verified through examination of applicable operational support.

Revenue Distribution

8.123 Production revenues generated from a property are paid by purchasers to the operator of the property or to the joint owners in accordance with the provisions of the executed division order. If the operator collects all production proceeds, the operator makes appropriate disbursements to the other joint owners on a periodic basis. At the audit date, a proper cutoff is important. Accordingly, the auditor should evaluate the timing of the last cash receipt received and revenue distribution payment made by the operator for reasonableness. The operator's revenue payable account is also affected by the period end revenue accrual in which the operator also records accounts receivable and revenue, net to their interest. 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. As a result, the auditor should examine the underlying facts and circumstances in evaluating the appropriateness of such accruals. 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.

8.124 Under the terms of many lease agreements, lessor is entitled to shut-in well payments, mandatory or minimum royalty payments, and payments of a similar nature. As of the balance sheet date, lessee accrues such mandatory payments to lessor to the extent earned. As appropriate, in identifying potential obligations and determining their proper treatment in the financial statements, the auditor may interview operations personnel, analyze certain lease agreements, perform trend analysis, or perform recalculations.

Borrowings From Production Purchasers

8.125 Entities seeking sources of oil and gas supplies sometimes advance cash to property owners to finance exploration or development. The auditor may confirm borrowings to determine that the borrower has complied with the terms of the borrowing arrangement. The auditor should determine the substance of the transactions involving advances from purchasers because they sometimes take the form of mineral sales, whose treatment is addressed under the preceding "Oil and Gas Property Conveyances" section.

Unapplied Advances

8.126 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 are usually 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. As there may be a timing difference between reductions communicated through JIBs to the joint interest owners and the costs incurred and posted to the unapplied advances account by the operator, the auditor should perform procedures to assess the reasonableness of the differences. The nonoperator's auditor should evaluate the reasonableness of the JIB statements.

Production Taxes Payable

8.127 Production taxes are usually determined by the value or volume (or a combination of both) of oil and gas produced and sold during a predetermined time. Production taxes are payable to state or other governmental agencies by either the purchaser or producer as determined by the taxing authority. When the producer is liable for the taxes, the operator usually pays production taxes on behalf of all joint interest owners. The auditor should evaluate whether the operator has properly recorded the liability for production taxes. To accomplish this, the auditor may corroborate the method utilized to calculate production taxes with information from the taxing authority and developing an expectation of the total expense to that recorded by the entity. The auditor may test payments made during the reporting period as well as the balance at the beginning of the period. The auditor may also include payments made after the reporting period date as audit evidence when evaluating the existence and accuracy of the accrual at the reporting date.

Asset Retirement Obligations

8.128 The auditor should perform audit procedures to evaluate the completeness and the valuation of asset retirement obligations for oil and gas properties. Procedures that the auditor may perform include the following:

a. *Completeness of asset retirement obligations*. Because federal and state regulations and contractual obligations require that wells be plugged, all facilities and equipment removed, and the terrain restored to specified conditions, the auditor may ensure that all wells do have a corresponding asset retirement obligation to validate the completeness of the overall obligation recorded by the entity.

b. *Valuation of the asset retirement obligation*. The development of an asset retirement obligation generally involves engineering estimates for the cost to abandon a well or field. The auditor obtains an understanding of how these estimates were determined and compares the estimates to actual asset retirement costs incurred for the abandonment of similar properties, when available, to gain audit evidence over the valuation of the asset retirement obligation.

c. *Other inputs.* The asset retirement obligations recorded in an entity's accounting records are also dependent upon other assumptions, including the estimated life of the wells (which can be derived from the entity's oil and gas reserve report), an inflation factor, a discount factor, as well as management's estimate of the wells it plans on abandoning over the 12 months subsequent to period end in order to ensure proper short-term versus long-term classification of the asset retirement obligations on the balance sheet. The auditor may assess the reasonableness of accretion expense recorded each period.

Tax and Other Regulatory Matters

8.129 Various tax and other regulatory matters can have a significant impact on the financial statements of an entity with oil and gas producing activities. 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 verify 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. In addition, the auditor may make certain other inquiries concerning taxes. These may include the following:

- 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 entity's reporting responsibility because of its role as general or managing partner in existing partnerships

8.130 Other regulatory matters may include the following:

- 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)
- Reporting to the SEC (current status of filings, identification of data, responsible personnel, and so on)

Derivatives and Hedging Activities

8.131 Exploration and production companies often use financial derivatives in their operations to mitigate risks associated with oil and gas prices, foreign currency exchange rates, and interest rates. Depending on the entity's risk management strategy, these derivatives may be designated as a hedge under FASB ASC 815. Exploration and production companies may also enter into nonfinancial contracts that may meet the definition of a *derivative* provided in paragraphs 83–139 of FASB ASC 815-10-15 or qualify for certain exclusions provided by FASB ASC 815, or both. Auditing derivatives and hedging activities of entities with oil and gas producing activities is similar to that of other entities that do not have oil and gas producing activities.

8.132 AU section 332, *Auditing Derivative Instruments, Hedging Activities, and Investments in Securities* (AICPA, *Professional Standards*), provides guidance to auditors in planning and performing auditing procedures for financial statement assertions about derivative instruments, hedging activities, and investments in securities. AU section 332 establishes requirements and provides guidance for the auditor when considering the work of internal auditors and when using internal auditors to provide direct assistance to the auditor in an audit performed in accordance with GAAS in connection with determining the nature, timing, and extent of auditing procedures performed on an entity's derivative and hedging activities. The auditor may consider the AICPA Audit and Accounting Guide *Auditing Derivative Instruments, Hedging Activities, and Investments in Securities* in determining the nature, timing, and extent of auditing procedures performed on an entity's derivative and hedging activities. AU section 328, *Auditing Fair Value Measurements and Disclosures* (AICPA, *Professional Standards*), establishes requirements and provides guidance regarding auditing fair value measurements and disclosures of derivative instruments.

8.133 When evaluating an entity's derivative and hedging activities, the auditor should also consider the following:

- Classification of derivative and hedging activities in the statement of cash flows in accordance with the guidance in FASB ASC 815 and FASB ASC 230, *Statement of Cash Flows*
- Affect of derivative and hedging activities on other areas, such as the full cost ceiling limitation under SEC *Codification of Staff Accounting Bulletins* Topic (12)(D)(3), "Full cost ceiling limitation," and disclosures under FASB ASC 932-235

Auditing Fair Value Measurements

8.134 Entities involved in the exploration and production of oil and gas often employ various valuation techniques to determine the fair value of oil and gas properties. These valuations may be used for various purposes, including the allocation of purchase price in business combinations and to determine potential asset impairments. AU section 328 establishes requirements and provides guidance regarding auditing fair value measurements and disclosures relating to the measurement and disclosure of assets, liabilities, and specific components of equity presented or disclosed at fair value in financial statements.[5]

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[5] PCAOB Staff Audit Practice Alert No. 2, *Matters Related to Auditing Fair Value Measurements of Financial Instruments and the Use of Specialists* (AICPA, *PCAOB Standards and Related Rules*, PCAOB Staff Guidance, sec. 400.02), establishes requirements and provides guidance for auditors when auditing fair value measurements of financial instruments and when using the work of specialists under the existing standards of the PCAOB, focusing on specific matters that are likely to increase audit risk related to the fair value of financial instruments in a rapidly changing economic environment.

PCAOB Staff Audit Practice Alert No. 4, *Auditor Considerations Regarding Fair Value Measurements, Disclosures, and Other-Than-Temporary Impairments* (AICPA, *PCAOB Standards and Related Rules*, PCAOB Staff Guidance, sec. 400.04), informs auditors about potential implications of the Financial Accounting Standards Board (FASB) Staff Positions on reviews of interim financial information and annual audits. This alert addresses the following topics: (1) reviews of interim financial information (reviews); (2) audits of financial statements, including integrated audits; (3) disclosures; and (4) auditor reporting considerations.

PCAOB Staff Audit Practice Alerts are not rules of the board, nor have they been approved by the PCAOB.

Other Audit Considerations

Statement of Cash Flows

8.135 When auditing the statement of cash flows of an entity with oil and gas producing activities, the auditor should evaluate certain noncash transactions that affect cash flows from operating and investing activities and determine whether such transactions meet the disclosure requirements under FASB ASC 230. Typical noncash transactions that are prevalent in the oil and gas industry include, but are not limited to, the following transactions:

- Accrued capital additions
- Asset retirement obligation additions and revisions

8.136 For entities following the successful efforts method of accounting, the auditor should evaluate the entity's policy for classification of unsuccessful exploration costs in the statement of cash flows. The auditor should ensure that only successful exploration costs are included in investing activities. The auditor should ensure that exploration costs, such as geological and geophysical costs, delay rentals, and internal technical costs are classified as operating activities.

Commitments and Contingencies

8.137 Due to increased competition in the oil and gas industry to secure drilling rigs for fulfillment of drilling program requirements, entities with oil and gas producing activities have begun entering into longer-term commitments to secure drilling rigs with service providers in the drilling industry. The auditor should inquire of the entity's management and evaluate these drilling contracts to determine if proper disclosure under U.S. GAAP has been made.

8.138 The auditor should also evaluate potential legal and environmental exposures with respect to the entity's ongoing operating and drilling activities.

Risks and Uncertainties

8.139 FASB ASC 275, *Risks and Uncertainties,* and paragraphs 15–19 of FASB ASC 932-360-55 require disclosure of significant estimates and concentrations. The auditor should evaluate the appropriateness of the entity's disclosures related to significant concentrations and estimates. Significant estimates prevalent in the oil and gas industry include, but are not limited to, the following:

- Proved oil and gas reserve and cash flow estimates, including DD&A, impairments and purchase price allocations, which are all affected by oil and gas reserves estimates
- Estimates of future development costs
- Asset retirement obligations
- Oil and gas revenue and expense estimates
- Estimates of environmental exposures

Related Parties

8.140 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, unique financing arrangements, royalty relationships, management fees, and so on. These transactions also occur from dealings with limited partnerships, joint ventures, and the like. Commonly encountered related party transactions include the following:

- 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 entity or the limited partners.

8.141 AU section 334, *Related Parties* (AICPA, *Professional Standards*), establishes requirements and provides guidance for the auditor regarding identifying related party relationships and transactions and to satisfy the auditor concerning the required financial statement accounting and disclosure when performing an audit of financial statements in accordance with GAAS. 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.

Supplementary Oil and Gas Reserve Disclosure Considerations and Related Procedures[†]

Reserve Quantity and Value Disclosures

8.142 Entities with oil and gas producing activities that are issuers 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 ASC 932-235. The contents of the supplementary reserve quantity and reserve value disclosure information are provided in FASB ASC 932-235.

[†] In February 2010, the Auditing Standards Board issued Statement on Auditing Standards (SAS) No. 118, *Other Information in Documents Containing Audited Financial Statements* (AICPA, *Professional Standards*, AU sec. 550); SAS No. 119, *Supplementary Information in Relation to the Financial Statements as a Whole* (AICPA, *Professional Standards*, AU sec. 551); and SAS No. 120, *Required Supplementary Information* (AICPA, *Professional Standards*, AU sec. 558). These standards amend or supersede AU section 550A, *Other Information in Documents Containing Audited Financial Statements*; AU section 551A, *Reporting on Information Accompanying the Basic Financial Statements in Auditor-Submitted Documents*; and AU section 558A, *Required Supplementary Information* (AICPA, *Professional Standards*), respectively. Collectively, these statements address the auditor's responsibilities with respect to information that is required by a designated standard setter (for example, FASB, the Governmental Accounting Standards Board, Federal Accounting Standards Advisory Board, and the International Accounting Standards Board), to accompany an entity's basic financial statements and supplementary information that is presented outside the basic financial statements. The effective date of the SASs is for audits of financial statements for periods beginning on or after December 15, 2010, and early application is permitted.

8.143 AU section 558A and Interpretation No. 1 of AU section 558A indicate that the auditor should perform certain procedures with respect to the reserve information. Paragraph .09 of AU section 558A 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 as a whole, the auditor may expand the audit report in accordance with paragraph .07 of AU section 550A, *Other Information in Documents Containing Audited Financial Statements* (AICPA, *Professional Standards*).

8.144 The auditor's objectives in applying procedures to supplementary reserve disclosures may include the following:

- Determining that the supplementary information 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

8.145 To meet these objectives, the auditor should apply the procedures specified in AU section 558A and AU section 9558A 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.[6]

8.146 In addition, independent reservoir engineers often use and rely on information, without corroboration, provided by the entity in formulating their reserve quantity information. This information includes listings of properties, the ownership interest in the properties, production data, prices, and so on. The auditor should consider appropriate procedures 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 circumstances identified in paragraph 8.147. However, the auditor should evaluate the reasonableness of the supplementary information based on the performance of the limited procedures and determine whether an appropriate expansion of the report is needed.

8.147 Because the supplementary information is not audited and is not a required part of the basic financial statements, the auditor need not add an

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[6] Interpretation No. 1, "Supplementary Oil and Gas Reserve Information," of AU section 558A (AICPA, *Professional Standards*, AU sec. 9558A par. .01–.11), provides guidance and establishes requirements for auditors on the nature of procedures to be applied to supplementary oil and gas reserve information. Interpretation No. 1 states that an auditor should inquire about the calculation of the standardized measure of discounted future net cash flows and whether, among other things, the prices used to develop future cash inflows from estimated production of the proved reserves are based on prices received at the end of the entity's fiscal year. SEC Final Rule 33-8995, *Modernization of Oil and Gas Reporting*, requires the use of a 12-month average price in estimating reserves and FASB *Accounting Standards Codification* 932, *Extractive Activities—Oil and Gas*, requires the use of a 12-month average price in estimating future cash inflows for purposes of determining the standardized measure. Although Interpretation No. 1 may not be amended, auditors should make sure the standardized measure is accounted for in accordance with the amended SEC and FASB guidance.

explanatory paragraph to the auditor's report on the financial statements to refer to the supplementary information, except in any of the following circumstances:

- The supplementary information that U.S. 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 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.

Supplementary Oil and Gas Reserves Procedures

8.148 Paragraphs .04–.05 of AU section 9558A provide detailed guidance of procedures the auditor should perform on supplementary oil and gas reserve information. With the implementation of Rule 404 of SOX, entities with oil and gas producing activities that are issuers generally evaluate and test internal control associated with the oil and gas reserves estimation process due to its significance to other processes and the disclosure requirements under U.S. GAAP. The auditor should evaluate the impact of the entity's internal control over the oil and gas reserves process, as well as other processes that may interact with the oil and gas reserves process (for example, land administration—division of interest), in determining the nature, timing, and extent of the procedures to be performed under AU section 9558A.

8.149 Typical procedures applied to oil and gas reserves estimates may include, but are not limited to, the following procedures:

- Comparison of estimated future net revenues, taxes other than income taxes, operating expenses and capital expenditures in the current year reserves estimates to the prior year reserves estimates, including a comparison of these items as a percentage of projected revenues
- Comparison of the entity's estimated production over the next 2–3 years to the entity's actual production in the current year
- Comparison of the entity's estimated price to the 12-month average price
- Comparison of the entity's oil and gas reserves estimate with the corresponding information used in computing the entity's DD&A and, in the case of full cost entities, the limitation of capital cost calculation
- Comparison of the estimated undiscounted abandonment costs included in the entity's reserves estimate to the corresponding undiscounted asset retirement obligation included in the entity's asset retirement analysis
- Comparison of the estimated undiscounted capital expenditures included in the entity's oil and gas reserves estimate to the entity's capital expenditure budget for the upcoming period
- Comparison of the entity's effective tax rate on future income taxes to the entity's actual effective tax rate for the current period

- Comparison of the discount factors used by the entity to the discount factors assuming 10 percent discounting from an independent source
- Accuracy testing of ownership interests used in calculating estimated net revenues and related expenses

Use of Specialist

8.150 Due to the nature of the oil and gas reserves estimation process, entities often engage third party reserve engineering firms to either (*a*) prepare the entity's oil and gas reserve estimates, or (*b*) audit or review oil and gas reserve estimates prepared by the entity's in-house reservoir engineers. Because the estimation of oil and gas reserves is a specialized field, the auditor often uses the work of the reservoir engineers to obtain an appropriate level of understanding of work performed by the specialist to evaluate the reserves. AU section 336 establishes requirements and provides guidance for the auditor who uses the work of a specialist in performing an audit in accordance with GAAS.

Other Considerations

8.151 When evaluating an entity's oil and gas reserves estimation process, the auditor may also consider the impact of reserve estimates on other audit areas, including the following:

- Depreciation, depletion, and amortization calculations
- Evaluation of impairment of oil and gas properties and goodwill
- Asset retirement obligations
- Gas imbalances for entities using the sales method
- Debt covenants affected by reserve quantities and values
- Business combinations and property acquisitions

Chapter 9

Internal Control Considerations

9.01 For an entity engaged in oil and gas producing activities, as for other types of entities, internal control is important to ensure that the entity's financial reporting, compliance, and operational objectives are met. The nature of a particular entity's internal control, among others, is influenced by its size, the degree of geographic dispersion of its operations, its types of operations (for example, operator versus nonoperator), governmental requirements, and management's information needs.

Definition of *Internal Control* and *Internal Control Framework*

Internal Control Framework

9.02 *Internal control* is broadly defined by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) as "a process, effected by an entity's board of directors, management and other personnel, designed to provide reasonable assurance regarding the achievement of objectives in the following categories: (i) effectiveness and efficiency of operations; (ii) reliability of financial reporting; and (iii) compliance with applicable laws and regulations."

9.03 Internal control consists of five interrelated components:

a. *The control environment.* Sets the tone of an organization, influencing the control consciousness of its people. It is the foundation for all other components of internal control, providing discipline and structure.

b. *Risk assessment.* The entity's process for identifying and analyzing relevant risks to achievement of its objectives, forming a basis for determining how the risks should be managed.

c. *Information and communication systems.* These systems support the identification, capture, and exchange of information in a form and time frame that enable people to carry out their responsibilities.

d. *Control activities.* The policies and procedures that help ensure that management directives are carried out.

e. *Monitoring.* A process that assesses the quality of internal control performance over time. This is accomplished through ongoing monitoring activities, separate evaluations, or a combination of the two.

This chapter focuses primarily on specific control activities most often used by the entities involved in oil and gas producing activities.

Internal Control Over Financial Reporting

9.04 The internal control framework developed by COSO is not required to be used by public or other entities; however, the requirements of the Securities and Exchange Commission (SEC) for public companies under the

Sarbanes-Oxley Act of 2002 (SOX) are consistent with the COSO Internal Control Framework. These reporting requirements are limited to *internal control over financial reporting*. Other aspects of control, such as controls pertaining to operating efficiency and compliance, are not within the scope of reporting requirements under SOX. However, in this chapter, certain aspects of control related to operating efficiency and compliance have been discussed because a complete evaluation of an entity's risks and control may provide benefits.

9.05 For publicly traded entities, the definition of *internal control over financial reporting* is provided in SEC Rule 13(a)-15(f). The SEC defines *internal control over financial reporting* as

> a process designed by, or under the supervision of, the issuer's principal executive and principal financial officers, or persons performing similar functions, and effected by the issuer's board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP) and includes those policies and procedures that
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> 1. pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the issuer;
> 2. provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the issuer are being made only in accordance with authorizations of management and directors of the issuer; and
> 3. provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the issuer's assets that could have a material effect on the financial statements.

9.06 Additionally, SEC Rule 13(a)-15(e) provides a definition of *disclosure controls and procedures* as

> controls and other procedures of an issuer that are designed to ensure that information required to be disclosed by the issuer in the reports that it files or submits under the Act is recorded, processed, summarized and reported, within the time periods specified in the Commission's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by an issuer in the reports that it files or submits under the Act is accumulated and communicated to the issuer's management, including its principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

Internal Control Considerations for Audit of a Nonpublic Entity

9.07 In general, internal control for oil and gas producing activities is not different from that of other types of entities. AU section 314, *Understanding the*

Entity and Its Environment and Assessing the Risks of Material Misstatement (AICPA, *Professional Standards*), 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*, Auditing 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.

9.08 In all audits, the auditor must obtain an understanding of the five components of internal control sufficient to assess the risk 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 then assesses control risk for the relevant assertions embodied in the account balance, transaction class, and disclosure components of the financial statements. The auditor must obtain a sufficient understanding by performing risk assessment procedures to evaluate the design of controls relevant to an audit of financial statements and to determine whether they have been implemented. The auditor should use such knowledge to

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

Reporting Requirements for Public Entity

9.09 Management of a publicly traded company is required by Section 404(a) of SOX 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. As directed by Section 404 of SOX, the SEC adopted final rules requiring companies subject to the reporting requirements of the Securities Exchange Act of 1934 (the 1934 Act), 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 website at www.sec.gov/rules/final/33-8238.htm for the full text of the regulation.

9.10 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 COSO definition, but the SEC does not mandate that the entity use COSO as its criteria for assessing effectiveness.

9.11 In June 2007, the SEC published an interpretive release to provide guidance for management regarding its evaluation and assessment of internal control over financial reporting. It sets forth an approach by which management can conduct a top-down, risk-based evaluation of internal control over financial reporting. See the SEC website at www.sec.gov/rules/interp/2007/33-8810.pdf for the full text of the interpretation. 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 SOX, nor is this chapter intended to help auditors perform an audit of internal control over financial reporting in accordance with Auditing Standard No. 5.

9.12 In accordance with the SEC rules, public entities are required to include the following disclosures in their annual reports filed with the SEC:

- Management's evaluation of effectiveness of disclosure controls and procedures—Item 307 of Regulation S-K
- Management's annual report on internal control over financial reporting—Item 308(a) of Regulation S-K
- Attestation report of the registered public accounting firm on the registrant's internal control over financial reporting—Item 308(b) of Regulation S-K
- Changes in internal control over financial reporting—Item 308(c) of Regulation S-K

9.13 Certain exceptions to these requirements are included in Item 308T of Regulation S-K. These exceptions are applicable only to a registrant that is neither a "large accelerated filer" nor an "accelerated filer" as those terms are defined in Rule 12b-2, under the 1934 Act. Additionally, smaller public companies are not required to provide the attestation reports in their annual reports filed with the SEC.[1]

9.14 Each quarter, the SEC rules also require management to evaluate the effectiveness of the entity's disclosure controls and procedures and disclose any changes in the entity's internal control that occurred during a fiscal quarter

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[1] In the Securities and Exchange Commission (SEC) Final Rule Release No. 33-9142, *Internal Control Over Financial Reporting in Exchange Act Periodic Reports of Non-Accelerated Filers*, the SEC adopted amendments to its rules and forms, effective September 21, 2010, to conform to new Section 404(c) of the Sarbanes-Oxley Act of 2002 (SOX), as added by Section 989G, *Exemption for Non-Accelerated Filers*, of the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act). Section 404(c) now provides that Section 404(b) of SOX shall not apply with respect to any audit report prepared for an issuer that is neither an accelerated filer nor a large accelerated filer as defined in Rule 12b-2 under the Securities Exchange Act of 1934. The Dodd-Frank Act was signed into law by the president on July 21, 2010.

that have materially affected, or are reasonably likely to materially affect, its internal control over financial reporting.[2]

Evaluating the Effectiveness of Internal Control by Management

Components of Internal Control

Control Environment

9.15 The control environment establishes the overall tone for the organization and is the foundation for all other components of internal control. The COSO framework identifies subcomponents of the control environment, including integrity and ethical values, management's philosophy and operating style, organizational structure, and others. Management must also address antifraud programs and the effectiveness of the audit committee when evaluating the control environment. Company-level controls and general computer controls are part of the control environment and are important elements of internal control over financial reporting.

Risk Assessment

9.16 For an entity to exercise effective control, it must establish objectives and understand the risks it faces in achieving those objectives. As part of its risk assessment process, management should determine and consider the implications of relevant risks that could hinder the achievement of its objectives. Management must then provide a basis for managing the risks. For purposes of management's Section 404 assessment, the SEC's June 2007 interpretive release indicates that management should identify the risks of material misstatement in the significant accounts and disclosures and related assertions of the financial statements. Management should implement controls to prevent or detect errors or fraud that could result in material misstatements. The subcomponents for the risk assessment include (*a*) business risk; (*b*) inherent risks, and (*c*) fraud risks.

9.17 Prior to determining the appropriate level of controls, management should perform a risk assessment and an analysis of significant accounts to determine the areas requiring key controls. To determine which control objectives are significant, a review should be made of the inherent risks associated with account balances. The impact of misstatements on the financial statements as well as qualitative considerations, such as the use of estimates and judgment, should also be evaluated.

Information and Communication

9.18 The information and communication component includes the systems that support the identification, capture, and exchange of information in a form and time frame that enable personnel to carry out their responsibilities and allow financial reports to be generated accurately. Information and communication also spans all of the other components of internal control. When evaluating this component, management must consider internally generated

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[2] Except for entities that meet the definition of a *foreign private issuer* and that file annual reports on Form 20-F or Form 40-F.

and externally generated data that enable management to make informed business decisions about financial reports and disclosures.

Control Activities

9.19 *Control activities* are the policies and procedures that help to ensure that management's directives are implemented. Control activities occur throughout the organization, at all levels, and in all functions. The activities involve approvals, authorizations, verifications, reconciliations, reviews of operating performance, security of assets, and segregation of duties. COSO discusses many different types of control activities, including preventive controls, detective controls, manual controls, computer controls, and management controls. Control activities address specified information processing objectives, such as ensuring completeness and accuracy of data processing. The following section includes certain control activities that are commonly performed by personnel at various levels in an oil and gas entity. Many control activities performed are similar to the activities performed in other types of businesses, such as those related to financial reporting, treasury, and human resources. However, certain business functions of the exploration, development, and production activities are unique and are discussed subsequently. Controls discussed are not always present because each entity must assess the controls appropriate to the particular transactions and organization of the entity.

Monitoring

9.20 Monitoring is the continuous process that management uses to assess the quality of internal control performance over time.

Common Control Activities for Oil and Gas Entities

Acquisition of Mineral Interests

Lease Acquisition

9.21 Accurate records of nonproducing and producing properties and the related financial obligations should be maintained. All expenditures for leasehold interests should be recorded to the proper authorization for expenditure (AFE), property, and account. Controls may include use of standardized lease agreements with approval of variances, secure archiving of original documents, and management authorization for payment of lease bonuses. 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 over maintenance of master files should include authorization of updates of those master files, periodic substantiation of master file contents, and prevention of unauthorized access to, or alteration of, data. Generally, land administration records should provide documentary support such as executed leases, division orders, and title opinions for entry or update of division of interest master files. Controls are also needed to ensure that critical dates are monitored and decisions to pay delay rentals or lease extensions are properly carried out to ensure leases are not lost. For example, an automated calendar system may be used to document management review and authorization of decisions to renew or surrender leases and to identify key dates.

Transactions for Transferring of Mineral Interests

9.22 Acquisitions and dispositions, of entities as well as properties, are common in the oil and gas industry. Properties may also be exchanged. Controls are needed to ensure costs of properties acquired are properly allocated and recorded. For properties disposed of, gains or losses should be properly calculated. 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. The timing and terms of sales or other dispositions of property should also be properly authorized. Controls should include management approval at the appropriate level depending on the size of a transaction as well as review and approval of all related contracts, such as confidentiality agreements, offer letters, memoranda of understanding, or purchase and sale agreements. There should be specific reviews for accounting and tax implications.

9.23 *Due Diligence.* Controls should be in place to ensure that the appropriate due diligence is done prior to making an acquisition, including issues related to reserve engineering, environmental and other liabilities, land and title, exploration, and production. A due diligence team with the appropriate mix of knowledge and skills should perform an evaluation and make recommendations concerning terms of the acquisition transaction.

9.24 *Recognizing and Measuring the Identifiable Assets, Liabilities Assumed, and Noncontrolling Interests Acquired.* When the acquisition is recorded, controls are needed to ensure assets are appropriately recognized and measured. The measurement to the individual properties acquired is generally made based on an evaluation of the value of reserves acquired. Any premium over the reserve value would be treated as goodwill. Controls over recording of acquisition transactions should include review and approval of the measurement calculations.

9.25 *Discontinued Operations and Properties Held for Sale.* Once a decision is made to dispose of properties or other assets, controls are needed to ensure that the appropriate analysis is made to determine whether the assets sold are required to be separately disclosed in the financial statements as discontinued operations and properties held for sale. Controls should include mechanisms to ensure that operational decisions concerning disposal of properties are promptly communicated to accounting personnel for recognition of the change in status in the financial statements.

Divisions of Interest

9.26 Many oil and gas exploration and development 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. The costs of drilling and producing oil and gas wells are borne by the working interest owners, and revenue from oil and gas producing properties are generally divided among multiple royalty and working interest owners. Typically, information about the ownership of working interests and revenue interests is maintained in division-of-interest master files. Divisions of interest, consistent with the working interest owners' legal ownership, must be properly set up as soon as an AFE is approved. Revenue divisions of interest should be set up as soon as a well is considered productive.

9.27 Controls over set up and maintenance of division of interest records may include the following: Division orders should be reviewed or adequately tested by individuals who do not have control over the properties. There should be a segregation of duties between those authorized to establish or make changes to divisions of interest and those who can establish new interest owners. Management should review divisions of interest set up, including ensuring that total interests for all owners on a property add up to100 percent.

9.28 Controls over division of interest changes may include the following: Changes to divisions of interest should be made on a timely basis and only after proper legal documentation of the change has been provided. 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. Controls should include management review of division of interest changes, including review of source documents that prompt the change.

9.29 *Payout.* When contracts provide for changes in revenue interests after one party has recovered its costs, as in farm outs and farm ins, payout should be tracked to insure that the change in interests is recorded at the appropriate time. Controls should be in place to ensure that wells are properly identified for tracking of payout status, as provided by governing contracts or local laws, and that payout is properly calculated and communicated to appropriate internal and external parties. Controls should include management review of payout calculations before notification of external parties and entry of changes into the division of interest system.

Exploration and Development Activities

Authorization For Expenditure

9.30 The procedure for giving written approval for large expenditures may require an AFE. AFEs are used for documenting approvals and usually contain a description of the project, a listing of budgeted expenditures, and appropriate support documentation. AFE procedural 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. Controls include approval of AFEs according to an established financial authority matrix and ensuring that AFEs are supported by appropriate documentation, including gross and net expenditure amounts based on the correct working interests.

9.31 Many companies in the industry reserve the term *authorization for expenditure* for those expenditures involving the drilling and equipping of exploratory or developmental wells. However, AFEs are also used for acquiring leases, purchasing major fixed assets and other significant projects that require approval of one or more individuals, and, for a joint venture, approval by all working interest owners. A company should have controls to analyze variances between actual expenditures and the amounts authorized in the AFEs as well as reconciling accumulated costs to drilling or other operational reports. In addition, controls should ensure that supplemental AFEs are obtained and properly approved as needed. Procedures should be established for reviewing proper classification of major projects as either expense or capital projects in accordance with U.S. GAAP. Procedures should also be established that ensure well classifications in the accounting records (which are used to determine treatment of drilling and seismic expenditures) properly reflect the current status of the well as exploratory or development.

Joint Interest Billing

9.32 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 other working interest 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 nonoperating party with the right to perform (or to have performed) joint interest audits of the operator. Controls include cutoff procedures that ensure that all billable expenses are billed to working interest owners; management approval of allocation computations and indirect expenses such as overhead and service unit costs in accordance with joint operating agreements; reconciliation of accounts receivable balances to the general ledger; and prompt resolution of any differences.

9.33 *Advances Under Cash Calls.* The operator of a property can request cash calls from the other interest owners under the terms of most joint operating agreements. Controls should be in place to properly record these cash advances and to apply them to expenditures made on the property. Similarly, controls should be in place to ensure that any advances made by a nonoperator have been applied by the operator when joint interest billings are distributed. Controls include reconciling cash receipts to the Joint Interest Receivables subledger and reviewing monthly account statements prior to distribution to joint interest owners.

9.34 *Collectability of Joint Interest Receivables.* Similar to other industries, controls should be in place to ensure that accounts receivable balances are collectable, and that allowances for doubtful accounts are recorded as appropriate. Controls include preparation and analysis of aged accounts receivable reports; reviewing partner balances against established credit limits; performing collection procedures on overdue accounts; management approval of any adjustments to accounts; and identification of delinquent accounts as compared with the reserve for doubtful accounts balance to ensure the reserve is adequate.

Reserve Estimation

9.35 The estimation of reserves affects the calculation of depreciation, depletion, and amortization (DD&A) and impairments as well as disclosures included in the financial statements. Reserve estimates should be prepared in conformity with professional standards and regulatory requirements; therefore, policies and controls should be in place to ensure the professional qualifications of reserves estimators. Controls are needed to ensure the appropriate data sources are used for the inputs that are part of the calculations, including price, volumes, costs and interests, projected timing of production and future investments, discount rate, and aggregation from the well level to the consolidated totals. Controls should include appropriate documentation and review of these factors and archiving of the reserve models. Often, third party reservoir engineers are engaged to audit or independently calculate the reserve estimates prepared by a company's in-house engineers, particularly of larger properties. If outside estimates are obtained, controls over the transfer of data to the outside reservoir engineer, as well as clear identification of how variances between the internal and external estimates will be resolved, are required. Analysis of the preliminary reserves, including reconciliation by category of reserves (producing, proved developed, and proved undeveloped) to the prior year, is an important control. Producing reserve schedules should be supported by a comprehensive listing of wells reconciled to production records. Controls should also include review of reserve reports by senior engineers, management, and outside parties.

Property Accounting

9.36 In order to fulfill tax and financial reporting requirements of accounting for oil and gas properties, companies accumulate the cost, expense, and revenue information at the individual lease or well level regardless of the accounting method used. In addition, property records should have sufficient detail of ownership, status (abandoned, leases held for sale, or operations) and assigned equipment. This requires coordination among the land department, the legal department, and the accounting department. Subsidiary property records should be routinely reconciled to the general ledger, and guidelines should be established that outline the proper recognition (capitalization or expense) and timely recording of costs. Controls should ensure that invoices from vendors and for other expenditures are complete, properly approved, and recorded to the correct AFE, property, and account based on documented procedures.

9.37 *Purchasing.* Controls over purchasing of equipment, services, and supplies should be in place, especially when that function is decentralized. Controls should ensure that counterparty information is set up only for valid approved vendors, and that name and address changes are made only when properly documented and approved. Appropriate segregation of duties is critical. Controls should include the use of sealed bids or other appropriate evaluation methods for selecting vendors and periodic notification to vendors of the company's conflict of interest and code of conduct standards, as well as a means to report possible violations of such standards.

9.38 *Accruals.* Operators should have controls to provide reasonable assurance that all material expenditures for exploration and development costs incurred are properly accrued at the end of the reporting period. 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 seismic and other exploration costs are accrued if significant. Nonoperating interest owners should similarly accrue payables to operators for their share of expenditures incurred. This may require controls for confirmation with the operator on properties in which material activities are in progress. Controls should include reviewing disbursements, statements, invoices, and credit notes immediately after the end of a reporting period to ensure complete and consistent recording in the appropriate period.

9.39 *Dry Hole Costs.* Under successful efforts accounting, costs incurred in drilling exploratory wells that are determined to be dry holes should be expensed. Because development dry holes are capitalized, well classifications in AFE records (used to determine treatment of drilling and seismic expenditures) should accurately reflect the current status of the well as exploratory or development. In addition, controls should ensure that the determination that a well is dry is made in the proper period. Controls in this area will largely be driven by the AFE process, in which the classification of wells is determined and timely closing of AFEs is enforced. See also paragraph 9.72 regarding suspended well costs. Communication with operations personnel between period end and filing date is also essential to ensure that wells being evaluated are properly reported.

9.40 *Capitalized Overhead.* Controls should ensure that drilling and producing overhead is properly calculated in accordance with the joint operating agreement and recorded in compliance with the successful efforts or full cost method of accounting. Controls include reconciliation of well listings used to calculate and record overhead to drilling reports and production record as well as verification of the accuracy of the overhead rates applied.

9.41 *Capitalized Interest.* Procedures should be documented that establish the company's capitalization policy for interest in accordance with existing accounting guidance.

9.42 *Wells in Progress.* Controls should be in place to ensure that work-in-progress and suspense accounts are used properly and cleared in a timely manner. Written procedures covering work-in-progress should be established that outline the review process and communicate guidelines of when costs may be suspended.

9.43 *Asset Retirement Obligations.* The calculation and recognition of legal obligations associated with the retirement of oil and gas properties is subject to judgment and should reflect the present fair value of estimated liabilities upon abandoning properties. Controls are needed over the identification and estimation of amounts required to plug and abandon wells, remove tangible equipment, and restore land or seabed at the end of production operations. In addition, the calculation and recording of the discounted liability and accretion expense recognized over time requires several key assumptions (including discount rates and inflation factors). Controls should ensure that the asset retirement obligation calculation and estimation processes are appropriately reviewed and documented and reconciled to the listing of properties to ensure completeness.

9.44 *Security Over Equipment and Inventory.* The substantial investment in physical assets and the ready marketability of equipment and inventory require appropriate controls over access and transfers of materials to and from inventory and well sites. 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, to properly safeguard them from loss through theft. The assets should be periodically verified. In addition, there should be specific responsibility for physical custody of assets and signature access (requisition authority) and controls over documentation and recording of material transfers including segregation of these duties. All transfers of materials should also be priced in accordance with Council of Petroleum Accountants Societies rules and other governing agreements.

Impairment Analysis

9.45 *Assessment of Unproved Properties for Impairment.* Unproved properties should be properly reviewed for possible impairment. Controls should ensure that events affecting the value of leases are considered, and that periodic amortization is recorded. Controls include reconciliation to general ledger property account balances to ensure all unproved properties are included in the impairment calculation; review of amortization rates based on accurate information concerning lease terms for each property or group of properties included in the calculation; and management review and approval of impairment journal entries.

9.46 *Assessment of Proved Properties for Impairment.* Proved oil and gas properties are required to be reviewed for impairments. Successful efforts companies require controls over the comparison of the expected undiscounted future cash flows to the unamortized capitalized cost of the assets usually at the field level. Companies using the full cost method require controls over the full cost ceiling test, discussed in chapter 5, "Full Cost Method of Accounting for Oil and Gas Activities." Controls include reconciliation to general ledger property account balances to ensure all proved properties are included in the impairment testing calculation, review by operations personnel of the assumptions used in the valuation and management review, and approval of impairment journal entries.

Exploration, Development, and Production—Nonoperator

9.47 Internal control for outside operated 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.
- Controls should be established for review of joint interest billings and comparison against the appropriate AFEs, and for review of AFEs for application of cash advances and for credits due when a project is completed.
- Production revenues should be reviewed against historical records and compared with estimates. Any unusual fluctuations should be investigated and appropriately resolved.
- Controls should be established to assure that the need for joint interest audits is given appropriate consideration in accordance with the joint operating agreement.

Production

Production and Inventories

9.48 *Volumes Produced.* 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, and that volumes recorded are measured in compliance with company policies, applicable laws and regulations, and contract terms. Such controls may involve periodic calibration and inspection of meters, manually gauging or witnessing the gauging of production tanks, and period-to-period comparison of production volumes.

9.49 *Prices and Revenues Recorded.* Prices should be monitored to ensure that maximum allowable prices are received, based on contractual terms and provisions. All production should be properly valued and recorded to the appropriate property, promptly and in accordance with agreements. Controls are needed over the accrual of revenues prior to receipt of payment by the purchaser, including comparison to prior months' revenues. Settlement reports and remittance advices from purchasers should be reconciled regularly to the company's production data and calculated revenues.

9.50 *Production Imbalances.* Imbalances may arise when an entity does not take its proportionate share of the oil and gas as compared with other owners or producers in a field. See paragraphs 4.59–.63 in this guide for more information. Whether the entitlement method or the sales method is used, controls should be in place to properly track and record the value (volumes and prices) of the under/over lift occurrences. The operator of a property should keep accurate records of any volumes taken in kind by nonoperators in order to fulfill the responsibility of balancing such volumes on behalf of the company and other nonoperators.

9.51 *Pipeline Imbalances.* When selling gas to a pipeline, a company nominates the volumes that it plans to inject into a pipeline. The actual amounts produced may vary from that estimate, resulting in pipeline imbalances. Controls should ensure that pipeline imbalances are properly calculated and reconciled with pipeline statements. Cash settlements of imbalances should be properly calculated, consistent with transportation agreements. Controls include a monthly reconciliation of the production department's volume records to the delivered volumes per the pipeline's statements, taking into account fuel usage and any other adjustments. The volumes should also be compared to those reported on transportation invoices and those reported by purchasers of the volumes. When more than one pipeline is used to transmit the volume to the ultimate purchaser, the volumes delivered by the original transporter should be reconciled to those received by the subsequent transporter as per the two pipelines' statements. Controls should also include management review and approval of entries to record gains, losses, and cashed out imbalances.

9.52 *Product Inventories.* Produced oil and gas may be stored in tanks or close to pipelines and should be properly safeguarded and measured. Pricing is at the lower of cost or market in the financial statements. See paragraphs 4.64–.67 in this guide for more information on inventory exchanges. Controls should include period-to-period balancing of inventory volumes and measures to ensure the pricing of the volumes is consistent with lower of cost or market prices.

9.53 *Dealings With Purchasers.* Prior to selling production, a company should ensure that appropriate credit assessment is done, and the marketing contract is given proper review and approval. Controls also include monitoring of ongoing sales activity to detect when credit limits are exceeded so that appropriate action can be taken. A reconciliation of production records to sales, taking into account pipeline imbalances and product inventories, should be performed to ensure that sales and purchaser accounts receivable are accurately recorded. As with joint interest receivables, controls should be in place to ensure that accounts receivable balances are periodically reviewed for collectability, and that allowances for doubtful accounts are properly recorded as appropriate.

9.54 *Severance taxes.* Severance and other production taxes are generally calculated based on volumes produced. Controls are needed to ensure that amounts are properly calculated and recorded. Controls should also be in place over the payment of severance taxes and the filing of tax returns. Controls include measures to ensure tax due dates are met; tax rates applied are accurate; all appropriate exemptions or deductions are applied; new well completions are added to tax reporting schedules; tax payments are reconciled to accruals; and tax payments are approved by management in accordance with the financial authority matrix.

9.55 *Royalties payable.* For revenues received on behalf of other coowners, the amounts to be remitted should be accurately computed and recorded based on division-of-interest file information. The operator with responsibility for remitting the revenues to the various interest owners should have reasonable assurance that all remittances are accurately computed. 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 are referred to legal counsel for interpretation. Amounts may be placed into royalty suspense when owner information is incorrect or interests are not known, as when a royalty check is returned undeliverable. Controls over reissuing checks or releasing amounts from royalty suspense should be in place to ensure that amounts are paid only to the appropriate owner. Controls that may be considered include regular review of detailed trial balances of royalties in suspense and investigations of significant balances and fluctuations performed by an employee with no conflicting duties. Controls may also include reconciliation of the royalties payable subledger to the general ledger and period-to-period royalty comparison by owner. Revenue checks should be prenumbered, and the sequence of checks processed accounted for, with spoiled checks voided to prevent reuse and filed for inspection. Controls should also include restricted access to the accounts payable system to prevent unauthorized adjustments to payable accounts in excess of approval limits. Nonsystematic adjustments to revenue payables records (those originating from sources other than a disbursement journal) should require management review and approval. Inquiries from royalty owners should be directed to personnel independent of those who process the payments, and resolutions of disputes with owners should be reviewed and approved by management.

9.56 *Expenses.* Controls should ensure that lease operating expenses and transportation costs, including ad valorem taxes and costs of compression and dehydration, are recorded to the proper AFE, property, and account. In addition, processes should be in place to accrue estimated production expenses if significant. Vendor invoices for operating expenses should be reviewed and approved by operations personnel, who should provide information for accurate coding to the correct property prior to payment. Controls also include analysis of actual expenditures on operated projects compared to budgeted amounts, with approval by management of significant variations. Calculations allocating field level facilities to wells should be reviewed and approved by management.

9.57 *Workovers.* Costs of working over a well to maintain production should be properly recorded as an expense. Controls should be in place to ensure proper determination of whether work done should be expensed as a workover or treated as completion to a new zone and, therefore, accounted for as development or exploratory costs. Controls should include approval of projects by appropriate operations personnel through use of workover AFEs, approval of vendor invoices including coding to the AFE/property prior to payment, and comparison of costs to budgeted amounts with management approval of significant variations.

Depreciation, Depletion, and Amortization

9.58 *Depreciation, Depletion, and Amortization.* Oil and gas companies following either the successful efforts or full cost methods of accounting calculate DD&A using the unit of production method. Controls should be in place to ensure that well costs are included in the appropriate DD&A pool, and that the estimated reserves and production expenses are appropriate. Controls should include reconciliation of the production volumes used for DD&A calculation to those reported in the revenue system, as well as other measures to ensure that all wells or other properties are included in DD&A calculations; that wells are included in the proper pools; that the cost basis used in the DD&A calculation is reconciled to the property account balances in the general ledger; and that entries to record DD&A expense are appropriately reviewed and approved by management.

9.59 *Depreciation of Support Equipment and Facilities.* Charges to reflect depreciation of fixed assets used in oil and gas producing activities should be properly calculated and recorded using the appropriate lives, depending on the activity with which the assets are involved. Controls should include reconciliation of the cost basis used in the depreciation calculation to the property account balances in the general ledger, and that entries to record the expense are appropriately reviewed and approved by management.

Other Control Areas

Commodity Derivative Activities

9.60 Commodity derivative activities, either financial or physical transactions, may be used to hedge the price of a company's production of oil and gas or to capture arbitrage or trading opportunities identified in the derivatives markets. Companies using derivatives should ensure that policies are adopted to provide clear direction on the types of transactions that are acceptable. For example, a company might require all financial transactions be supported by an offsetting physical transaction. Once these governing policies are in place, controls should be developed to ensure all transactions are initiated and approved in accordance with those policies. Proper segregation of duties is generally key to providing effective internal control over derivative activities. Individuals placing trades should not be responsible for doing mark-to-market pricing or settling transactions. As a best practice, counterparty trade confirmations and daily broker statements should be routed directly to those responsible for settlement and accounting because this provides independent verification of trades reported by the company's traders. Controls are also needed relating to calculating and reporting mark-to-market (for fair value treatment) or ensuring all documentation is proper (if hedge accounting is used). Controls, such as contract review procedures, are needed to ensure that any embedded derivatives are properly identified and accounted for.

Investments in Entities

9.61 As with other industries, oil and gas companies may own investments in other companies. Controls are needed over the determination of method used to account for this investment as well as the gathering of financial information to be recorded. Controls should include review and approval by management of accounting methods, calculations that support amounts recorded, and the journal entries.

International Operations

9.62 *Contractual Arrangements.* Many oil and gas companies have operations in countries outside the United States. In many countries, entities may not own interests in leases but instead have contractual rights. See chapter 6, "Accounting for International Oil and Gas Activities," of this guide for more information about these arrangements. Controls are needed to ensure that activity under these arrangements is properly monitored and recorded. Controls should include management review and approval of contracts, reporting of activities that demonstrate compliance with contractual arrangement, as well as review and approval of journal entries recording this activity.

9.63 *Expatriate Compensation.* Companies may send expatriates to work in foreign locations. Controls are needed to ensure that compensation arrangements for these employees are in compliance with management's intent, and that they are properly recorded. Often arrangements also exist to compensate for taxes to foreign governments, and controls should be in place to ensure these payments are properly calculated and paid. For example, some international companies, particularly those based in the United States, have "tax equalization" programs, facilitating the employees' payment of the equivalent of a home-country tax rate regardless of domicile of the employee. The company should then record liability for foreign income taxes for their employees in the country of domicile and institute controls over the calculation and payment of foreign personal income taxes. Controls should include review and approval of tax equalization calculations and any commodity and services allowances payments and appropriate recording of such payments in payroll records to ensure accurate year-end payroll statements. Overall compensation arrangements should be reviewed periodically for reasonableness.

9.64 *Foreign Corrupt Practices Act of 1977 (FCPA).* The FCPA includes antibribery and accounting records provisions. See paragraphs 8.38–.39 of this guide. Companies doing business outside the United States should have controls in place to ensure that payments made are lawful under the FCPA, and that their books and records are maintained in compliance with the FCPA. One such control is to have a written code of business conduct that is provided to all employees. Companies that institute this practice should make sure that the publication is reviewed and updated, and that employees undergo periodic training and orientation. Additionally, companies may institute a periodic (quarterly or annual) statement of compliance, particularly for its officers and senior employees. Appropriate controls should be established over the use of agents, including reporting to management of agents' activities and expenditures. Separate general ledger accounts may be set up to record payments, such as facilitating payments, and a review of these amounts should be performed periodically.[*]

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[*] On July 21, 2010, the president signed into law the Dodd-Frank Act. Section 1504, *Disclosure of Payments By Resource Extraction Issuers*, of the Dodd-Frank Act amends Section 13 of the Securities Exchange Act of 1934 (*Commerce and Trade, U.S. Code* Title 15, Section 78m) to require a resource extraction issuer to include in its annual report (and also submit in an interactive data

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Transactions With Related Parties

9.65 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 (FASB) *Accounting Standards Codification* (ASC) 850, *Related Party Disclosures*. Examples include crude oil and gas sales, materials transfers, and other transactions and balances with unconsolidated entities. Controls may include periodic requests to appropriate personnel for information regarding any related party transactions, establishment of a formal disclosure review process, and periodic certification by management regarding full disclosure of related party activities.

Contract Reviews

9.66 Significant operating, procurement, and other contracts should be reviewed for identification and resolution of accounting, tax, and reporting issues. This may include embedded derivatives, possible capital lease issues, end-of-contract liabilities, and special contract provisions. Controls should be in place to ensure that all contracts that should be reviewed are identified and sent to the appropriate personnel for review. It is important that accounting personnel are kept informed of amendments and other changes to facilitate evaluation of the impact on accounting, tax, and disclosure.

Computer Based Controls

9.67 *Interfaces.* Oil and gas entities use many specialized systems to track activities. Information may be transferred from one system to another, such as from a land administration system to a division of interest accounting system, or from a production volumes system to a revenue system. In addition, transfer of information to an external party, such as to a payroll provider or reserve engineers, may be done electronically. Joint interest billings may be electronically exchanged with partners. In these situations, controls are needed

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(footnote continued)

format) information relating to any payment made by the resource extraction issuer, a subsidiary of the resource extraction issuer, or an entity under the control of the resource extraction issuer to a foreign government or the U.S. Federal Government for the purpose of the commercial development of oil, natural gas, or minerals, including (*a*) the type and total amount of such payments made for each project of the resource extraction issuer relating to the commercial development of oil, natural gas, or minerals, and (*b*) the type and total amount of such payments made to each government.

Section 1504 of the Dodd-Frank Act indicates that *commercial development of oil, natural gas, or minerals* includes exploration, extraction, processing, export, and other significant actions relating to oil, natural gas, or minerals, or the acquisition of a license for any such activity, as determined by the SEC. Section 1504 of the Dodd-Frank Act also indicates that the term *payment* means a payment that is made to further the commercial development of oil, natural gas, or minerals, and is not de *minimis*, including taxes, royalties, fees (including license fees), production entitlements, bonuses, and other material benefits, that the SEC, consistent with the guidelines of the Extractive Industries Transparency Initiative (to the extent practicable), determines are part of the commonly recognized revenue stream for the commercial development of oil, natural gas, or minerals.

Section 1504 of the Dodd-Frank Act can be found at www.sec.gov/about/laws/wallstreetreform-cpa.pdf.

On December 15, 2010, the SEC issued Proposed Rule No. 34-63549, *Disclosure Payments by Resource Extraction Issuers*, for public comment. Proposed Rule No. 34-63549 can be found at www.sec.gov/rules/proposed/2010/34-63549.pdf. Additional information on this proposed rule, including discussion of the proposed disclosure requirements and comment letters received by the SEC, can also be found at www.sec.gov/news/press/2010/2010-247.htm. Readers are encouraged to monitor the SEC's website at www.sec.gov/index.htm for the latest developments on this rulemaking project.

to ensure that the data transferred through these interfaces is the same in both systems. Controls, such as check sums and hash totals, may be used to ensure complete processing of interface transactions. Application software may report gaps in document number sequences for review and resolution.

9.68 *Calculations.* Due to the large volume of transactions, calculation of revenues, royalties, and severance taxes is generally automated. Controls are needed in the accounting system to ensure that this calculation is done properly. Controls, such as review and reconciliation of run-to-run totals, system alert reports, or controls logs should be used to ensure complete processing of data. Reasonableness tests or periodic recalculation of test transactions may be used to ensure that systematic calculations are accurate.

9.69 *Complex Spreadsheets.* Spreadsheets may be used in numerous areas, including recording of revenues, calculations of DD&A and impairments, calculations of accruals, and tax calculations. Spreadsheets that support material entries made to the general ledger or disclosures in the financial statements should be identified and controls documented over access, backup and archiving, change control, data integrity, version control and documentation. Controls may include periodic inventory of key spreadsheets and verification of documented controls within the spreadsheets.

Control Over Financial Statement Disclosures Specific to Oil and Gas Entities

9.70 Oil and gas disclosures are required by FASB ASC 932-235. Controls should ensure that these disclosures are presented in the appropriate manner, in compliance with FASB ASC 932-235, and that the amounts used are consistent with the financial statements. Controls should include reconciling disclosure schedules to reserve reports, asset balances in property ledgers, production volumes, revenues reported, and related operating expenses. The final disclosure draft should be reviewed and approved by appropriate management personnel.

9.71 Material rig commitments should be included in the footnote disclosures on commitments and contingencies. Controls are needed to ensure that all commitments that are required to be disclosed are identified and properly valued. Controls include maintenance by appropriate operations personnel of rig rental and contract expiration and renewal dates including related financial commitments. Rig fleet reports should be provided to financial accounting personnel responsible for developing the required disclosure draft. The final disclosure draft should be reviewed and approved by appropriate management personnel.

9.72 Environmental liabilities that meet the requirements for disclosure should be included in footnote disclosures on commitments and contingencies. Controls are needed to ensure that all contingencies that are required to be disclosed are identified and properly valued. Controls include review by the general counsel and the principal accounting officer of reports from outside counsel or the legal department detailing litigation activities or regulatory proceedings that may have a material outcome. These reports are used to develop disclosures drafts and material loss contingency amounts to be recorded. The final disclosure draft should be reviewed and approved by appropriate management personnel.

9.73 Suspended well costs are required to be disclosed in accordance with paragraphs 1A–1B of FASB ASC 932-235-50 and FASB ASC 932-360-25-18. Controls are needed to ensure that all changes to suspended well costs are included in an analysis of causes of the changes from the previous period end, and that information is provided on amounts capitalized for more than one year. Controls should include a quarterly process to identify wells that have been completed but not yet designated as producing or dry holes. The listing should be reconciled to that of the prior period and appropriate explanations given for wells remaining on the list over time. The final disclosure draft should be reviewed and approved by appropriate management personnel.

9.74 Risk management activities, including price, basis, interest rate, currency exchange, and credit risk, should be disclosed in accordance with FASB ASC 815, *Derivatives and Hedging*. Concentrations of credit should be described. Controls should be in place to ensure that these disclosures are complete and accurate. Controls include reconciling mark-to-market gains and losses disclosed to related general ledger accounts. Tables detailing commodity and financial instrument positions should be reconciled to outstanding position reports maintained by marketing and accounting personnel. Accounts receivable and allowance for doubtful accounts balances reported should be reconciled to general or subledger balances. The final disclosure draft should be reviewed and approved by appropriate management personnel.

9.75 Subsequent events requiring disclosure for an oil and gas entity may include property acquisitions or dispositions, dry hole decisions and, for full cost companies, changes to ceiling test writedowns as a result of additional reserves being proven subsequent to period end. Controls should be in place to ensure that these disclosures are complete and accurate. Controls should include communication with the principal accounting officer regarding emerging material transactions or management decisions that may give rise to a disclosure. The final disclosure draft should be reviewed and approved by appropriate management personnel.

Control Over Compliance With Tax and Regulatory Requirements

9.76 Oil and gas drilling and 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, certain tax regulations, such as the ad valorem taxes and statutory depletion allowances, exist 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. Controls may include a calendar system to alert personnel of filing deadlines as well as review by management of tax and regulatory reports prior to filing.

9.77 The calculation of tax provisions, including the determination of current and deferred taxes, includes consideration of tax treatment and calculation of intangible drilling costs, depreciation, and depletion. Controls should be in place to ensure that personnel are able to properly calculate the tax provision and temporary differences that affect deferred taxes. Controls include maintaining a calendar of due dates for tax filings, and monitoring tax law changes as well as changes in the company's operations such as new legal entities, acquisitions, and divestitures that could affect tax liabilities. Charts of accounts should be established that allow items requiring different tax treatment to be accumulated into separate accounts to facilitate preparing accurate tax filings and reporting and recording of deferrals. Reconciliations of year-to-year cumulative book versus tax differences should be prepared. Senior tax and other management personnel should review and approve tax-related financial statement disclosures and related journal entries. Intercompany service agreements and transfer pricing policies should be documented and maintained to support the company's tax positions. All tax-related documentation should be securely archived to meet tax audit requirements.

9.78 Environmental, health, and safety are governed by federal, state, and local laws and regulations, in addition to the company's policies. Controls are needed to ensure that potential violations are identified and reported to the appropriate internal personnel and regulatory agencies, and that processes are in place to mitigate any damage and prevent future problems. Controls should include establishment and monitoring by management of incident reporting systems and safety awareness programs.

Appendix A

Summary of the Successful Efforts and Full Cost Methods of Accounting[1, 2]

Successful Efforts Method	Chapter Reference	Full Cost Method	Chapter Reference
Principal Accounting Literature			
• Financial Accounting Standards Board (FASB) *Accounting Standards Codification* (ASC) 932, *Extractive Activities—Oil and Gas* • Impairment or disposal of long lived assets subsections of FASB ASC 360-10 • FASB ASC 932-360-25-18 and FASB ASC 932-235-50-16		• Rule 4-10 of Regulation S-X • FASB ASC 932 • Topic No. 12(D), "Application of Full Cost Method of Accounting," in the Securities and Exchange Commission's (SEC's) *Codification of Staff Accounting Bulletins*	
Capitalization of Costs			
Acquisition, Exploration, and Development Costs			
• See the following commentary for each respective type of expense.		• All acquisition, exploration, and development costs are capitalized, regardless of whether the results of such activities are successful. • No exploration expenses are reflected in an income statement.	5.04

(continued)

[1] The summary included in this appendix represents the principal provisions of the successful efforts and full cost methods of accounting. It also highlights the most significant differences between the accounting methods. For a complete understanding of the successful efforts and full cost methods of accounting, the reader should refer to the applicable accounting literature.

[2] Refer to chapters 1, "Overview of the Industry," 4, "Successful Efforts Method and General Accounting for Oil and Gas Activities," and 5, "Full Cost Method of Accounting for Oil and Gas Activities," for further discussion of the Securities and Exchange Commission's (SEC) Final Rule No. 33-8995, *Modernization of Oil and Gas Reporting*.

Successful Efforts Method	Chapter Reference	Full Cost Method	Chapter Reference
Acquisition Costs			
• Acquisition costs should be capitalized when incurred.	4.09	• See the preceding.	
Exploration Costs			
• Exploration costs, other than exploration drilling costs, should be charged to expense when incurred. These costs include the following: — Geological and geophysical costs — Costs of carrying and retaining unproved properties — Dry hole and bottom hole contributions	4.10–.11	• See the preceding.	
• The costs of drilling exploratory wells should be capitalized, pending determination of whether the well has found proved reserves. The capitalized costs of unsuccessful exploratory wells, net of any salvage value, should be charged to expense.	4.11–.15		
• Specific indicators have to be considered when evaluating whether suspended exploratory well costs should continue to be capitalized.	4.12–.14		

Successful Efforts Method	Chapter Reference	Full Cost Method	Chapter Reference
Development Costs			
• Development costs are capitalized. These include the costs to obtain access to proved reserves and to drill development wells. • The costs of drilling development wells, including unsuccessful development wells, should be capitalized.	4.18–.23	• See the preceding.	
Internal Costs			
• Internal costs for acquisition, development, and exploration may be capitalized if directly related to acquisition, development, or exploration activities that are capitalizable under the successful efforts method. Indirect internal costs should be expensed.	4.03	• Internal costs that are capitalized are limited to those costs that can be directly identified with acquisition, exploration, and development activities undertaken by the reporting entity for its own account. Any costs related to production, general corporate overhead, and similar activities are not capitalized.	5.07
Capitalization of Interest			
• Interest costs are capitalized based on qualifying assets, which include the following: — Drilling and development costs — Leasehold costs • Capitalized interest is attached to the	4.19	• Interest costs are capitalized based on qualifying assets, which include the following: — Unusually significant costs of unproved properties and major development projects that	5.08

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Successful Efforts Method	Chapter Reference	Full Cost Method	Chapter Reference
qualifying costs on which the interest was computed and is amortized or impaired in the same manner as those costs.		are not being amortized — Significant properties or projects in cost centers with no production for which exploration and development are in progress	
Accumulation of Costs			
• Capitalized costs are accumulated on a property-by-property basis or on the basis of some reasonable aggregation of properties with a common geological structural feature or stratigraphic condition, such as a field or reservoir.	4.03	• Capitalized costs are accumulated by cost centers established on a country-by-country basis.	5.05
Depreciation, Depletion, and Amortization (DD&A)			
Aggregation of Assets for the Purposes of DD&A			
• Capitalized costs are amortized on a property-by-property basis or on the basis of some reasonable aggregation, as previously indicated.	4.25	• Capitalized costs are amortized on a consolidated basis for each cost center.	5.09–.14
DD&A Method and Application			
• Capitalized acquisition costs should be amortized on the unit-of-production method using total proved (both developed and undeveloped) reserves.	4.26–.27	• Capitalized costs of all evaluated properties (including costs of unsuccessful drilling efforts) in each cost center are amortized on the unit-of-production method using total proved reserves for that cost center.	5.09

Successful Efforts Method	Chapter Reference	Full Cost Method	Chapter Reference
• Capitalized exploration and development costs should be amortized on the unit-of-production method using proved developed reserves.	4.27	• Rule 4-10 of Regulation S-X allows an alternative method of amortization based on units of revenue.	5.11
Consideration of Future Development Costs			
• Future development costs and asset retirement obligations (AROs) not currently included in the recorded asset value are not considered when computing the DD&A rate.	4.28	• Costs to be amortized include the following: — The estimated future costs to be incurred in developing proved reserves — Estimated AROs that have not yet been recorded as asset retirement costs	5.09
Costs Excluded From DD&A Calculation			
• If significant development costs (such as the cost of 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 will be necessary to exclude a portion of those development costs in determining the unit-of-production amortization rate until the additional development wells are drilled. Similarly, it will be necessary to	4.29	• The cost of unproved properties, major development projects, and related future development costs for such properties may be excluded from capitalized costs to be amortized until the earlier of determination of whether additional reserves are proved or impairment occurs.	5.15–.18

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Successful Efforts Method	Chapter Reference	Full Cost Method	Chapter Reference
exclude, in computing the amortization rate, those proved developed reserves that will be produced only after significant additional development costs are incurred, such as for improved recovery systems.			
Impairment			
Unevaluated Properties			
• Unevaluated properties are assessed for impairment regularly, either individually on a property-by-property basis (for significant properties) or by groups. • If impairment is determined, a loss is recognized in the income statement.	4.33–.37	• Unevaluated properties are assessed for impairment regularly, either individually (for significant properties) or by groups. • If impaired, the cost of such properties is added to the amortization base (full cost pool).	5.16
Other Properties			
• Capitalized costs for proved properties are tested for impairment, as set forth in the impairment or disposal of long lived assets subsections of FASB ASC 360-10.	4.38–.39	• Capitalized costs in each cost center are subject to a ceiling test and cannot exceed the present value (using a 10 percent discount factor) of estimated future net revenues computed by applying current prices[3] to estimated	5.19–.22

[3] Under the SEC reporting requirements contained in Final Rule No. 33-8995, the term *current prices* is defined as the historical 12-month average price calculated as the average of the first day of the month price for each month within the 12-month period prior to the reporting date. Under previous guidance, application of current prices for purposes of the full cost ceiling test was interpreted as single day, year-end prices. See further discussion of SEC reporting requirements in chapter 1 of this guide.

Successful Efforts Method	Chapter Reference	Full Cost Method	Chapter Reference
		future production based on current cost less estimated future expenditures to be incurred to develop and produce the reserves.	
• 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.	4.40	• Temporary waiver for application of the ceiling test may be obtained from the SEC for recently acquired properties. An entity requesting a waiver should be able to demonstrate that the additional value exists beyond reasonable doubt.	5.23
• The undiscounted net future cash flows are based on total proved and risk-adjusted probable and possible reserves. Future prices and costs should be in nominal dollars and must reflect management's best estimates. Future cost projections should include future capital expenditures, development costs, operating costs, and AROs not currently accrued on the balance sheet.	4.41	• Subsequent events also may be considered in the determination under certain circumstances, as described in Topic No. 12(D)(3)(c) of the SEC's *Codification of Staff Accounting Bulletins.*	5.24–.28
ARO Considerations			
• ARO costs are excluded from the future costs when determining net future cash flows, to	4.41	• The future cash outflows associated with AROs that have been accrued on the balance sheet should	5.21

(continued)

Successful Efforts Method	Chapter Reference	Full Cost Method	Chapter Reference
the extent such costs have already been accrued on the balance sheet.		be excluded from the computation of the future net revenues for purposes of the full cost ceiling calculation. However, the estimated future cash outflows related to AROs that have not been accrued on the balance sheet should be included in the computation.	
Conveyances and Dispositions			
Gain or Loss Recognition			
• Generally, gain or loss should be recognized if the entire operating interest is sold, and other required criteria are met.	4.42–.51	• Conveyances of oil and gas properties are accounted for as adjustments of capitalized costs, with no gain or loss recognized, unless the adjustment would significantly alter the relationship between capitalized costs and proved oil and gas reserves attributable to a cost center.	5.45–.48
• FASB ASC 932 provides specific accounting guidance for certain forms of conveyance transactions for which gain recognition is prohibited.	4.42–.51		
Goodwill Considerations at Disposition			
• General guidance of FASB ASC 350, *Intangibles—Goodwill and Other*, should be applied.		• The guidance issued by the SEC staff does not address whether any portion of goodwill should be allocated to a	5.51–.55

Successful Efforts Method	Chapter Reference	Full Cost Method	Chapter Reference
		disposition that would result in a gain or loss on sale under the full cost rules.	
Discontinued Operations			
• A component is generally assessed in the same manner as the amortization base for DD&A and for measuring impairment (that is, usually at the field level).	4.89–.95	• A component (as defined in the impairment or disposal of long lived assets subsections of FASB ASC 360-10) would be an individual cost center. Unless the entire cost center is disposed of, reporting as discontinued operations is not appropriate.	5.49

Appendix B

Sample Management Representations for Entities With Oil and Gas Producing Activities

Note: The following information represents examples of potential representations to be obtained by the auditor from management in connection with the audit of an oil and gas producing entity. These examples will not be relevant in all situations. In addition, many other representations that may be appropriate in other situations have not been included. These examples are provided for informational purposes only.

Financial Accounting Standards Board (FASB) ***Accounting Standards Codification*** **(ASC) 410-20**

1. The Company has evaluated its legal and constructive obligations relative to the estimated future cost of abandoning the Company's oil and gas properties, other tangible long-lived assets, operating lease agreements that contain return provisions that require the leased assets to be returned in the same condition that existed at lease inception (that is, the agreement requires the removal of any leasehold improvements at the end of the lease term), and other agreements for associated asset retirement obligations (AROs), and has recognized related liabilities where required, in accordance with FASB ASC 410-20. The methods and assumptions used to measure the fair value of recorded AROs are appropriate and reasonable under the circumstances and utilize the best available information.

2. The Company has properly identified all additions and disposals, either through sales or settlement, to the asset retirement obligation and properly included such amounts in the underlying account balance.

Oil and Gas Reserves

3. The supplementary proved oil and gas reserve information has been prepared based on assumptions and measurement techniques that are reasonable and has been prepared and presented in accordance with the requirements of FASB ASC 932-235.

4. Depletion of the cost of producing leases, depreciation of the costs of wells and other lease facilities, and reported supplemental information on estimated quantities of proved oil and gas reserves are based on estimated oil and gas reserves which have been updated and revised, as appropriate, during the year ended [*Date*], by competent petroleum reserve engineers. In our opinion, these reserves are commercially productive and will result in revenues to the Company adequate to recover remaining and undepleted capitalized costs as of [*Date*].

5. We agree with/We assume responsibility for the findings of the Company's petroleum reservoir engineers in evaluating the quantities and future net cash flows attributable to the Company's oil and gas interests. We have adequately considered the qualifications of the petroleum reservoir engineers in determining the amounts and disclosures used in the consolidated financial statements and underlying accounting records. We did not give, or cause any instructions to be given, to these petroleum reservoir engineers with respect to the values and amounts derived in an attempt to bias their work, and we are not otherwise aware of any matters that have had an impact on the objectivity of the petroleum reservoir engineers.

Oil and Gas Reserves (Full Cost)

6. Depreciation and depletion of evaluated oil and gas property costs and supplemental information reported on estimated quantities of proved oil and gas reserves are based on estimated oil and gas reserves which have been reviewed and revised, as appropriate, during each of the three years in the period ended [*Date*] by competent petroleum reservoir engineers. In our opinion, these reserves are commercially productive and will provide revenues to the Company adequate to recover net capitalized costs for evaluated oil and gas properties as of [*Date*]. The cost of certain unevaluated properties is properly excluded from the full cost pools for purposes of calculating depreciation and depletion.

7. The supplementary oil and gas reserve information disclosed in the financial statements complies with the definitions and disclosure guidelines of Rule 4-10 of Regulation S-X of the Securities and Exchange Commission (SEC) and FASB ASC 932-235 and has been prepared on the basis of assumptions and measurement techniques believed to be reasonable.

8. Future development costs as reflected in the Reserve Engineer's year end reserve report and included in the Company's full cost amortization base are based on management's best estimate of such future costs and have been prepared on the basis of assumptions that we believe are appropriate and reasonable under the circumstances and utilize the best available information.

Capitalized Costs

9. Property, plant, and equipment at [*Date*] and [*Date*] includes amounts relating to unproved properties, including drilling prior to completion costs. The capitalization of such costs and related charges for depreciation, depletion, and amortization at [*Date*] and [*Date*] are in accordance with FASB ASC 932, *Extractive Activities—Oil and Gas*.

10. Overhead costs capitalized into the full cost pool represent management's best estimate of direct costs relating to the acquisition, exploration, and development of oil and gas properties and are, therefore, properly capitalized in accordance with the provisions of SEC Regulation S-X, Rule 4-10 (c)(2).

Suspended Well Costs

11. We have reviewed exploratory well costs in accordance with paragraphs 1A and 1B of FASB ASC 932-235-50 and 932-360-25-18. At [*Date*], the Company has exploratory well costs of [*Amount*] related to [*number*] wells that have been capitalized for a period greater than one year. We assess individual wells that have been in "suspended status" up to and exceeding one year to ascertain that carrying such costs forward is appropriate given the provisions of paragraphs 1A and 1B of FASB ASC 932-235-50 and 932-360-25-18 and existing management plans. All material costs that have been deferred to future periods are believed to be recoverable.

12. We have reviewed the guidance in paragraphs 1A and 1B of FASB ASC 932-235-50 and 932-360-25-18 and believe that the continued capitalization of exploratory well costs that have completed their related program of exploratory drilling and have found a sufficient quantity of reserves to justify their completion as producing wells is appropriate as we are making sufficient progress towards assessing the reserves and the economic and operating viability of the associated projects, giving due consideration to indicators (a)–(i) of the guidance in FASB ASC 932-360-35-19.

Impairment and Dry Hole Costs

13. The Company fully expects to develop all projects currently classified as unevaluated property and is currently unaware of any circumstances that would indicate that such property should be impaired.

14. The Company has the ability and intent to fund estimated future development costs related to nonproducing and undeveloped proved reserves.

15. We have reviewed unproved properties for impairment in accordance with FASB ASC 932 and have appropriately recorded adjustments to the carrying value of these assets based on the results of the impairment tests. Unproved properties withheld from amortization as of [*Date*] are evaluated for possible impairment utilizing methods and assumptions based on management's best estimate of reserves, development periods, lease expirations, and success rates associated with unproved properties.

16. The Company has evaluated exploratory wells in progress in accordance with the provisions of FASB ASC 932-360-40-10. There are no exploratory wells in progress at [*Date*] that were determined not to have found proved reserves subsequent to year end.

17. As of [*Date*], the Company had [*Number*] exploratory wells in progress that had not reached a decision point as to drilling success. As of the date of this letter, a decision has been made with respect to [*Number*] of these wells. Accordingly, we expensed [*Amount*] in dry hole costs associated with these wells in our [*Date*] financial statements in accordance with FASB ASC 932-360-40-10. As of the date of this letter, the net exposure of the additional exploratory wells drilling that had not yet been evaluated is approximately [*Amount*].

Ceiling Test—Full Cost

18. During each period during the 12 months ended [*Date*], the Company performed a full cost ceiling test as specified in Regulation S-X Rule 4-10 on a quarterly basis, and no write-down of its proved oil and gas properties was necessary.
19. We have considered the impact of FASB ASC 410-20 on our ceiling test and depreciation, depletion, and amortization computations and appropriately applied the guidance prescribed in SEC *Codification of Staff Accounting Bulletins* topic 12(D), "Application of the Full Cost Method of Accounting."
20. Unevaluated properties and associated costs withheld from amortization at [*Date*] are being transferred to our full cost pool utilizing methods and assumptions based on management's best estimates of total reserves to be discovered in connection with our exploration program. Such properties are expected to be evaluated and, therefore, become subject to amortization within ______ years from the balance sheet date.
21. We determined that a write-down of [*Amount*] was required in the third quarter of [*Date*] for the costs related to our full cost pool in [*Geographic Location*], as our net capitalized oil and gas property costs in the [*Geographic Location*] cost pool exceeded the related capitalization ceiling as of [*Date*] as defined by SEC Regulation S-X 4-10. Our ceiling test calculations include the effects of derivative instruments we have designated as cash flow hedges of our anticipated natural gas and oil production that qualify for hedge accounting in determining our future net revenues.
22. In performing our ceiling test, we have compared the net book value of all costs incurred in the acquisition, exploration, and development of oil and gas properties by cost center (by country) to the cost center ceiling, and we have fully disclosed to you the following:
    - *a*. The carrying value of all oil and gas properties
    - *b*. The tax basis of these properties
    - *c*. The future estimated net revenue, based on period-end oil and gas prices (discounted at 10 percent per annum)
    - *d*. The fair value of all unproved properties
    - *e*. The net mark-to-market value of the hedge position, if any, used in the calculation
23. The Company has the ability and intent to fund estimated future development costs related to nonproducing and undeveloped proved reserves.

Revenue and Working Interest

24. The Company has satisfactory title to all its proportionate share of working interests and the related revenue interest in the producing oil and gas leases from which we have received and recorded revenue. In addition, accounts payable and accrued liabilities recorded in the financial statements include all amounts representing royalties received on producing leases operated by the Company, which are payable to third parties. These liabilities have been determined based upon the Company's calculation of the third parties' proportionate revenue interest in producing leases.

25. The Company follows the sales method in recognizing revenues from the production of natural gas from producing properties subject to gas balancing arrangements when imbalances occur. At [*Date*] and [*Date*], differences between these sales and our share of production are not significant.

26. We have reviewed the criteria for revenue recognition included in SEC *Codification of Staff Accounting Bulletins* topic 13(A), "Selected Revenue Recognition Issues," namely, evidence of arrangement, delivery, fixed price, and collectability, and are recognizing revenue in accordance with SEC *Codification of Staff Accounting Bulletins* topic 13(A). Revenues from natural gas production from properties in the United States of America are recognized on the basis of the Company's net working interest (entitlement method).

Environmental Remediation

27. Compliance with existing environmental laws and regulations has not required and is not expected to require the Company to expend amounts that are material in relation to our total capital expenditure program or would alter our competitive position. No provision has been made for any material loss from environmental remediation liabilities. The Company believes it is in substantial compliance with applicable environmental laws and regulations.

28. Provision has been made for any material loss that is probable from environmental remediation liabilities associated with the Company's operations. We believe that such estimate is reasonable based on available information and that the liabilities and related loss contingencies and the expected outcome of uncertainties have been adequately described in the Company's consolidated financial statements.

29. The Company maintains insurance coverage, which it believes is customary in the industry, although it is not fully insured against all environmental risks. The Company is not aware of any environmental claims as of [*Date*], which would have a material impact on its financial position, cash flows, or results of operations.

Proportionate Consolidation

30. The Company accounts for its noncontrolling interest in [*Investment Name*] using the equity method and proportionately consolidates the results in accordance with the guidance in FASB ASC 323-30-25-1, 810-10-45-1, and 932-810-45-1.

Transportation

31. The Company has properly accounted for transportation expenses related to oil and gas sales in accordance with FASB ASC 323-30-25-1, 810-10-45-1, and 932-810-45-1.

32. The Company records transportation and marketing related revenue and the related purchase cost on a gross basis as prescribed by FASB ASC 605-45 because the Company takes title to the oil and gas production, and all risks of loss reside with the Company.

Mergers and Acquisitions

33. We agree with the work of specialist, [*insert specialist name*], in valuation of oil and gas properties related to the acquisition of [*insert name*] and have adequately considered the qualifications of

the specialist in determining amounts and disclosures used in the financial statements and underlying accounting records. We did not give any instructions, or cause any instructions to be given, to specialists with respect to values or amounts derived in an attempt to bias their work, and we are not aware of any matters that have affected the independence or objectivity of the specialists.

34. On [*Date*], the Company closed the [*Name*] acquisition. Since that date, the Company has recorded revenues and expenses. The recognition and measurement of the identifiable assets acquired, the liabilities assumed, and any noncontrolling interests in the acquired entity are described in [*Note X*]. The initial measurement of [*insert description*] is preliminary and subject to change as additional information becomes available. Management does not expect to make any material changes during the measurement period.

Appendix C

International Financial Reporting Standards

> ***Note:*** The following content may include certain changes made since the original print version of the guide.

Introduction

The following information provides a brief overview of the ongoing globalization of accounting standards, International Financial Reporting Standards (IFRSs) as a body of accounting literature, the status of convergence with IFRSs in the United States, and the related issues that accounting professionals need to consider today.

Globalization of Accounting Standards

As the business world becomes more globally connected, regulators, investors, audit firms, and public and private companies of all sizes are expressing an increased interest in having common accounting standards among participants in capital markets and trading partners around the world. Proponents of convergence with, or adoption of, IFRSs for financial reporting in the United States believe that one set of financial reporting standards would improve the quality and comparability of investor information and promote fair, orderly, and efficient markets.

Many critics, however, believe that accounting principles generally accepted in the United States of America (U.S. GAAP) are the superior standards and question whether the use of IFRSs will result in more useful financial statements in the long term and whether the cost of implementing IFRSs will outweigh the benefits. Implementing IFRSs will require a staggering effort by management, auditors, and financial statement users, not to mention educators.

The increasing acceptance of IFRSs, both in the United States and around the world, means that now is the time to become knowledgeable about these changes. The discussion that follows explains the underpinnings of the international support for a common set of high quality global standards and many of the challenges and potential opportunities associated with such a fundamental shift in financial accounting and reporting.

The international standard setting process began several decades ago as an effort by industrialized nations to create standards that could be used by developing and smaller nations. However, as cross-border transactions and globalization increased, other nations began to take interest, and the global reach of IFRSs expanded. More than 100 nations and reporting jurisdictions permit or require IFRSs for domestic listed companies and most have fully conformed to IFRSs as promulgated by the International Accounting Standards Board (IASB) and include a statement acknowledging such conformity in audit reports. Several countries, including Argentina and Canada, adopted IFRSs on January 1, 2011, and many other countries have plans to converge (or eliminate significant differences between) their national standards and IFRSs in 2012.

For many years, the United States has been a strong leader in international efforts to develop globally accepted standards. Among other actions in support of IFRSs, the U.S. Securities and Exchange Commission (SEC) removed the requirement for foreign private issuers registered in the United States to reconcile their financial reports with U.S. GAAP if their accounts complied with IFRSs as issued by the IASB. In addition, the SEC continues to analyze and evaluate appropriate steps toward, and challenges related to, incorporating IFRSs into the U.S. financial reporting system, as subsequently described.

In addition to the support received from certain U.S. based entities, financial and economic leaders from various organizations have announced their support for global accounting standards. Most notably, in 2009, the Group of Twenty Finance Ministers and Central Bank Governors (G20), a group from 20 of the world's systematically important industrialized and developing economies (with the 20th member being the European Union, collectively), called for standard setters to redouble their efforts to complete convergence in global accounting standards.

Acceptance of a single set of high quality accounting standards may present many significant opportunities, including the improvement in financial reporting to global investors, the facilitation of cross-border investments, and the integration of capital markets. Further, U.S. entities with international operations could realize significant cost savings from the use of a single set of financial reporting standards. For example, U.S. issuers raising capital outside the United States are required to comply with the domestic reporting standards of the foreign country and U.S. GAAP. As a result, additional costs arise from the duplication and translation of financial reporting information.

Many multinational companies support the use of common accounting standards to increase comparability of financial results among reporting entities from different countries. They believe common standards will help investors better understand the entities' business activities and financial position. Large public companies with subsidiaries in multiple jurisdictions would be able to use one accounting language company-wide and present their financial statements in the same language as their competitors. In addition, some believe that in a truly global economy, financial professionals, including CPAs, will be more mobile, and companies will more easily be able to respond to the human capital needs of their subsidiaries around the world.

Although certain cost reductions are expected, the initial cost of convergence with IFRSs is expected to be one of the largest obstacles for many entities, including accounting firms and educational institutions. Substantial internal costs for U.S. corporations in the areas of employee training, IT conversions, and general ledger software have been predicted. In addition, the time and effort required from various external functions, including the education of auditors, investors, lenders, and other financial statement users, will be significant factors for consideration.

Although the likelihood of acceptance of IFRSs may lack clarity for the time being, U.S. companies should consider preparing for the costly transition to new or converged standards, which likely will include higher costs in the areas of training and software compliance.

Who is the IASB?

The IASB is the independent standard setting body of the IFRS Foundation, formerly, the International Accounting Standards Committee Foundation. As a private sector organization, the IFRS Foundation has no authority to impose funding regimes on countries. However, a levy system and national contributions through regulatory and standard-setting authorities or stock exchanges have been introduced in a number of countries to fund the organization. Although the AICPA was a founding member of the International Accounting Standards Committee, the IASB's predecessor organization, it is not affiliated with the IASB.

The IASB, founded on April 1, 2001, in London, England, is responsible for developing IFRSs and promoting the use and application of these standards. In pursuit of this objective, the IASB cooperates with national accounting standard setters to achieve convergence in accounting standards around the world.

The structure includes the following primary groups: (*a*) the IFRS Foundation, an independent organization having two main bodies: the IFRS Foundation trustees and the IASB; (*b*) the IFRS Advisory Council; and (*c*) the IFRS Interpretations Committee, formerly the International Financial Reporting Interpretations Committee (IFRIC). The trustees appoint the IASB members, exercise oversight, and raise the funds needed, but the IASB itself has responsibility for establishing IFRSs.

The IFRS Foundation is linked to a monitoring board of public authorities, including committees of the International Organization of Securities Commissions, the European Commission, and the SEC. The monitoring board's main responsibilities are to ensure that the trustees continue to discharge their duties as defined by the IFRS Foundation Constitution, as well as approving the appointment or reappointment of trustees. In addition, through the monitoring board, capital markets authorities that allow or require the use of IFRSs in their jurisdictions will be able to more effectively carry out their mandates regarding investor protection, market integrity, and capital formation.

The IASB board members are selected chiefly upon their professional competence and practical experience. The trustees are required to select members so that the IASB will comprise the best available combination of technical expertise and international business and market experience and to ensure that the IASB is not dominated by any particular geographical interest or constituency. The IASB has members from several different countries, including the United States. The members are responsible for the development and publication of IFRSs, including *International Financial Reporting Standard for Small- and Medium-sized Entities* (*IFRS for SMEs*), and for approving the interpretations of IFRSs as developed by the IFRS Interpretations Committee.

The IFRS Interpretations Committee, founded in March 2002, is the successor of the previous interpretations committee, the Standing Interpretations Committee (SIC), and is the interpretative body of the IASB. The role of the IFRS Interpretations Committee is to provide timely guidance on newly identified financial reporting issues not specifically addressed in IFRSs or issues in which interpretations are not sufficient.

IFRSs are developed through a formal system of due process and broad international consultation, similar to the development of U.S. GAAP.

Readers are encouraged to become involved in the standard-setting process by responding to open calls from the standard setting organizations.

What Are IFRSs?

The term *IFRSs* has both a narrow and broad meaning. Narrowly, IFRSs refers to the numbered series of pronouncements issued by the IASB, collectively called *standards*. More broadly, however, IFRSs refer to the entire body of authoritative IASB literature, including the following:

- Standards, whether labeled IFRSs or International Accounting Standards (IASs)[1]
- Interpretations, whether labeled IFRIC (the former name of the interpretive body) or SIC (the predecessor to IFRIC)[2]

The preface to the IFRS *2011 Bound Volume* states that IFRSs are designed to apply to the general purpose financial statements and other financial reporting of all profit-oriented entities, including commercial, industrial, and financial entities, regardless of legal form or organization. IFRSs are not designed to apply to not-for-profit entities or those in the public sector,[3] but these entities may find IFRSs appropriate in accounting for their activities.

The IASB's *Framework for the Preparation and Presentation of Financial Statements* (IASB Framework) establishes the concepts that underlie the preparation and presentation of financial statements for external users. The IFRS Foundation is guided by the IASB Framework in the development of future standards and in its review of existing standards. The IASB Framework is not an IFRS, and when there is a conflict between the IASB Framework and any IFRS, the standard will prevail. The IASB Framework is an overall statement of guidance for those interpreting financial statements, whereas IFRSs are issue and subject specific.

When an IFRS specifically applies to a transaction, other event, or condition, the accounting policy or policies applied to that item shall be determined by applying the IFRS and considering any relevant implementation guidance issued by the IASB for the IFRS.

Further, if an IFRS does not address a specific transaction, event, or condition explicitly, IAS 8, *Accounting Policies, Changes in Accounting Estimates and Errors*, states that management should use its judgment in developing and applying an accounting policy that results in information that is relevant and reliable. With respect to the reliability of financial statements, IAS 8 states that the financial statements (*a*) represent faithfully the financial position, financial performance, and cash flows of the entity; (*b*) reflect the economic substance of transactions, other events, and conditions; (*c*) are neutral; (*d*) are prudent; and (*e*) are complete in all material respects. When making this type of judgment, management should refer to, and consider the applicability of, the following in descending order:

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[1] See www.ifrs.org for a current listing of International Financial Reporting Standards (IFRSs) and International Accounting Standards (IASs).

[2] See www.ifrs.org for a current listing of International Financial Reporting Interpretations Committee and Standing Interpretations Committee interpretations.

[3] Generally speaking, *public* means government-owned entities, and *private* means nongovernment-owned entities.

- The requirements and guidance in IFRSs dealing with similar and related issues
- The definitions, recognition criteria, and measurement concepts for assets, liabilities, income, and expenses in the IASB Framework
- The most recent pronouncements of other standard setting bodies that use a similar conceptual framework (for example, U.S. GAAP), other accounting literature, and accepted industry practices to the extent that these do not conflict with IFRSs

IFRS for SMEs

IFRS for SMEs is a modification and simplification of full IFRSs aimed at meeting the needs of private company financial reporting users and easing the financial reporting burden on private companies through a cost-benefit approach. *IFRS for SMEs* is a self-contained, global accounting and financial reporting standard applicable to the general purpose financial statements of entities that, in many countries, are known as small- and medium-sized entities (SMEs). Full IFRSs and *IFRS for SMEs* are promulgated by the IASB.

SMEs are entities that publish general purpose financial statements for external users and do not have public accountability. An entity has public accountability under the IASB's definition if it files its financial statements with a securities commission or other regulatory organization or it holds assets in a fiduciary capacity (for example, banks, insurance companies, brokers and dealers in securities, pension funds, and mutual funds). It is not the IASB's intention to exclude entities that hold assets in a fiduciary capacity for reasons incidental to their primary business (for example, travel agents, schools, and utilities) from utilizing *IFRS for SMEs.*

The needs of users of SME financial statements often are different from the needs of users of public company financial statements and other entities that likely would use full IFRSs. Whereas full IFRSs were designed specifically to meet the needs of equity investors in the public capital markets, *IFRS for SMEs* was developed with the needs of a wide range of users in mind. Users of the financial statements of SMEs may be more focused on shorter-term cash flows, liquidity, balance sheet strength, interest coverage, and solvency issues. Full IFRSs may impose a burden on SME preparers in that full IFRSs contain topics and detailed implementation guidance that generally are not relevant to SMEs. This burden has been growing as IFRSs have become more detailed. As such, a significant need existed for an accounting and financial reporting standard for SMEs that would meet the needs of their financial statement users while balancing the costs and benefits from a preparer perspective.

Practically speaking, *IFRS for SMEs* is viewed as an accounting framework for entities that do not have the capacity or resources to use full IFRSs. In the United States, the term SME would encompass many private companies.

In May 2008, the AICPA Governing Council voted to recognize the IASB as an accounting body for purposes of establishing international financial accounting and reporting principles and amended appendix A, "Council Resolution Designating Bodies to Promulgate Technical Standards," of Rule 202, *Compliance With Standards* (AICPA, *Professional Standards*, ET sec. 202 par. .01), and Rule 203, *Accounting Principles* (AICPA, *Professional Standards*, ET sec. 203 par. .01). This amendment gives AICPA members the option to use IFRSs as an alternative to U.S. GAAP. Accordingly, IFRSs are not considered to be an other comprehensive basis of accounting. Rather, they are a source of generally accepted accounting principles.

As such, a key professional barrier to using IFRSs and, therefore, *IFRS for SMEs*, has been removed. Any remaining barriers may come in the form of unwillingness by a private company's financial statement users to accept financial statements prepared under *IFRS for SMEs* and a private company's expenditure of money, time, and effort to convert to *IFRS for SMEs*.[4]

The AICPA has developed a resource that compares *IFRS for SMEs* with corresponding requirements of U.S. GAAP. This resource is available in a Wiki format, which allows AICPA members and others to contribute to its development. To learn more about the resource, view available sections, and contribute to its content, visit the Wiki at http://wiki.ifrs.com/.

The Financial Accounting Standards Board and IASB Convergence Efforts[5]

To address significant differences between IFRSs and U.S. GAAP, the Financial Accounting Standards Board (FASB) and the IASB agreed to a "Memorandum of Understanding" (MoU), which was originally issued in 2006 and subsequently updated. Readers are encouraged to monitor the FASB and IASB websites for additional developments regarding the convergence efforts, such as discussion papers, exposure drafts, and requests for comments.

Comparison of U.S. GAAP and IFRSs

One of the major differences between U.S. GAAP and IFRSs lies in the conceptual approach: U.S. GAAP is based on principles, with heavy use of rules to illustrate the principles; however, IFRSs are principles based, without heavy use of rules.

In general, a principles-based set of accounting standards, such as IFRSs, is broad in scope. The standards are concise, written in plain language, and provide for limited exceptions and bright lines. Principles-based standards typically require a higher level of professional judgment, which may facilitate an enhanced focus on the economic purpose of a company's transactions and how the transactions are reflected in its financial reporting.

A noticeable result of these differences is that IFRSs provide much less overall detail. In developing an IFRS, the IASB expects preparers to rely on core principles and limited application guidance with fewer prescriptive rules. In contrast, FASB often leans more toward providing extensive prescriptive guidance and detailed rules. The guidance provided in IFRSs regarding revenue recognition, for example, is significantly less extensive than U.S. GAAP. IFRSs also contain relatively little industry-specific guidance.

An inherent issue in a principles-based system is the potential for different interpretations of similar transactions across jurisdictions and entities, which may affect the relative comparability of financial reporting.

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[4] CPAs are encouraged to consult their state boards of accountancy to determine the status of reporting on financial statements prepared in accordance with *International Financial Reporting Standard for Small- and Medium-sized Entities* within their individual state.

[5] Because the convergence projects discussed are active and subject to change, updates will be posted periodically to www.journalofaccountancy.com. Readers also are encouraged to monitor the progress of these projects at the respective boards' websites: www.ifrs.org and www.fasb.org.

Because of long-standing convergence projects between the IASB and FASB, the extent of the specific differences between IFRSs and U.S. GAAP is decreasing. Yet, significant differences remain, which could result in significantly different reported results, depending on a company's industry and individual facts and circumstances. For example, some differences include the following:

- IFRSs do not permit last in, first out (LIFO) inventory accounting.
- IFRSs allow for the revaluation of assets in certain circumstances.
- IFRSs use a single-step method for impairment write-downs rather than the two-step method used in U.S. GAAP, making write-downs more likely.
- IFRSs have a different probability threshold and measurement objective for contingencies.
- IFRSs generally do not allow net presentation for derivatives.

U.S. GAAP also addresses some specific transactions not currently addressed in IFRSs, such as accounting for reorganizations, including quasi reorganizations; troubled debt restructuring; spin-offs; and reverse spin-offs. In addition, U.S. GAAP is designed to apply to all nongovernmental entities, including not-for-profit entities, and includes specific guidance for not-for-profit entities, development stage entities, limited liability entities, and personal financial statements.

The difference in the amount of industry-specific guidance also illustrates the different approaches. Currently, IFRSs include only several standards (for example, IAS 41, *Agriculture*)[6] that might be regarded as primarily industry-specific guidance. However, the scope of these standards includes all entities to which the scope of IFRSs applies. In contrast, U.S. GAAP has considerable guidance for entities within specific industries. For example, on liability recognition and measurement alone, U.S. GAAP contains specific guidance for entities in the following industries, which is not found in IFRSs:

- Health care
- Contractors and construction
- Contractors and the federal government
- Entertainment, with separate guidance for casinos, films, and music
- Financial services, with separate guidance for brokers and dealers and depository and lending, insurance, and investment companies

For nonmonetary transactions, U.S. GAAP provides specific guidance for the airline, software, and entertainment industries.

SEC Work Plan

The SEC continues to affirm its support for a single set of high-quality, globally accepted accounting standards and for the convergence of U.S. GAAP and IFRSs. In May 2011, the SEC staff produced a work plan outlining how such a transition might happen. Many of the panelists favored the "condorsement" approach that was included in the work plan. Under this approach, FASB would endorse new IFRSs one at a time as part of the convergence process, instead of

[6] In addition to IAS 41, *Agriculture*, the other IFRSs that address issues specific to certain industries are IFRS 4, *Insurance Contracts*, and IFRS 6, *Exploration for and Evaluation of Mineral Resources*.

following a "big bang" approach. Among other things, the work plan addresses some of the comments and concerns received regarding future convergence, including the following:

- Sufficient development and application of IFRSs for the U.S. reporting system
- The independence of standard setting for the benefit of investors
- Investor understanding and education regarding IFRSs
- Examination of the U.S. regulatory environment that would be affected by a change in accounting standards
- The impact on issuers, both large and small, including changes to accounting systems, changes to contractual arrangements, corporate governance considerations, and litigation contingencies
- Human capital readiness

The work plan is included as an appendix at the end of the SEC's release, which is located on the SEC's website at www.sec.gov.

In July 2011, the SEC held a roundtable discussion on IFRSs and how they ultimately may be incorporated into the U.S. financial reporting system. Although the SEC has not yet made a decision on whether or not to approve the use of IFRSs, a decision is expected by the end of 2011.

AICPA

In response to an SEC staff paper issued in May 2011, the AICPA issued a comment letter in August 2011, recommending that U.S. public companies be allowed the option of adopting use of IFRSs as the commission weighs a possible future framework for incorporating IFRSs into the U.S. financial reporting system. The letter states that the adoption option would be another important step towards achieving the goal of incorporating IFRSs into the U.S. financial reporting system and that the number of companies that would choose such an option would not be such that system-wide readiness would become an issue. The comment letter further states AICPA's agreement with the SEC in that FASB should continue to have an active role in the international financial reporting arena to ensure that U.S. interests are suitably addressed in the development of IFRSs.

Additional Resources

Website	*URL*
AICPA	www.aicpa.org
AICPA International Financial Reporting Standards Resources	www.ifrs.com
International Accounting Standards Board and IFRS Foundation	www.ifrs.org
Comparison Wiki of *International Financial Reporting Standard for Small- and Medium-sized Entities* and U.S. generally accepted accounting principles	http://wiki.ifrs.com
Financial Accounting Standards Board	www.fasb.org

Appendix D

Schedule of Changes Made to the Text From the Previous Edition

As of July 1, 2011

This schedule of changes identifies areas in the text and footnotes of this guide that have been changed from 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.

Reference	*Change*
Paragraphs 1.06, 1.19, 1.30, 1.34–.35, and 1.74	Revised for clarification.
Paragraph 3.05	Revised due to the issuance of Financial Accounting Standards Board (FASB) Accounting Standards Update (ASU) No. 2009-17, *Consolidations (Topic 810): Improvements to Financial Reporting by Enterprises Involved with Variable Interest Entities*.
Former footnote * in paragraph 3.05	Deleted.
Footnote * in heading before paragraph 4.113	Added.
Paragraph 4.128	Revised due to the issuance of FASB ASU No. 2010-06, *Fair Value Measurements and Disclosures (Topic 820): Improving Disclosures about Fair Value Measurements*.
Footnote † in heading before paragraph 4.128	Revised for clarification.
Footnote ‡ in heading before paragraph 4.132	Added.
Footnote * in paragraph 6.05	Added.
Footnote † in paragraph 6.42	Added.
Paragraph 8.01	Revised for clarification.
Paragraph 8.06, footnote 2 in paragraph 8.06, and paragraph 8.11	Revised for clarification.
Footnote * in heading before paragraph 8.16	Added.

Reference	*Change*
Paragraphs 8.18, 8.32, 8.39, 8.43, 8.59, 8.63–.65, and footnote 5 in paragraph 8.134	Revised for clarification.
Paragraphs 9.07, 9.11, and 9.13	Revised for clarification.
Footnote 1 in paragraph 9.13	Added.
Footnote * in paragraph 9.64	Added.

Glossary and Other Commonly Used Industry Terms

This glossary is organized into three sections. Section I includes terms found in the Financial Accounting Standards Board (FASB) *Accounting Standards Codification* (ASC) glossary. Section II includes general terms that are used in this guide but are not defined in the FASB ASC glossary or in Securities and Exchange Commission (SEC) guidance. Section III includes terms that are defined differently in SEC guidance or that are defined in SEC guidance and not included in the FASB ASC glossary.

Section I—Terms Defined by the FASB ASC Glossary

analogous reservoir. Reservoirs, as used in resources assessments, that have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure), and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, analogous reservoir refers to a reservoir that shares all of the following characteristics with the reservoir of interest:

- Same geological formation (but not necessarily in pressure communication with the reservoir of interest)
- Same environment of deposition
- Similar geological structure
- Same drive mechanism

Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

condensate. Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure but that when produced is in the liquid phase at surface pressure and temperature.

conduit debt securities. Certain limited-obligation revenue bonds, certificates of participation, or similar debt instruments issued by a state or local governmental entity for the express purpose of providing financing for a specific third party (the conduit bond obligor) that is not a part of the state or local government's financial reporting entity. Although conduit debt securities bear the name of the governmental entity that issues them, the governmental entity often has no obligation for such debt beyond the resources provided by a lease or loan agreement with the third party on whose behalf the securities are issued. Further, the conduit bond obligor is responsible for any future financial reporting requirements.

deterministic estimate. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

development project. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

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.

economically producible. The term economically producible, as it relates to a resource, means a resource that generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue should be determined at the terminal point of oil- and gas-producing activities.

estimated ultimate recovery (EUR). Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

exploration. Exploration involves both of the following:

- *a.* Identifying areas that may warrant examination
- *b.* Examining specific areas that are considered to have prospects of containing oil and gas reserves, including drilling exploratory wells and exploratory-type stratigraphic test wells.

exploratory well. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, a service well, or a stratigraphic test well.

field. A field is an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by geological barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms structural feature and stratigraphic condition are intended to indentify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, and so forth.

mineral interests. See the glossary term **properties**.

oil- and gas-producing activities. Oil- and gas-producing activities include:

- *a.* The search for crude oil, including condensate and natural gas liquids, or natural gas in their natural states and original locations
- *b.* The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties
- *c.* The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
    1. Lifting the oil and gas to the surface
    2. Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons).
- *d.* Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable

natural resources that are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

(Further SEC-specific information provided subsequently.)

probabilistic estimate. The method of estimation of reserves or resources when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

probable reserves. Probable reserves are reserves for which quantity and grade and/or quality are computed from information similar to that used for proven reserves, but the sites for inspection, sampling, and measurement are farther apart or are otherwise less adequately spaced. The degree of assurance, although lower than that for proven (measured) reserves, is high enough to assume continuity between points of observation.

(Further SEC-specific information provided subsequently.)

production. Production involves lifting the crude oil and natural gas to the surface, extracting saleable hydrocarbons in the solid, liquid, or gaseous state from oil sands, shale coalbeds, or other nonrenewable natural resources that are intended to be upgraded into synthetic oil or gas, gathering, treating, field processing (as in the case of processing gas to extract liquid hydrocarbons), and field storage.

The oil and gas production function should be regarded as ending at a terminal point, which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal

b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser before upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility that upgrades such natural resources into synthetic oil or gas.

properties. Mineral interests in properties (hereinafter referred to as properties), which include all of the following:

a. Fee ownership or a lease

b. Concession

c. Other interest representing the legal right to produce or a revenue interest in the production of oil or gas subject to such terms as may be imposed by the conveyance of that interest.

Properties also include:

a. Royalty interests

b. Production payments payable in oil or gas

c. Other nonoperating interests in properties operated by others.

Properties include those agreements with foreign governments or authorities under which an entity participates in the operation of the related properties or otherwise serves as producer of the underlying reserves (see FASB

ASC 932-235-50-7); but properties do not include other supply agreements or contracts that represent the right to purchase (as opposed to extract) oil and gas.

Properties are classified as proved properties or unproved properties.

proved area. A proved area is the part of a property to which proved reserves have been specifically attributed.

proved developed oil and gas reserves. Proved developed oil and gas reserves are proved reserves that can be expected to be recovered:

a. Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of the new well

b. Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

proved oil and gas reserves. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geosciences and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulation before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether the estimate is a deterministic estimate or probabilistic estimate.

The project to extract the hydrocarbons must have commenced, or the operator must be reasonably certain that it will commence the project, within a reasonable time.

The area of the reservoir considered as proved includes all of the following:

a. The area identified by drilling and limited by fluid contacts, if any

b. Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establish a lower contact with reasonable certainty.

Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

Reserves that can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when both of the following occur:

a. Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based.

b. The project has been approved for development by all necessary parties and entities, including governmental entities.

Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price should be the average price during the 12-month period before the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(Further SEC-specific information provided subsequently.)

proved properties. Proved properties are properties with proved reserves.

proved undeveloped oil and gas reserves. Proved undeveloped oil and gas reserves are 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 recompletion.

Reserves on undrilled acreage should be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

Under no circumstances should estimates for proved undeveloped reserves 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 projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

(Further SEC-specific information provided subsequently).

proven reserves. Proven reserves are reserves for which both of the following conditions are met:

a. Quantity is computed from dimensions revealed in outcrops, trenches, workings, or drill holes; grade and/or quality are computed from the results of detailed sampling.

b. The sites for inspection, sampling, and measurement are spaced so closely and the geologic character is so well defined that size, shape, depth, and mineral content of reserves are well established.

publicly traded company. A publicly traded company includes any company whose securities trade in a public market on either of the following:

a. A stock exchange (domestic or foreign)

b. In the over-the-counter market (including securities quoted only locally or regionally), or any company that is a conduit bond obligor for conduit debt securities that are traded in a public market (a domestic or foreign stock exchange or an over-the-counter market, including local or regional markets).

Additionally, when a company is required to file or furnish financial statements with the SEC or makes a filing with a regulatory agency in preparation for sale of its securities in a public market, it is considered a publicly traded company for this purpose.

Conduit debt securities refers to certain limited-obligation revenue bonds, certificates of participation, or similar debt instruments issued by a state or local governmental entity for the express purpose of providing financing for a specific third party (the conduit bond obligor) that is not a part of the state or local government's financial reporting entity. Although conduit debt securities bear the name of the governmental entity that issues them, the governmental entity often has no obligation for such debt beyond the resources provided by a lease or loan agreement with the third party on whose behalf the securities are issued. Further, the conduit bond obligor is responsible for any future financial reporting requirements.

publicly traded entity. Any entity that does not meet the definition of a nonpublic entity.

reasonable certainty. If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

reliable technology. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

reserves. Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a nonproductive reservoir (that is, absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (that is, potentially recoverable resources from undiscovered accumulations).

reservoir. A reservoir is a porous and permeable underground formation containing a natural accumulation of oil or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

(Further SEC-specific information provided subsequently.)

resources. Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

saleable hydrocarbons. Hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

service well. A service well is a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane, or flue gas), water injection, steam injection, air injection, saltwater disposal, water supply for injection, observation, or injection for in-situ combustion.

(Further SEC-specific information provided subsequently.)

significant oil- and gas-producing activities. An entity is regarded as having significant oil- and gas-producing activities if it satisfies any of the following criteria. The criteria should be applied separately for each year for which a complete set of annual financial statements is presented.

a. Revenues from oil- and gas-producing activities, as defined in FASB ASC 932-235-50-24 (including both sales to unaffiliated customers and sales or transfers to the entity's other operations), are 10 percent or more of the combined revenues (sales to unaffiliated customers and sales or transfers to the entity's other operations) of all of the entity's industry segments. An industry segment is a component of an entity engaged in providing a product or service or a group of related products or services primarily to external customers (that is, customers outside the entity) for a profit.

b. Results of operations for oil- and gas-producing activities, including equity earnings or losses from oil- and gas-producing activities of equity method investees and excluding the effect of income taxes, are 10 percent or more of the greater of the following:

1. The combined operating profit (including equity earnings) of all industry segments that did not incur an operating loss.
2. The combined operating loss (including equity losses) of all industry segments that did incur an operating loss.

c. The identifiable assets of oil- and gas-producing activities (tangible and intangible entity assets that are used by oil- and gas-producing activities, including an allocated portion of assets used jointly with other operations and the investment balance in the oil- and gas-producing activities of equity method investees) are 10 percent or more of the assets of the entity, excluding assets used exclusively for general corporate purposes.

stratigraphic test well. A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intention of being completed for hydrocarbon production. This classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as exploratory-type if not drilled in a proved area or development-type if drilled in a proved area.

(Further SEC-specific information is provided subsequently.)

support equipment and facilities. Support equipment and facilities used in oil- and gas-producing activities, such as seismic equipment, drilling equipment, construction and grading equipment, vehicles, repair shops, warehouses, supply points, camps, and division, district, or field offices.

uncompleted wells, equipment, and facilities. Uncompleted wells, equipment, and facilities, the costs of which include those incurred to:

a. Drill and equip wells that are not yet completed

b. Acquire or construct equipment and facilities that are not yet completed and installed

unproved properties. Unproved properties are properties with no proved reserves.

wells and related equipment and facilities. Wells and related equipment and facilities are often referred to in the oil and gas industry as lease and well equipment even though, technically, the property may have been acquired other than by a lease. The costs include those incurred to:

a. Drill and equip those exploratory wells and exploratory-type stratigraphic test wells that have found proved reserves

b. Obtain access to proved reserves and provide facilities for extracting, treating, gathering, and storing the oil and gas, including the drilling and equipping of development wells and development-type stratigraphic test wells (whether those wells are successful or unsuccessful) and service wells.

Section II—General Terms in This Guide Not Defined in SEC Guidance or the FASB ASC 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 1 metric ton, 7.5 barrels weigh 1 long ton, and 6.65 barrels weigh 1 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 it will be profitable enough to set production casing and complete the well.

compensatory royalties. Payments made by lessees to royalty owners as compensation for lost income during periods when the entity has not fulfilled its drilling and production obligations.

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.

condition value. The application of a percentage of replacement cost for new materials to used equipment at the time when taken out of service.

crude oil. Liquid petroleum that has not been refined. Sour crude oils have relatively large amounts of sulfur (1 percent or more). Sweet crudes have less sulfur and are more valuable. Most U.S. crudes tend to be sweet, whereas 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 present and adjusted to the standard base temperature of 60 degrees Fahrenheit. Light crude oils have a lower specific gravity than 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, which is usually one year.

directional drilling. The practice of beginning vertical drilling of a new well from an existing surface location and subsequently altering the drilling direction to drill at an angle.

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 that is payable only if the well is unsuccessful.

enhanced recovery. Production resulting from an artificial reservoir drive, such as water flooding, chemical injection, gas injection, enriched gas and miscible injection, thermal stimulation, or in situ combustion. Enhanced recovery also is referred to as *improved recovery*.

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.

fee interest. Ownership of both the surface and minerals rights in a tract of land.

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 well. 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.

gas-to-liquids. A refinery process to convert natural gas or other gaseous hydrocarbons into longer chain hydrocarbons, such as gasoline or diesel fuel.

horizontal drilling. A form of directional drilling whereby the lower part of the well bore parallels the oil zone. The angle of the well bore does not have to reach 90○ to be classified as horizontal drilling.

improved recovery. Production resulting from an artificial reservoir drive, such as water flooding, chemical injection, gas injection, enriched gas and miscible injection, thermal stimulation, or in situ combustion. Improved recovery also is referred to as *enhanced recovery*.

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 extend the life of the oil field, and it gets rid of a potential pollutant.

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). Billings made by the operator to the other working interest owners for the costs of joint exploration, development, and operations.

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.

liquefied natural gas (LNG). Natural gas that has been converted to a liquid by cooling the natural gas to –260○ F.

liquefied petroleum gas (LPG). A mixture of hydrocarbon gases, primarily propane and butane, commercially produced from petroleum and stored under pressure in order to maintain a liquid state.

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.

OPEC. The Organization of Petroleum Exporting Countries (OPEC) is a permanent intergovernmental organization formed in 1960 by the oil rich countries of Iran, Iraq, Kuwait, Saudi Arabia, and Venezuela. The member countries of OPEC control a substantial portion of the world's oil reserves, production, and excess productive capacity.

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 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.

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.

production sharing contract (PSC). The most common contractual arrangements used in oil and gas producing countries by entities with oil and gas producing activities to specify the sharing of costs (both exploration and development) and the value attributed to any production. The other contracting party is often a governmental agency or a government owned entity (GOE) designated by the host country's energy minister.

recompletions. Workovers that entail completion of the well in a productive structure, either shallower or deeper, that has not previously been produced through the well.

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.

rotary drilling. The application of a rotating motion to a drill bit to bore a hole into the earth.

royalty. The right to a share of production retained by the lessor free and clear of exploration, development, and operating costs.

secondary recovery. The production resulting from utilizing enhanced recovery techniques when a large part of the crude oil in a reservoir cannot be recovered using primary recovery methods.

service contract. A contractual arrangement often used by entities with oil and gas producing activities. A service contract may be either a risk service contract (that is, the oil and gas entity accepts the exploration, development, exploitation, and production risks and pays the related costs) or a nonrisk service contract (that is, the oil and gas entity provides services in the form of exploration, development, and production activities, and the host country or GOE pays a fee covering costs incurred by the oil and gas entity plus profits).

shut-in royalties. Payments by the operator to the royalty owner if a successful well has been drilled but production has not begun within a specified time after completion.

tangible equipment. Equipment such as casing, tubing, pumps, tanks, and other equipment installed on a well.

tertiary recovery. The production resulting from the second or subsequent new driver mechanism when using enhanced recovery methods.

working interest. The interest in the oil and gas in-place with responsibility for the cost of development and operation of the property. A working interest also is called the *operating interest*.

workover. Major remedial operations required to maintain or increase production rates. See **recompletions**.

Section III—Terms Defined Differently in SEC Literature or Defined Only in SEC Literature

acquisition of properties (as defined by SEC Regulation S-X Rule 4-10). Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

bitumen (as defined by SEC Final Rule No. 33-8995). Petroleum in a solid or semi-solid state in natural deposits. In its natural state, it usually contains sulfur, metals, and other non-hydrocarbons. Bitumen has a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis.

developed oil and gas reserves (as defined by SEC Final Rule No. 33-8995). Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

i. Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

ii. Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

development costs (as defined by SEC Regulation S-X Rule 4-10). Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

i. Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.

ii. Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

iii. Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.

iv. Provide improved recovery systems.

exploration costs (as defined by SEC Regulation S-X Rule 4-10). Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

i. Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or G&G costs.

ii. Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.

iii. Dry hole contributions and bottom hole contributions.

iv. Costs of drilling and equipping exploratory wells.

v. Costs of drilling exploratory-type stratigraphic test wells.

oil and gas producing activities (as defined by SEC Final Rule No. 33-8995).

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;

(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;

(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:

(1) Lifting the oil and gas to the surface; and

(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and

(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

The oil and gas production function shall be regarded as ending at a "terminal point," which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and

b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

For purposes of this definition, the term saleable hydrocarbons means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;

(B) Processing of produced oil, gas or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;

(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or

(D) Production of geothermal steam.

possible reserves (as defined by SEC Final Rule No. 33-8995). Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

(vi) Where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

probable reserves (as defined by SEC Final Rule No. 33-8995). Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

production costs (as defined by SEC Regulation S-X Rule 4-10). Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

A. Costs of labor to operate the wells and related equipment and facilities.

B. Repairs and maintenance.

C. Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.

D. Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.

E. Severance taxes.

Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

proved oil and gas reserves (as defined by SEC Final Rule No. 33-8995). Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

proved undeveloped reserves (as defined by SEC Regulation S-X Rule 4-10). Proved undeveloped oil and gas reserves are 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 recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled 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 should estimates for proved undeveloped reserves 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.

reservoir (as defined by SEC Regulation S-X Rule 4-10). A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

service well (as defined by SEC Regulation S-X Rule 4-10). A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, saltwater disposal, water supply for injection, observation, or injection for in-situ combustion.

stratigraphic test well (as defined by SEC Final Rule No. 33-8995). A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic test wells are classified as "exploratory-type" if not drilled in a known area or "development-type" if drilled in a known area.

undeveloped oil and gas reserves (as defined by SEC Final Rule No. 33-8995). Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves 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 projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

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