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UPSTREAM PETROLEUM OPERATIONS

Companies in the oil and gas industry may be involved in only upstream activities—exploration and production activities—or they may also be involved in downstream activities—transportation, refining, and marketing activities. This book focuses on the upstream activities of companies engaged in international oil and gas operations. Chapter 1 provides a brief introduction to oil and gas accounting standards and then definitions of terms, including the phases of operations encountered in upstream operations that are essential to understanding the discussions throughout this book. The remaining chapters discuss various topics related to accounting for international oil and gas upstream operations, including the following:

- the international operating environment (with contracts and policies encountered in international operations)
- accounting for phases of operations encountered in international upstream operations
- joint interest accounting
- required disclosures for oil and gas producing companies

Oil and Gas Industry Accounting Standards

In the United States, the development and enforcement of accounting standards falls under the jurisdiction of the Securities and Exchange Commission (SEC). (See Appendix D: Acronyms Commonly Used in the International Petroleum Industry.) The Financial Accounting Standard Board (FASB) is a private, standard-setting body that issues statements and standards in establishing generally accepted accounting principles (GAAP). When the SEC accepts a FASB statement, use of the statement becomes mandatory for companies that are publicly traded in the U.S. capital markets. Globally many other countries also have established accounting

standards. For example, in the UK the Accounting Standards Board (ASB) has traditionally established local accounting standards. There are also international accounting standards issued by the International Accounting Standards Board (IASB) (previously the International Accounting Standard Committee [IASC]). Historically many countries have opted to permit use of U.S. GAAP, IASB or other widely recognized standards for local accounting purposes. However, in June 2002, the Council of Ministers of the European Union (EU) approved regulations requiring all publicly traded companies in EU member states to convert to the use of IASB standards no later than 2005 (this includes companies in the UK). Additionally, a number of other countries around the world have made the decision to convert to IASB standards by 2005. At the present time, there is also an effort underway to harmonize FASB and IASB standards. These evolving reporting practices have significant implications for oil and gas producing companies.

Some countries have issued industry-specific oil and gas accounting standards. Perhaps the most widely accepted oil and gas industry-specific accounting standards are those of the United States. In the United States, *Statement of Financial Accounting Standards No. 19* (*SFAS*), "Financial Accounting and Reporting by Oil and Gas Producing Companies," *SFAS No. 69*, "Disclosures About Oil and Gas Producing Activities," and various procedures and rules issued or sanctioned by the SEC establish US GAAP for oil and gas producing activities. Another widely recognized set of oil and gas industry-specific accounting standards is that of the UK. There the Oil Industry Accounting Committee (OIAC) routinely issues *Statements of Recommended Practice* (*SORP*s) that must be used by oil and gas producers. In addition, the IASC undertook a project in 1999 to develop an international accounting standard for companies in the upstream oil and gas and mining industries. Toward this end, in November 2000, the IASB released an issues paper focusing on key financial accounting and reporting issues unique to the extractive industries. However, due to the list of more pressing matters, the extractive

industries project has not made its way onto the IASB's main agenda. Currently, the project has been assigned to a group of national standard setters from Australia, Norway, South Africa, and Canada who are continuing to work on the project. However, at the present time, there is no estimated completion date for the project. Current projections are that the extractive industries standard will not be in place until some time after 2005.

Given that many oil and gas companies must convert to IASB standards by 2005, there is significant concern regarding the IASB reporting requirements applicable to oil and gas companies. In the absence of specific International Financial Reporting Standards (IFRS), *International Accounting Standard* (*IAS*) *1*, "Presentation of Financial Statements" permits companies to rely on the pronouncements of other standard-setting bodies and on accepted industry practices, provided that the accounting policies are consistent with the IASB framework. It is anticipated that the U.S. and the UK oil and gas industry standards will provide the basis for the accounting policies utilized by companies that use IASB standards. It is for this reason that this book presents in-depth discussions of both U.S. and UK oil and gas industry-related standards and practices. Where an IASB standard exists and is applicable to a specific issue, application of the IASB standard to upstream oil and gas operations is also discussed. Issues related to specific oil and gas industry accounting practices are discussed in more detail in chapter 2.

Understanding Internationally Used Reserve Estimation Methods

The true value of an oil and gas company is the underlying value of its oil and gas reserves. Accordingly, important accounting decisions and disclosures hinge on the type, if any, of reserves discovered. Understanding the various categories of reserves is crucial to understanding the financial statements of oil and gas companies.

There are two broad categories of reserve estimation methodologies used by engineers

and geologists, with both methodologies involving a great deal of uncertainty. These two categories are deterministic versus probabilistic methodologies. A reserve estimation methodology is referred to as deterministic if a single best estimate of reserves is made based on known geological, engineering, and economic data. The methodology is referred to as probabilistic if known geological, engineering, and economic data are used to generate a range of estimates and their associated probabilities.

The Society of Petroleum Engineers (SPE) and the World Petroleum Congress (WPC) have developed definitions of reserves estimated using these two methodologies. These definitions have been studied by and— to varying degrees, adopted by— various accounting boards around the world. Reserves estimated using deterministic methodologies include proved reserves and the two subcategories of proved reserves: proved developed reserves and proved undeveloped reserves. Reserves estimated using probabilistic methodologies include proven and probable reserves and possible reserves. (Note that there is both a proved reserve category and a proven and probable reserve category. These categories differ in part based on the methodology used to estimate the reserves.) More information regarding these engineering methodologies is available at www.spe.org and www.world-petroleum.org .

Use of Reserves in Financial Accounting

The most important event in the operations of an oil and gas company is the discovery of reserves. Consequently, estimated reserve quantities are relied upon heavily in oil and gas accounting. For example, reserve quantities are used in computing depreciation, depletion, and amortization (DD&A) using the units-of-production method and for purposes of complying with disclosure requirements. In establishing accounting and disclosure standards, it is necessary for standard setters to define the reserves that are to be used and/or disclosed. Both U.S. and UK GAAP provide reserve definitions and requirements or guidance as to which reserves can be

utilized and reported by firms. Under U.S. GAAP, only proved reserves (proved developed reserves and proved undeveloped reserves) are sanctioned by *SFAS No. 19, SFAS No 69*, and the SEC. Proved reserves are those quantities of oil and gas that—under current economic and operating conditions—are anticipated to be commercially recovered from known reservoirs (deterministically estimated). UK GAAP provides for the use of *commercial reserves* that includes both proven and probable reserves (probabilistically estimated) or proved reserves (developed and undeveloped). The reserve definitions prescribed by U.S. GAAP and UK GAAP are aligned with the deterministic and/or probabilistic-related definitions utilized by engineers. These definitions are given in the next section.

Reserve Definitions Provided by U.S. GAAP

The only reserves that may be reported under U.S. GAAP are proved reserves, with proved reserves being further classified as being developed or undeveloped. Proved reserves and proved developed reserves are utilized for the purpose of computing DD&A and are required for disclosure purposes. U.S. GAAP prescribes the following definitions:

> ***Proved reserves -*** *Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.*
>
> ***Proved developed reserves -*** *Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid*

injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved undeveloped reserves - *Proved undeveloped oil and gas reserves are 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.* (SEC Reg. S-X, Rule 4-10)

Reserve Definitions Provided by UK GAAP

UK GAAP permits companies to choose between various reserve categories. The term commonly used to refer to the allowed reserve categories in the UK is *commercial reserves*. According to the *2001 SORP*, commercial reserves, as defined in paragraph 12 may, at a company's option, be either:

a. Proven and probable oil and gas reserves (estimated using probabilistic methodology)
b. Proved developed and undeveloped oil and gas reserves (subcategories of proved reserves estimated using deterministic methodology)

According to the *2001 SORP*, the option chosen should be applied consistently in respect to all exploration, development, and production activities.

(a) *Proven and probable oil and gas reserves*

Proven and probable reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate with a specified degree of certainty (see below) to be recoverable in future years from known reservoirs and which are considered commercially producible. There should be a 50 percent statistical probability that the actual quantity of recoverable reserves will be more than the amount estimated as proven and probable and a 50 percent statistical probability that it will be less. The equivalent statistical probabilities for the proven component of proven and probable reserves are 90 percent and 10 percent respectively.

Such reserves may be considered commercially producible if management has the intention of developing and producing them and such intention is based upon:

- *a reasonable assessment of the future economics of such production;*
- *a reasonable expectation that there is a market for all or substantially all the expected hydrocarbon production; and*
- *evidence that the necessary production, transmission and transportation facilities are available or can be made available.*
- *Furthermore*

(i) Reserves may only be considered proven and probable if producibility is supported by either actual production or conclusive formation test. The area of reservoir considered proven includes (a) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, or both, and (b) the

immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geophysical, geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

(ii) Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are only included in the proven and probable classification when successful testing by a pilot project, the operation of an installed programme in the reservoir, or other reasonable evidence (such as, experience of the same techniques on similar reservoirs or reservoir simulation studies) provides support for the engineering analysis on which the project or programme was based.

(b) Proved developed and undeveloped oil and gas reserves

The estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, that is, prices and costs as at the date the estimate is made.

(i) Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of reservoir considered proved includes (a) that portion delineated by drilling and defined by gas-oil or oil-water contacts, if any, or both, and (b) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known

structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

(ii) Reserves that can be produced economically through the application of improved recovery techniques (such as fluid injection) are generally only included in the 'proved' classification if successful testing by a pilot project, or the operation of an installed programme in the reservoir, provides support for the engineering analysis on which the project or programme was based.

(iii) Estimates of proved reserves do not include the following: (a) crude oil, natural gas and natural gas liquids that may become available from known reservoirs but are classified separately as indicated additional reserves; (b) crude oil, natural gas and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (c) crude oil, natural gas and natural gas liquids that may occur in undrilled prospects; and (d) crude oil, natural gas and natural gas liquids that may be recovered from oil shales, coal, gilsonite and other such sources.

Proved reserves may be sub-divided into 'proved developed' and 'proved undeveloped':

(i) Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should generally be included as proved developed reserves only after testing by a pilot project or

after the operation of an installed programme has confirmed through production response that increased recovery will be achieved.

(ii) All other proved reserves which do not meet this definition are proved undeveloped.

As stated earlier, the term used to refer to allowed reserve categories in the UK is commercial reserves. For U.S. GAAP, proved reserves are those reserves estimated to be recoverable under existing prices and costs, in other words, those reserves thought to be commercially recoverable. For ease of usage and to avoid confusion, the term commercial reserves is used frequently throughout this book to refer to both the U.S. allowed reserve categories and the UK allowed reserve categories. When more specific reserve definitions are required, reference to the more specific reserve category is provided.

Phases Encountered in Upstream Operations

The phases of operations historically have been of great importance in accounting for upstream activities. For example, different types of oil and gas contracts encountered in international operations may require sorting upstream oil and gas activities into various phases. In some government contracts, especially production sharing contracts, how the costs are shared by the parties is dictated largely by the phase in which the costs were incurred. In addition, in making capitalization versus expense decisions for financial accounting purposes, the phase in which the costs are incurred may be helpful in evaluating the uncertainty associated with the costs and thus the potential for future economic benefit. Although the phase does not necessarily dictate the financial accounting treatment, accounting standard setters and company accountants typically consider the phase of operations during which the expenditure was made as a major factor in the decision of whether to capitalize or expense a cost. Accountants, however, are not always in agreement regarding the financial accounting treatment of the costs.

An important point that must be understood is that the capitalization versus expense treatment of costs for financial accounting purposes is not necessarily consistent with how costs are defined and treated in various oil and gas contracts. This fact has resulted in much confusion, and perhaps even conflict, particularly in international joint operations. These differences and the rational behind the differing treatments are explained in more detail in chapter 3.

Upstream oil and gas operations are typically divided into the following phases:

1. pre-license prospecting
2. mineral right acquisition/contracting
3. exploration
4. evaluation and appraisal
5. development
6. production
7. closure

The first five phases may be referred to collectively as preproduction phases and the last two phases may be referred to as production phases; although, substantial levels of production may occur during the development phase. The sequencing of the phases is not identical for all companies or for all projects. Moreover, in any particular operation and/or company, two or more of these phases may well be combined into a single phase; for example, pre-license prospecting and exploration or production and closure. In addition, the phases will almost certainly overlap, for example exploration during the development phase or production during the development phase. Nevertheless, in order to understand how costs are shared in various contracts and the rationale behind certain issues regarding capitalization versus expense decisions, it is helpful to understand these phases.

Phase 1—pre-license prospecting

Pre-license prospecting (sometimes referred to as pre-license exploration) typically involves the geological evaluation of relatively large areas before acquisition of any petroleum rights. The activities involved in pre-license prospecting vary widely but are usually general in scope and are not necessarily part of an integrated project. For example, sometimes companies purchase geological and geophysical data (G&G) covering fairly large areas of a country (frequently referred to as a library). Other activities include researching and analyzing an area's historic geologic data, carrying out G&G studies, or assessing topographical information. (Definitions of oil and gas industry terms may be found in publications such as *Introduction to Oil and Gas Production* or *The Petroleum Industry: A Nontechnical Guide*.)

Some pre-license prospecting activities may be undertaken without having physical access to the area; however, usually pre-license prospecting cannot take place without first obtaining permission from the owner of the land and/or the mineral rights. (In most countries other than the United States, the government typically owns the mineral rights and hence permission must be obtained from the government.) Satellite imagery, aerial photographs, gravity-meter tests, magnetic measurements, and various similar observations or measurements are often used to target specific areas without having to physically enter onto the property. Geologists may also study areas where the rock formations are readily observable, in mountainous areas or where roads or railways have been constructed. More detailed evaluation of an area of interest, such as conducting seismic testing, requires specific permission of the owner of the land and/or the mineral rights owner since such activities involve physical testing on the site.

In countries where the government owns the mineral rights, the program the government has in place largely determines the extent and nature of the pre-license prospecting that occurs. If the government is actively seeking to contract with companies for petroleum exploration and

production, it may be quite eager to accommodate companies by allowing them access to the area of potential interest. In some cases companies may be required to purchase or otherwise acquire G&G information directly from the local government. Often companies are required to purchase such data whether or not the company regards the data as being especially beneficial.

Pre-license prospecting is significant in accounting since it occurs before petroleum rights have been acquired for the area on which the exploration is conducted. Capitalization versus expense-type accounting decisions are affected by the level of certainty (or uncertainty) regarding the future economic benefits that will accrue to the company as a result of the expenditures in question. Some accountants argue that general exploration occurring prior to the acquisition of petroleum rights should be expensed since (a) the certainty of future economic benefits is very low and (b) the right to those benefits does not rest with the company at the time the expenditures are made. Others argue that all exploration activities collectively represent a company's efforts to find and produce oil and gas reserves and therefore the timing of the activity (*i.e.*, before or after petroleum rights acquisition) is irrelevant. As will be seen in later chapters these various points of view have resulted in two very different methods of accounting (the successful efforts method and the full cost method) as well as differences between U.S. GAAP and UK GAAP.

Phase 2—mineral interest acquisition/contracting

Mineral interest acquisition involves the activities related to obtaining from the mineral rights owner the legal rights to explore for, develop, and produce oil or gas in a particular area. Typically the oil and gas company receives a mineral interest if the negotiations are successful. A mineral interest is an interest in a property that gives the owner the right to share in the proceeds from oil or gas produced. In U.S. domestic operations, these legal rights are acquired by entering into a lease agreement with the mineral rights owner(s). In operations outside the

United States these legal rights are acquired by entering into any one of a number of different types of contracts. These contracts, which will be discussed in detail in chapter 3, include:

a. concessions
b. production-sharing contracts
c. risk service agreements

In the United States, mineral rights are frequently owned by individuals. The type of contract executed in the United States between the individual mineral rights owner(s) and the company seeking to explore, develop, and produce oil and gas from the property is an oil and gas lease. In the United States mineral rights may also be owned by the government and other entities. For example, in the United States, federal or state governments own the mineral rights in offshore locations and in federal or state-owned lands. Lease agreements are also used when contracting with the government for mineral rights in the United Sates.

Outside the United States mineral rights are typically owned by the government and the contracts executed between the government and the oil and gas producer are quite varied. Concession agreements are quite popular and are used by many governments, including the UK, Canada, and Australia. Perhaps the most commonly used contract is the production-sharing contract (PSC) or production-sharing agreement (PSA). This contract is used to acquire petroleum rights in many countries, including Indonesia, Malaysia, China, Thailand, Angola, and Nigeria, to name a few. Risk service agreements are less popular but nevertheless are also used in contracting for the right to explore and produce oil and gas. Risk service agreements have been used in such countries as Venezuela, Bolivia, and Kuwait.

Leases. An oil and gas lease grants to the oil and gas company the right (and obligation) to operate a property. This includes the right to explore for, develop, and produce oil and gas from the property and also obligates the company to pay all costs. (The type of interest owned

by the oil and gas company that obligates it to pay all of the costs is a working interest and the oil and gas company is a working interest owner. If there are multiple working interest owners in the same property, the property is a joint working interest and the parties are joint working interest owners.) The typical mineral lease calls for:

a. Payment of a bonus (called a signature bonus) by the lessee (the oil and gas company) to the lessor (the mineral rights owner) at the time the contract is signed
b. Payment of a royalty equal to a specified percentage of the value of the oil and gas produced each period
c. The lessee being responsible for payment of essentially all of the costs and incurrence of all of the risks associated with exploration, development, and production without reimbursement from the lessor
d. The lease remaining in effect indefinitely, so long as minerals continue to be produced from the property

In addition to paying a royalty to the lessee and paying the costs incurred in developing and operating the property, the oil and gas company must pay certain taxes. For example, income taxes to the federal and/or state governments and taxes to the state governments are assessed at the point of production based on the volume or value of the oil and gas produced. These latter taxes are typically referred to as severance or production taxes.

Concession agreements. Concession agreements are similar to lease agreements. The primary difference is that concession agreements are encountered in operations outside the United States where the mineral rights owner is the local government. In addition, some concession agreements provide for government participation in the form of a joint working interest. Typical provisions found in a concession agreement are:

a. Payment of a bonus by the exploration and production company to the government at the time the contract is signed or at specified points during development and/or production.
b. Payment of a royalty equal to a specified percentage of the value of the oil and gas produced or an in-kind payment of a specified portion of oil and gas production. In-kind payments involve payment in physical quantities of oil and gas as opposed to payment in money.
c. The contractor (*i.e.*, the non-government oil and gas company(ies) involved in the contract) being responsible for payment of all of the costs and incurrence of all of the risks associated with exploration, development, and production without reimbursement.
d. The agreement remaining in effect indefinitely, so long as minerals continue to be produced from the contract area.

As with a lease agreement, the oil and gas company is responsible for paying all of the costs incurred in developing and operating the property. The oil and gas company also must pay a variety of taxes, including income taxes and severance type-taxes often referred to as value added taxes. In addition in some countries, such as the UK, Australia, and Trinidad, special taxes on petroleum profits are also paid.

Production sharing contracts (PSC). As mentioned earlier, in the international petroleum industry today, the most commonly used arrangement by which companies obtain the rights from the government to explore for, develop, and produce oil and gas is the PSC or PSA (from this point on, the term PSC will be used). Although the precise form and content of PSCs vary from country to country, and even within a single country, the following features are likely to be encountered:

a. The contractor pays a bonus to the national government at the time the contract is signed. Additionally, development bonuses may be paid if the operation goes into development and/or production bonuses when predefined production levels are achieved.
b. The contractor pays royalties to the national government as production occurs.
c. The national government retains ownership of the reserves. It simply grants the contractor the right to explore for, develop, and produce the reserves.
d. The contractor is required to bear all of the costs and risks related to exploration with the government (through a state oil company) having the option to participate in development and production as a working interest owner.
e. The contractor is required to provide infrastructure development for the host country. For example, the contractor may be required to build roads, water systems, hospitals, schools, and other facilities before or during the course of operations. Additionally, the contactor is typically required to provide training of local personnel related to the project. The costs associated with infrastructure development and personnel training may or may not be recoverable from future production.
f. Operating costs and, perhaps, exploration and development costs are recoverable out of a specified percentage of production. The estimated volume of oil or gas production necessary to recover the agreed upon costs is referred to as *cost oil*.
g. An amount of production (typically corresponding to the production remaining after royalty and cost recovery), referred to as *profit oil* is typically split between the government and the contractor on a predetermined basis.
h. Since the contractor is prohibited from owning an interest in reserves, the contractor has an interest often referred to as an *entitlement interest*, that is, an interest in the reserves that corresponds to its share of cost oil and profit oil.

Consistent with the lease and concessionary environment, the contractor is typically responsible for various taxes including taxes on its income generated in the country. Taxes may alternatively be assessed on the contractor's share of profit oil.

Risk service contracts. Another type of contract encountered in international operations is a risk service contract. Risk service contracts were initially used in areas where oil and gas production had been achieved but the need existed to rejuvenate the field or production area. The "service" provided by the oil and gas producing company was typically in the form of performing workovers and other operations aimed at restoring or stimulating production including application of current technology to currently producing fields. More recently, risk service contracts have also been executed in unproved areas with the service being defined to include exploration, development, and production of any reserves that might be discovered. There is no *standard* risk service contract; however, features that may be encountered include:

a. Payment of a bonus to the national government at the time the contract is signed
b. Payment of royalties to the national government as production occurs
c. Retention of ownership of the reserves by the national government (since the contractor is deemed to be providing a service)
d. All of the costs and risks related to exploration, development, and production being borne by the contractor
e. Operating costs and capital costs incurred by the contractor being recovered through payment of operating fees and capital fees
f. The government (through a state-owned oil company) having the right to participate in operations as a working interest owner

Accounting. Agreements similar to PSCs and risk service agreements are unique to the oil and gas industry, and little if any guidance exists in the authoritative accounting literature. Instead, oil and gas companies have relied on accounting and reporting requirements (such as *SFAS Nos. 19* and *69* and the *2001 SORP*) that were developed for other contracts, such as leases and concessions.

Regardless of the type of contract, signature bonuses are the most common payment made to acquire a mineral interest in a property and can range from fairly nominal amounts to tens of millions of dollars. Since a bonus can be very significant, the question of whether to capitalize or expense mineral interest acquisition costs is no small matter. Additionally, legal fees and negotiating costs associated with negotiating PSCs and risk service agreements can also run into the millions of dollars. During the pre-license prospecting phase, costs are incurred in a highly uncertain period prior to a mineral interest having been secured. During the mineral acquisition phase, the level of uncertainty regarding the presence of commercial oil and gas reserves continues to be very high. However, the fact that a legal right to explore, develop, and/or produce oil and gas has been acquired has led most accountants to agree that the costs should be capitalized pending determination of whether or not commercial reserves will ultimately be associated with the mineral interest. Capitalization in light of high levels of uncertainty has resulted in the requirement in many oil and gas accounting standards that the capitalized costs be subject to annual impairment testing.

Phase 3—exploration

Exploration is the detailed examination of an area for which a mineral interest has been acquired. Generally, the geographical area has demonstrated sufficient potential to justify further exploration to determine whether oil and gas are present in commercial quantities. The activities involved in exploration are similar to those in the pre-license prospecting phase, however they

are usually concentrated on a smaller geographical area and include the drilling of wells. Exploration activities are varied but are likely to include conducting topographical, geological, geochemical, and geophysical studies and exploratory drilling.

Specifically, exploration of potential petroleum-bearing structures involves techniques such as conducting seismographic studies, core drilling, and ultimately, if other types of exploration have indicated a sufficient likelihood that petroleum exists in commercial quantities, the drilling of exploratory wells in order to determine whether commercial reserves do in fact exist.

Financial accounting for exploration phase costs may be challenging since the costs incurred are likely to be quite large while the likelihood of future economic benefit is highly uncertain. Some accountants believe that if the uncertainty is sufficiently high, all exploration phase costs should be expensed as incurred. Other accountants would treat exploration costs in a manner consistent with the cost of acquisition or construction of a productive asset. The specific accounting treatment of the various exploration-related costs under U.S. and UK GAAP are discussed in detail in chapter 4 and in chapter 8.

Phase 4—evaluation and appraisal

The evaluation and appraisal phase involves confirming and evaluating the presence and extent of reserves that have been indicated by previous G&G testing and exploratory drilling. Exploratory wells may have found reserves; however, evaluation and appraisal are often necessary in order to justify the capital expenditures related to the development and production of the reserves—in other words confirming that the reserves are commercial.

Specifically, after an exploratory well or multiple exploratory wells have been drilled into a reservoir and have resulted in the discovery of oil and/or gas reserves, additional wells, known as appraisal wells, may be drilled to gain information about the size and characteristics of the

reservoir, to help in assessing its commercial potential, and to better estimate the recoverable reserves. In addition to drilling appraisal wells and possibly further geological and geophysical testing, the appraisal and evaluation phase typically includes conducting detailed engineering studies to determine the nature and extent of the reserves and the formulation of a plan for developing and producing the reserves in order to obtain maximum recovery. Marketing studies may also be necessary, especially in the case of gas discoveries, in order to evaluate transportation costs and market price potential.

In U.S. operations, especially in areas with a history of production, when an exploratory well finds reserves, the oil and gas company may briefly evaluate the results of drilling and then move directly into development. This is particularly likely in onshore operations in locations where an existing transportation and marketing infrastructure exists. In U.S. domestic offshore operations, the market and transportation infrastructure may also be in place; however, drilling of additional wells may be necessary in order to determine whether the reserves are sufficient to warrant construction of a production platform, additional pipelines, and/or onshore facilities to handle the production. If additional wells are drilled in order to determine whether reserves are sufficient to justify installing the necessary infrastructure, they are often treated as a part of the exploration phase.

In operations outside the United States, the appraisal and evaluation phase is more likely to be necessary and is likely to much better defined. PSC and risk service agreements often specify certain appraisal activities that must be carried out by the contractor in the event that an exploratory well indicates the presence of reserves. In these types of agreements, instead of appraisal activities being defined as a separate phase, they are often defined as a distinctive set of activities occurring during the exploration phase. In any case, even when not contractually defined, appraisal may be critical in certain locations where there is no preexisting infrastructure for the production and marketing of the oil and gas or in frontier areas with no history of oil and

gas production, where there may be little existing knowledge of the geological conditions prevailing in the area and of the potential for commercial oil and gas production.

By the time a project enters the appraisal and evaluation phase, the level of certainty that investments will ultimately be recovered has increased significantly. There is little controversy that the expenditures necessary to assess and determine the commercial viability of a field and to prepare for the development of the field should be capitalized at least temporarily. If, however, the decision is made that the field is not commercial, many accountants contend that all costs incurred up to that point should be written off. Others argue that unless the entire area is abandoned, the costs that have been incurred represent the total cost to achieve commercial production in the area.

Phase 5—development

After the formulation of a development plan, companies typically move into the development phase. This phase involves undertaking the steps necessary to actually achieve commercial production. Typically this phase involves:

a. Drilling additional wells necessary to produce the commercial reserves
b. Constructing platforms and gas treatment plants
c. Constructing equipment and facilities necessary for getting the oil and gas to the surface and for handling, storing, and processing or treating the oil and gas
d. Constructing pipelines, storage facilities, and waste disposal systems

Development activities often continue into the production phase.

In operations outside of the United States, the development phase may be significant since the companies participating in the working interest may change. As discussed earlier, typically in PSCs and sometimes in concession contracts and risk service agreements, the government (through the state oil company) has the option to participate in development and

production. If this is the case, the contractor has incurred all of the costs and risks associated with exploration and appraisal. Once the information obtained during exploration and appraisal has been analyzed, the government may exercise its option to participate. After the government's level of participation has been determined (often up to a maximum of a 51% working interest), the development phase moves forward with each company paying their proportionate share of future costs.

There is little controversy regarding the financial accounting treatment of development costs. Since the companies are in the process of developing an oil and gas asset and the level of uncertainty is relatively small, the costs are capitalized.

Phase 6—production

The production phase involves the extraction of oil and gas from the earth and includes all of the related processes necessary to make the produced oil and gas marketable and transportable. Production activities include lifting the oil or gas to the surface, gathering production from individual wells and transporting it to a common point in or near the field. Field treating and processing (for example, removal of basic sediment and water [BS&W] and separation of the oil and gas), and storage of production conclude the production activities. The production phase is normally regarded as terminating at the outlet valve on the field production storage facility. However, based on operating circumstances, the production function may be deemed to be complete at the first point of saleability of the oil and gas, which may be when the minerals are delivered to a main pipeline or to other means of transportation, such as to a marine terminal from an offshore platform or to a refinery. This point is also the end of upstream activities other than closure.

During the production phase, the working interest parties typically share the cost of production in proportion to their working interest. For financial accounting purposes, since the costs of production are related to generating revenue, the costs are expensed as incurred.

Phase 7—closure

At the end of the productive life of an oil or gas field, the site typically must be restored to its pre-existing condition. Accordingly, the closure phase includes plugging and abandoning wells, removing equipment and facilities, rehabilitating and restoring the operational site, and abandoning the site. In offshore operations, equipment must be removed from platforms, platforms must be dismantled and removed, and any pipelines extending to or from the platforms must be removed. The degree of dismantlement, restoration, and removal depends upon the local laws and statutes, provisions contained in the lease, concession, PSC, service agreement, or other contract, and on the policies of the companies involved. Traditionally, these activities have been referred to by a variety of names such as *decommissioning and abandonment*, *dismantlement, removal, and remediation*, *site closure*, or *asset retirement*.

A common provision that appears in PSCs and risk service agreements is that ownership of the equipment and facilities passes to the government through the state oil company. The transfer of ownership along with the fact that the majority of contracts have not historically dealt with the actual payment of closure costs has lead to much controversy in the industry. Recently, the United States, the UK, and the IASB have issued standards requiring producers to estimate the future costs of closure and recognize the future cost as a liability at the time the equipment and facilities are first installed. This issue will be discussed in detail in chapter 12.

Overlap of Operations in Various Phases

Although it is a simple matter to envision the different phases of upstream operations as self-contained and sequential, in reality it is often difficult to determine with precision the phase

during which an event occurs or a cost is incurred. The phases of operations frequently overlap and in some cases they may occur simultaneously. Furthermore, the same assets may be used in more than one phase of upstream activities and sometimes, the same asset may also be used in downstream activities. For instance, an office may be used to manage equipment and personnel employed in exploration, development, and production activities and also to manage the sale of products. To the extent that the phase of operations or the nature of specific activities influences accounting policies, careful consideration must be given to the overlap of the various phases and how costs should be allocated.

Pre-license versus post-license exploration

In this book, pre-license prospecting has been described as occurring before a mineral interest is acquired and exploration as occurring after a mineral interest is acquired. In fact, other than drilling, the exploration activities that occur before versus after the acquisition of a mineral interest may be identical. Some accountants have concluded that, since a mineral interest does not exist prior to signing a contract and given the level of uncertainty that exists, the costs associated with pre-license prospecting should be expensed. Other accountants argue that if these costs can be identified with a particular geological structure, the level of uncertainty is reduced and the costs should be at least temporarily capitalized. The former is true for U.S. successful efforts and the latter for UK successful efforts. The treatment for exploration (other than drilling) performed after a mineral interest has been acquired is the same. U.S. successful efforts focuses on the level of uncertainty and again requires that the costs be expensed as incurred while UK successful efforts acknowledges that a mineral interest has been acquired and calls for the same costs to initially be capitalized. This process will be discussed in detail in chapter 4. Many other accountants accept a method of accounting for oil and gas operations referred to as the full cost method. Accountants who find the method acceptable would argue for

the permanent capitalization all of these costs. The full cost method is discussed in detail in chapter 8.

Exploration and appraisal during the development and production phases

After the development phase has begun, additional evaluation, including exploratory drilling may be necessary. Even after production has begun, activities that are exploratory in nature may occur. It is often difficult to distinguish between costs incurred to develop an existing field and costs incurred to explore for additional, new reserves (perhaps a new reservoir) in the same geographical area as the existing field. Some accountants argue that once a commercial field has been identified and development begins, all subsequent costs incurred to develop the reserves and to find additional reserves in the same geographical area should be capitalized. Other accountants take a different position arguing that given the differing level of uncertainty, if costs are incurred related to activities undertaken to find new reserves, even in an area that is under development or in production, and if those activities are not successful, they should be expensed.

Support Equipment and Facilities (Service Assets)

Support equipment and facilities are used throughout all phases of activities. Examples include seismic equipment, drilling equipment, construction and grading equipment, vehicles, repair shops, warehouses, supply points, camps, docks, and office buildings. Accounting for these assets may be complicated by the fact that they are used in various phases of operations. Accounting as required by either the applicable contract or financial accounting standards may involve allocating these costs between the various phases being supported.

References

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