WORKBOOK ON
OIL AND GAS ACCOUNTING – Part 1

Prepared by
Professor Gary Schugart
University of Houston
TABLE OF CONTENTS

Chapter 1 - Basic Concepts and Accounting Principles for Oil and Gas Producing Companies - Successful Efforts

Chapter 2 - Accounting for Exploration Costs Under Successful Efforts

Geological and Geophysical Costs
Record Keeping and Control
The Authorization System

Chapter 3 - Acquisition Costs of Unproved Property Under Successful Efforts

Economic Interests
Special Interest Created out of the Working Interest
Basic Features of a Typical Oil and Gas Lease

Chapter 4 - Exploration Activities – Drilling and Development

Chapter 5 - Drilling and Development Cost Under Successful Efforts
CHAPTER 1
BASIC CONCEPTS AND ACCOUNTING PRINCIPLES
FOR OIL AND GAS PRODUCING COMPANIES
SUCCESSFUL EFFORTS
LEARNING OBJECTIVES

Chapter 1 introduces basic concepts and accounting principles for oil and gas exploration and production companies. Studying this chapter should enable you to:

1. Describe the difference between full cost and successful efforts accounting.

2. Understand the basic concepts of successful efforts accounting.

3. Identify and describe the various terms used in FASB #19.

4. List and briefly describe the four categories of costs as defined in successful efforts accounting.
BASIC CONCEPTS AND ACCOUNTING PRINCIPLES
FOR OIL & GAS PRODUCING COMPANIES -
SUCCESSFUL EFFORTS

Since 1859, when “Colonel” Edwin L. Drake drilled the first commercially successful oil well near Titusville, Pennsylvania, the oil and gas producing industry has been one of controversy, excitement, intrigue, quick fortunes, and dismal bankruptcies. The people working in the industry have been historically characterized as rugged individuals. This individualism has pervaded the oil and gas producing industry from the days of Titusville in the 1860’s to the international market of today. This individualism has brought a unique strength to the industry, which is needed in dealing with the complexities of oil and gas producing companies. The capital intensive nature of oil and gas exploration efforts has contributed to these complexities making the industry one of a kind. As the oil and gas producing industry is unique, so are the financial accounting and reporting principles used. Several alternatives have been implemented in the accounting and reporting of financial data of the industry, with it being further complicated by variations of the alternatives being used.

Reasons for Diversity

This diversity in the accounting practice of oil and gas producing companies is the result of several factors. The nature of the industry encourages the different methods of accounting and reporting. A high risk is involved in finding producing properties. It is estimated that only one out of ten wells drilled ever finds oil or gas reserves, and that only one out of forty wells drilled ever finds enough reserves to be considered economically productive. Companies in the industry vary in size and degrees of integration ranging from one-man operations to large multinational corporations. The types of contracts and sharing arrangements that exist in the industry are numerous. With increasing government regulation, complicated and more onerous tax laws, and growth of the international market for oil and gas, the complexities of the industry have reached an all time high, with a large element of uncertainty underlying it all.

The alternatives used in financial accounting and reporting by oil and gas producing companies have been grouped under two basic methods of accounting - the full cost method and the successful efforts method.

Full Cost

The basic difference between the two methods is the reporting of costs which cannot be directly related to the discovery of specific oil and gas reserves. The full cost method capitalizes these costs as part of the total cost of finding oil and gas reserves and carries the costs to future periods where they are matched with revenues derived from production of the discovered reserves.
Successful Efforts

The successful efforts method, however, charges the costs that cannot be related to specific reserves to expense as incurred. Though the full cost method did not come into use until around 1960, this method, as well as the successful efforts method, is used widely throughout the oil and gas producing industry, with a full costing being adopted frequently by emerging smaller and medium sized companies rather than large established companies. One reason for the use of full costing by these companies is that unsuccessful exploration and development costs need not be expensed if sufficient known reserves existed to insure recoverability of the costs. A rationale for the full cost method is that all costs are incurred in search of oil and gas reserves whether they are directly or indirectly related to specific reserves, and therefore all such costs should be capitalized and amortized over the actual production of the reserves found. Proponents of the successful efforts method, however, state that costs incurred in drilling a dry hole do not provide future benefits, and thus should be expensed when it is determined that the well is indeed not commercially productive. As can be seen, each method has a logical basis and so a controversial solution is inevitable.

SUCCESSFUL EFFORTS ACCOUNTING – BASIC CONCEPTS

In Statement No. 19, paragraph 143, the Financial Accounting Standards Board (FASB) describes the presently accepted financial accounting framework, in part, as follows: “(A)n asset is an economic resource that is expected to provide future benefits, and nonmonetary assets generally are accounted for at the cost to acquire or construct them. Costs that do not relate directly to specific assets having identifiable future benefits normally are not capitalized - no matter how vital those costs may be to the ongoing operations of the enterprise. If costs do not give rise to an asset with identifiable future benefits, they are charged to expense or recognized as a loss.”

The basic concept underlying the successful efforts method of accounting for oil and gas exploration and production activities is based on a direct cause-and-effect relationship. The successful efforts method follows the premise that an enterprise is to capitalize only those costs it incurs that directly result in an asset that has future benefit measured in terms of future cash flows. There must be such a direct relationship between the exploration cost the enterprise incurs and the specific proved reserves it discovers before it can capitalize the costs. In practice, an enterprise would capitalize the cost of drilling an exploratory well only when that well discovered economically producible oil and gas hydrocarbons.

Statement No. 19 changed little with regard to accounting for an unproved property. Its cost remains capitalized until the character of the property changes. An enterprise can explore the property and associate the related unproved property costs with proved reserves if it discovers proved reserves. If the enterprise does not find any reserves, it shall expense the cost of the unproved property. If some event takes place that impairs the cost of the unproved property, the Statement contains a provision for loss. Such an event could be the drilling of a dry hole on the property or an adjoining property. In the past, some enterprises capitalized geological and geophysical (G&G) costs they incurred during the acquisition of unproved properties as an additional acquisition cost. Under Statement No. 19, enterprises charge to expense all G&G
costs as they incur them, since these costs provide no future benefit. Statement No. 19 also requires enterprises to charge to expense carrying costs, such as delay rentals, a period cost.

The decision to capitalize or expense an exploratory well depends on whether the well is successful in discovering economically producible reserves. Once a well finds proved reserves, the considerable risk involved in oil and gas exploration activities is removed somewhat. Once an enterprise locates economically producible reserves, the production process of such reserves is akin to other manufacturing processes.

The cost of development wells and related support facilities are considered as similar to a manufacturing plant. Therefore, all development wells, whether successful or not, are considered as cost incurred in building the production facility. Thus, all successful efforts companies capitalize all development costs.

Statement No. 19 also eliminated the variations in practice for amortizing the capitalized costs of producing oil and gas properties. It requires that companies amortize acquisition costs of proved oil and gas properties based on proved reserves; whereas, companies amortize the capitalized costs of exploring for, drill and equipping producing wells over the only proved developed reserves.

FASB Statement No. 19, Basic Concepts

The appropriate paragraphs from Statement No. 19 follow:

1]. An enterprise’s oil and gas producing activities involve certain special types of assets. Costs of those assets shall be capitalized when incurred. Those type of assets broadly defined are:

a. Mineral interests in properties (hereinafter referred to as properties), which include fee ownership or a lease, concession, or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of that interest. Properties also include royalty interests, production payments payable in oil or gas, and other nonoperating interests in properties operated by others. Properties include those agreements with foreign governments or authorities under which an enterprise participates in the operation of the related properties or otherwise serves as “producer” of the underlying reserves…; but properties do not include other supply agreements or contracts that represent the right to purchase (as opposed to extract) oil and gas. Properties shall be classified as proved or unproved as follows:

i. Unproved properties - properties with no proved reserves.
ii. Proved properties - properties with proved reserves.

b. Wells and related equipment and facilities, the costs of which include those incurred to:

---

1 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.

© 2002 by Institute for Energy, Law & Enterprise, University of Houston Law Center. All rights reserved.
i. Drill and equip those exploratory wells and exploratory-type stratigraphic test wells that have found proved reserves.

ii. 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.

c. 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.

d. Uncompleted wells, equipment, and facilities, the costs of which include those incurred to:

i. Drill and equip wells that are not yet completed.

ii. Acquire or construct equipment and facilities that are not yet completed and installed.

2]. The costs of a company’s wells and related equipment and facilities and the costs of the related proved properties shall be amortized as the related oil and gas reserves are produced. That amortization plus production (lifting) costs become part of the cost of oil and gas produced. Unproved properties shall be assessed periodically, and a loss recognized if those properties are impaired.

3]. Some costs incurred in an enterprise’s oil and gas producing activities do not result in acquisition of an asset and, therefore, shall be charged to expense. Examples include geological and geophysical costs, the costs of carrying and retaining undeveloped properties, and the costs of drilling those exploratory wells and exploratory-type stratigraphic test wells that do not find proved reserves.

Reserves

The definitions for categories of reserves used in Regulation S-X follow:

(1) Proved oil and gas 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, that is, 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.

(i) Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if
any, 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 which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the “proved” classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

(iii) Estimates of proved reserves do not include the following: (A) oil that may become available from known reservoirs but is 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 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.

(2) **Proved developed oil and gas 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.

(3) **Proved undeveloped 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 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 would 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.

**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 local geologic 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 identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.
Reservoir

The definition of a field relies, in turn on the definition of a reservoir. A reservoir is a porous and permeable underground formation containing a natural accumulation of producible oil or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Exploratory Wells

An exploratory well is a well that is not a development well, a service well, or a stratigraphic test well as those terms are defined. In Regulation S-X, an exploratory well is “a well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir.”

Development Well

A development well is a well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

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 fuel gas) water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

Stratigraphic Test Well

A stratigraphic test 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 test wells, sometimes called expendable wells, are classified as follows:

a. Exploratory-type, if not drilled in a proved area.

b. Development-type, if drilled in a proved area.

Proved Area

The term proved area is used in the definitions of development well, exploratory-type stratigraphic test well and development-type stratigraphic test well. As used therein, a proved area is the part of a property to which proved reserves have been specifically attributed.
Additional SEC Definition

Regulation S-X has its own definitions, which in certain instances duplicate the definitions developed by the FASB. Definitions in Rule 4-10 of Regulation S-X follow, except when this would duplicate the FASB’s definitions already given.

Oil and Gas Producing Activities

According to SEC Regulation S-X:

(I) Such 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 and/or for the purpose of removing the oil or gas from existing reservoirs on those properties.

(C) The construction, drilling and production activities necessary to retrieve oil and gas from its natural reservoirs, and the acquisition, construction, installation, and maintenance of field gathering and storage systems --including lifting the oil and gas to the surface and gathering, treating, field processing (as in the case of processing gas to extract liquid hydrocarbons) and field storage. The oil and gas production function shall normally be regarded as terminating at the outlet valve on the lease or field storage tank; if unusual physical or operational circumstances exist, it may be appropriate to regard the production functions as terminating at the first point at which oil, gas, or gas liquids are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal.

(II) Oil and gas producing activities do not include:

(A) The transporting, refining and marketing of oil and gas.

(B) Activities relating to the production of natural resources other than oil and gas.

(C) The production of geothermal steam or the extraction of hydrocarbons as a by-product of the production of geothermal steam or associated geothermal resources.

(D) The extraction of hydrocarbons from shale, tar sands, or coal.

Acquisition of Properties

Regulation S-X says acquisition of properties costs are “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.”

**Exploration Costs**

According to Regulation S-X, these are:

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, they 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.
Development Costs

These, according to the Regulation S-X are:

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 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, cleaning 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 well-head 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.

Production Costs

Definitions of production costs (sometimes called lifting costs) according to Regulation S-X follows:

(i) 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 costs of oil and gas produced. Examples of production 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.

(ii) Some support equipment of 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 become part of the cost of oil and gas produced along with production (lifting) costs identified above.
CHAPTER 2
ACCOUNTING FOR EXPLORATION COSTS
UNDER SUCCESSFUL EFFORTS
LEARNING OBJECTIVES

Chapter 2 introduces accounting for non-drilling exploration costs under successful efforts. Studying this chapter should enable you to:

1. Identify and describe the various types of exploration costs.

2. Understand the difference between nondrilling exploration costs and exploratory drilling costs.

3. Identify and describe G&G costs.

4. Briefly describe the accounting procedure for the various nondrilling exploration costs.

5. Identify support equipment and facilities and describe the accounting procedure for each cost.

6. Understand the basic concepts for record keeping and control.

7. Understand the basic concepts for the authorization system (AFE).
ACCOUNTING FOR EXPLORATION COSTS UNDER SUCCESSFUL EFFORTS

Exploration involves identifying and examining areas that may contain oil and gas reserves. The principal types of exploration costs are defined in FASB No. 19, par. 17 as follows:

a. Costs of topographical, geological and geophysical studies, rights to 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 (G&G) costs.

b. Costs of carrying and retaining undeveloped properties such as delay rentals, ad valorem taxes on the properties, legal costs for title defense, and maintenance of land and lease records.

c. Dry-hole contributions and bottom hole contributions.

d. Costs of drilling and equipping exploratory wells.

e. Costs of drilling exploratory-type stratigraphic test wells.

The first three types of costs are often incurred before any drilling activities begin and are nondrilling in nature. In order to distinguish them from types d and e costs, which are drilling costs, types a, b, and c are referred to as nondrilling exploration costs. Nondrilling exploration costs are to be charged to expense as incurred as shown in Exhibit 2-1.
Exhibit 2-1

Incur Exploration Cost

includes two categories: (1) G&G costs, costs of carrying and retaining undeveloped properties, and dry- and bottom-hole contributions and (2) costs of drilling exploratory wells

Type 1 nondrilling

Expensed

Stop

Type 2 exploratory drilling

See Chapter 4
G&G COSTS

The purpose of geological and geophysical (G&G) exploration is to locate or identify areas with the potential of producing oil and gas in commercial quantities. Both surface and subsurface G&G techniques are used to locate these areas. Surface techniques are used to evaluate the surface for evidence of subsurface formations with characteristics favorable to the accumulation of oil or gas. Subsurface techniques identify formations capable of containing or gas by utilizing the fact that all types of rocks have different characteristics and respond differently to stimuli such as shock or magnetic waves.

A reconnaissance survey is a G&G study covering a large or broad area, while a detailed survey is a G&G study covering a smaller area, one possibly identified as a result of the reconnaissance survey. By studying the data revealed by G&G studies, geologists and geophysicists can identify interest areas that may warrant the acquisition of a working interest. G&G studies may be conducted either before or after a property is acquired. If exploration is done before acquisition of the property, rights to access the property, called shooting rights, must first be obtained. Typically, acquisition of shooting rights is coupled with an option to lease, so the company performing the G&G activities will have the opportunity to lease the property if the G&G data are promising.

G&G costs include all the costs related to conducting G&G studies and the cost of access rights to properties to conduct those studies. These G&G costs must be expensed as incurred regardless of whether the G&G costs were incurred before or after acquisition of a working interest in the property. G&G costs are similar to research costs because they are incurred to provide information. To a large extent, G&G costs are incurred prior to property acquisition. Surveyed property is never acquired and, if acquired, is subsequently abandoned. The correlation of G&G costs with specific discoveries (months or years later) is very difficult or impossible and cannot be made at the time the G&G costs are incurred. Therefore, G&G costs should be expensed as incurred.

EXAMPLE -- G&G COSTS

a. U.S. Oil Company obtained shooting rights - access rights to a property - so that G&G studies may be conducted - to 10,000 hectares paying $5.00 per hectare.

Entry
The $50,000 payment made to a foreign government or the government oil company would be recorded as a G&G expense on the books of U.S. Oil, and charged to their income statement.

b. U.S. Oil Company then hired ABC Company to conduct the G&G work and paid the company $25,000. (This is the normal situation, that is, a company usually contracts out its G&G work).

Entry
The same entry as in part ‘a’ would be made on the book of U.S. Oil with the entire $25,000 recorded as an expense.

As described above, the broad G&G surveys determine interest areas that may be leased or further explored. Detailed surveys may be made to further delineate the more promising areas for possible leasing. Although not required by the successful efforts method, both broad and detailed survey costs are in many cases allocated to the leases acquired. However, even if allocated to individual leases by companies using successful efforts, G&G costs are still expensed.

G&G studies may also be conducted on a property owned by another party in exchange for an interest in the property if proved reserves are found; if proved reserves are not found, G&G costs incurred are reimbursed. In this situation, G&G costs should be recorded as receivable when incurred and if proved reserves are found should be transferred to become part of the cost of the proved property acquired. If proved reserves are not found, reimbursement is received. G&G studies are also typically performed to locate a specific drillsite before drilling a well. This type of costs, although involving G&G activity, is considered part of the drilling process and is accounted for as a drilling cost rather than a nondrilling exploration cost.

Carrying and Retaining Costs

Carrying and retaining costs are incurred primarily to maintain the lessee’s property rights, not to acquire those rights. Delay rentals, a common carrying and retaining cost, are paid prior to drilling in order to delay drilling operations for a year. Property taxes assessed on the economic interest owned by the working interest and levied by a governmental agency, that is, city, county, etc. Legal costs for title defense include attorneys’ fees, court costs, etc., incurred when a working interest owner is sued in connection with claims to title to the property. Lease records maintenance costs are incurred by the land department in maintaining, evaluating, and updating the company’s lease records. Employee salaries, materials, and supplies comprise the bulk of these maintenance costs.

Carrying costs do not increase the potential recoverable amount of oil and gas and do not enhance the future benefits to be derived from the acquired properties. Instead, carrying and retaining costs are in essence penalties for delaying drilling and producing activities. For these reasons, carrying and retaining costs are expensed as incurred.

The carrying and retaining costs under discussion are related to unproved properties and are usually insignificant in terms of cost. For instance, delay rentals are typically a nominal amount as little as $1 or $2 per hectare. Lease records maintenance cost is generally relatively small in dollar amount. Ad valorem taxes on unproved properties will, in most cases, also be a small amount because the existence of any minerals is not yet known. Legal costs, in contrast, may be relatively significant.

Example

a. The land department of U.S. Oil Company incurred allocable costs of $5,000 in maintaining land and lease records on undeveloped property.
Entry

The $5,000 cost should be recorded as records maintenance expense and charged to the company income statement.

The carrying and retaining costs under discussion are associated with undeveloped properties and are classified as exploration costs. If ad valorem taxes or lease record maintenance costs are associated with proved properties, they are classified as a production cost, not an exploration cost.

Test Well Contributions

Test well contributions, diagrammed in Exhibit 2-2, are payments made by Company A to Company B in exchange for G&G information obtained in a nearby property. Since test well by Company B when drilling a well on contributions are in essence G&G costs, they are expensed as incurred for the same reasons previously described.

A test well contribution may be one of two types. It may be a dry-hole contribution where payment is made only if the well is dry or not commercially producible. Or it may be a bottom-hole contribution where payment is made when an agreed-upon depth is reached, regardless of the outcome of the well.

Exhibit 2-2

Well drilled by Company B. Company A gets G&G information from Company B’s well.

Example – Test Well Contributions
Several wells were being drilled on leases close to an undeveloped lease owned by U.S. Oil Company. In order to obtain G&G information from the wells, U.S. Oil Company entered into the following agreements:

Well 1, dry-hole contribution of $15,000
Well 2, dry-hole contribution of $25,000
Well 3, bottom-hole contribution of $10,000
Well 4, bottom-hole contribution of $20,000

The following results were obtained:

WELL 1 - dry

Entry (dry-hole contribution)

U.S. Oil Company should record a test well contribution expense for the entire $15,000. This expense is classified as G&G expense.

WELL 2 - Completed as a producer

Entry (dry-hole contribution)

There is no expense, therefore no accounting entry is required.

WELL 3 - Drilled to agreed depth and determined to be dry

Entry (bottom-hole contribution)

The entire $10,000 is recorded as test well contribution expense. (G&G) expense.

WELL 4 - Well abandoned before reaching agreed depth

Entry (bottom-hole contribution)

There is no expense, therefore no accounting entry is required.

Note: A company receiving a test well contribution records it as a reduction in intangible drilling costs.

A dry-hole contribution is paid only if the well does not find proved reserves. But whether a producer is found or not, the driller is obligated to furnish G&G information to the company making the dry-hole contribution. A bottom-hole contribution is paid when the driller reaches the predetermined contract depth, even if proved reserves are not found. The bottom-hole
contribution will not be paid if the driller fails to drill to the predetermined depth. Depending on contract terms, the bottom-hole contributor may receive G&G information even if the well is not drilled to contract depth and no payment is made. The primary reason for making a test well contribution is that valuable information (well logs, drillstem tests, etc.) can be obtained without the cost of drilling a well. On the other hand, the entity receiving the contribution receives valuable financial help. A dry-hole contribution may be entered into when the driller needs financial help if the well is dry but does not require financial help if proved reserves are found. In a bottom-hole contribution situation, the driller wants financial assistance even if the well is a producer. The following example illustrates the accounting for different types of nondrilling exploration costs.

**Comprehensive Example**

a. U.S. Oil Company was interested in a large section of land west of Baku and obtained shooting rights to 6,000 hectares for $1.50 per hectare.

**Entry**

G&G expense (6,000 x $1.50)………………………….$9,000

The $9,000 should be recorded as G&G expense.

b. U.S. Oil Company paid a geological firm $50,000 to conduct a reconnaissance survey on the area

The $50,000 should be recorded as G&G expense.

c. Based on the results of that study, U.S. Oil Company acquired one 700 hectare lease and immediately commissioned the same geological firm to conduct detailed G&G studies on the lease at a cost of $15,000.

**Entry**

The 15,000 should be recorded as G&G expense.

d. During the first year, U.S. Oil Company had to pay $2,000 in local taxes and $10,000 for title defense.

**Entries**

The $2,000 should be recorded as tax expense. The $10,000 legal fees should be recorded as legal expense-exploration.

e. Early in the second year, drilling began on a well on a nearby property. U.S. Oil Company entered into a bottom-hole contribution agreement to obtain the G&G information from the
well. The depth specified in the agreement was reached two months later, and U.S. Oil Company paid $20,000 as per agreement.

**Entry**

The $20,000 should be recorded as test well contribution expense - G&G.

**Support Equipment and Facilities**

Support equipment and facilities include such items as seismic equipment, repair shops, warehouses, and division offices. Support equipment may be used in a single oil and gas producing activity, that is, exploration, acquisition, development, or production, or it may be used to serve two or more of those activities or other activities such as marketing or refining. Any depreciation or operating costs of support equipment should be classified as an exploration, acquisition, development, or production cost to the extent the support equipment is used for that activity.

**Example - Support Equipment and Facilities**

Depreciation of the seismic equipment used by U.S. oil company was $10,000 for 1996. Operating costs were $21,000.

**Entry to record depreciation**

The $10,000 for depreciation should be recorded as G&G expense - depreciation.

**Entry to record operating costs**

The $21,000 for operating costs should be recorded as G&G expense - operating costs.

**RECORD KEEPING AND CONTROL**

The accounting system must provide information to be used in the published financial reports. But it must also furnish data to meet many other needs. In developing procedures and records to account for exploration costs, the following needs are typical of those that must be kept in mind.

1. Exploration activities center around specific projects undertaken to locate structures favorable to the accumulation of hydrocarbons. Management must know the costs of each project in order to determine its ultimate profitability.

2. Development of the exploratory budget is extremely dependent on the accounting system for information.

3. Cost control depends on an adequate accounting and reporting system.
4. Regulatory agencies impose specific reporting requirements necessitating appropriate classification and accumulation of data.

5. Frequently, detailed historical cost records are required for legal and contractual purposes.

Thus the accounting and record-keeping procedures must be designed to serve a multitude of persons and users. There is no single system that will serve the needs of all companies.

THE AUTHORIZATION SYSTEM

Most exploration is undertaken on a “project” basis, with work on a project sometimes extending over a considerable period of time, frequently several years. Approvals are usually required because of the large expenditures incurred, the length of time involved, and the need to maintain tight control over cash expenditures. Depending upon company policy, approvals for specific expenditures in excess of some specified amount will be necessary. Endorsements and approvals are usually required from one or more individuals having functional responsibilities. The procedure for giving written approval for large expenditures may require an Authorization for Expenditure (AFE), containing a description of the project, a listing of proposed expenditures, and spaces for appropriate approvals.

Many companies in the industry reserve the term Authorization for Expenditure only for those expenditures involving the drilling of exploratory or developmental wells. They use other procedures and forms such as Project Approvals for other activities. The procedures involved are basically the same. In any case, expenditure of major amounts requires approval of one or more individuals in any organization. Accordingly, the Authorization for Expenditure is used in this course for any planned expenditures where approval is required.

For example, assume that U.S. Oil Company is contemplating exploration in an area and that the estimated amount of the direct expenditures involved will be $50,000, requiring and approved AFE before work can commence. The form illustrated in Exhibit 2-1 has been initiated by a district geologist.

The detailed items specified on the exploration AFE correspond to the subsidiary accounts for exploration expense. The amount for overhead is simply an estimate (in this case, 20 percent of direct costs) and does not indicate expected cash expenditures on the project.

Approval of the AFE does not require an entry in the formal accounting records; its primary purpose is for internal control of expenditures. However, a record of the AFE will be required for internal control purposes. Even though exploration budgets are somewhat flexible, the AFE encumbers some portion of the budget. Costs are accumulated for each project to be compared with the amounts authorized. The columns entitled actual costs and variance provide the means for making comparisons between estimated and actual cost when the project is completed.

Exhibit 2-3
## AUTHORIZATION FOR EXPENDITURE - EXPLORATION

**REQUEST FOR AUTHORITY BY**

H. Etheridge, Exploration Dept.

**AFE NO.** 81012

**DATE** 2/10/96

**LOCATION:** TTN, R21E

**PURPOSE:** To conduct exploration activities for possible leasing and subsequent drilling and development in the area.

<table>
<thead>
<tr>
<th>ITEM</th>
<th>ESTIMATED COST</th>
<th>ACTUAL COST</th>
<th>VARIANCE</th>
</tr>
</thead>
<tbody>
<tr>
<td>01 - G&amp;G Contract</td>
<td>$40,000</td>
<td></td>
<td></td>
</tr>
<tr>
<td>02 - G&amp;G Services - other</td>
<td>-0-</td>
<td></td>
<td></td>
</tr>
<tr>
<td>03 - Field Party Salaries</td>
<td>7,000</td>
<td></td>
<td></td>
</tr>
<tr>
<td>04 - Field Party Supplies</td>
<td>-0-</td>
<td></td>
<td></td>
</tr>
<tr>
<td>05 - Field Party - Other</td>
<td>1,000</td>
<td></td>
<td></td>
</tr>
<tr>
<td>06 - Support Facilities</td>
<td>-0-</td>
<td></td>
<td></td>
</tr>
<tr>
<td>07 - Shooting Rights &amp; Damage</td>
<td>2,000</td>
<td></td>
<td></td>
</tr>
<tr>
<td>08 - Mapping Expenses</td>
<td>-0-</td>
<td></td>
<td></td>
</tr>
<tr>
<td>09 - Equipment Rental</td>
<td>-0-</td>
<td></td>
<td></td>
</tr>
<tr>
<td>10 - Other G&amp;G</td>
<td>-0-</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>TOTAL DIRECT</strong></td>
<td><strong>$50,000</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>OVERHEAD</strong></td>
<td>10,000</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>$60,000</strong></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**APPROVALS:** Gary Schugart 2/20/96  
*Signature*
### Exhibit 2-4

**COMPLETED AFE**

**AUTHORIZATION FOR EXPENDITURE - EXPLORATION**

REQUEST FOR AUTHORITY BY  
H. Etheridge, Exploration Dept.  
DATE  2/10/96

LOCATION: TTN, R21E

PURPOSE: To conduct exploration activities for possible leasing and subsequent drilling and development in the area.

<table>
<thead>
<tr>
<th>ITEM</th>
<th>ESTIMATED COST</th>
<th>ACTUAL COST</th>
<th>VARIANCE</th>
</tr>
</thead>
<tbody>
<tr>
<td>01 - G&amp;G Contract</td>
<td>$40,000</td>
<td>$38,000</td>
<td>$2,000</td>
</tr>
<tr>
<td>02 - G&amp;G Services - other</td>
<td>-0-</td>
<td>-0-</td>
<td>-0-</td>
</tr>
<tr>
<td>03 - Field Party Salaries</td>
<td>7,000</td>
<td>7,400</td>
<td>(400)</td>
</tr>
<tr>
<td>04 - Field Party Supplies</td>
<td>-0-</td>
<td>-0-</td>
<td>-0-</td>
</tr>
<tr>
<td>05 - Field Party - Other</td>
<td>1,000</td>
<td>1,200</td>
<td>(200)</td>
</tr>
<tr>
<td>06 - Support Facilities</td>
<td>-0-</td>
<td>-0-</td>
<td>-0-</td>
</tr>
<tr>
<td>07 - Shooting Rights &amp; Damage</td>
<td>2,000</td>
<td>2,300</td>
<td>(300)</td>
</tr>
<tr>
<td>08 - Mapping Expenses</td>
<td>-0-</td>
<td>-0-</td>
<td>-0-</td>
</tr>
<tr>
<td><strong>TOTAL DIRECT</strong></td>
<td><strong>$50,000</strong></td>
<td><strong>$48,900</strong></td>
<td><strong>$1,100</strong></td>
</tr>
<tr>
<td><strong>OVERHEAD</strong></td>
<td><strong>10,000</strong></td>
<td><strong>9,780</strong></td>
<td><strong>220</strong></td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>$60,000</strong></td>
<td><strong>$58,680</strong></td>
<td><strong>$1,320</strong></td>
</tr>
</tbody>
</table>

APPROVALS: Gary Schugart  2/20/96  
Signature
CHAPTER 3
ACQUISITION COSTS OF UNPROVED PROPERTY UNDER SUCCESSFUL EFFORTS
LEARNING OBJECTIVES

Chapter 3 discusses acquisition costs of unproved property under successful efforts and the accounting procedures used to record the purchase, transfer and expending of these costs.

1. Describe acquisition costs.
2. Identify economic interests.
3. Discuss special interests created from the working interest.
4. Identify and discuss the basic features of a typical oil and gas lease.
5. Understand the accounting procedure for acquisition costs.
6. Describe the process of disposition of capitalized acquisition costs.
7. Understand the procedure to account for post-balance sheet events.
ACQUISITION COSTS OF UNPROVED PROPERTY UNDER SUCCESSFUL EFFORTS

**Acquisition costs** include 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' fee, recording fees, legal costs, and other costs incurred in acquiring properties. Leasing is the typical method of acquiring property. A lease bonus is the amount given by the lessee to the mineral interest owner or government at the time the working interest is acquired through a lease arrangement. A property may also be acquired through purchase of the mineral rights or purchase of the fee interest. An option to purchase or lease a property is a contract that gives the prospective lessee a stated period of time in which to decide whether to purchase or lease the property. Land purchased in fee means that both the mineral interest and surface rights are acquired rather than just the mineral rights.

**ECONOMIC INTERESTS**

An understanding of the various kinds of interests that may be held in underground minerals is essential in understanding the manner in which oil companies obtain the rights to drill for and produce petroleum. The term “economic interest”, although not clearly and completely defined, is used to denote the ownership of minerals. The most commonly used meaning of the term is: “An economic interest is possessed in every case in which a person has acquired, by investment any interest in mineral in place or standing timber secures, by any form of legal relationship, income derived from the extraction of the mineral or severance of the timber to which he must look for a return of his capital. A number of economic interests are defined below.

1. **Mineral Interest**

   This term refers to ownership of minerals in place without considering ownership of the surface. (Surface and mineral fee interest in property.) Mineral interest owners have the option of financing their own drilling and producing operations; this process would provide the mineral interest owners with 100% of the revenue, if any, from the production and sale of minerals. A second option, most commonly used in the oil industry, involves leasing the mineral rights to another party, giving that party the right to explore and develop the property. The lease agreement also calls for the lessor to retain a royalty interest.

2. **Royalty Interest**

   The royalty interest is the portion of the total minerals which the mineral interest owner retains when he leases the development rights to another party. The royalty owner is entitled to a specified fraction of the minerals in place free and clear of any developing and operating costs except severance taxes and, in some instances, certain gathering costs. Royalty interest is transferable. Thus, a royalty interest may be acquired through purchase.
3. Working Interest

This interest, also called the operating interest, is the total mineral interest minus any and all non-operating interests. The working interest is burdened with the cost of developing and producing the minerals and thus receives a large share of revenue from the property. In the simplest situation—a leasing arrangement—the mineral interest owner would retain a fractional interest (royalty interest) in the minerals he formerly owned in full and would convey a fractional interest (working interest) to another party. The holder of the operating interest could then retain its ownership throughout the life of the lease, sell all of it, or sell parts of the interest to spread risk and obtain financing. In any event, the owners of the working interest bear the responsibility for developing and producing the property.

SPECIAL INTEREST CREATED OUT OF THE WORKING INTEREST

The royalty interest is a continuing interest a permanent ownership right—while the life of the working interest is created by and limited to the terms of the lease contract. The owner of the working interest may further divide the working interest into a number of different types of property rights, and often does so in financing the development of the property and in spreading the risk of that development. Some of the more common rights are described and explained in the following paragraphs. It is important to keep in mind that these rights are created out of the working interest, and thus their life is limited to the life of the working interest.

a. Overriding Royalty Interest

This mineral interest is created or retained in addition to the royalty interest. It is similar to the basic royalty in that it bears no portion of the operating costs and entitles the owner to a specified share of production payable out of gross revenue or out of the working interest revenue. Amounts payable to an overriding royalty owner come out of the working interest share of production. An overriding royalty interest expires at the termination of the lease.

b. Production Payments Interest

A production payment entitles its owner to a specified fraction of the production for a certain time or until a specified sum of money or a specified number of units of product has been recovered. Production payments are used to obtain financing for development and production purposes and reduce the portion of the revenue which would otherwise accrue to the working interest. They are non-operating interest and are similar to overrides.

c. Net Profits Interest

This interest is created out of the working interest and is usually defined as a fractional portion of the operator's net profit from the operation of the property. A clear definition of the items of revenue and expense included in the net profit computation is essential. The net profits interest is a nonoperating interest and thus bears some similarity to the overriding royalty interest.
BASIC FEATURES OF A TYPICAL OIL AND GAS LEASE

As indicated earlier, the most common manner in which a company obtains drilling rights in a particular location is to execute a lease in which the owner of the minerals conveys the rights to drill and develop the property to the oil company. Along with the conveyance of the rights goes the transfer of a portion of the mineral ownership to the petroleum firm. While there is no single lease form in use, the Producer's 88 form (shown later in this chapter) is frequently found in the industry. Also, regardless of the form used, both parties to the contract may strike or add to the printed words as they finalize an agreement. However, most leases contain the following basic provisions.

1. **Lease Bonus**

The term refers to the cash or other consideration given to the lessor by the lessee in return for the lessor's conveyance of the rights to explore, drill, etc. The actual lease bonus is the result of bargaining between the parties and is affected by such factors as location of the property relative to proved production, the term of the lease, and many other variables. Agreement is usually reached on “per acre” amount that may range from a few dollars in wildcat locations to many hundreds of dollars for locations near producing properties.

Bonuses on state and federally owned properties are usually awarded as a result of a bidding process with leases granted to the highest bidder. Offshore tracts often cover 5,000 or more acres, and lease bonuses in the millions of dollars are common.

2. **Primary Term**

The maximum period of time allowed the lessee to commence drilling a well which discovers oil or gas is referred to as a primary term. The lessor is anxious for the oil company to drill as quickly as possible and, thus, would prefer a short lease. The company acquiring the rights would prefer a long period of time so that the property can be evaluated, the drilling budget reviewed other property nearby could be obtained, etc.

3. **Drilling Obligation**

The lease carries the stipulation that drilling operations must begin within one year, without such activity, the lease will terminate (regardless of the length of the primary term) unless the lessee tenders a specified payment to the lessor. In succeeding years, the same drilling obligation exists but can be deferred (and the lease can be retained) for successive periods of one year each with an annual payment; however, no provision is made for the extension of the lease beyond the primary term by mailing a rental payment to the lessor.

4. **Production Holds Lease**
If at any time during the primary term of the lease successful drilling occurs and production continues without long and indefinite interruption, the lease remains in effect indefinitely. If production ceases, the company must act in good faith to restore the extraction of oil or gas within a reasonable time. Prolonged inactivity will result in a loss of the lease, in which case all mineral interest revert to the royalty owners.

Acquisition costs should be capitalized when incurred. The most significant acquisition cost is normally the lease bonus. Typically, other acquisition costs are relatively insignificant.

**Example—Acquisition Cost**

U.S. Oil Company acquired a 500 hectare unproved property. Acquisition costs included a lease bonus of $40 per hectare and recording fees of $1,000.

**Entry**

The $21,000 bonus should be recorded as unproved property and will appear on the company records as a current asset.

\[
\text{Unproved property (500 x } \$40 + \$1,000) = \$21,000
\]

**Note:**

Occasionally, a proved property may be acquired. In that case, the bonus will be recorded as proved property instead of unproved property. Acquisition costs of proved properties would include the costs discussed above and would be capitalized as a fixed (long term asset) when incurred.

The majority of acquisition costs would simply be recorded as unproved property when incurred, as illustrated above. The treatment of other acquisition costs is not always so straightforward. Acquisition costs needing further discussion are the following:

- Purchase In fee
- Internal costs
- Options to purchase or lease,
- Delinquent taxes and mortgage payments
- Top leasing

**Exhibit 3-1**
Successful Efforts, Acquisition Costs
Incur acquisition costs
Includes bonuses, option, broker’s fees, recording fees, and legal fees

Capitalize as unproved property

Periodically assess property

Is property impaired or abandoned

Yes

See Figure 3-2

No

Has oil or gas been discovered?

Yes

Transfer from unproved property to proved property

No

Amortize on basis of production (proved reserves)

Amortization of exploration and development costs based on proved developed reserves

Cost of oil and gas produced

Production costs

From Figure 3-2
Exhibit 3-2

Successful Efforts, Unproved Property

Unproved property

Periodically assess property

Is property surrendered or abandoned?

Yes

Is there a sufficient impairment allowance?

No

Charge to impairment allowance and recognize loss for excess over allowance of cost

Stop

Is property impaired?

No

Has oil or gas been discovered?

Yes

See Figure 3-1

No

Are individual unproved property costs significant?

Yes

Provide for valuation allowance on a property-by-property basis

No

Provide for a valuation allowance on an aggregate or a group basis

Cycle through again

Charge to impairment allowance
Internal Costs

Theoretically, the portion of the salaries of in-house lawyers or landmen and the portion of other internal or overhead costs relating to lease-acquisition should be capitalized. Directly allocating this type of cost to specific leases may be impractical if the amount of the cost is insignificant. However, if the costs are material, they should be allocated to individual properties. Two reasonable allocation basis follows.

a. Capitalize the costs and allocate to individual leases acquired, based on total acreage acquired.

b. Allocate the costs on an acreage basis to all prospects investigated, capitalizing the portion of the costs allocated to prospects acquired and expensing the portion of costs allocated to prospects not acquired.

Most companies, appear to be expensing these costs because they are generally immaterial in amount.

Example—Internal Costs

U.S. Oil Company acquired an 800 acre undeveloped lease at a $10 per acre bonus. Legal costs and recording fees were $200. The salary of an in-house lawyer working on lease acquisition was $10,000. The lawyer's salary is allocated to all leases acquired, based on relative acreage acquired. Leases totaling 8,000 acres were acquired.

Entry

The total amount of $9,200 should be capitalized and recorded as unproved property.
Unproved property (800 x $10 + $200 + 800/8,000 x $10,000) = $9,200

Disposition of Capitalized Costs -- Assessment of Unproved Property

Unproved properties should be assessed periodically to determine whether they have been impaired. The following questions may be asked to help determine if a property has been impaired:

a. Have there been any dry holes drilled on the lease or on surrounding leases, or has any additional negative G&G information been obtained?

b. How close is the expiration of the primary lease term?

c. Are there any firm plans for drilling?
Dry holes and negative G&G information would normally indicate that the property value in terms of replacement cost has declined, or at least a portion of the original cost has expired and impairment should be recognized. If neither drilling nor production is in progress at the end of the primary term, the lease terminates and the leasehold costs will be expensed. Therefore, a property may also be impaired if the end of the primary term is near and no firm plans for drilling have been established.

Impairment estimation is difficult and subjective. However, the above-mentioned variables should be taken into account in determining whether a property has been impaired and, if impaired, in determining the impairment percentage.

If the results of the assessment indicate the property has an impaired, a loss should be recognized by providing a valuation allowance. The exact approach used depends upon whether the acquisition costs of the property under consideration are significant. In determining significance, factors such as cost of the properties, company size, number of unproved leases held, and management's view toward detail are taken into consideration.

One current practice to determining significance is to compare the cost of a property to the total cost of all unproved properties. If the cost of that property exceeds some percentage of the total capitalized costs of all unproved properties, then it is considered significant. Many companies consider the property significant if the cost of the individual property exceeds 10% to 20% of the total capitalized costs of all the unproved property. There are significance guidelines for full cost companies but not for successful efforts companies. Under the full cost guidelines, a property is significant if its costs exceed 10% of the net capitalized costs of the cost center, which for full cost is a country.

If the acquisition costs are significant, the property should be assessed individually. Under individual assessment, each significant lease is examined individually to determine if it has been impaired. Therefore, variables such as dry holes drilled, plans for drilling, and the nearness of the end of the primary term should be considered in determining impairment for each significant lease.

**Example—Impairment of Significant Properties**

On January 1, 1995, U.S. Oil Company acquired an undeveloped lease paying significant acquisition costs of $40,000. During the year, U.S. Oil Company drilled two dry holes on the property. As a result of drilling these dry holes, U.S. Oil Company decided on December 31, that the lease was 25% impaired, that is, the impaired value was less than cost.

**Entry**

The $10,000 should be recorded as an expense. Since there is no cash being paid, a new account called allowance for impairment will be created. The allowance for impairment account is a contra asset account. The pertinent part of a balance sheet prepared following this entry would be as follows:

<table>
<thead>
<tr>
<th>Assets: Unproved Property</th>
<th>$40,000</th>
</tr>
</thead>
</table>

© 2002 by Institute for Energy, Law & Enterprise, University of Houston Law Center. All rights reserved.
Less: Allowance for Impairment ............  10,000
                                   $30,000

If acquisition costs are not individually significant, assessing impairment on an individual property basis may not be practical. In that case, impairment should be calculated by amortizing individually insignificant properties on a group or aggregate basis. This calculation is similar to that of providing an allowance for bad debts. The percentage used in calculating impairment may be based on the historical experience of the company and factors such as the primary terms of the involved properties, the average holding period of insignificant unproved properties, and the historical percentage of such properties that have been proved.

In the following example, the amount of impairment is determined by applying the impairment percentage to the total balance of individually insignificant unproved properties being assessed on a group basis. The resulting dollar figure is the desired balance of the impairment allowance account. The amount of impairment recognized is the difference between the ending balance in the impairment allowance account before impairment and the desired balance.

Example -- Impairment of Insignificant Properties

On December 31, 1993, the unproved property account containing leases that are not individually significant had a $100,000 balance and the allowance for impairment account has a $20,000 balance. Past experience indicates that 65% of all insignificant unproved properties are eventually abandoned. Therefore, U.S. Oil Company has a policy of providing at year end an allowance equal to 65% of gross unproved properties.

Entry

The amount of $45,000 should be recorded as lease impairment expense. Also, the allowance for impairment account should be increased by $45,000.

Calculations

\[
\begin{align*}
$100,000 \times 0.65 &= $65,000 \\
\text{Allowance} &= 20,000 \\
\text{45,000 (adjustment)} &= 65,000 \text{ balance needed}
\end{align*}
\]

This example provides an allowance equal to the total amount of unproved properties expected to be abandoned, a very conservative approach. An approach yielding an amount closer to the actual amount of unproved properties abandoned might take into account the average holding period for insignificant properties and the average period for which the current properties have been held.

All the individually insignificant properties of a company may be amortized together in one group or the properties may be grouped into different groups with each group being amortized...
separately. Groupings being used in practice include country by country, state by state, geological prospect, or onshore versus offshore.

If a property is a joint working interest property, each working interest owner makes a separate decision whether the property is significant and how or if to impair the property. Even if all the working interest owners assess a property on an individual basis, each party could legitimately decide on a different amount of impairment based on their future plans for the property. For example, one party's geologist may, after examining data concerning the property, decide on full impairment while another party's geologist may feel the lease has potential and recommend no impairment.

Unproved property should be assessed individually or in the aggregate at least once a year. Once impairment has been recognized on a property, it should not be subsequently written back up.

Disposition of Capitalized Costs -- Surrender or Abandonment of Property

The actual abandonment of a property may be accomplished in one of several ways. Failure to begin drilling or production operations before the end of the primary term automatically terminates the lease. In some situations, property may be abandoned before the date of the next delay rental payment or before the end of the primary term.

When unproved property is surrendered or abandoned, the capitalized acquisition costs should be charged against the related allowance for impairment account. If the allowance account is inadequate, the excess should be charged to surrendered lease expense. For properties assessed individually, abandonment results in the net carrying value (acquisition cost minus impairment allowance) of the abandoned property being expensed.

Example --Abandonment of Significant Properties

U.S. Oil Company abandoned the following unproved properties, all assessed individually.

<table>
<thead>
<tr>
<th>Lease</th>
<th>Acquisition cost</th>
<th>Impairment Allowance</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>$50,000</td>
<td>$50,000 (100% impaired)</td>
</tr>
<tr>
<td>B</td>
<td>80,000</td>
<td>20,000 (25% impaired)</td>
</tr>
<tr>
<td>C</td>
<td>70,000</td>
<td>0</td>
</tr>
</tbody>
</table>

Entries

LEASE A
Both the unproved property and the impairment allowance accounts would be eliminated. There is no expense to record.

LEASE B
Both the unproved property and the allowance for impairment accounts would be eliminated. A $60,000 expense should be recorded for surrendered lease expense.

LEASE C
The unproved property account would be eliminated and $70,000 should be recorded for surrendered lease expense.

For abandonment of individually significant unproved properties assessed on a group basis, the entire unproved property amount should be charged against the allowance for impairment account, group basis. The allowance account should normally be adequate; however, in the event it is inadequate, such as at the end of the year, the excess of the abandoned property over the allowance account should be charged to surrendered lease expense.

**Example -- Abandonment of Insignificant Properties**

During December, U.S. Oil Company abandoned two unproved leases that had been assessed on a group basis. Being near the end of the year, the impairment allowance for individually insignificant properties had only a $30,000 balance. Data for the abandoned leases are as follows:

<table>
<thead>
<tr>
<th>Lease</th>
<th>Acquisition Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>D</td>
<td>$10,000</td>
</tr>
<tr>
<td>E</td>
<td>25,000</td>
</tr>
</tbody>
</table>

**Entries** (assume Lease D was abandoned first)

LEASE D
Reduce the allowance for impairment by $10,000. Eliminate the unproved property - Lease D account.

LEASE E
Eliminate the allowance for impairment and unproved property - Lease E. $5,000 should be recorded as surrendered lease expense.

Partial abandonment may occur when a company surrenders part of a property but continues paying delay rental payments on the remaining acreage. The following example illustrates a partial abandonment.

**Example -- Partial Abandonment**

U.S. Oil Company leased 5,000 acres. The lease stipulated that U.S. Oil Company could surrender a portion of the lease and pay delay rentals on the remainder. Surrendered portions were required to be in 1,000-acre tracts. The original lease bonus was $40 per acre and the delay rental payments were to be made in the amount of $2 per acre. At the end of the second year,
U.S. Oil Company surrendered 2,000 acres and paid a delay rental amount on the remaining 3,000 acres.

**Entries**

The unproved property account should be reduced by $80,000 and surrendered lease expense of $80,000 should be recorded.

Surrendered lease expense ($40 x 2,000 acres) = $80,000

Delay rental expense ($2 x 3,000 acres) = $6,000

A delay rental expense of $6,000 should be recorded.

**Post-Balance Sheet Events**

Information that becomes available after the end of the period covered by the financial statements but before those financial statements are issued shall be taken into account in evaluating conditions that existed at the balance date, for example, in assessing unproved properties and in determining whether an exploratory well has found proved reserves. For example, dry holes completed during the interim period (after the balance sheet date but before the audit report date) may determine whether impairment has occurred or whether the property should be abandoned. The impairment or abandonment amounts should be reflected in the financial statements at fiscal year end. These changes are accomplished by adjusting entries recognizing impairment or abandonment.

**Example—Post-Balance Sheet Events**

U.S. Oil Company has unproved property costs on Lease A of $12,000 at December 31, 1993. On January 18, 1994, prior to the issuance of audited financial statements, a well was determined to be dry and was plugged and abandoned on an adjacent lease owned by another party. No impairment on Lease A had been taken on December 31, 1993. Due to the dry hole on the adjacent property, management now estimates that Lease A was impaired 60% at December 31, 1993. Prepare any additional adjusting entries necessary for the year ending December 31, 1993.

**Entry**

A $72,000 impairment expense should be recorded and allowance for impairment should be increased by $7,200.

Impairment expense ($12,000 x 60%) = $7,200

**Disposition of Capitalized Costs - Reclassification of an Unproved Property**
When proved reserves are discovered on an unproved or undeveloped property, the property should be reclassified from an unproved property to a proved property. For property that has been assessed individually, the net carrying value should be transferred to proved property.

**Example -- Reclassification of Significant Properties**

U.S. Oil Company discovered proved reserves on the following unproved properties, all assessed individually.

<table>
<thead>
<tr>
<th>Lease</th>
<th>Acquisition Costs</th>
<th>Impairment Allowance</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>$ 150,000</td>
<td>$ 0</td>
</tr>
<tr>
<td>B</td>
<td>100,000</td>
<td>25,000</td>
</tr>
</tbody>
</table>

**Entries**

**LEASE A**
The entire amount of $150,000 should be transferred from unproved property to proved property.

**LEASE B**
Proved property should have $75,000 recorded. The unproved property and the allowance for impairment accounts should be reduced to a zero balance.

For a property assessed on a group basis, the gross acquisition cost should be transferred when reclassifying the property because a net carrying value cannot be determined on a separate property basis for properties based on a group basis.

**Example – Reclassification of Insignificant Properties**

U.S. Oil Company discovered proved reserves on a lease that had been assessed on a group basis. The acquisition cost of the property was $30,000, and the impairment allowance for individually insignificant properties had a balance of $200,000.

**Entry**

$30,000 should be transferred from unproved property to proved property.

For a property to be proved, it is not necessary that the entire property be classified as a proved area, only that proved reserves are found on the property. Thus, only a very small portion of a proved property may actually be a proved area. As a result, it is still possible to drill an exploratory well on a proved property.

Occasionally, a property is so large that only the portion of the property to which the proved reserves relate should be reclassified from unproved to proved. An example is a foreign lease or
concession; some authorities state that this would also be true for small properties with a very high cost or for certain offshore properties whose development requires multiple wells.

**Example -- Partial Reclassification**

U.S. Oil Company has an offshore lease with the government that costs $2,000,000. This lease covers four tracts of 6,400 acres each. Proved reserves are found on one tract. Management decides to reclassify only one-fourth of the lease.

**Entry**

The amount of $500,000 should be transferred from unproved property to proved property.

\[
\text{Proved property} \times \frac{1}{4} = 500,000.
\]

**Land Department**

The land department of an oil company usually is responsible for property acquisition and property administration. The exploration and legal departments are also concerned with these functions. The exploration department is responsible for recommending property acquisition, retention, development, or abandonment. The legal department conducts title examinations and title litigation and approves or prepares any legal documents.

The land department acts on information obtained from the exploration department's activities and from land department scouts in acquiring properties. Subscription services and information exchanges provide additional information to the land department.

The actual acquisition of properties is negotiated by landmen. Landmen also promote trades, joint ventures, unitizations, and various types of sharing arrangements.

The land department is responsible for recording and maintaining basic records on properties, ensuring that all contractual obligations in the lease contract are fulfilled, and preparing various types of reports. An example of an important contractual obligation is the delay rental payment. It is very important that the record system give adequate notice of leases due for rental payment because failure to pay delay rentals when due will result in the lease terminating.
CHAPTER 4
EXPLORATION ACTIVITIES--DRILLING AND DEVELOPMENT
LEARNING OBJECTIVES

Chapter 4 discusses the exploration activities of drilling a well. Studying this chapter should enable you to:

1. Describe the types of drilling contracts.
2. Discuss the preparation of the drill site.
3. Describe the basic components of a rotary drilling rig.
4. Describe the various procedures that take place during the drilling process.
EXPLORATION ACTIVITIES - DRILLING AND DEVELOPMENT

Exploration activities encompass many methods used in the search for oil and gas reserves. The geologist, through the use of various geological and geophysical techniques, plays a major role in the oil and gas search. Such G&G methods become an integral part in determining well site locations. Once the G&G tests are completed, the next major step in the exploration process is the actual drilling of the well. Determination as to whether hydrocarbons exist in a discovered trap can be made only by drilling. It is for this reason that a low success ratio for finding oil and gas reserves in commercial quantities exists. In that drilling the well is so important to the oil and gas producing company, and because of the increasing costs related to such drilling, it is necessary that the oil and gas accountant have a general understanding as to what is involved in the drilling of a well. Such an understanding will provide for a better foundation for learning how to account for the related exploration costs.

Drilling Contractors

Some of the larger oil and gas producing companies drill their own wells, but in the majority of cases, most companies will hire drilling contractors to perform the drilling of a well. Due to the costly type of equipment needed and the high level of experience required, it is usually more expedient and economical to hire an outside drilling contractor.

Types of Contracts

Because the outside drilling contractor is hired, different types of contracts have been used between the driller and the oil and gas producing company. In past years, a common type of contract was the turnkey drilling contract which provides for payment at a fixed price for the drilling of a well. Due to the increasing costs of drilling and the increasing demands for drilling rigs, the drilling contractor does not use the turnkey contract as often. Instead, such contracts as the footage drilling contract, which provides for payment at a specified price per foot, or the day-rate contract, which provides for payment at a specified price per day, are used. Though these contracts can result in a higher cost for the drilling of the well, the drilling contractor is better protected from economic loss. In addition, if the demand for drilling rigs becomes high, the drilling contractor holds the leverage necessary for requesting the contracts other than turnkey.

The Crew Members of a Drilling Rig

Though the number of people on a drilling crew can vary, for most land rigs there are from six to seven crew members. They are:

1. The tool pusher,
2. The driller,
3. The derrickman,
4. Two to three floormen or roughnecks, and
5. The motorman.
For offshore operations, more crew members are required due to the complexity of the operations. Thus, in addition to the crew members mentioned above, several roustabouts are hired for the handling of equipment and supplies.

The toolpusher is the individual who supervises all drilling operations at several drill sites. The driller, reporting directly to the toolpusher, is the supervisor of the individual drill-site crew. He also operates the drilling machinery on the rig floor through use of a control panel. The derrickman works on a small platform located up in the derrick, known as a monkeyboard. Drill pipe is in thirty-foot lengths. When the drill pipe is taken out of the well bore (tripping out), usually for the changing of a dull drill bit, it is normally done so in units of three (ninety feet). Thus the derrickman handles the upper end of the pipe directing it to and from the well bore opening. While drilling is going on, the derrickman also has the responsibility of maintaining the drilling mud mixture and its related equipment. The roughnecks are responsible for general maintenance of the drill site and the handling of the lower end of the drill pipe when tripping in or out of the well bore. Finally, the motorman is responsible for the maintenance of the engines providing the drilling rig the necessary power. Drilling goes on twenty-four hours a day, seven days a week. Therefore, there are usually four crews available for each rig. Three crews each work eight-hour shifts with the fourth crew taking time off. Due to the high costs involved, a company cannot afford to shut down operations and thus drill less than a twenty-four hour day.

Cable-Tool Drilling

In past years, two types of drilling methods were used in searching for oil and gas reserves. The first type is known as cable-tool drilling. The drilling bit is attached to a cable and is picked up and dropped many times until the desired depth is reached. Drilling has to often stop, however, to remove the cuttings made by the bit.

Rotary Drilling

Rotary drilling is the second type and currently the more predominant method of drilling. Pipe, instead of wire, is run through a rotating machine called the rotary table. A drilling bit is attached to the pipe and when the rotary table turns, the pipe and bit rotate thus drilling the well bore. The advantage of rotary drilling is that drilling fluid or mud can be pumped down through the drill pipe and bit and back up to the surface. This drilling mud is a mixture of clay, water, and chemicals, which cool the bit, carry the cuttings of the drilling to the surface, and prevent the well bore from caving in while drilling. In that the cuttings can be removed without having to remove the drill pipe, drilling operations are much faster than those of the cable-tool drilling rig.

Preparing the Drill Site

Once the geological and geophysical tests have been completed and a drill site location chosen, the next step is preparing the site for drilling. Such preparation includes:

1. Building of access roads (if necessary),
2. Clearing and leveling the drill site area,
3. Digging disposal pits for the well cuttings,
4. Digging the rectangular pit (cellar) over which the drilling rig will sit,
5. Digging the 'rathole' which is a hole that stores the six-sided steel pipe known as the
   'kelly' (the kelly is connected to the drill pipe at the surface turning the drill stem when the
   rotary table turns),
6. Digging the 'mouse hole' which is a hole that temporarily stores a drill stem joint being
   readied for coupling to the stem,
7. Drilling water service wells and salt water disposal wells, and
8. Installing the rig components.

Components of the Rig

The components of the rig are complex and a detailed discussion of such systems is beyond the
scope of this course. The accountant, however, should be aware that the basic systems of the
rotary rig are:

1. The power system (the engines of the rig),
2. The rotating system (including the rotary table, kelly, drill string or pipe, bits and more),
3. The hoisting system (including drawworks, the derrick, wire lines and other equipment used
to raise and lower the drill pipe in and out of the well bore), and
4. The circulating system (including the tanks, shale shaker, mud pits, pumps, and any other
equipment related to the drilling mud circulated through the well bore for cave-in prevention,
cooling, and cutting removal).

Cutting Analysis

As the well is drilled, cuttings from various depths are analyzed to evaluate the formations of the
geologic structure. At times, based on this analysis, casing or hollow pipe must be lowered into
the well bore and cemented to prevent possible cave-in. Drilling is then continued by lowering
the drill string down inside the casing.

Well Logs and Drill-stem-Test

The cuttings are also analyzed to determine possible oil or gas content. Electrical well logs can
be processed to analyze the formation by lowering logging tools into the well bore on a wire line.
In order to measure the pressure and fluids of a formation, a drill-stem test can be made by
lowering a drill-stem tool to the bottom of the well bore, and through the use of an expandable
rubber packer, production can be simulated as though the well were completed.

Actual completion of the well is the next step, if it is, determined that reserves can be
commercially produced. Often times, production casing is cemented in the well bore both to
prevent cave-in and to protect water deposits from being contaminated by the oil and gas due to
seepage.
Perforation, Tubing and Christmas tree

Since the casing is cemented in, the casing and the cement must be perforated at the productive zone to allow the oil or gas to flow into the well bore. Perforation is commonly accomplished by lowering bullet-like charges to the productive zone which are then fired forcing the shaped charges through the casing and cement into the reservoir. Tubing is lowered inside the casing through which the reserves flow. The Christmas tree or control valves are positioned at the surface of the well bore to control the flow of the reserves if sufficient natural drive pressure exists. Otherwise a pump can be installed for the artificial lift of the reserves.

Acidizing and Fracturing

If permeability is low, either an acidizing process may be used which is a method of dissolving the rocks of the formation with acid, or a fracturing process can be implemented which forces fluid into the formation under great pressure causing the formation to literally crack open. Decisions as to the use of such methods are those of the production engineer.

Once completed, the well begins production and the exploration phase of the oil and gas producing company comes to an end for that particular area.

PETROLEUM ENGINEERING

The oil and gas producing industry employs the work of many professionals in its operations. In order to understand these operations and thus be able to properly account for the related costs, the oil and gas accountant should be familiar with the work of each professional in the industry. Thus far we have discussed the work of the petroleum geologist, presented the duties of the landman, and discussed the responsibilities and work performed by the drilling crew. The accountant must work closely with all of these professionals to allow for a profitable operation. A key individual of this team of professionals, yet to be discussed, is the petroleum engineer. Like the petroleum geologist, the work of the petroleum engineer can be part of several phases of the industry's operating cycle.

Types of Engineers

Before the job of the petroleum engineer can be discussed, it is necessary to differentiate among the types of petroleum engineers working in the oil and gas producing industry. There are basically three types of petroleum engineers. They are:

1. The drilling engineer,
2. The production engineer, and
3. The reservoir engineer.

Duties of the Drilling Engineer

The drilling engineer is responsible for all engineering matters pertaining to drilling. The duties of the drilling engineer include:
1. Preparation of authorities for expenditure (AFE’s), which are basically budgets for the drilling of a well,

2. Evaluation of the performance of drilling crews, equipment, and suppliers,

3. Recommendation of economical and efficient drilling operations,

4. Evaluation and compilation of drilling information acquired during the drilling operation,

5. Compliance with governmental regulations affecting drilling operations, and

6. Evaluation of potential drilling programs in which the company can participate.

The drilling engineer is very involved with the drilling operations. In simpler terms, this engineer directs the drilling operations until the determination is made that the well is commercially productive and the well is completed as a producer.

**Duties of the Production Engineer**

If commercially productive reserves are located, the production engineer is then called upon to plan, monitor, and coordinate field engineering activities. The duties of the production engineer can include:

1. Evaluation of the performance of each well, recommending economical and efficient maintenance and operating procedures (e.g., use of pumps, workovers, water disposal, etc.),
2. Obtaining and reporting completion and production data,
3. Submitting completion programs for development and secondary recovery wells,
4. Supervision of field operations related to development drilling, workovers, new completions, etc., and
5. Compliance with governmental regulations affecting production operations.

**Reserve Recovery**

It is the production engineer that develops the production from a reservoir to its greatest potential. One hundred percent of a reservoir's oil and gas reserves can never be produced, in that there will always remain some deposits in the pores of the formation. When oil and/or gas is produced, often times natural drives (that is, gas or water) can provide the pressure to force the reserves to the surface. If the natural drive is insufficient, the production engineer can use surface and subsurface pumping units. Even these units, however, cannot deplete the entire reservoir. Secondary recovery methods such as drilling additional wells in the reservoir and
forcing water down through these wells to wash the reserves up through the producing wells can be designed by the production engineer. To enhance recovery even more, the production engineer can employ tertiary methods which basically floods the reservoir with detergent-like solutions forcing the reserves up through the producing well bores. Yet the tertiary methods cannot remove all reserves. The situation can be correlated with the pouring of motor oil on a paved street. The motor oil can first be wiped up with a sponge, yet some will still remain. The area can then be hosed down with water and some motor oil will still be present on the pavement. Even after scrubbing the area with soap, not all of the oil that was originally poured can be removed from the pavement. Because the production engineer is continually trying to determine new and better ways to remove as much of the reserves of a reservoir as possible, the challenges and complexities of the task are forever growing.

The Reserve Report

As the drilling engineer and the production engineer are working to discover and produce oil and gas reserves, the oil and gas producing company and its investors must be informed on a current basis as to how much reserves have already been discovered and are to be produced. The importance of such estimates cannot be stressed enough. The future of the company rests on such estimates. Much of the work of the oil and gas accountant depends on these reserve estimates in computing depletion, depreciation, and amortization (DD&A), and determining impairment problems.

It is the reservoir engineer who is involved in the determination of reserve estimates. Once these estimates are made, they are reported in a “reserve report.” This report becomes a key document affecting the accountant’s calculations. Due to the importance of the report, every possible step should be taken in verifying the estimated data.

Methods of Estimating Reserves

In making reserve estimates, the reservoir engineer can employ different methods. If a well is newly discovered, thus having no production history, volumetric can be used which basically determines the volume of space that the reservoir has for holding the reserves and then adjusting such volume for those amounts of reserves that cannot be drawn from the ground, as discussed earlier in the example of the motor oil being poured on a paved street. Analogies can also be made in determining reserve estimates by comparing the well being analyzed to other wells in the area, studying the other wells’ production history and estimates. Various mathematical models can be employed. Finally, as the well produces over a longer period of time the performance history of the well itself can be studied in projecting future recoverable reserves and the related rate of production of those reserves.

Estimates of reserves are just that - 'estimates.' There is no definitive way to calculate the exact number of recoverable reserves of a designated reservoir. The reservoir engineer can, however, approximate such reserves, and based on current technical expertise provide reasonable estimates. These estimates are subject to change as more well data is compiled, but these gray areas are what makes the work of the reservoir engineer most interesting.
The presentation of the work of the petroleum engineer in this chapter has been rather clear cut. It should be understood, however, that the responsibilities of these engineers can overlap and commingle, for the activities of the oil and gas producing company are many, ongoing, and complex. In fact, for the smaller companies, one engineer may perform the functions of the three engineers described. This is not to lessen, however, the position of the petroleum engineer, for as stated earlier the engineer, like the other members of the industry's professional teams, is an integral part of the oil and gas producing company's operating cycle.
CHAPTER 5
DRILLING AND DEVELOPMENT COST UNDER SUCCESSFUL EFFORTS
LEARNING OBJECTIVES

Chapter 5 discusses various drilling and development costs and how they are recorded under successful efforts. Studying this chapter should enable you to:

1. Identify the difference between intangible drilling costs (IDC) and equipment costs.
2. Identify the various costs incurred during exploratory drilling.
3. Describe the accounting procedures used to record exploratory drilling costs.
4. Understand AFEs and drilling contracts.
5. Discuss and understand work over cost and the accounting procedures used to record these costs.
6. Describe support equipment and facilities and the accounting procedures used to record these costs.
7. Discuss post-balance sheet events.
8. Understand interest capitalization.
DRILLING AND DEVELOPMENT COSTS UNDER SUCCESSFUL EFFORTS

Under successful efforts accounting, a direct relationship is required between costs incurred and specific reserves discovered before costs are ultimately identified as assets. Consequently, with respect to exploration costs, only successful exploration costs incurred in the search for oil and gas are considered to be a part of the cost of finding oil or gas. In contrast, development costs, both successful and unsuccessful, are considered to be a part of the cost of oil or gas because the purpose of development activities is considered to be building a producing system of wells and related equipment and facilities rather than searching for oil and gas.

Therefore, the cost of drilling an exploratory well is expensed if the well is dry and capitalized if the well is successful, while the cost of drilling a development well is always capitalized regardless of the outcome of the well. Despite this disparity between the final accounting treatment for exploratory drilling and development drilling, preliminary accounting for the costs of drilling a well, that is, accounting for drilling in progress, is the same whether the well is an exploratory well or a development well.

Intangible Drilling and Development Costs

Drilling and development costs are classified as either intangible drilling and development costs (IDC) or equipment costs (lease and well equipment). Costs which are classified as IDC include any cost which in itself has no salvage value and which is incident to and necessary for the drilling of wells and the preparation of wells for the production of oil and gas. These expenditures include wages, fuel, repairs, hauling, and supplies that are used in:

a. Clearing of ground, drainage, roads, surveying well site, and geological work in preparation for drilling.

b. Construction of derricks, tanks, pipelines, and other physical structures needed for drilling wells and preparing them for production.

c. Drilling, cleaning, shooting, cementing, logging, perforating, testing, acidizing, mud, etc.

Note that the definition includes the installation costs of tangible equipment placed in the well, but not the cost of the equipment itself. The definition excludes expenditures for installation of equipment, structures, etc., used in producing, storing, and testing gas and oil.

A list of common IDC items is given below. The list is not intended to be exhaustive.

a. COSTS PRIOR TO DRILLING

(1) Work performed by the geologist to determine exact location of drill site (not G&G work discussed earlier).

(2) Bulldozer costs for clearing well site; digging slush pits; building roads; survey costs involved in staking well location.

(3) Cost of pads (gravel, etc.) for drilling rig; cost of bridges.
(4) Laying flow lines for water to be used in drilling; installation of tanks for water and fuel for drilling purposes.

(5) Moving and erecting drilling rig (if company owned).

(6) Constructing racks for drill pipe and other tubular goods to be used in the drilling process.

b. COST INCURRED DURING DRILLING

(1) If the well is drilled by a contractor, the contractor's bill will constitute the majority of the IDC costs in the category. The drilling mud and possibly other items may represent an additional charge to the operator.

(2) If the well is drilled by the operator's rig, then the wages paid the crew, drilling rig maintenance and supplies, depreciation on the rig, mud, water, fuel, power, chemicals, bits, reamers, and company overhead related to the operation of the rig will represent IDC charges.

c. COST INCURRED TO COMPLETE

(1) Drill stem tests, well logging, and other testing such as cores and side wall sampling.

(2) Perforating, cementing, fracturing, acidizing.

(3) Transportation and installation of subsurface equipment.

d. CHARGES INCURRED FOLLOWING COMPLETION OF THE WELL

(1) Removing drilling equipment from the location (of operator owned).

(2) Restoring the land by filling slush pits and grading the areas.

(3) Surface damages.

(4) Plugging and abandonment costs (if the well is a dry hole).

It should be noted that it is usually considered that all labor and other installation costs incurred in completing the well up to and including the “Christmas tree” are IDC items, but the costs of installing equipment after that point represent tangible equipment costs.

In general, equipment costs include all tangible or salvageable costs of drilling and development before the Christmas tree, plus both intangible and tangible costs past the Christmas tree. Note that neither the word salvageable nor the word tangible is completely correct in defining which costs are IDC rather than equipment. Tangible costs such as casing, which may not be
salvageable, are still considered equipment. On the other hand, tangible costs such as
cement or drilling mud, which are not salvageable, are considered to be IDC. The
distinction appears to be whether a tangible cost in itself has a salvage value.
IDC and equipment costs may be diagrammed as follows:

<table>
<thead>
<tr>
<th>Begin drilling</th>
<th>Christmas tree</th>
</tr>
</thead>
<tbody>
<tr>
<td>Intangible costs = IDC</td>
<td>Intangible costs = equipment</td>
</tr>
<tr>
<td>Tangible costs = equipment</td>
<td>Tangible costs = equipment</td>
</tr>
<tr>
<td>Labor incurred during this stage to install equipment or to build an access road would be IDC.</td>
<td>Labor incurred during this stage to install equipment or to build an access road would be an equipment cost.</td>
</tr>
</tbody>
</table>

As can be seen from the diagram, the purpose for constructing a lease road determines whether the costs of constructing the road are considered IDC.

**Example—IDC versus Equipment**

a. U.S. Oil Company incurred acquisition (purchase) costs of $5,000 for casing and installation costs of $1,000. Casing is subsurface well equipment and is therefore before Christmas tree.

IDC = $1,000, installation costs
Equipment = $5,000, purchase cost

b. U.S. Oil Company purchased flow lines and storage tanks for a cost of $10,000. Installation costs were $2,000. Flow lines and tanks are nonwell equipment and are past the Christmas tree.

IDC = $0, all costs are considered to be equipment costs since this is past the Christmas tree
Equipment = $12,000, purchase cost and installation costs.

c. U.S. Oil Company incurred $15,000 in labor costs in building an access road to a drill site. This cost is related to drilling a well and is therefore before the Christmas tree.

IDC = $15,000
Equipment = $0

d. U.S. Oil company incurred $15,000 in labor costs in building an access road to a producing well. This cost is past the Christmas tree.

IDC = $0, all costs are considered to be equipment costs since this cost is past the Christmas tree.
Equipment = $15,000
As stated earlier, because of the importance of the classification of costs as either intangible drilling and development costs or equipment costs, the distinction between IDC and equipment costs is usually made for financial accounting.

**Exploratory Drilling Costs**

Exhibit 5-1 diagrams the accounting treatment of all five types of exploration costs. The two types, (1) the costs of drilling and equipping exploratory wells and (2) the costs of drilling exploratory-type stratigraphic test wells, are discussed here and are to be accounted for as follows:

The cost of drilling exploratory wells and the costs of drilling exploratory-type stratigraphic test wells shall be capitalized as part of the enterprise's uncompleted wells, equipment, and facilities, pending determination of whether the well has found proved reserves. If the well has found proved reserves, the capitalized costs of drilling the well shall become part of the enterprise's wells and related equipment and facilities (even though the well may not be completed as a producing well); if, however, the well has not found proved reserves, the capitalized costs of drilling the well, net of any salvage value, shall be charged to expense.

The following example illustrates typical drilling and completion costs and their accounting treatment under successful efforts. As shown in the example, drilling costs are temporarily classified as (1) wells in progress-IDC or (2) wells in progress-lease and well equipment. When drilling reaches the targeted depth, a decision must be made as to whether the well has found proved reserves or not.

If proved reserves have been found, both wells in progress account balances will be transferred to wells and related equipment and facilities accounts. In addition, if the well is the first successful exploratory well drilled on the property, the unproved property account will be reclassified or, transferred into a proved property account because proved reserves have been found and are now attributed to that property.

If proved reserves have not been found, the well must be plugged and abandoned. The costs of plugging and abandonment, in addition to the capitalized costs in the wells in progress accounts (net of any salvaged equipment), must be written off to dry-hole expense. If the lease is also abandoned, the amount capitalized as unproved property will be written off as surrendered lease expense.
Exhibit 5-1
Successful Efforts, Exploration Costs

Incur Exploration Costs includes two categories:

1. G&G costs, costs of carrying and retaining undeveloped properties, dry- and bottom-hole contributions, and
2. costs of drilling exploratory wells

Type 1
nondrilling

Type 2
drilling

Classify temporarily as uncompleted wells, equipment, facilities

STOP

Expensed

Dry

Successful

Classify well as dry or successful

Capitalize as wells and related equipment and facilities

Add costs to amortization base (cost center is reservoir, field, or lease)

Amortize on basis of production (proved developed reserves)

Amortization of acquisition costs (proved reserves)

Cost of oil and gas produced

Amortization of development costs (proved developed reserves)

Production costs

Stop
Example Problem

a. On January 2, 1992, as a result of G&G work done in 1991, U.S. Oil Company decided to lease 1,000 acres at $20 per acre. The lease was undeveloped.

Entry

Capitalize $20,000 as unproved property.

b. Early in 1992, U.S. Oil Company decided to begin drilling operations and incurred G&G costs of $5,000 to select a specific drill site.

Entry

A temporary asset account (wells in progress - IDC) should be capitalized for $5,000.

c. In preparing the drill site, U.S. Oil Company incurred costs of $2,000 in clearing and leveling the site and building an access road. (The activities normally would be performed by a drilling contractor).

Entry

Capitalize the $2,000 into the Wells in Progress - IDC account.

d. Additional preparation costs of $4,000 were incurred in digging a mud pit and installing a water line. Pipes for the water line cost $2,000. (These activities normally would be performed by a drilling contractor.)

Entry

The $4,000 cost for preparation should be capitalized into wells in progress. The $2,000 costs for water line (a tangible item) should be capitalized into a new account: wells in progress - lease and well equipment.

e. U.S. Oil company purchased pipe and casing for the well at a cost of $6,000.

Entry

Capitalize the $6,000 into wells in progress - lease and well equipment.

f. U.S. Oil Company had hired a drilling contractor on a footage-rate contract and, as is usual in such an agreement, payment was contingent upon the contractor drilling to a specified depth. The depth was reached and U.S. Oil company paid the contractor $40,000.

Entry
Capitalize the $40,000 payment into wells in progress - IDC.

g. In evaluating the well, U.S. Oil Company incurred costs of $8,000. A well log was run and a drillstem test was made.

**Entry**

Capitalize the $8,000 cost into wells in progress - IDC.

h. U.S. Oil Company decided to complete the well and paid $4,000 for casing for the well and $3,000 for cementing services.

**Entry**

Capitalize the $4,000 cost for casing into wells in progress - lease and well equipment.
Capitalize the $3,000 cost for cementing into wells in progress - IDC.

i. U.S. Oil Company incurred acquisition (purchase) costs of $2,100 for a Christmas tree and installation costs of $300.

**Entry**

Capitalize the $2,100 cost of the Christmas tree into wells in progress - lease and well equipment.
Capitalize the $300 installation cost into wells in progress - IDC.

j. U.S. Oil Company incurred $2,000 for perforating and acidizing services.

**Entry**

Capitalize the $2,000 cost into wells in progress - IDC.

k. The work on the well is finished and proved reserves have been found. Two entries are necessary: one to transfer the cost of the well from an unfinished goods account to a finished goods account and one to reclassify the lease as proved.

**Entry 1**

Two permanent asset accounts are now used:
(1) Wells and related equipment - IDC
(2) Wells and related equipment - lease and well equipment.

Transfer $64,300 from well in progress - IDC to wells and related equipment - IDC. Transfer $14,100 from wells in progress - lease and dwell equipment to wells and related equipment - lease and well equipment.
CALCULATION:

<table>
<thead>
<tr>
<th></th>
<th>W/P - IDC</th>
<th>W/P L&amp;WE</th>
</tr>
</thead>
<tbody>
<tr>
<td>b</td>
<td>5,000</td>
<td>d. 2,000</td>
</tr>
<tr>
<td>c</td>
<td>2,000</td>
<td>e. 6,000</td>
</tr>
<tr>
<td>d</td>
<td>4,000</td>
<td>h. 4,000</td>
</tr>
<tr>
<td>f</td>
<td>40,000</td>
<td>i. 2,100</td>
</tr>
<tr>
<td>g</td>
<td>8,000</td>
<td>Balance</td>
</tr>
<tr>
<td>h</td>
<td>3,000</td>
<td></td>
</tr>
<tr>
<td>i</td>
<td>300</td>
<td></td>
</tr>
<tr>
<td>j</td>
<td>2,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Balance</td>
<td>64,300</td>
</tr>
</tbody>
</table>

**Entry 2**

Transfer the $20,000 acquisition costs from unproved property to proved property.

l. U.S. Oil company purchased pipes (flow line to lease tanks), storage tanks, and separators for a cost of $15,000. Installation costs were $1,000.

**Entry**

Both the cost of equipment ($15,000) and the installation cost ($1,000) should be capitalized to wells and related equipment - lease and well equipment.

Note that the cost center under successful efforts is a lease or field, not an individual well.

m. If instead, after evaluating the well in part g, U.S. Oil Company had decided the well as dry, only costs in parts a-g would have been incurred and the entry to record the dry hole would have been:

**Entry**

Wells in progress - IDC ($59,000) and wells in progress - lease and well equipment ($8,000) would both be transferred to dry-hole expense.

n. Costs of $2,000 were incurred in plugging and abandoning the hole.

**Entry**

The $2,000 cost should be charged to dry-hole expense.

Note that it is important to distinguish between abandonment of the well and abandonment of the lease. In this case only the well had been abandoned and therefore no entry would be made relating to the lease, that is, the unproved or proved property account.

**Development Drilling Costs**
Development costs shall be capitalized as part of the cost of an enterprise's wells and related equipment and facilities. Thus, all costs incurred to drill and equip development wells, development-type stratigraphic test wells, and service wells are development costs and shall be capitalized, whether the well is successful or unsuccessful. Costs of drilling those wells and costs of constructing equipment and facilities shall be included in the enterprise's uncompleted wells, equipment, and facilities until drilling or construction is completed.

Most of the entries (a through k) in the above example would have been the same if the well had been a development well. Only three entries-k2, m, and n-would have been different. If the well had been a development well instead of an exploratory well, it would have been drilled by definition in a proved area. Therefore, entry k2, reclassifying the property, would not have been made. Instead, the reclassification to proved property would have been made at an earlier time when proved reserves were first discovered on the property.

Entries m and n assumed a dry hole and recorded a dry-hole expense. If the well had been a development well, these costs would have been capitalized, regardless of the well's outcome, as wells and related equipment and facilities.

Exhibit 5-2 outlines the flow of development costs. A brief example that illustrate the accounting for a development well follows.

Example

During 1991 and 1992, U.S. Oil Company drilled several successful exploratory wells on lease A. As a result, Lease A was classified as a proved property and the estimated boundaries of the reservoir were delineated. U.S. Oil Company decided in 1993 to drill an additional well within the proved area—a development well—and hired a drilling contractor under a turnkey contract. The drilling contract specified that the contractor was to perform all services and furnish all materials up to completion.

a. The well is drilled and equipped to the point of completion, and U.S. Oil Company pays the contractor the agreed upon amount of $150,000. Of this $150,000, IDC was $120,000 and equipment costs were $30,000.

Entry

Capitalize $120,000 into wells in progress - IDC.

Capitalize $30,000 into wells in progress - lease and well equipment.

b. Assume the well was determined to be dry and plugged and abandoned for an additional $2,000.

Entry to record plugging and abandoning costs
Capitalize $2,000 into wells in progress - IDC.

**Entry to record completion of work on well, that is, to close out W/P accounts**

Transfer $122,000 from wells in progress - IDC to wells and related equipment - IDC.

Transfer $30,000 from wells in progress - lease and well equipment to wells and related equipment - lease and well equipment.

c. Assume instead that the well was successful and that additional IDC of $15,000 and equipment costs of $70,000 were incurred to complete the well

**Entry to record completion costs**

Capitalize $15,000 into wells in progress - IDC. Capitalize $70,000 into wells in progress - lease and well equipment.

**Entry to record completion of work on well**

Transfer $135,000 from wells in progress - IDC to wells and related equipment - IDC. Transfer $100,000 from wells in progress - lease and well equipment to wells and related equipment - lease and well equipment.
Exhibit 5-2

Successful Efforts, Development Costs

- Incur development costs
  - includes costs to gain access to and prepare well locations, to drill and equip wells, and to provide production facilities and improved recovery systems
  - Classify until completed as uncompleted wells and equipment and facilities
  - Work completed
  - Capitalize as wells and related equipment and facilities
  - Add costs to amortization base (cost center is reservoir, field, or lease)
  - If significant development costs are incurred before all planned wells have been drilled, exclude a portion of the development costs in determining amortization rate
  - Exclude those proved developed reserves that will be produced only after significant development costs are incurred
  - Amortize on the basis of production (proved developed reserves)

- Amortization of acquisition costs (proved reserves)
- Amortization of exploration costs (proved developed reserves)
- Costs of oil and gas produced
- Production costs
- Stop

Stratigraphic Test Wells

© 2002 by Institute for Energy, Law & Enterprise, University of Houston Law Center. All rights reserved.
The rules for capitalizing or expensing costs of exploratory-type stratigraphic test wells and development-type stratigraphic test wells are the same as the rules for capitalizing or expensing the costs of exploratory wells and development wells. As a result, dry exploratory-type stratigraphic test wells are expensed; successful exploratory-type stratigraphic test wells are capitalized. All development-type stratigraphic test wells, whether dry or successful, are capitalized. Thus, capitalization is not dependent upon whether the well will be completed as a producer, but upon whether the well has either found proved reserves or is a development well.

**AFEs and Drilling Contracts**

Costs to be incurred in drilling operations are generally budgeted and approved by the operator and nonoperators. The estimated budgeted expenditures are detailed in an Authority for Expenditure (AFE). An AFE would include enough detail for the nonoperator to determine the reasonableness of the estimated costs. AFEs contain information about intangible drilling costs, equipment drilling costs, and, if the well is successful, about completion costs. AFEs present drilling and completion costs on a well-by-well basis. As a result, detailed accounting records can be kept on a well basis, even though the cost center for depreciation, depletion, and amortization (DD&A) is a lease, field, or reservoir. Accounting records are generally kept on a well basis because of management needs.

After the nonoperators approve an AFE, the operator will typically contact a drilling contractor and negotiate a drilling contract. Drilling contract dollar amounts are usually based on a day rate or footage rate. Under the **day-rate** contract, a stated amount is paid for each day of drilling. The drilling contractor generally provides a rig and crew and specified contractual services while the operator provides all materials, supplies, equipment, etc. Under a **footage-rate** contract, a stated dollar amount is paid for each foot drilled. Normally, payment under a footage rate contract is contingent upon a specified depth being reached. Under this contract, the drilling contractor generally provides the rig, crew, specified contractual services, and certain materials and supplies. Logging, core tests, drilling mud, and well equipment are typically supplied by the operator.

A drilling contract may also be on a **turnkey** basis, whereby the contractor agrees to drill to a specified depth for an exact dollar amount. This contract generally is used when several investors are buying an interest in the well by paying a designated amount ($5,000, $10,000, etc.) and need to know the total well cost prior to investing. Unlike the other types of contracts, the contractor under a turnkey contract assumes all responsibility and is in total charge of drilling operations, providing all labor, equipment, and supplies.

The drilling contractor bills the operator for services rendered as drilling progresses and when drilling operations are completed. The billing statements should, at a minimum, detail the drilling costs by categories of intangible drilling costs and equipment costs so the working interest owners can correctly classify these costs in their accounts.

**Special Drilling Operations and Problems**
WORKOVERS

Workover operations generally involve contracting for a special workover rig to restore or stimulate production from a particular well. A situation in which a workover may be necessary would be an open-hole completion where sand from the producing formation has clogged the tubing end, reducing or completely cutting off the liquid flow from the producing horizon. A workover may also be necessary when the casing has been perforated and rock or sand particles have clogged the openings in the casing. Both of these cases may require a workover to restore production. These types of workover costs are expensed as lease operating expense because production has merely been restored. A workover that materially increases the useful life of the asset or materially enhances the use value of the asset is capitalized rather than expensed.

Workover operations may also involve recompletion in the same producing zone in an effort to restore production. This type of workover is also expensed as a lease operating expense. In contrast, a workover operation may involve plugging back and completing at a shallower depth. As an example, a well was drilled to 8,000 feet. No reserves were found at that depth, so the well was plugged back to 5,000 feet where there was a producing formation and completed. In another workover operation, a well was drilled to 8,000 feet and casing was set to that depth. The well was then completed at 5,000 feet rather than 8,000 feet. Later, the well was dually completed at 8,000 feet. In both of these examples, the costs would be treated as drilling costs and would be subject to successful efforts drilling capitalization rules because the purpose of the workovers was to obtain production from a new formation, not merely to restore production from a formation already producing. In these cases, the costs would be capitalized because production was obtained. Similarly, a well might be re-entered and deepened below the casing point in the attempt to obtain production from a deeper horizon. Again, the costs would be treated as drilling costs, with the final accounting treatment dependent upon whether the attempt was successful and whether that portion of the well was classified as development or exploratory.

Example

U.S. Oil Company had the following expenditures during July, 1992

<table>
<thead>
<tr>
<th>Date</th>
<th>Description</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>July 10, 1996</td>
<td>Workover costs in connection with well #1036 - cleaning and reacidizing production formation</td>
<td>$5,000</td>
</tr>
<tr>
<td>July 20, 1996</td>
<td>Workover costs on well #1097 - testing, perforating, and completion at 8,000 feet. This depth is a new producing formation. Casing previously set.</td>
<td>IDC 20,000, Equipment 2,000</td>
</tr>
<tr>
<td>July 30, 1996</td>
<td>Workover completed in deepening well #1102 to a new unproved formation at 9,000 feet. Result was dry hole at that depth. Continued producing</td>
<td></td>
</tr>
</tbody>
</table>
Oil and Gas Accounting – Part I

from formation at 5,000 feet.

IDC . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 50,000

Equipment transferred to
inventory . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 5,000

Prepare entries.

Entries

July 10, 1996
The $5,000 cost should be expensed as lease operating expense.

July 20, 1996
Capitalize $2,000 as wells and related equipment - lease and well equipment.
Capitalize $20,000 as wells and related equipment - IDC.

July 30, 1996
Capitalize $50,000 as workover in progress - IDC.
Capitalize $50,000 as workover in progress - lease and well equipment.
Transfer $50,000 from workover in progress to dry hole expense.
Transfer $5,000 from workover in progress - lease and well equipment to inventory.

DAMAGED OR LOST EQUIPMENT AND MATERIALS

Equipment or materials may be damaged or lost during the drilling process. Some examples of
damaged or lost equipment or material would be drillpipe twisted off downhole or stuck in the
hole. Drilling mud may also be lost into a very porous formation with large cracks or fissures.

These costs are incurred in the drilling process and are handled in the same manner as other
drilling costs. Damaged or lost material or equipment, less salvage value, is capitalized if the
well is a development well. If the well is an exploratory well, they are expensed or capitalized,
depending upon whether the well is successful or unsuccessful.

SIDETRACKING

When equipment is lost in the hole, recover of the lost equipment may be attempted through
fishing. If fishing is not successful, drilling through or sidetracking around the lost pipe may be
necessary. Sidetracking involves plugging the lower portion of a well and drilling around the
obstruction. Sidetracking is possible because drillpipe is flexible and allows deviations from the
vertical. Costs of sidetracking are generally considered a part of drilling costs and are
capitalized or expensed, depending upon whether the well is a development well or an
exploratory well and whether proved reserves are found. However, if the well is an exploratory
well, expensing the costs of the abandoned portion of the well regardless of whether proved
reserves are found appears more consistent with the theory of successful efforts because that
portion of the well obviously has no future economic benefit.
COST OF ABANDONED WELL IN PROGRESS

Sometimes in drilling an exploratory well with a specific formation or trap as the objective, difficult drilling conditions may be encountered, making it necessary to abandon the hole already drilled and to start a new well nearby. If the second hole is completed as a producer, the question arises as to whether the costs incurred on the abandoned hole should be charged to expense or should be capitalized as part of the cost of the completed well that found proved reserves.

It appears that the former treatment is preferable and that the costs applicable to the abandoned hole should be charged as an exploratory dry-hole expense because the abandoned hole added nothing to the utility or value of the well actually completed. If the well originally being drilled was classified as a development well, all costs involved would be capitalized. If drilling difficulties force abandonment of only the lower portion of a well and “side-tracking” or directional drilling continues, the cost of the abandoned portion should be treated as part of the cost of the entire well.

Additional Development Cost

In the previous example, only development costs directly relating to drilling and completing a well were discussed. All development costs should be capitalized as wells and related equipment and facilities. Development costs are defined as follows:

Development costs are those 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:

a. 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.

b. 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.

c. 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 utility and waste disposal systems.

d. Provide improved recovery systems.

Service wells are drilled to support production in an existing field and are considered to be a development cost. Examples of service wells include gas injection wells, water injection wells, saltwater disposal wells, and water supply wells. Costs associated with secondary and tertiary
recovery methods, that is, improved recovery systems, are also considered to be development costs. Gas or water injection wells may be used for saltwater disposal, pressure maintenance, or secondary or tertiary recovery purposes.

Support Equipment and Facilities

Any depreciation or operating costs of support equipment and facilities used in exploration or development activities become an exploration or development cost as appropriate.

Example - Support Equipment and Facilities

Depreciation of equipment used to drill a development well was $2,000. Give the entry to record the depreciation. Ignore the wells-in-progress account and use the appropriate final account.

Entry

Capitalize $2,000 to wells and related equipment - lease and well equipment. Increase accumulated depreciation account by $2,000.

Assume instead the well was an exploratory well that was later determined to be dry. Again, ignore the wells-in-progress account.

Entry

Charge $2,000 to dry hole expense. Increase the accumulated depreciation account by $2,000.

G&G to Select Drillsite

G&G costs incurred to determine a specific drillsite are considered to be part of the cost of drilling a well and are initially recorded as wells in progress - IDC. If the well is a development well, the G&G costs will ultimately be recorded either as wells and related E&F or dry-hole expense, depending upon whether the well finds proved reserves. The G&G costs incurred to determine a specific drillsite are not considered nondrilling G&G.

Post-Balance Sheet Events

The costs of drilling an exploratory well are capitalized as wells in progress until it is determined whether the well has found proved reserves. If the well is dry, the capitalized costs are charged to expense; if the well is successful, the capitalized costs are reclassified as wells and related equipment and facilities. Normally, all the costs of an exploratory dry hole must be written off in the year a well is determined to be dry. However, if a well is determined to be dry after year end but before the financial statements are issued, the costs incurred prior to year end should be written off in that fiscal year. If the well were in progress at year end, any costs incurred in the second year relating to the well should be charged to expense in the second year.
Example - Post Balance Sheet Events

U.S. Oil Company incurred the following drilling costs on Well #1:

Prior to December 31, 1996:
- IDC $235,000
- Equipment $20,000

During January 1997:
- IDC (testing) $30,000

The well was determined to be dry on February 1, 1997, before the financial statements were published. What disposition of the drilling costs should be made, assuming equipment costing $5,000 was salvaged?

Answer

IDC costs of $235,000 and equipment costs of $15,000 should be expensed as dry-hole costs for the year ended December 31, 1996. The $30,000 of IDC incurred in 1997 should be expensed in 1997.

Deferred Classification of Costs of an Exploratory Well

The determination of whether a well has found proved reserves is usually made around the time drilling operations are completed. However, sometimes an exploratory well is determined to have found oil or gas reserves but the reserves cannot be classified as proved at the time drilling is completed.

Classification may be delayed and the well carried as an asset if:

1. A major capital expenditure such as a pipeline is required before production can begin, and additional successful exploratory wells need to be drilled to justify the major expenditure by finding a sufficient quantity of additional reserves. In this situation, the classification may be delayed and the well carried as an asset, pending determination of whether proved reserves have been found as long as both of the following conditions are met:
   a. the well has found reserves sufficient to justify its completion, if the need for the required major capital expenditure is ignored.
   b. Drilling of additional wells is under way or firmly planned for the future.

OR
2. All other exploratory wells, that is, those wells not requiring a major capital expenditure, may be carried as an asset for one year following completion of drilling without classification of the found reserves as proved.

If the exploratory well is the type described in 1 above, and the specified conditions are not met or cease to be met without the reserves being classified as proved, then the costs of the well should be expensed. However, as long as the conditions of (1) sufficient reserves and (2) firm drilling plans along with (3) the need for a major capital expenditure are met, the well may be carried in suspense indefinitely.

As stated in item 2 above, wells not needing a major expenditure must be classified as either successful (proved reserves found) or unsuccessful within one year. If classification is still not possible at the end of one year following completion of drilling operations, the well costs must be expensed.

Estimating reserves is done by taking core samples and well logs (electric, magnetic, etc.), in addition to examining mud logging reports and pressure tests. In some cases, the results obtained by reserve engineer examinations may be inconclusive, and further testing may be required. When marginal exploratory wells are involved, proved reserves determination may take a significant period of time and deferred classification may be necessary.

Delays in well classification may also occur in situations similar to the Austin chalk in Texas. Wells in the Austin chalk formation have, in many instances, suffered rapid production declines following completion. Great care in estimating reserves is required in such situations to allow for decline in production.

Deferred classification is not appropriate, however, based on the chance that some event beyond the control of the company may occur. For example, classification should not be deferred based on the chance that the price of oil or gas will go up in the future, resulting in proving reserves that are not currently commercially producible.

**DEFERRED CLASSIFICATION OF COSTS OF AN EXPLORATORY-TYPE STRATIGRAPHIC TEST WELL**

If a major capital expenditure is required on an exploratory-type stratigraphic test well, classification may be delayed as long as the following conditions are satisfied: (1) a quantity of reserves has been found that would justify completion had the well not been a stratigraphic test well; (2) drilling of additional exploratory-type stratigraphic test wells has been started or is planned in the near future. These stratigraphic test wells are generally drilled offshore. A common example of a major capital expenditure is construction of a drilling platform that can be justified only if further successful stratigraphic test wells are drilled.

**Interest Capitalization**
Capitalizing interest is part of the cost of assets that require a period of time to be prepared for their intended use. Essentially, this requires interest capitalization for all qualifying assets, where qualifying assets are defined as assets that are constructed by an entity for its own use. Either the interest rate on specific borrowing associated with the qualifying asset may be used or a weighted average interest rate may be used. The interest rate is applied to the average amount of accumulated capital expenditures to obtain the amount of interest to capitalize each period. Capitalized interest cannot exceed actual interest costs. The interest capitalization period begins when the three following conditions are met:

1. Expenditures for the asset have been made.
2. Activities necessary to get the asset ready for its intended use are in progress.
3. Interest cost is being incurred.

The term “activities,” as used in condition 2 above, is to be construed broadly — encompassing technical and administrative activities such as obtaining permits. The interest capitalization period should end when the asset is substantially complete and ready for productive use.

Applying this statement to an industry as unique as the oil and gas industry creates interpretation problems. The starting point used has ranged from the time a prospect is acquired to the spud-in date. The stopping point, which is less varied, has ranged from the time proved reserves are found to the time when production begins. Activity cost has included leasehold costs and tangible and intangible drilling costs or IDC and tangible equipment only. Specifically, capitalized interest is computed as follows:

\[
\text{Average accumulated expenditures during construction} \times \text{interest rate} \times \text{construction period}
\]

Average accumulated capitalized expenditures is computed by adding the beginning balance and ending balance and dividing by two. A simple example of one interpretation of interest capitalization for an oil and gas company follows.

**Example**

U.S. Oil Company has unproved property costs of $60,000 for Lease A at January 1, 1996. During the year 1996, drilling costs are incurred on Lease A in the amount of $300,000. A 10%, $400,000 note is outstanding during the entire year and was specifically obtained for the acquisition and drilling program related to Lease A. Compute the interest capitalization amount and prepare the entry to record the interest.

Interest to be capitalized during 1996:

- Average accumulated expenditures: $60,000 + $360,000 = $210,000
- Interest costs to be capitalized: $210,000 x 10% = $21,000

**Entry**
Capitalize $21,000 to wells in progress - IDC.
Reduce interest expense by $21,000.