WORKBOOK ON
OIL AND GAS ACCOUNTING - Part 2

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CHAPTER 1
ACCOUNTING FOR OIL AND GAS RESERVES
LEARNING OBJECTIVES

Chapter 1 discusses the accounting procedures used to record the sale of oil and gas. Studying this chapter should enable you to:

1. Make the necessary calculations used in the decision to complete a well.
2. Make the necessary calculations used to determine the profitability of a well or property.
3. Describe the procedures to place a well on production.
4. Discuss the various procedures to record revenue from oil and gas.
5. Describe the basic accounting entries for oil and gas production and purchase.
ACCOUNTING FOR OIL AND GAS REVENUES

Decision to Complete a Well

In making a decision to complete a well, the incremental costs to complete the well should be compared with the future net cash flows expected to be received from the sale of oil or gas produced from the well. This comparison entails estimating the following items:

1. Quantity of oil or gas contained in the reservoir
2. Timing of future production of the oil or gas
3. Future selling price of the oil or gas
4. Future production costs of the oil or gas, including severance taxes
5. Completion costs
6. Cost of capital

If expected future net revenue is greater than expected completion costs, the well is usually completed.

Determination of total recoverable reserves is an inexact science. This is especially true for the first well discovered in a field. A study done by Price Waterhouse found that reserve estimates when a field is first discovered are inaccurate by at least ± 50%, and it may be only after five years of production that reserve estimates can be made within ± 20%.

Reserve estimates are usually made by a reservoir engineer, who may be an employee of the company or an independent contractor. Some factors or characteristics that are taken into account by the reservoir engineer in preparing a reserve estimate are as follows:

1. Size of the reservoir
2. Porosity and permeability of the reservoir
3. Pressure and temperature in the reservoir
4. Oil, gas, and water contained in the reservoir pores

In addition to estimating the total recoverable reserves, the reserve engineer also must estimate the timing of production of the oil and gas reserves. Reserve recovery timing depends on such factors as the characteristics of the reservoir, product demand, and government regulations. Product demand is especially important for natural gas because gas is difficult and expensive to store.
Another important consideration affecting the decision to complete a well is the future product price and the cost of producing the product. Both items must be estimated before net revenue can be determined. Estimating the future price of the product is difficult, and the result may be inaccurate. The price of oil or gas is affected by product supply and demand probably more than any other factor. Governmental intervention, whether domestic or foreign, also affects the price and is usually impossible to predict. On the other hand, lifting costs can generally be estimated with a relatively high degree of accuracy. Severance taxes are part of production costs and must also be estimated.

Finally, completion costs must be estimated and compared to future net cash inflows. Completion costs can typically be estimated relatively easily and accurately. An example showing the necessary comparison of net cash inflows and completion costs when deciding whether to complete a well follows.

**Example Completion Decision**

U.S. Oil Company data follow:

- Proved property cost (acquisition cost) $40,000
- Drilling cost $200,000
- Estimated completion cost $150,000
- Estimated lifting costs per bbl $6
- State severance tax 4 1/2%
- Working interest percentage 100%
- Royalty interest percentage 10%
- Selling price per bbl $20

**Required:** Should the well be completed, assuming the following total production?

Case A: 5,000 bbl
Case B: 10,000 bbl
Case C: 20,000 bbl
### Computation

<table>
<thead>
<tr>
<th></th>
<th>CASE A</th>
<th>CASE B</th>
<th>CASE C</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total revenue</td>
<td>$100,000</td>
<td>$200,000</td>
<td>$400,000</td>
</tr>
<tr>
<td>Less RI’s revenue</td>
<td>( 10,000)</td>
<td>( 20,000)</td>
<td>( 40,000)</td>
</tr>
<tr>
<td>Revenue to WI</td>
<td>90,000</td>
<td>180,000</td>
<td>360,000</td>
</tr>
<tr>
<td>Less: Severance tax</td>
<td>( 4,850)</td>
<td>( 9,000)</td>
<td>( 18,000)</td>
</tr>
<tr>
<td>Net revenue before lifting costs</td>
<td>85,000</td>
<td>171,000</td>
<td>342,000</td>
</tr>
<tr>
<td>Less: Lifting costs ($6 x bbl)</td>
<td>( 30,000)</td>
<td>( 60,000)</td>
<td>( 120,000)</td>
</tr>
<tr>
<td>Net revenue to WI owner</td>
<td>$ 55,000</td>
<td>$111,000</td>
<td>$222,000</td>
</tr>
</tbody>
</table>

CASE A: No, do not complete. The net revenue to the WI owner is only $55,500 and estimated completion costs are $150,000. Reserve estimates for new production are usually higher than actual; therefore, the actual net cash inflow may be even less.

CASE B: No, do not complete. The net cash inflow is projected to be $111,000 as compared with completion costs of $150,000. The reasoning is the same as in Case A.

CASE C: Yes, complete. The net revenue is $222,000 and completion costs are $150,000.

In the above example, the timing of reserve recovery was not addressed and the time value of money was not discussed. The estimated future net cash inflows should be discounted to present value using an appropriate interest rate. Discounting is especially important in this type of analysis because many of the costs are up front while the revenues are received over time. If the net cash inflows are received over a period of time, the completion costs will in all likelihood exceed the discounted future net cash inflows.

### Profitability of a Well or a Property

Even when a decision is made to complete a well because future net revenue is expected to be greater than completion costs, the well may still not be profitable. In order to be profitable, the net revenue from the well must exceed not only completion costs but all other costs as well. The costs incurred before deciding to complete a well, such as drilling costs, etc., are sunk costs and do not enter into the completion decision. These costs are relevant, however, in determining whether the well has ultimately been profitable.

The data from the preceding example, except for a change in reserve amounts, are used in the two following similar examples which illustrate an analysis to determine the ultimate profitability of a well and an analysis to determine the ultimate profitability of a property.
**Example--Profitability of a Well**

The following information applies to a well drilled and produced by U.S. Oil Company:

<p>| | | |</p>
<table>
<thead>
<tr>
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</tr>
</thead>
<tbody>
<tr>
<td>Drilling cost</td>
<td>$200,000</td>
<td></td>
</tr>
<tr>
<td>Completion cost</td>
<td>$150,000</td>
<td></td>
</tr>
<tr>
<td>Lifting costs per bbl</td>
<td>$ 4</td>
<td></td>
</tr>
<tr>
<td>State severance tax</td>
<td>5%</td>
<td></td>
</tr>
<tr>
<td>Working interest</td>
<td>100%</td>
<td></td>
</tr>
<tr>
<td>Royalty interest</td>
<td>10%</td>
<td></td>
</tr>
<tr>
<td>Selling price per bbl</td>
<td>$ 20</td>
<td></td>
</tr>
</tbody>
</table>

Required: Determine if the well was profitable.

Total production

CASE A: 500 bbl per month for 30 months

CASE B: 800 bbl per month for 30 months

<table>
<thead>
<tr>
<th></th>
<th>CASE A</th>
<th>CASE B</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total revenue per month</td>
<td>$ 10,000</td>
<td>$ 16,000</td>
</tr>
<tr>
<td>Less: RI’s revenue</td>
<td>(1,000)</td>
<td>(1,600)</td>
</tr>
<tr>
<td>Revenue to WI</td>
<td>9,000</td>
<td>14,400</td>
</tr>
<tr>
<td>Less: severance tax</td>
<td>(500)</td>
<td>(800)</td>
</tr>
<tr>
<td>Net revenue before lifting costs</td>
<td>8,500</td>
<td>13,600</td>
</tr>
<tr>
<td>Less: Lifting costs</td>
<td>(2,000)</td>
<td>(3,200)</td>
</tr>
<tr>
<td>Net revenue to WI owner</td>
<td>$ 6,500</td>
<td>$ 10,400</td>
</tr>
<tr>
<td>Total net revenue (revenue x 30)</td>
<td>$195,000</td>
<td>$312,000</td>
</tr>
</tbody>
</table>

Estimated drilling cost $200,000

Estimated completion costs $350,000
CASE A: The well was not profitable.

CASE B: The well was not profitable.

An important point to note is that if a well is completed, it is classified as successful. But even though classified as successful, the well may still be unprofitable. Thus, even though 1 exploratory well in 9 or 10 wells is successful, only about 1 exploratory well out of 49 is profitable.

In determining the ultimate profitability of a property, management and potential investors are interested in the total recovery of all costs and how quickly the costs are recovered (payout). The following example illustrates the computation of total recovery of all costs.

**Example – Profitability of a Property**

U. S. Oil Company provided the following information:

Property cost (acquisition cost) $40,000
Drilling cost $200,000
Completion cost $120,000
Lifting costs per bbl $4
State severance tax 5%
Working interest 100%
Royalty interest 10%
Selling price per bbl $20

Required: Would an investment made in this property have been successful assuming management or the investor wanted a 36-month payout?

Production

CASE A: 500 bbl per month
CASE B: 800 bbl per month
Computation

Total revenue per month $10,000 $16,000
Less: RI’s revenue (1,000) (1,600)
Revenue to WI 9,000 14,400
Less: Severance tax (500) (800)
Net revenue before lifting costs 8,500 13,600
Less: Lifting costs (2,000) (3,200)
Net revenue to WI owner $ 6,500 $10,400

Costs to recover

Proved property cost $ 40,000
Estimated drilling cost 200,000
Estimated completion cost 120,000
$360,000

CASE A: $360,000 / 6,500 = 55.4 months
CASE B: $360,000 / 10,400 = 34.6 months

CASE A: No-- payout is 55.4 months
CASE B: Yes--payout is 34.6 months
PLACING THE WELL ON PRODUCTION

After an oil or gas well is completed and it is determined that the well is a commercial producer, procedures are instituted to place the well on production. This entails finding a purchaser for the product, installing production facilities such as flow lines, treating equipment, oil storage tanks and gas metering equipment, and connecting the purchaser's gathering system to these facilities.

Flow lines are used to gather production from the individual wells to a central location for further handling of the products. Since few reservoirs produce only crude oil or gas, it is usually necessary to remove gas from liquids (crude oil) or remove liquids (condensate) from gas. The device used to separate the gas and the liquids is called a separator. The technical details of the separator vary depending on various production factors (e.g., gas/oil ratios, pressures, impurities, etc.), but its purpose is to separate the two ingredients into separate streams for further handling and marketing.

A device called a heater, or heater treater, may also be a part of the producing equipment. Its purpose is to remove water and other impurities from the crude oil. Most purchasers of crude oil require that there be less than one percent basic sediment and water (B.S. & W.) in the crude. If the B.S. & W. content of the oil exceeds that level, a heater treater is installed to remove the impurities. Since many reservoirs contain salt water, the heater treater is a commonly found unit of equipment.

Each lease normally has two or more tanks (referred to as a tank battery) for storing oil before it is sold. The total storage capacity of a tank battery is usually from three to seven days of production from the wells connected to the battery. There are normally two or more tanks in a battery so that while oil is being run from one tank the other can be filling. Storage tanks have a drain outlet at the bottom for draining off basic sediment and water. The pipe through which oil is withdrawn from the tank usually is connected one foot above the tank's bottom. The space below the pipeline outlet provides room for the collection of basic sediment and water. The pipeline outlet valve is closed with a metal seal while the tank is being filled and is sealed in open position while the tank is being discharged into the pipeline. A record of the serial numbers of seals used provides safeguards against unauthorized movement of oil from storage tanks.

Oil enters the top of the tank through an inlet opening. A valve is positioned on the inlet line so that it may be closed to prevent oil from entering the tank after the tank is ready for delivery, or during delivery, to the pipeline company. Also at the top of the tank is an opening known as a thief or gauge hatch which permits sampling and measuring the oil in the tank.

VOLUME DETERMINATION

One of the most important steps in revenue accounting in determining the volume and quality of the oil, condensate, and natural gas being produced and sold. The physical activities of taking readings, testing, and measuring are performed by field personnel. However, it is the revenue
accountant's responsibility to know and understand these procedures and to periodically ensure that correct procedures are being followed. This is a major point in internal control because revenue can be lost if inaccurate measurements are made for volume or for quality.

MEASUREMENT OF OIL

Before a tank battery is put into operation, each tank is strapped, that is, the measurements or dimensions of the tank are taken. Measurements are obtained using a pipeline gauger. The measurements are recorded on a tank strapping report, which is signed by the pipeline gauger and the producer's representative. The strapping report is sent to an independent tank engineer who computes the amount of oil that can be contained in each interval (usually each one-quarter inch) of height of the tank.

The standard unit of measurement of crude oil is a barrel of 42 gallons at a temperature of 60°F. The capacity of the tank in barrels, according to the height of liquid in the tank, is prepared in table form, usually referred to as a tank table. The tables are customarily prepared to show the capacity for each one-quarter inch from the bottom to the top.

GAUGING

Immediately before running a tank of oil into the pipeline, the pipeline gauger measures the top level, or opening gauge, of the oil with a steel measuring tape weighted by a plumb bob. By the use of a device known as a thief, which permits extraction of oil from any desired level in the tank, samples of the oil are secured for several intervals just above and below the pipeline connection in order to determine whether the B.S. & W. content of the oil is less than one percent. If the tank contains too much B.S. & W., the measurements will indicate how much B.S. & W. must be drained from the tank in order to lower the salable oil to the pipeline connection. The samples obtained are placed in glass tubes and spun in a centrifuge. Centrifugal force causes the B.S. & W. to settle to the bottom of the glass tube and the B.S. & W. content can be read from graduations on the tube. The amount of B.S. & W. in the salable oil is also determined by this method.

The A. P. I. gravity of the oil, adjusted to 60 °F, is a factor in the volumetric correction to 60 °F and is often a determinant of the value of the oil. The gauger measures the gravity of the oils with a hydrometer, recording the temperature at which the gravity was observed, for later use in adjusting observed gravity to the gravity at 60°F. In order to adjust the volume of oil, the temperature of the oil in the tank is taken by lowering a thermometer into the oil. After the tank has been drained to the level of the pipeline connection, the bottom, or closing gauge, is measured and the temperature of the remaining oil taken. The above information and appropriate identification of the lease and tank from which the oil is run are entered on the pipeline run ticket and the ticket is signed by both the pipeline gauger and the lease pumper-gauger.

THE RUN TICKET
The pipeline run ticket is the document on which the pipeline gauger, witnessed by the lease pumper, records the information necessary for later calculation of the volume and gravity of the oil delivered or run from the lease tank to the pipeline. The information recorded on the ticket includes the pipeline name; the lease owner or operator's name; the date of the run; and run ticket number; lease identification; the tank number; the opening and the closing measurements (oil height and temperature plus the observed gravity and the temperature at which it was observed); the B.S. & W. content; the signatures of the pipeline gauger and the owner's witness. The run ticket also has spaces for recording gravity adjusted to 60°F and the result of volume calculations.

VALUE DETERMINATION

After the volume of oil has been calculated and allocated to the appropriate property, they must be valued in accordance with the sales contract and in compliance with any applicable government regulations. (The accounting centers used in valuing oil are the leases, and gas processing plants are used as accounting centers when sales are made from plants.) These accounting centers are used in order to set up receivables, calculate taxes, and make proper distribution of proceeds to the working interest and royalty interest owners.

OIL PRICING

Each run of oil (separate delivery of oil from the storage tanks) from the lease is priced separately. The values of all runs during the month are accumulated and settlement is made monthly by the purchaser.

To price the oil delivered, the volumes and the API gravity and grade (this is the geographical area of production and sometimes a reference to physical characteristics of the oil, e.g., Wyoming Sour, West Texas Sweet, South Louisiana, etc.) of the oil must be known. The volumes are then priced on the basis of a Price Bulletin or a Crude Oil Price Bulletin.

The Price Bulletin is a posting of the price per barrel the purchaser will pay for each grade of crude oil. The prices, within a range of gravities, change with each degree change in API gravity of the oil, normally about two cents per barrel for each degree of gravity. The lower gravity oil receives the lowest price. Each degree increase in the API gravity will receive an incremental increase in the price up to a maximum gravity. The gravity range, for example, could run from 11° API to 40° API. Generally, oil with gravities outside the range of the postings will receive the posted price for the gravity closest to it, that is, gravities below 11° would receive the 11° price and gravities above 40° would receive the 40° price. The Price Bulletin will also state the effective date of the prices.

OWNERSHIP INTERESTS IN PRODUCTION
An important function of the revenue accountant is the distribution of revenues and expenses (when appropriate) to the proper owners. Ownership interests in minerals determine the factors used to allocate revenue and expense. The percentage of revenue received by an owner may not be the same percentage used to allocate the expenses that the owner must bear. (At this point, we are interested only in the allocation of production revenues.)

Contractual agreements between the parties determine ownership interests, and rarely are two contracts exactly the same. Because of the high risks involved in drilling and the large amount of capital investment required, many contracts and arrangements for sharing the risks are made. These arrangements can create many different owners in a single mineral property, requiring distribution of sales proceeds to each. In almost every case there will be at least two recipients of production proceeds—the working interest owner and the royalty owner. Thus, a division of interest order (or simply division order) is prepared to indicate how the purchaser should distribute production proceeds.

DIVISION ORDERS

A regular division order is a contract between the purchaser of oil production and all the various owners of interests in the oil property. This contract includes the legal description of the property; the owners of interests in the property; the interest owned by each, as indicated by a title opinion rendered by the Legal Department after examination of abstracts of title supplied by the operator of the property; and the terms of purchase, including provisions dealing with passage of title to the oil, price, measurement, and related items. The operator of the property circulates the division order to the various owners of interest. Each owner, by signing the division order, guarantees his ownership to be as stated, authorizes the purchaser to receive oil from the property and to make payment to the owners in proportion to their respective interests, and agrees to all other provisions of the division order.

RECORDING REVENUE AT TIME OF SETTLEMENT

Some producers await receipt of the statement of pipeline runs and the accompanying check from the purchaser before recording production revenues. Usually, producers using this procedure calculate production from the run tickets and then compare their calculations with the statement of pipeline runs when it is received from the purchasing company. They record the revenue earned from production, the cash received, and the related taxes only when the settlement statement and check are received.

To illustrate, suppose that a company that produces oil and sells it to a purchaser follows this procedure and receives a statement of oil runs from a lease showing the data below. The purchaser withholds taxes and pays each interest owner the net amount due.

Production (operator's share) 700 Barrels

Production revenue ($20/bbl) $14,000
Production Tax (5%)  
Net Proceeds received

Using the procedure under which revenue is recorded at time of payment the settlement would be recorded as follows:

**Entry**

Increase the cash balance by $13,300.
Charge lease operating expense - production taxes for $700.
Increase the crude oil revenue account by $14,000.

Some companies using this method adjust the revenue account to reflect accrual of the sales price of oil that has been run into the pipeline, but for which settlement has not been received at the end of the fiscal year or each quarter. This may in some cases be a material amount because of the long period required for settlement. The entry, to be complete, should reflect the sales price of the operator's share of pipeline runs, the applicable production taxes, and the net amount receivable.

The procedure above has ignored oil stored in lease tanks and not yet turned into the pipeline. Even though this is a violation of good accrual accounting concepts, most small operators ignore Inventory in lease tanks on the basis that the amounts involved are immaterial and that the total inventory in lease tanks does not vary significantly from period to period.

**RECORDING REVENUE BASED ON PIPELINE RUNS**

The producer may account for sales revenues on an accrual basis by recording revenues and related items on the basis of pipeline runs. The entries may be made monthly or as each pipeline run is made. The former procedure is far more common.

For example, if during January 1996, pipeline runs from lease No.1234 showed the working interest share of runs to be 1,000 barrels and the appropriate price for production from the lease was $20 per barrel, the following entry would be made summarizing the month's activity.

**Entry**

Accounts receivable - oil and gas should be increased by $20,000.
Crude oil revenue should also be increased by $20,000.

Any differences between amounts recorded in the above entry and those appearing in the settlement statement received subsequently from the purchaser would be reconciled and any recording errors corrected. Note that this method places the sales transactions on an accrual
basis, but does not place production on an accrual basis because the inventory in lease storage tanks is unrecorded.

Most companies using this procedure ignore altogether inventories in lease tanks. Others, however, do record inventories in the tanks at the end of each year, adjusting the inventory account to reflect the posted field price (rather than a “cost” figure) at the balance-sheet date. They view the oil in the tanks as a completed product with an assured market and thus are willing to report the full market value of the inventory as an asset.

RECORDING DAILY PRODUCTION

Two records are needed to supply the detailed data to record daily production: (1) a daily gauge report and (2) a production ledger. The daily gauge report is prepared for each tank as near as possible to the same hour each day–often early in the morning. The ticket shows the stock on hand in feet and inches in all tanks standing on the lease, including flow tanks and settling tanks if used.

The daily gauge report is routed to the accounting office where the amount of oil produced is posted to a production ledger. This ledger record serves not only as an accumulating record of daily production but also to provide data concerning inventories, and a reconciliation of production, runs, adjustments, and ending inventory. Following the computation of the operator's interest in oil produced during the month from each lease, production and inventory data and the price per barrel for all leases are accumulated.

BASIC ACCOUNTING ENTRIES FOR OIL PRODUCTION AND PURCHASE

The accounting entries related to oil production and purchase by an integrated company can be classified into three groups:

1. Entries for revenue from a lease in which the company owns the working interest and sells production to another company.
2. Entries for revenue from a lease in which the company owns the working interest and purchases the production itself.
3. Entries for purchases of oil from a lease in which the company owns no interest.

The internal entries to record actual intracompany sales or transfers (e.g., “sale" by production department to pipeline and corresponding “purchase" by the pipeline) vary. However, these variations are a matter of mechanical procedures and do not affect the basic accounting concepts involved.

ACCOUNTING FOR NATURAL GAS PRODUCTION
The basic concepts of accounting for natural gas production and sale are essentially the same as those of accounting for oil production and sale. However, because of special contracts between gas producers and purchasers and because gas frequently must be processed before its sale, special accounting problems do arise. In this chapter, accounting for the routine sale of non-processed gas is summarized.

MEASURING GAS PRODUCTION

Gas production and sales are measured in cubic feet and usually expressed in thousands of cubic feet (MCF). The standard conditions for volume measurement are expressed in standard pressure of 14.73 pounds per square inch (p.s.i.) at a temperature of 60 degrees Fahrenheit.

MEASURING VOLUME

Gas volume is normally measured by the use of an orifice meter, which registers the pressure drop that occurs when gas flows through a calibrated restriction in the line of flow. This type of measurement is based on the physical law that the quantity of ideal gas passing through an orifice varies as the square root of the static and differential pressures. It is therefore necessary to translate the static and differential pressures, as recorded on the orifice chart, into units of measure (cubic feet). Volumes of gas measured by orifice meters are determined by multiplying the pressure extension, which is the average square root value of the static and differential pressure, by a flow constant which is based on the size of the line and the size of the orifice.

PROCESSED GAS

Contracts are executed between producers and gas plant operators for the processing of oil-well and gas-well gas for two principal reasons. First, in the interest of conservation and pollution control, state governing bodies prohibit the flaring of gas in many areas. The flaring of gas, except in cases of emergency such as equipment failures, could result in a governmental order to stop production from the wells. Therefore, in order for the producer to continue the production of oil and gas, he must dispose of the gas produced. This can be accomplished only if the gas is placed in a state of utility; that is, it is made free of impurities and liquids and compressed to sufficient pressure to meet sales requirements. The gas plant extracts those liquids remaining after liquid separation and the residue gas is often sold to gas pipeline companies. Generally, the residue gas remaining from the processing of gas-well gas is sold at the plant by the producer while such gas remaining from oil-well gas is sold by the plant operator. The processing of gas may be mutually profitable to the producer and the plant operator.

Revenue Components

Residue gas remaining after gas-well gas has been processed is generally sold according to the terms of a sales contract between the producer and a pipeline company at the discharge of the gas plant. Gas-well gas is usually processed under the terms of an agreement between the
producer and the plant operator under which the plant operator's consideration for processing the gas is a percentage of the proceeds received from the sale of the liquid products attributable to the gas. The percentage paid to the plant operator varies from 10 percent to 50 percent. The producer customarily receives 100 percent of the proceeds realized from the sale of the residue gas.

RECORDING SALES

Recording sales of unprocessed gas involved is essentially the same process as recording sales of oil. There is, however, one simplifying factor: there is no on-lease inventory.
CHAPTER 2
ACCOUNTING FOR PRODUCTION ACTIVITIES
LEARNING OBJECTIVES

Chapter 2 discusses accounting for production activities. Studying this chapter should enable you to:

1. Identify the various types of production costs.
2. Identify and discuss the various types of direct production costs.
3. Identify and discuss the various types of indirect production costs.
4. Explain the process of accounting for production costs.
5. Explain the process for indirect cost allocation.
ACCOUNTING FOR PRODUCTION ACTIVITIES

This chapter discusses the accounting treatment of costs incurred in producing oil and gas. Accounting for these activities is essentially the same whether the company is a successful efforts company or a full cost company.

After a well has been completed and flow lines, heater treaters, separators, etc., have been installed, production activities begin. Production activities involve lifting the oil and gas to the surface and then gathering, treating, processing, and sorting the oil and gas. Costs incurred in these activities are called production costs, lease operating costs, or lifting costs.

A. PRODUCTION COSTS DEFINED

Production costs are defined as follows:

1. Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation applicable to operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

   a. Cost 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. Insurance applicable to proved properties and wells and related equipment and facilities.

   e. Severance taxes.

2. Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the costs of oil and gas produced along with production (lifting) costs.
B. ACCOUNTING FOR PRODUCTION COSTS

Although production costs theoretically become part of the cost of oil and gas produced and therefore allocable to inventory and to cost of goods sold, rarely do oil companies that produce and sell crude oil value crude oil inventories in storage tanks at cost. Inventories of the oil produced and stored in lease tanks are generally ignored, or they are valued at market price. In either case production costs are treated in full as expenses (see Exhibit 2-1) when they are incurred. Thus the accounting problems related to production costs involve cost control, analysis of profitability and record keeping for reporting purposes.

In accounting for production costs, one of the first requirements is to determine the functional accounts that will be used. The accounting system must provide information in sufficient detail to permit the accounting for costs in accordance with recognized accounting principles and at the same time meet the needs of operating personnel in evaluating operations, In accounting for production costs, it is essential that the accounting records furnish the necessary data for the computation of allowable depletion for each property;

C. DIRECT PRODUCTION COSTS

Direct production costs are those costs that can be closely related to the production of oil or gas on specific mineral properties. These costs are largely controlled at the lease operating level. Several of these directed costs will be examined to illustrate both the nature of the costs involved and the manner in which they are handled for accounting purposes.

Exhibit 2-1

- Incur production costs which includes lifting, gathering, treating, field processing and field storage, e.g., labor, repairs, supplies, depreciation, and severance taxes.
- Amortization of acquisition costs
- Cost of oil and gas produced
- Amortization of exploration costs
- Amortization of development costs
1. SALARIES AND WAGES

Field employees are pumpers, gaugers, and other employees below first-level supervisors. They are employed directly by the oil and gas producing properties. These employees are concerned with the basic lease and facility operations and routine maintenance. Time sheets or other written, documentation will customarily show the time spent on each job or each property and provide the basis for charging the salaries and wages to individual properties. Therefore, it is necessary that the time sheets give sufficient detail to permit the proper allocation of charges to the various leases.

2. EMPLOYEE BENEFIT

Employee benefits are considered to be part of the total cost of labor and would also be allocated to the individual leases. The normal practice is for the company to develop estimates of the ratio of employee benefits to direct labor costs.

3. REPAIR AND MAINTENANCE

Costs of repairing lease equipment such as tank batteries, separators, flow lines, lease buildings, engines, motors, pumpers, derricks, other above-ground production equipment, and lease roads, are charged to this account. In general, costs related to repairs of the well or sub-surface well equipment are charged to the Well Service and Workover account. Where company labor is used in such operations, the labor costs are charged to Salaries and Wages rather than to Repairs and Maintenance.

4. WELL SERVICE AND WORKOVER

Costs of outside services relating to the reconditioning, recompletion, or otherwise reworking of a well already drilled and operating are accumulated in this account. Similarly, costs of deepening producing wells within the same producing horizon when such operations are conducted for the purpose of restoring efficient operating conditions. Costs such as reperforating casing, repairing casing leaks, or acidizing and shooting to get the well producing again are proper charges to this account rather than to capital additions and improvements. However, projects that call for deepening the well to lower horizons or attempting to secure production from a shallower horizon are treated as drilling costs.

5. CONTRACT PUMPING SERVICES

It is common in the industry for individuals to render pumping and routine maintenance services to companies on a contract-basis. The company and the individual enter into a
contract whereby the individual renders certain services on specific properties for a stipulated sum that gives consideration to the number of wells, their location, the type of services to be rendered, the time schedule involved and other factors negotiated by the parties. In this arrangement the individual is acting as an independent contractor and is not considered to be an employee of the company. Unusual items will be billed individually to the company for approval. The monthly invoice from the contractor will provide the details necessary for accounting entries.

6. PRODUCTION AND OTHER TAXES

Certain taxes such as ad valorem taxes are recorded as lease operating expense at the time they are accrued for payment or they will be accrued monthly during the year, based upon some reasonable estimate of the amount which will be assessed. Other taxes, such as production or severance taxes are recorded at the time the revenue on which they are based is recorded. Production taxes are recorded at the time the oil is sold.

7. AUTO AND TRUCK EXPENSES

If an employee or an individual performing contract services classified as lease operating expenses uses a personal vehicle in the performance of those services, the costs associated with the use of the vehicle are considered to be direct expenses and are charged directly to the properties involved. In this situation there is usually an agreement between the individual and the company as to the amount of costs that can be charged.

D. INDIRECT PRODUCTION COSTS

Indirect operating costs are all costs that are not closely related to the production of oil and gas on specific leases and are not controllable at the lease level. These indirect costs are accounted for in much the same way as overhead costs. In general the costs of a function or activity are accumulated and then apportioned or allocated to individual properties on the basis of direct labor hours, direct labor costs, number of wells, time of equipment use, volume of service rendered, the volume of production, or some other reasonable basis.

1. DEPRECIATION OF SUPPORT FACILITIES

In virtually all of the clearing and apportionment accounts, depreciation of tangible real and/or personal property is involved. Under the successful efforts method of accounting, the costs of all support equipment and facilities used in oil and gas producing activities shall be capitalized.

The depreciation method is left to the experience of the company. Depreciation of support equipment and facilities will usually be computed by the straight-line method or declining balance method because use of the assets involved is not related directly to the
production of specific units of oil or gas revenues. Salvage may or may not be considered, depending upon the circumstances in each instance.

2. **TRANSPORTATION EQUIPMENT EXPENSE**
   
a. salaries and wages of maintenance personnel,
   
b. employee benefits of maintenance personnel,
   
c. maintenance supplies and parts,
   
d. depreciation of maintenance equipment,
   
e. depreciation of maintenance facilities,
   
f. depreciation of company vehicles,
   
g. fuel,
   
h. insurance on vehicles, and
   
i. other costs related to the maintenance and operation of company-owned vehicles.

Each of the above items is measured and recorded in accordance with the normal practices of the company and charged to Transportation Equipment Expense.

3. **SALTWATER DISPOSAL**

Soft water is also produced in varying quantities whenever oil is produced. The salt water is a waste item which must be disposed of in an environmentally safe manner. This usually requires that the salt water be gathered and reinjected back into a formation below the surface of the earth.

If only one property is served by a particular system, the costs can be handled as a direct cost and charged directly into lease operating expense. However, if more than one lease is served by the system or systems, some means of apportioning the costs must be determined.

If the ratio of water to oil does not differ significantly among the properties served by a system, an apportionment based on the number of wells served would be appropriate. However, if the oil-to-water ratio differs significantly among the properties served, a charge based on the volume of salt water handled might be appropriate.
Exhibit 2-2 contains a partial list of various production costs and their classifications:
## Exhibit 2-2

<table>
<thead>
<tr>
<th>Direct Costs</th>
<th>Indirect Costs</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>a.</strong> Direct materials, supplies and fuel-wells and leases involved identified in the invoices.</td>
<td><strong>a.</strong> Fringe benefits of workers who work on several leases</td>
</tr>
<tr>
<td><strong>b.</strong> Direct labor (pumpers), gaugers, etc. employees who work on the lease only or who designate hours worked on certain wells or leases</td>
<td><strong>b.</strong> Salaries and fringe benefits of field or regional supervisors of several leases or fields</td>
</tr>
<tr>
<td><strong>c.</strong> Contract labor or services for oxidizing, refracturing, scrubbing, etc.- invoices indicate wells involved</td>
<td><strong>c.</strong> Depreciation of support facilities, gathering systems, treatment systems - several leases</td>
</tr>
<tr>
<td><strong>d.</strong> Repairs and maintenance that can be traced to individual wells and leases</td>
<td><strong>d.</strong> Transportation and hauling - several leases involved</td>
</tr>
<tr>
<td><strong>e.</strong> Property taxes and system-insurance traceable from tax receipts or property descriptions on insurance policies</td>
<td><strong>e.</strong> Operating costs of saltwater disposal several leases involved</td>
</tr>
<tr>
<td><strong>f.</strong> Production or severance taxes-reports to the state identify these taxes to specific leases</td>
<td><strong>f.</strong> Boat and fuel expenses, offshore operations</td>
</tr>
<tr>
<td><strong>g.</strong> Depletion and depreciation related to proved reserves or proved developed reserves for a particular lease or well</td>
<td><strong>g.</strong> Operating costs of waterflooding systems- several leases involved</td>
</tr>
</tbody>
</table>
Example – Indirect Cost Allocation

Expenses for District Office A of U.S. Oil Company amounted to $10,000 for the month of May. The district office has supervision over the following leases and wells:

<table>
<thead>
<tr>
<th>Lease</th>
<th>Number of Wells</th>
<th>Barrels of Oil Produced</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>1</td>
<td>1,000</td>
</tr>
<tr>
<td>B</td>
<td>3</td>
<td>500</td>
</tr>
<tr>
<td>C</td>
<td>4</td>
<td>2,000</td>
</tr>
<tr>
<td>D</td>
<td>2</td>
<td>1,500</td>
</tr>
<tr>
<td>Total</td>
<td>10</td>
<td>5,000</td>
</tr>
</tbody>
</table>

a. If the district expense is allocated on the basis of the number of barrels produced, each lease would be charged the following amount:

<table>
<thead>
<tr>
<th>Lease</th>
<th>Computations</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>($10,000/5,000 bbl) x 1,000 bbl</td>
<td>$ 2,000</td>
</tr>
<tr>
<td>B</td>
<td>($10,000/5,000) x 500</td>
<td>1,000</td>
</tr>
<tr>
<td>C</td>
<td>($10,000/5,000) x 2,000</td>
<td>4,000</td>
</tr>
<tr>
<td>D</td>
<td>($10,000/5,000) x 1,500</td>
<td>3,000</td>
</tr>
<tr>
<td>Total</td>
<td>($10,000/5,000) x 1,500</td>
<td>$10,000</td>
</tr>
</tbody>
</table>

b. If the district expense is allocated on the basis of the number of wells supervised, each lease would be charged the following amount:

<table>
<thead>
<tr>
<th>Lease</th>
<th>Computations</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>($ 10,000/10 wells) x 1 well</td>
<td>$ 1,000</td>
</tr>
<tr>
<td>B</td>
<td>($ 10,000/10) x 3</td>
<td>3,000</td>
</tr>
<tr>
<td>C</td>
<td>($ 10,000/10) x 4</td>
<td>4,000</td>
</tr>
<tr>
<td>D</td>
<td>($ 10,000/10) x 2</td>
<td>3,000</td>
</tr>
<tr>
<td>Total</td>
<td>($ 10,000/10) x 2</td>
<td>$10,000</td>
</tr>
</tbody>
</table>
Secondary and Tertiary Recovery

Installation of secondary and tertiary recovery methods frequently requires large expenditures, for example, to drill the injection wells and provide injection equipment. These expenditures are considered part of the development phase and are therefore capitalized and amortized using the unit-of-production method. On the other hand, routine maintenance and operating costs of secondary and tertiary recovery systems are considered production costs and are expensed as incurred.

An example illustrating drilling and operating a secondary recovery system follows:

Example -- Secondary Recovery System

U.S. Oil Company incurred $3,000,000 in drilling and equipping a waterflood secondary recovery system. In the month following completion of the installation, $4,000 was incurred for supplies and fuel to operate the system.

Entries

$3,000,000 should be capitalized into the account named secondary recovery systems. The liability account, notes payable should be increased by $3,000,000. Lease operating expense should be increased by $4,000. Cash should be decreased by $4,000.

Gathering Systems

A gathering system begins with pipelines that move the oil and gas produced from individual wells to a central point where the oil and gas is separated and the BS &W is removed. The oil gathering system includes equipment such as oil and gas separators and gathering tanks. The gas gathering system includes equipment such as compressors and dehydrators.

Attendant costs incurred for gathering system installation are development costs subject to unit-of-production DD&A computations. The operating costs, however, are considered as production costs and are expenses in the current period.

Tubular Goods

Another capital expenditure that gives rise to production costs involves tubular goods. (In the oil and gas industry, tubular goods refers to casing and tubing.) Even though the purchase and installation costs of tubular goods are capitalized, repair and replacement costs are production costs and are expensed as incurred. In general, the price of tubular goods includes the invoice amount and transportation costs.
The following example presents the purchase of tubing for replacement of damaged tubing.

**Example -- Tubular Goods**

U.S. Oil Company obtained a new string of tubing to replace damaged tubing in a producing well on Lease A. The net cost of the new tubing was $100,000, and loading, hauling, and unloading costs were $10,000. Installation costs of the new tubing were $20,000. Record the expenditures.

**Entry**

Lease operating expense is increased by $130,000.
Cash is decreased by $130,000.

**PRODUCTION COSTS STATEMENTS**

Production costs statements or lease operating statements are prepared monthly for each lease or property. Since the individual property has been used as the cost center, these statements are somewhat analogous to an income statement for a property. Some companies include income from production in the statement, while others show expenses only. The entity's share of revenue and its share of the operating expenses are shown. Details of all items are indicated and usually are shown for the current month and for the year-to-date.
CHAPTER 3
DISPOSITION OF CAPITALIZED COST UNDER SUCCESSFUL EFFORTS - (DD&A)
LEARNING OBJECTIVES

Chapter 3 discusses the disposition of capitalized cost using successful efforts method of accounting. Studying this chapter should enable you to:

1. Explain the unit-of-production method of amortization.
2. Illustrate the calculations for the unit-of-production formula used to determine the amount of amortization.
3. Explain and illustrate the DD&A calculations when oil and gas reserves are produced jointly.
4. Discuss the accounting method used for estimated dismantlement and salvage values.
5. Discuss the exclusion of costs or reserves from DD&A calculations.
6. Describe and calculate the revision of DD&A rates.
7. Explain annual and quarterly DD&A calculations.
8. Describe depreciation of support equipment and facilities.
9. Discuss cost disposition through abandonment or retirement of proved property.
DISPOSITION OF CAPITALIZED COST UNDER SUCCESSFUL EFFORTS - (DD&A.)

There are basically three ways by which an enterprise can recognize capitalized acquisition exploration, and development costs as expenses. An enterprise may expense acquisition costs by a valuation allowance, by depletion as the property produces the proved oil and gas reserves, or as a result of abandonment of an unproved property when the enterprise decides it is worthless or allows the lease to expire.

At the time a company decides an exploratory well has not found proved reserves, the company charges the cost of that well to expense. Otherwise, the company handles the cost of exploratory wells that find proved reserves by depreciation, depletion, and amortization on the unit-of-production method during production of the related proved reserves.

Companies amortize acquisition costs of proved properties and capitalized development costs by the unit-of-production method as the properties produce the related reserves. This chapter will discuss the accounting standards and provide examples and interpretations of the various means by which an enterprise disposes of capitalized costs of acquisition, exploration, and development by charges to expense.

The accounts below show the types of costs capitalized as proved properties and wells and related equipment and facilities. Note that only completed costs are included in wells and related equipment and facilities, i.e., wells in progress are not included.

<table>
<thead>
<tr>
<th>Proved Property</th>
<th>Wells and Related E&amp;F</th>
</tr>
</thead>
<tbody>
<tr>
<td>Acquisition costs of property classified as proved, net of impairment</td>
<td>Completed Development costs</td>
</tr>
<tr>
<td></td>
<td>Completed successful exploratory drilling costs</td>
</tr>
</tbody>
</table>

Exhibit 3-1 is a flowchart summary of the four basic types of petroleum industry costs and their accounting treatment. Trace through this flowchart for further clarification or as a refresher of how costs become part of proved properties and wells and related equipment and facilities.
Exhibit 3-1

- **Incur acquisition costs**
  - Capitalize as unproved property
  - Abandoned
  - Impaired
  - Expense
  - Change in status
  - Transfer from unproved property to proved property
  - Add costs to amortization base
  - Amortize costs based on PR
  - Costs of oil and gas produced

- **Incur exploration costs**
  - Type 1 (predrilling)
    - Expensed
    - Dry
    - Add costs to amortization base
    - Amortize costs based on PDR

- **Incur development costs**
  - Type 2 (drilling)
    - Classify temporarily as uncompleted wells, equipment, and facilities
    - Work completed
    - Successful
    - Classify well as dry or successful
    - Capitalize as wells and related equipment and facilities
    - Add costs to amortization base
    - Amortize costs based on PDR
    - Exclude certain costs or reserves

- **Incur production costs**
  - Classified until completed as uncompleted wells equipment and facilities
  - Work completed
  - Proved
  - Transfer from unproved property to proved property
  - Add costs to amortization base
  - Amortize costs based on PDR

- **Impaired**
  - Abandoned

- **Change in status**
  - Recognize loss
Cost Disposition Through Amortization

Acquisition costs of proved properties and the costs of wells and related equipment and facilities are amortized to become part of the cost of oil and gas produced. Acquisition costs are amortized over proved reserves. Wells and related equipment and facilities are amortized over proved developed reserves. Acquisition costs represent expenditures made on behalf of the entire cost center and thus apply to all reserves that will be produced from that cost center. Proved reserves are the reserves reasonably certain of being produced from a property and include both reserves which will be produced from wells already completed and from wells to be drilled in the future. Therefore, proved reserves should be used to amortize acquisition costs. Proved developed reserves are reserves which will be produced from existing wells and equipment. Wells and related equipment and facilities should be amortized using proved developed reserves because, by definition, those are the reserves that will be produced as a result of the costs already incurred for completed wells and equipment.

Under the unit-of-production method, amortization (depreciation) may be computed either on a property-by-property basis or on some reasonable aggregation of properties with a common geological structural feature or stratigraphic condition, such as a reservoir or field. This limits the size of the cost center to a relatively small area and eliminates the prior practice of some companies of using districts, states, and other arbitrary cost centers for amortization purposes.

For a firm with a relatively large number of royalty interests, none of which is individually significant, the enterprise can group the royalty interests without regard to geological structure for purposes of unit-of-production amortization. If reserve estimates are not available, the enterprise may use some method other than unit-of-production.

Both acquisition costs and the costs of wells and related equipment and facilities are amortized using the unit-of-production method.

Unit-of-production formula

\[
\frac{\text{Book value at year end}}{\text{Estimated reserves at beginning of year}} \times \text{Production for year}
\]

Equivalent formula

\[
\frac{\text{Production for year}}{\text{Estimated reserves at beginning of year}} \times \text{Book value at year end}
\]

In these formulas, the book value at year end is used. Book value at year end is the total cost accumulated to year end minus accumulated DD&A at the beginning of the year. Consistency would suggest that a book value at year end would be used with a reserve estimate also at year end, so that all added reserves found by the costs incurred during the year would be included in the DD&A computation. In both formulas, the denominator calls for estimated reserves as of the
beginning of the year. However, instead of using a reserve estimate of the beginning of the year, the most current estimate—preferably an estimate as of the end of the year—should be used. The production during the year is then added to the estimate as of the end of the year to convert the reserve estimate to an estimate as of the beginning of the year. The resulting estimate of beginning of the year reserves would, therefore, include the reserves discovered by costs incurred during the year. In this way, the most accurate estimate is used, one that reflects the additional reserves found by costs incurred during the year.

Example 1

U.S. Oil Company drilled the first successful well on Lease A early in 1994. The company plans to develop this lease fully over the next several years. Data for the lease as of December 31, 1994, is as follows:

Leasehold cost (acquisition cost)                                            $ 50,000
IDC (wells and related E&F)                                                     90,000
Lease and well equipment (wells and related E&F)                    30,000
Production during 1994,                                                              5,000 bbl.
Total estimated proved reserves, December 31, 1994               895,000 bbl.
Total estimated proved reserves recoverable from the well,
December 31 199,4 (proved developed reserves)                        95,000 bbl.

Calculations

a. To calculate DD&A (depreciation, depletion, and amortization), first determine reserves as of the beginning of the year.

PROVED RESERVES (BARRELS):

Estimated proved reserves, December 31, 1994 - end of year 895,000 bbl.
Add: current year's production 5,000 bbl.
Estimated proved reserves, beginning of year 900,000 bbl.

PROVED DEVELOPED RESERVES (BARRELS):

Estimated proved developed reserves,
December 31, 1994 -- end of year 95,000 bbl.
Add: current year's production 5,000 bbl.
Estimated proved developed reserves, beginning of year 100,000 bbl.

b. Second, calculate DD&A rate

FOR ACQUISITION COSTS (LEASEHOLD):
Current year's production  
5,000  
Estimated proved reserves, beginning of year  
900,000  

= .056%

FOR WELLS AND RELATED E&F (IDC AND LEASE AND WELL EQUIPMENT):

Current year's production  
5,000  
Estimated proved developed reserves, beginning of year  
100,000  

= 5%

c. Third, multiply year-end costs by DD&A rates

LEASEHOLD COSTS:

Leasehold costs  
$50,000  
Multiply by DD&A rate  
× 0.0056  
Leasehold DD&A  
$280

IDC AND LEASE AND WELL EQUIPMENT:

IDC  
$90,000  
Add: Lease and well equipment  
$30,000  
Total wells and related E&F  
120,000  
Multiply by DD&A rate  
× 0.05  
Wells and related E&F DD&A  
$6,000  
Total DD&A ($280 + $6,000) = $6,280

Entry to record DD&A

$6,280 should be charged to DD&A expense.

Example 2

Data for U.S. Oil Company’s partially developed lease as of December 31, 1992, is as follows:

COST DATA:

Lease bonus  
$500,000  
Other capitalized acquisition costs  
40,000  
Total leasehold cost at year end  
$540,000  
Accumulated DD&A on leaseholds cost at beginning of year  
40,000  

Lease and well equipment  
275,000  
Accumulated DD&A on equipment at beginning of year  
50,000  

IDC  
650,000
Accumulated DD&A on IDC at beginning of year  120,000

RESERVE AND PRODUCTION DATA:

Estimated proved developed reserves, December 31  1,750,000 bbl
Estimated proved undeveloped reserves, December 31  2,200,000 bbl
Production during year  50,000 bbl

Calculations

a. To calculate DD&A, first determine reserves as of the beginning of the year. Proved reserves are proved developed reserves plus proved undeveloped reserves:

Estimated proved developed reserves, December 31  1,750,000 bbl
Add: Estimated proved undeveloped reserves, December 31  2,200,000 bbl
Estimated proved reserves, December 31, end of year  3,950,000 bbl
Add: Current year's Production  50,000 bbl
Estimated proved reserves, beginning of year  4,000,000 bbl

PROVED DEVELOPED RESERVES:

Estimated proved developed reserves, December 31, end of year  1,750,000 bbl
Add: Current year's production  50,000 bbl
Estimated proved developed reserves, Beginning of year  1,800,000 bbl

b. Second, calculate the DD&A rate.

FOR LEASEHOLD COSTS:

\[
\frac{\text{Current-year's production}}{\text{Estimated proved reserves, beginning of year}} = \frac{50,000}{4,000,000} = 1.25\%
\]

FOR WELLS AND RELATED E&F:

\[
\frac{\text{Current year's production}}{\text{Estimated proved developed reserves, beginning of year}} = \frac{50,000}{1,800,000} = 2.8\%
\]

c. Third, multiply year-end costs by DD&A rates.

LEASEHOLD COSTS:
Leasehold costs $540,000
Less: Accumulated DD&A on leasehold costs 40,000
Net leasehold costs 500,000
Multiplied by DD&A rate x 0.0125
Leasehold DD&A $6,250

IDC AND LEASE AND WELL EQUIPMENT:

IDC $650,000
Less: Accumulated DD&A on IDC 120,000
Net IDC $530,000

Lease and well equipment $275,000
Less: Accumulated DD&A on L&WE 50,000
Net lease and well equipment $225,000

Net IDC $530,000
Add: Net lease and well equipment $225,000
Net wells and related E&F $755,000
Multiplied by DD&A rate x 0.028
Wells and related E&F DD&A $21,140

Total DD&A $6,250 + $21,140 = $27,390

Entry to record DD&A

$27,390 should be charged to DD&A expense.
The accumulated DD&A account should increase by $27,390.

If the production and reserve amounts given in the above example were total production and total reserves from the property, then the unit-of-production formula would actually be the following, assuming a 7/8 working interest:

$$\frac{7/8 \times \text{production for the year}}{7/8 \times \text{reserves at beginning of year}} \times \text{book value at year end}$$

However, the seven-digits cancel, so the formula becomes identical to the formula given earlier.

$$\frac{\text{Production for the year}}{\text{Reserves at the beginning of year}} \times \text{book value at year end}$$

Thus, the 7/8, 5/6, etc., values normally may be ignored.
Oil and Gas Accounting – Part 2

DD&A WHEN OIL AND GAS RESERVES ARE PRODUCED JOINTLY

Many properties contain both oil and gas. In those cases, **convert** oil and gas reserves and oil and gas produced to a common unit of measure based on relative energy content. The BTU content of a barrel of oil may be converted to the BTU content of an Mcf of gas at an approximate rate of 6 to 1. In other words, one barrel of oil is equal to 6 Mcf of gas. The conversion can be made by either multiplying the barrels of oil by 6 to get an equivalent Mcf amount, or the Mcf amount may be divided by 6 to get the equivalent number of barrels.

However, if relative proportion of oil and gas extracted in the current period is expected to remain the same, then amortization may be computed based on only one of the two minerals—either oil or gas.

If either oil or gas clearly dominates both the reserves and the current production based on relative energy content, then amortization may be computed based on the dominant mineral only.

Therefore, if oil and gas reserves are produced jointly, one of three different amortization methods may be used, assuming the appropriate conditions given above are satisfied:

1. common unit of measure-converting to common unit
2. same relative proportion-using either oil or gas
3. dominant material-using the dominant mineral

In practice, the dominant mineral is typically used when oil and gas are produced jointly. Also, in many cases, gas is measured and priced in terms of MMBTU (million British thermal units) rather than Mcf. The MMBTU measurement process of gas may cause a small change in the relative proportion between oil and gas when both are produced jointly, i.e., the conversion ratio may no longer be 6 to 1. However, the conversion process is the same.

**Example--Joint Production DD&A**

U.S. Oil Company has a fully developed producing lease that has both oil and gas reserves. Data for the lease are as follows:

Net capitalized costs, December 31 $2,200,000

Estimated proved developed reserves, December 31:
For oil...............................................................400,000 bbl
For gas.........................................................1,800,000 Mcf

Production during the year:
For oil ....................................................... 50,000 bbl
For gas ....................................................200,000 Mcf

Calculations to determine DD&A based on a common unit of measure

To calculate DD&A, first determine the reserve estimates. All reserves are proved developed because the lease is fully developed.

a. Convert oil bbl to gas Mcf using a ratio of 6:1

Oil reserves:
400,000 bbl x 6 = 2,400,000 equivalent Mcf

Oil production:
50,000 bbl x 6 = 300,000 equivalent Mcf

b. Compute reserves at beginning of year.

Proved developed reserves, December 31:

Oil 2,400,000 equivalent Mcf
Gas 1,800,000 Mcf
Total 4,200,000 equivalent Mcf

Production during year:

Oil 300,000 equivalent Mcf
Gas 200,000 Mcf
Total 500,000 equivalent Mcf

Proved developed reserves, beginning of year:

Proved developed reserves, December 31 4,200,000 equivalent Mcf
Add: Production 500,000 equivalent Mcf
Proved developed reserves, beginning of year 4,700,000 equivalent Mcf

Second, calculate DD&A rate.

For acquisition and wells and related E&F:

Current year’s production 500,000 = 10.6%
Estimated proved developed reserves, beginning of year 4,700,000

Third, multiply year-end costs by DD&A rate. Net capitalized costs for lease as cost center;

Net costs $2,200,000
Multiplied by DD&A rate x 0.106
Total DD&A $ 233,200
Entry

A DD&A expense should be recorded for $233,200. The accumulated DD&A account should increase by $233,200.

Instead assume that oil is clearly the dominant mineral and that U.S. Oil Company decides to calculate DD&A based on the dominant mineral.

Calculations

To calculate DD&A, first determine reserve estimates. Proved developed reserves:

Proved developed reserves, December 31 400,000 bbl
Add: Current year's production 50,000 bbl
Proved developed reserves, beginning of year 450,000 bbl

Second, calculate DD&A rate.

\[
\frac{\text{Current year's production}}{\text{Estimated proved developed reserves, beginning of year}} = \frac{50,000}{450,000} = 11.1\%
\]

Third, multiply year-end costs by DD&A rate. Net capitalized costs:

Net costs $2,200,000
Multiplied by DD&A rate x 0.111
Total DD&A $ 244,200

Entry

A DD&A expense should be recorded for $244,200. The accumulated DD&A account should increase by $244,200.

ESTIMATED DISMANTLEMENT COSTS AND SALVAGE VALUES

Estimated dismantlement, restoration and abandonment costs and estimated salvage values shall be taken into account in determining amortization rates. Firms to not need to apply these provisions to immaterial items. In practice, most companies have taken the position that ordinary abandonments take place each year for onshore properties and that incremental abandonment costs net of salvage values would not be material in any given year. Except for unusual situations, this position is reasonable. Unusual situations include offshore properties where enterprises are required by the terms of the lease to remove facilities, e.g., platforms. Other examples are large leases or federal leases where a firm expects land restoration costs to be significant.

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When firms expect dismantlement, restoration, and abandonment costs to be material, they add the estimated costs to the capitalized costs for purposes of amortization only. The following example illustrates an amortization computation where dismantlement costs are estimated to be material.

**Example -- Dismantlement Costs**

<table>
<thead>
<tr>
<th>Description</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capitalized costs</td>
<td>$10,000,000</td>
</tr>
<tr>
<td>Estimated dismantlement costs</td>
<td>2,500,000</td>
</tr>
<tr>
<td>Estimated salvage value</td>
<td>(500,000)</td>
</tr>
<tr>
<td><strong>Total costs to be amortized</strong></td>
<td><strong>$12,000,000</strong></td>
</tr>
<tr>
<td>Proved reserves at beginning of year</td>
<td>1,000,000 bbls</td>
</tr>
<tr>
<td>Production for year</td>
<td>100,000 bbls</td>
</tr>
<tr>
<td><strong>Unit-of-production rate:</strong></td>
<td></td>
</tr>
<tr>
<td>For costs ($10,000 ÷ 1,000,000 bbls)</td>
<td>$10/bbl</td>
</tr>
<tr>
<td>For dismantlement ($2,000,000 ÷ 1,000,000 bbls)</td>
<td>2/bbl</td>
</tr>
<tr>
<td><strong>Amortization of:</strong></td>
<td></td>
</tr>
<tr>
<td>Capitalized costs (100,000 bbls x $10)</td>
<td>$1,000,000</td>
</tr>
<tr>
<td>Dismantlement costs (100,000 bbls x $2)</td>
<td>200,000</td>
</tr>
<tr>
<td><strong>Total amortization</strong></td>
<td><strong>$1,200,000</strong></td>
</tr>
</tbody>
</table>

In practice, there are at least two methods of recording the amortization relating to the dismantlement costs. One method is to credit the $200,000 to liability account. When the company abandons the property and incurs the dismantlement cost, it charges these costs to the liability account. The company charges or credits to income any difference between actual dismantlement costs and the liability. A second method is to credit the allowance for amortization for the full amount of the amortization, in this example $1,200,000. The company then makes an additional entry for $200,000 to capitalized costs and a liability account. A variation of the above methods is for the company to credit the full amount of amortization to accumulated amortization until the net unamortized costs are zero. The company credits the full amount of amortization from that point forward to a liability account.

Estimating dismantlement costs, etc., is highly subjective and subject to change because of price changes or changes in law, regulation, or technology. Also, the firm may not incur the estimated costs for ten or more years, and the dismantlement process may take several years. Therefore, frequent changes in estimates of dismantlement costs over the life of the property would generally be the rule rather than the exception.

There has been limited experience in accounting for dismantlement costs. Accounting rules specifically requires that firms take dismantlement costs into account when determining
amortization. In the future, however, different thoughts may surface. For instance, another approach would be to consider the present value of estimated future dismantlement costs. Then, firms would discount future dismantlement costs (at an appropriate interest rate) to arrive at a present value amount. They would record this amount as cost of wells, equipment, and facilities with the contra to a liability account. Firms would amortize the amount in wells, equipment, and facilities on the unit-of-production method. They would record changes in the present value of dismantlement costs because of the passage of time as interest expense.

EXCLUSION OF COSTS OR RESERVES

Development costs are amortized over proved developed reserves. If significant development costs such as an offshore platform have been incurred before all planned wells have been drilled, then the portion of the proved reserves which will eventually be produced as a result of both the significant development costs already incurred and the development costs to be incurred in the future would be classified as proved undeveloped reserves. Consequently, unless a portion of the significant development costs already incurred is excluded from DD&A, costs and reserves will be mismatched in the DD&A calculation. For this reason, a portion of those development costs must be excluded in determining the DD&A rate until the additional wells are drilled.

Similarly, if proved developed reserves will be produced only after significant additional development costs, e.g., improved recovery system, are incurred, then those proved developed reserves must be excluded in determining the DD&A rate. However, proved developed reserves are defined to be reserves that are expected to be recovered through existing wells with existing equipment and operating methods. When an improved recovery system is involved, reserves may be classified as proved developed reserves after testing by a pilot project or after the operation of an installed program has confirmed increased recovery will result. Thus, by definition the situation of proved developed reserves being produced only after significant future development costs are incurred should not arise unless an improved recovery system is involved.

Example—Exclusion of Costs

U.S. Oil Company has constructed an offshore drilling platform costing $48,000,000. At year end 1992, only two wells have been drilled, with 46 more wells to be drilled in the future. Proved developed reserves at year end were 3,000,000 barrels, and 300,000 barrels were produced during the year.

DD&A Calculation

A portion of the drilling platform must be excluded in computing DD&A. In this case 46/48 of the $48,000,000 would be excluded.

\[
\text{DD&A} = \frac{2,000,000}{300,000} = \$181,818
\]
In the example, the amount of development costs to be amortized was determined based on the percentage of wells already drilled over total wells, both drilled and yet to be drilled. Other reasonable methods which may be used include drilling costs incurred over total expected drilling costs or proved developed reserves over total proved reserves.

The following example illustrates the situation in which proved developed reserves will be produced only after significant additional development costs are incurred.

Example -- Exclusion of Reserves

U. S. Oil Company has an offshore lease that has proved developed reserves of 50,000,000 barrels at the beginning of the year. Of those 50,000,000 barrels, 10,000,000 are associated with significant development costs to be incurred in the future. Total capitalized drilling and equipment costs (i.e., wells and related equipment and facilities) at the end of the year are $3,000,000. Production during the year was 250,000 barrels.

DD&A Calculation

Proved developed reserves associated with the future development costs must be excluded for the DD&A calculation.

\[
\text{DD&A} = \frac{3,000,000}{50,000,000 - 10,000,000} \times 250,000 \text{ bbl} = \$18,750
\]

Under no circumstances should future development costs be included in computing the DD&A rate.

REVISION OF DD&A RATES

DD&A rates should be revised whenever needed but at least once a year. Any revisions should be accounted for prospectively as a change in estimate. If a company reports on a yearly basis, the revised reserve estimate is used in the year-end DD&A calculation. If a company reports on a quarterly basis, then the effect of a change in an accounting estimate should be accounted for in the period in which the change is made. No restatement of previously reported interim information should be made for changes in estimates. However, interim periods are considered an integral part of the annual period rather than a discrete time period.

The following example illustrates one method used in revising DD&A rates when a new reserve estimate is obtained. In the method shown, the fourth quarter DD&A amount --the quarter in which the revised estimate was received-- is determined by using the new reserve estimate converted to an estimate as of the beginning of the year.
Example 1 - Revision of DD&A Rates

U.S. Oil Company reports on a quarterly basis. On December 2, 1992, the company received a new reserve report dated November 30, 1992, concerning a fully developed lease near Baku. The reserve report showed proved developed reserves of 450,000 barrels. The last report, dated December 31, 1991, showed reserves of 400,000 barrels. Net capitalized costs as of December 31, 1991, were $1,000,000. Production and amortization through the third quarter of 1992 were as follows:

<table>
<thead>
<tr>
<th>Quarter</th>
<th>Production</th>
<th>Amortization</th>
<th>Calculations</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>20,000 bbl.</td>
<td>$50,000</td>
<td>$1,000,000/400,000 x 20,000</td>
</tr>
<tr>
<td>2</td>
<td>16,000 bbl.</td>
<td>40,000</td>
<td>$1,000,000/400,000 x 16,000</td>
</tr>
<tr>
<td>3</td>
<td>22,000 bbl.</td>
<td>55,000</td>
<td>$1,000,000/400,000 x 22,000</td>
</tr>
</tbody>
</table>

October and November 10,000 bbl.  December 13,000 bbl.

Calculations of DD&A

FOR FOURTH QUARTER

Determine the reserve estimate as of the beginning of the year using the new estimate.

Reserve estimate, November 30 | 450,000 bbl
Add: Production 1st quarter | 20,000
Production 2nd quarter | 16,000
Production 3rd quarter | 22,000
Production during October and November | 10,000
Reserve estimate, January 1, 1992 | 518,000 bbl

DD&A, fourth quarter | $1,000,000 x 23,000 bbl | $44,402 | 518,000

FOR FULL YEAR

Amortization for the first three quarters | $ 50,000
| 40,000
| 55,000
Amortization for the fourth quarter | 44,402
| $189,402
Another widely accepted method computes the entire DD&A for the year by using the new estimate and then subtracting the previously recognized quarterly amounts to arrive at the current quarterly amount to be recognized. The following example illustrates this method using exactly the same data as in the previous example.

**Example 2 - Revision of DD&A Rates**

U.S. Oil Company reports on a quarterly basis. December 2, 1992, the company received a new reserve report dated November 30, 1992, concerning a fully developed lease. The reserve report showed proved developed reserves of 450,000 barrels. The last report, dated December 31, 1991, showed reserves of 400,000 barrels. Net capitalized costs as of December 31, 1992, were $1,000,000. Production and amortization through the third quarter of 1992 were as follows:

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<th>Calculations</th>
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</thead>
<tbody>
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<td>1</td>
<td>20,000 bbl.</td>
<td>$50,000</td>
<td>1,000,000/400,000 x 20,000</td>
</tr>
<tr>
<td>2</td>
<td>16,000 bbl.</td>
<td>40,000</td>
<td>1,000,000/400,000 x 16,000</td>
</tr>
<tr>
<td>3</td>
<td>22,000 bbl.</td>
<td>55,000</td>
<td>1,000,000/400,000 x 22,000</td>
</tr>
</tbody>
</table>

October and November 10,000 bbl.
December 13,000 bbl.

**Calculations of DD&A**

Determine the reserve estimate as of the beginning of the year using the new estimate:

- Reserve estimate, November 30: 450,000 bbl
- Add: Production 1st quarter: 20,000
- Production 2nd quarter: 16,000
- Production 3rd quarter: 22,000
- Production during October and November: 10,000
- Reserve estimate, January 1, 1992: 518,000 bbl

DD&A, for the full year = $1,000,000 x 81,000 bbl = $156,371

FOR FOURTH QUARTER

- Amortization for the first three quarters: $50,000
- $40,000
- $55,000
- Amortization for the fourth quarter: $11,371
- $156,371
Annual Quarterly Calculations:

The previous examples demonstrate the calculation of unit-of-production amortization. Although the basic methodology should be about the same for all companies, there are some differences in practice. This is particularly true for those companies that have to report quarterly financial information publicly. In applying this provision, many firms make the calculation of amortization only once a year. Those following this practice normally use the following formula:

\[
\text{Amortization} = \frac{\text{Units of Production for year}}{\text{Units of proved reserves at end of year plus units of production for year}} \times \text{Net unamortized cost at end of year}
\]

Although this method is acceptable and widely practiced in the industry, it may not produce the most realistic result in some instances. For example, when there are significant development costs and/or reserve additions on a previously producing property toward the latter part of the year, this method of amortization considers both additional costs and reserves as if they had been in place at the beginning of the year. This can have the effect of increasing or decreasing the yearly amortization as compared with using the unit-of-production rate prospectively from the time of addition.

Example -- Annual Calculation With Production Change

U. S. Oil Company has working interest in Lease A, which had net unamortized cost at the beginning of the year of $500,000 and proved developed reserves of 50,000 bbls. Production through September was 10,000 bbls. In early October, U.S. Oil Company drills a development well on the lease for $250,000 and adds 12,500 bbls to proved developed reserves. Production from October to December is 3,500 bbls.

Method 1:

Amortization calculated using end-of-year reserves and costs is as follows:

\[
\text{Amortization} = \frac{10,000 \text{ bbls} + 3,500 \text{ bbls}}{50,000 \text{ bbls} + 12,500 \text{ bbls}} \times 750,000 = 162,000
\]

Method 2:

If U.S. Oil Company changes the amortization rate prospectively from October, the yearly amortization is:
9-month amortization = 10,000 bbls x $500,000 = $100,000
50,000 bbls

3-month amortization = 3,500 bbls x $650,000 = 43,355
52,500 bbls

Total amortization $143,355

Although either of the above computations is acceptable, method 2 more clearly reflects the economics of what happened from an operational point of view. (In practice, most enterprises use a technique to estimate the impact on quarterly amortization other than method 2 illustrated above. The example is intended merely to emphasize the difference between the two methods.)

The difference that can result takes on additional significance for public enterprises that must report quarterly earnings to shareholders. These enterprises must make some estimate of quarterly amortization. Although there are several ways in which an enterprise can calculate quarterly amortization, there are two methods frequently encountered in practice. One is to calculate a unit-of-production rate at the beginning of the year and apply that rate to each quarter's production. The enterprise then makes an adjustment in the fourth quarter to bring the yearly amortization to an amount determined by method I above. The other method is to adjust the amortization rate, prospectively each quarter. In this case, the enterprise calculates the unit-of-production rate at the beginning of each quarter then applies this rate to production during that quarter. At the beginning of the second quarter, the enterprise adjusts the, unit-of-production rate for properties with reserve additions (revisions) and increased costs that materially affect the unit-of-production rate. The company then applies the revised unit-of-production rate to the second-quarter production. The same process is applied to the third and fourth quarters. The yearly amortization is then the four individual quarterly computations added together. For properties that do not have a material quarterly change in capitalized costs, the enterprise could make the adjustment to the annual amount of amortization in the fourth quarter without materially affecting amortization for all the quarters.

Example—Quarterly Adjustment

This example illustrates the two methods of calculating quarterly amortization. Assume Company A and Company B each own a 50% interest in Leases X, Y, and Z at January 1. Company A calculates its quarterly provision for amortization using the reserves and costs at January 1 with an adjustment in the fourth quarter. Company B updates its unit-of-production rate quarterly for significant changes in oil and gas reserves and uses the updated rates prospectively. Annual amortization is the sum of the four quarterly calculations. Each company's share of oil reserves and production associated with these leases is as follows:

<table>
<thead>
<tr>
<th>Proved reserves at</th>
<th>Actual production by quarter (bbls)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Lease | January 1 | 1 | 2 | 3 | 4
--- | --- | --- | --- | --- | ---
X | $100,000 bbls | 25,000 | 25,000 | 25,000 | 25,000
Y | $1,000,000 bbls | 10,000 | 40,000 | 40,000 | 40,000
Z | $750,000 bbls | 20,000 | 20,000 | 92,500 | 92,500

Each company's unamortized cost at January 1 is $1,000,000, $5,000,000, and $3,000,000 for Leases X, Y, and Z, respectively. (Leasehold costs have been ignored for this example.) Each company incurs additional development cost of $3,000,000 on Y and $1,000,000 on Z on July 1. The additional development in Y results in an increase of proved developed reserves by 500,000 bbls as of July 1. The development well drilled on Lease Z at July 1 is dry. In addition, accelerated production trends indicate a more rapid depletion of the field, resulting in a decrease of 300,000 bbls in estimated proved developed reserves.

At January 1, Company A computed an amortization rate to be used throughout the year as follows:

Lease

<table>
<thead>
<tr>
<th>Lease</th>
<th>Cost</th>
<th>Proved Developed Reserves</th>
</tr>
</thead>
<tbody>
<tr>
<td>X</td>
<td>$1,000,000</td>
<td>$10/bbl</td>
</tr>
<tr>
<td>Y</td>
<td>$5,000,000</td>
<td>$5/bbl</td>
</tr>
<tr>
<td>Z</td>
<td>$3,000,000</td>
<td>$4/bbl</td>
</tr>
</tbody>
</table>

Company A, under this method, reports amortization each quarter as shown below:

<table>
<thead>
<tr>
<th>Lease</th>
<th>Quarter 1</th>
<th>Quarter 2</th>
<th>Quarter 3</th>
<th>Quarter 4</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>X</td>
<td>$250,000</td>
<td>250,000</td>
<td>250,000</td>
<td>250,000</td>
<td>1,000,000</td>
</tr>
<tr>
<td>Y</td>
<td>50,000</td>
<td>50,000</td>
<td>200,000</td>
<td>233,334</td>
<td>533,334</td>
</tr>
<tr>
<td>Z</td>
<td>80,000</td>
<td>80,000</td>
<td>370,000</td>
<td>1,470,250</td>
<td>2,000,250</td>
</tr>
</tbody>
</table>

The fourth-quarter amortization provision reflects an adjustment for the additional reserves and development cost and reduction of reserve estimate based on an annual calculation. The fourth quarter provision for amortization, which is the annual calculation minus the amounts recorded in the first three quarters, is calculated below:

Lease Y

$8,000,000 ÷ 1,500,000 bbls. = $5.33/bbl
$5.33/bbl x 100,000 bbls = $533,334
$533,334 - $300,000 = $233,334
Oil and Gas Accounting – Part 2

Lease Z

\[
\frac{4,000,000}{450,000 \text{ bbls}} = 8.89/\text{bbl}
\]

\[
8.89/\text{bbl} \times 225,000 \text{ bbls} = 2,000,250
\]

\[
2,000,250 - 530,000 = 1,470,250
\]

As there was no change during the year in Lease X, there was no need for a revision to the amortization estimate at January 1. For Leases Y and Z, Company A recalculated the amortization rate at January 1, taking into effect the development cost incurred on both properties and the decrease in reserves on Lease Z. The full effect of this recalculation is reported in the fourth quarter as illustrated above.

Company A could have recalculated the amortization rate using the additional development cost incurred and decrease in reserves for the applicable quarters. This would have further refined the adjustment in the fourth quarter. Both methods are in practice in the industry.

The calculation of amortization on a quarterly basis by Company B shows the following:

<table>
<thead>
<tr>
<th>Lease</th>
<th>Quarter 1</th>
<th>Quarter 2</th>
<th>Quarter 3</th>
<th>Quarter 4</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>X</td>
<td>250,000</td>
<td>250,000</td>
<td>250,000</td>
<td>250,000</td>
<td>1,000,000</td>
</tr>
<tr>
<td>Y</td>
<td>50,000</td>
<td>50,000</td>
<td>213,514</td>
<td>213,514</td>
<td>527,028</td>
</tr>
<tr>
<td>Z</td>
<td>80,000</td>
<td>80,000</td>
<td>866,341</td>
<td>866,341</td>
<td>1,892,682</td>
</tr>
<tr>
<td></td>
<td>380,000</td>
<td>380,000</td>
<td>1,329,855</td>
<td>329,855</td>
<td>3,419,710</td>
</tr>
</tbody>
</table>

Company B has an annual amortization provision of $3,419,710 (sum of the four quarters above). By making the calculation annually, Company A's amortization provision defers the impact of the additional development cost and downward revision in reserves until the fourth quarter.

This example illustrates the different results in yearly amortization obtained using two methods frequently seen in practice. Quarterly information has taken on increasing importance to the investing community in recent years. For enterprises reporting quarterly information, it is important that they give some recognition quarterly to events that could materially affect the annual amount of amortization.

**DEPRECIATION OF SUPPORT EQUIPMENT AND FACILITIES**

Depreciation of support equipment should be computed using an acceptable depreciation method according to Generally Accepted Accounting Principles (GAAP). Acceptable methods include straight-line, sum-of-the-years-digits, and unit-of-output (e.g., machine hours). GAAP depreciation methods are used rather than the unit-of-production method based upon oil and gas reserves because the support equipment may be used for many different properties involving a large number of different amortization bases. To calculate unit-of-production DD&A, the cost of...
support equipment would have to be allocated to individual amortization bases. This allocation would be difficult or impractical in many situations. Therefore, DD&A based on the units-of-production method often cannot be calculated. Even if the cost of particular support equipment may be allocated to an individual amortization base, the useful life of the support equipment may be significantly different from the life of the related reserves.

**Example Depreciation of Support E&F**

Costs incurred by U.S. Oil during the calendar year 1992 are as follows:

March 1  Purchased seismic equipment, 10-year life $30,000

July 1  Purchased a truck to be used half-time $15,000

hauling seismic equipment and half-time hauling repair parts for producing wells,
3-year life

August 1  Purchased heavy-duty motors for drilling activities, 10-year life $120,000

U.S. Oil Company uses the straight-line depreciation method. Assume zero salvage value for each asset. Compute depreciation and give any entries necessary to record the purchase and depreciation of the equipment.

**Computation of depreciation**

Seismic equipment:

\[ 10/12 \times \frac{30,000}{10} = \text{2,500} \]

Truck:

\[ 6/12 \times \frac{15,000}{3} = \text{2,500} \]

Heavy-duty motor:

\[ 5/12 \times \frac{120,000}{10} = \text{5,000} \]

**Entries**

March 1, 1992:
Capitalize $30,000 to the account - support equipment and facilities

July 1, 1992:
Capitalize $15,000 to support equipment and facilities

August 1, 1992:
Capitalize $120,000 to support equipment and facilities.
December 31, 1992, depreciation:
Expense $3,750 (seismic equipment and ½ of truck)
Expense $1,250 (½ of truck) to production expense
Capitalize $5,000 to wells in progress L&W
Increase accumulated depreciation - support equipment and facilities by $10,000

Cost Disposition Through Abandonment or Retirement of Proved Property

Normally, no gain or loss should be recognized until the last well, item of equipment, or lease in an amortization base is abandoned. Until that time, an abandoned item that is part of an amortization base should be treated as fully amortized and charged to accumulated DD&A. However, if the abandonment or retirement results from a catastrophic event, a loss or gain should be recognized.

Example 1 - Well Abandonment

U.S. Company abandons a well with total capitalized costs of $500,000. This well is located on a lease with ten other producing wells. Total accumulated DD&A for wells and related equipment and facilities on this lease was $1,500,000. No equipment was salvaged.

Entry to record Abandonment

Reduce accumulated DD&A by $500,000.
Reduce wells and related equipment by $500,000

It does not matter if the lease constitutes a separate amortization base because a well is being abandoned and a well is always part of an amortization base. However, it would matter if the well was the last one in the amortization base.

Example 2 - Lease Abandonment

U.S. Oil Company abandons a $70,000 lease with capitalized drilling and equipment costs of $200,000. Equipment worth $30,000 was salvaged.

a. The lease was part of an amortization base with total accumulated DD&A of $700,000.

Entry

Capitalize $30,000 to materials and supplies (salvage).
Reduce accumulated DD&A by $240,000.
Reduce proved property by $70,000.
Reduce well and related equipment by $200,000.
To illustrate the concepts relating to proved property cost disposition under successful efforts as well as to tie together the material learned in the previous chapters, the following comprehensive example is presented.

Comprehensive Example

a. On February 2, 1991, U.S. Oil Company acquired a lease for $100,000. The property was undeveloped and the acquisition costs were considered to be individually significant.

Entry

Capitalize unproved property for $100,000.

b. Several dry holes were drilled on surrounding leases during 1992. As a result, on December 31, 1992, U.S. Oil Company decided the lease was 40% impaired.

Entry

Charge $40,000 to impairment expense. Increase allowance for impairment by $40,000.

c. In January 1993, U.S. Oil Company drilled a dry hole at a cost of $150,000 for IDC and $35,000 for equipment.

Entry to accumulate costs

Capitalize wells in progress - IDC for $150,000 and wells in progress - lease and well equipment for $35,000.

Entry to record dry hole

Charge $185,000 to dry hole expense. Wells in progress - IDC and wells in progress - lease and well equipment should be reduced to a zero balance.

d. Undiscouraged, U.S. Oil company drilled another exploratory well in February at a cost of $500,000 for IDC and $175,000 for equipment.

The well found proved reserves.

Entry to accumulate costs

Capitalize wells in progress - IDC for $500,000 and wells in progress - lease and well equipment for $175,000.

Entry to record completion of well
Transfer $500,000 from wells in progress - IDC to wells and related equipment - IDC. Transfer $175,000 from wells in progress - lease and well equipment to wells and related equipment - lease and well equipment.

**Entry to reclassify property as proved**

Capitalize $60,000 to proved property. Allowance for impairment and unproved property should be reduced to zero balance.

e. The successful well produced 10,000 barrels of oil during 1993. Related lifting costs were $4 per barrel. (Lifting costs should be expensed.)

**Entry**

Charge $40,000 lifting cost to operating expense.

f. During December U.S. Oil Company began drilling a third exploratory well. Accumulated costs by December 31 were IDC of $100,000 and equipment costs of $15,000.

**Entry**

Capitalize $100,000 to wells in progress - IDC and $15,000 to wells in progress - lease and well equipment.

g. The reserve report as of December 31, 1993, showed:

<table>
<thead>
<tr>
<th>Proved reserves</th>
<th>900,000 bbl</th>
</tr>
</thead>
<tbody>
<tr>
<td>Proved developed reserves</td>
<td>300,000 bbl</td>
</tr>
</tbody>
</table>

**DD&A calculation** (assume the lease constitutes a separate amortization base)

Reserve estimates as of beginning of year
Proved reserves = 900,000 + 10,000 = 910,000 bbl
Proved developed reserves = 300,000 + 10,000 = 310,000 bbl

DD&A rate
For acquisition costs
\[
\frac{10,000}{910,000} = 1.1\%
\]

For wells and related E&F
\[
\frac{10,000}{310,000} = 3.2\%
\]

Apply DD&A rates
For acquisition costs  \[ \$60,000 \times 1.12 = \$660 \]

For wells and related E&F  \[ \$675,000 \times 3.2\% = \$21,600 \]
(Note that W P is not included.  
Total DD&A = 22,260

**Entry**

Charge $22,260 to DD&A expense. Increase accumulated DD&A by $22,260.

**h.** During 1994, U.S. Oil Company completed the third well at an additional cost of $300,000 for IDC and $76,000 for equipment. The well was successful.

**Entry to record additional costs**

Capitalize $300,000 to wells in progress - IDC and $75,000 to wells in progress - lease and well equipment.

**Entry to record successful well**

Transfer $400,000 from wells in progress - IDC to wells and related facilities - IDC. Transfer $90,000 from wells in progress - lease and well equipment to wells and related facilities - lease and well equipment.

**i.** During 1994, 30XM barrels of oil were produced. Related lifting costs were $5 per barrel (expense lifting costs).

**Entry**

Charge $150,000 (lifting costs) to operating expense.

**j.** The reserve report as of December 31, 1994, showed:

<table>
<thead>
<tr>
<th>Proved reserves</th>
<th>1,470,000 bbl</th>
</tr>
</thead>
<tbody>
<tr>
<td>Proved developed reserves</td>
<td>970,000 bbl</td>
</tr>
</tbody>
</table>

**DD&A Calculation**

(1) Reserve estimates as of beginning year:
Proved reserves = 1,470,000 + 30,000 = 1,500,000 bbl
Proved developed reserves = 970,000 + 30,000 = 1,000,000 bbl

(2) DD&A rates:
For acquisition costs  \[ \frac{30,000}{1,500,000} = 2\% \]
For wells and related E&F \[ \frac{30,000}{1,000,000} = 3\% \]

(3) Apply DD&A rates:
Acquisition costs = \((60,000 - 660) \times 2\% = \$1,187\)
Wells and related E&F = \((675,000 \text{ (Well 2)} + 490,000 \text{ (Well 3)} - 21,600) \times 3\% = \$34,302\)
Total DD&A = $1,187 + $34,302 = $35,489

**Entry**
Charge $35,489 to DD&A expense. Increase accumulated DD&A by $35,489.

1. A disaster struck and U.S. Oil Company abandoned the lease. No equipment was salvaged.

**Entry**
Charge $1,167,251 to surrendered lease expense.
Write off the following accounts:

Accumulated DD&A – total $57,749
Surrendered lease expense 1,167,251

Proved property $60,000
Wells and related E&F – IDC 900,000
Wells and related E&F – L&WE 265,000

The following comprehensive example illustrates accounting for the disposition of costs on a field-wide basis rather than a lease or reservoir basis.

**Example—Field DD&A**

U.S. Oil Company computes DD&A on a field-wide basis. Balance sheet data as of 12/31/92 for U.S. Oil Company’s field are as follows:

Unproved properties, net of impairment 200,000
Proved properties $500,000
Less: Accumulated DD&A 200,000
Wells and related E&F – IDC 2,100,000
Less: Accumulated DD&A – IDC 600,000
Wells and related E&F - L&WE 800,000
Less: Accumulated DD&A – L&WE 250,000

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U.S. Oil Company’s activities during 1993 were as follows:

Unproved properties acquired $50,000
Test well contributions paid 30,000
Lease record maintenance, unproved properties 10,000
Title defenses paid 20,000
Unproved properties proved during 1993, net of impairment 60,000
Impairment of unproved properties 40,000
Exploratory dry hole drilled 300,000
Successful exploratory well drilled 500,000
Development dry hole drilled 350,000
Service well 275,000
Tanks, separators, etc. installed 100,000
Development well, in progress 12/31/93 160,000

Production

<table>
<thead>
<tr>
<th></th>
<th>Oil (bbl)</th>
<th>Gas (Mcf)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production</td>
<td>50,000</td>
<td>200,000</td>
</tr>
<tr>
<td>Proved reserves, 12/31/93</td>
<td>900,000</td>
<td>3,000,000</td>
</tr>
<tr>
<td>Proved developed reserves, 12/31/93</td>
<td>500,000</td>
<td>1,600,000</td>
</tr>
</tbody>
</table>

Additional data: A truck serving this field was driven 4,000 miles during 1993. Total estimated miles for the truck are 50,000. The truck cost $12,000 and salvage value is estimated to be $0.

**DD&A calculations**

### PRODUCTION

<table>
<thead>
<tr>
<th></th>
<th>Oil: 50,000 x 6 = 300,000 Eq. Mcf</th>
<th>Gas: 200,000</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>900,000 x 6 = 5,400,000 Eq. Mcf</td>
<td>3,000,000</td>
</tr>
<tr>
<td></td>
<td>500,000 Eq. Mcf</td>
<td>8,400,000 Eq. Mcf</td>
</tr>
</tbody>
</table>

### PROVED DEVELOPED RESERVES

<table>
<thead>
<tr>
<th></th>
<th>Oil: 50,000 x 6 = 300,000 Eq. Mcf</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Gas: 1,600,000 x 6 = 1,600,000</td>
</tr>
<tr>
<td></td>
<td>1,900,000 Eq. Mcf</td>
</tr>
</tbody>
</table>

Leasethold
Costs to amortize:

| Proved properties, net at 12/31/92 | $300,000 |
| Properties proved during 1993      | 60,000   |
|$$\text{Leasethold}$$ $360,000 \frac{500,000}{8,400,000 + 500,000}$$ | $20,225 |

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Wells
Cost to amortize:
IDC, net $1,500,000
L&WE, net 550,000
New successful exploratory well 500,000
New development well 350,000
New service well 275,000
New tanks, etc. 100,000
$3,275,000

$3,275,000 x 500,000 = $321,078
4,600,000 + 500,000

Truck:
$12,000 x 4,000 ÷ 50,000 = $960

Entry
DD&A expense-proved property, 20,225
DD&A expense-lease and well equipment 321,078
Depreciation expense-truck 960
Accumulated DD&A-proved property 20,225
Accumulated DD&A-lease and well equipment 321,078
Accumulated depreciation-truck 960

Ceiling Test - Successful Efforts

Generally Accepted Accounting Principles (GAAP) requires inventory reduction when the expected future net cash flows from inventory is less than cost. The reduction is treated as a loss on the income statement. The practice of applying the realization concept to all balance sheet assets has become an accepted accounting principle, even though no definitive position has been taken by the accounting rule-making bodies. The realization concept would also seem to be applicable to proved property and wells and related equipment and facilities. Consequently, when capitalized costs exceed the expected future net realizable value of reserves, the costs should be reduced to expected future benefit and the loss charged to the income statement. In other words, if the expected revenue from oil and gas sales less production costs (ceiling) is less than capitalized costs, theoretically a portion of the capitalized costs should be written off.
LEARNING OBJECTIVES

Chapter 4 presents a brief discussion of mineral interests and conveyances. Studying this chapter should enable you to:

1. Explain the concept of mineral interests.
2. Describe the various types of mineral interests.
3. Discuss the various methods of conveying mineral interests.
4. Discuss the accounting for conveyances.
CONVEYANCES

There are different ways to acquire mineral interests in properties. Such interests may be acquired by a lease from the landowner either, directly or indirectly through a broker. Land may be purchased whereby the ownership of the minerals of the land and the right to remove those minerals are included in the land acquisition (total costs of the acquisition would be allocated between the surface and various mineral rights). Finally, mineral interests may be acquired by conveyance or assignment from a third party. There is a wide variety of these types of conveyances. Knowing how to account for conveyances should become a top priority for the oil and gas accountant, for it is this area of oil and gas accounting that can either save or cost a company a great deal in time and money.

Subsurface rights include minerals in and under a tract of land. Various types of mineral interests can be separated in whole or in part from the surface right. By the same token, rights to exploit one resource can be separated from rights to exploit another resource. It must be emphasized that the discussion of mineral interests is concerned with their accounting treatments for oil and gas and not with other types of minerals.

Minerals

As a bundle of legal rights, minerals may be defined as the total of all rights to oil and gas in place. Although the owner of the minerals frequently does not own the surface of the land under which the minerals lie, ownership of the minerals carries with it the right to make such reasonable use of the surface as is necessary to develop the property for production of oil and gas. The owners of minerals have the right to reduce the deposits in their possession and remove them from the property. It is the owners of the minerals, not the surface owners, who have the right to grant an oil and gas lease. They are also entitled to any lease bonus and delay rentals that may be payable in connection with a lease. The owner of the minerals may assign all, a segregated portion, or an undivided fractions. The owner may make a so-called horizontal assigning all or some portion of the minerals above or below specified depths.

When the mineral rights are assigned, the assignors may reserve to themselves the portion of any bonus or delay rentals arising out of future leasing arrangements that would accrue to their assignees. Interest so assigned is described as non-participating minerals. The minerals can be regarded as the sum of two major interests, the royalty and the operating interest, which is called a working interest.

ROYALTY

A royalty interest is a right to oil and gas in place that entitles its owner to a specified fraction, in kind or in value, of the total production from the property, free of expense of development and operation. It is, therefore, a mineral interest stopped of the burdens and rights of developing the property.
WORKING OR OPERATING, INTEREST

The mineral interest minus any non-operating interest equals the working, or operating, interest in a mineral property. This interest in an oil and gas property is usually called the working interest. The working interest is an interest in minerals in place burdened with the cost of development and operation of the property. Because the interest must bear the burden of these expenses, it receives a large share of the total production from the property.

OVERRIDING ROYALTY

An overriding royalty is similar to a royalty in that each is a right to minerals in place and entities their owners to a specified fraction of production, in kind or in value. Neither is burdened with the costs of development or operation. They differ in that an owner creates an overriding royalty from the operating interest, and its term is co-extensive with that of the operating from which it was created.

NET PROFITS INTEREST

A net profits interest is an interest in minerals in place that is defined as a share of gross production measured by net profits from operation of the property. As with the overriding royalty, an owner creates a net profits interest out of the working interest. Its duration is also similar. Unlike the overriding royalty, specified development and operating costs reduce the income accruing to the net profits interests. The interest bears such expenses only to the extent of its share of the income. It is not required to pay out, advance, or become liable for these costs, as is the working interest.

PRODUCTION PAYMENT

A production payment is a contractual arrangement that gives the owner a right to receive a fraction of production or proceeds from the sale of production until the owner receives a specified quantity of minerals or a definite sum of money, which can include “interest” or a definite sum of money plus interest. A production payment is a non-operating interest, although the owner bears no part of exploration, development, or operating costs.

CARRIED INTEREST

The carried interest is an arrangement between the two or more co-owners of a working interest, whereby one agrees to advance all or some part of the development costs on behalf of the other and to recover such advances from future production, if any, accruing to the owner's share of the working interest. The owner who advances the costs is known as the carrying party, and the owner for whom costs are advanced is called the carried party. A carried interest may extend to partial or full development of the property.
FARM-OUT ARRANGEMENT

This is an arrangement in which the owner or lessee of mineral rights (the party) assigns part of a working interest to an operator (the second party), the consideration for which is specified exploration and/or development activities. The first party retains an overriding royalty or other type of economic interest in the mineral production. The arrangement from the viewpoint of the second party is termed a “farm-in arrangement.”

DRILLING ARRANGEMENT

This is a contractual agreement under which a working interest owner (the assignor) assigns a part of a working interest in a property to another party (the assignee) in exchange for which the assignee agrees to develop the property. A drilling arrangement is an agreement by which an operator assigns fractional shares in production from a property to participants for cash considerations, as a means of acquiring cash for developing the property. Under a disproportionate cost drilling arrangement, the participants normally pay a greater total share of costs than the total value of the fractional shares of the property received in the arrangements.

FREE WELL

A free well is a well drilled and equipped by an assignee as consideration for the assignment of fractional share of the working interest, commonly under a farm-out agreement.

UNITIZATION

This is the joint operation as single property of several smaller individual properties. The purpose of unitization is to form a larger and more economically efficient entity for exploration or development.

CONVEYANCE OR BORROWING

Certain transactions referred to as conveyances are often no more than finance arrangements. If cash advances are made to finance exploration in return for the right to purchase the oil or gas discovered, and the advances are repayable in cash should insufficient oil and gas be produced, the transaction is in substance a borrowing and shall be accounted for as a receivable by the lender and a payable by the borrower. Also, if funds are advanced that are repayable in cash out of the proceeds from a specified share of future production until the advance plus interest is paid in full, the transaction shall be accounted for as a borrowing. The key to determining whether a transaction is a conveyance or a borrowing is the element of a specified repayment provision. A conveyance does not specify a fixed dollar amount.
TYPES OF CONVEYANCES

(1) An “overriding royalty” transaction involving the assignment of the operating interest in an unproved property with retention of a non-operating interest in return for drilling, development, and operation by the assignee,

(2) A “free well” transaction involving the assignment of a part of an operating interest in an unproved property in exchange for the drilling of a well with provision for joint ownership and operation,

(3) A “carried interest” transaction is the assignment of a part of an operating interest whereby the assignee agrees to pay for all costs of drilling, developing, and operating the property and is entitled to all of the revenue from the production of the property, excluding any third-party interest, until the assignee's costs have been recovered, at which time the assignor will share in both costs and production,

(4) A transaction involving a joint venture where part of an operating interest is exchanged for part of an operating interest owned by another party, and

(5) A unitization transaction in which all operating and nonoperating participants pool their assets in a producing area to form a single unit and in return receive an undivided interest in that unit.

ACCOUNTING FOR CONVEYANCE - NO GAIN OR LOSS

The “overriding royalty,” the “free well,” the “carried interest” transactions, and unitization are all considered pooling of assets in a joint undertaking and thus no gain or loss is recognized. In accounting for the costs involved in these transactions, the following treatments are required:

a. “Overriding royalty” transaction - the assignor’s cost of the original interest becomes the cost of the interest retained. None of the assignee’s costs are allocated to the mineral interest acquired.

b. “Free well” transaction - the assignor records no cost for the required well. The assignee records no cost for the mineral interest acquired.

c. “Carried interest” transaction - the assignee or carried party does not account for any costs and revenue until after payout of the carried costs by the assignor or carrying party.
d. Joint venture - each party shall account for its own cost.

e. Unitization - the cost of the assets contributed plus or minus any cash paid or received is the cost of the participant's undivided interest in the assets of the unit.

A carried interest situation becomes a joint working interest upon payout. The computation of the number of barrels that must be produce and sold in order for the carrying party to recover its costs, i.e., barrels until payout, should be examined carefully. The WI owner pays all the lifting costs but receives only a portion of the revenues. Therefore, in the computation of the number of barrels until payout, 100% of the lifting costs incurred per barrel should be subtracted from the portion of the selling price to be received by the WI owner.

Another important and difficult feature of the carried interest is the computation of DD&A before payout. Before payout, the carried party does not recognize DD&A because all of the WI's share of production belongs to the carrying party. In the carrying party's computation of DD&A, the estimate of proved developed reserves used is the carrying party's portion of reserves. (The royalty interest's portion of reserves and production may be ignored. The carrying party's portion of reserves is the number of barrels necessary to recover his costs, i.e., barrels until payout, plus the carrying party's share of the reserves remaining after payout.)

**ACCOUNTING FOR CONVEYANCE - LOSSES MAY BE RECOGNIZED**

The next two types of conveyances do not recognize gain at the time of conveyance but may recognize a loss. They are:

a. A part of an interest owned is sold and the exists a substantial amount of uncertainty as to the recovery of the costs applicable to the retained interest, and

b. A part of an interest owned is sold and the seller has a substantial obligation for future performances. Conveyances which are classified in this third and fourth category are characterized by the uncertainties of cost recovery (e.g., oil and gas is not discovered) or future substantial obligations (e.g., drill a well or operate the property without reimbursement).

**ACCOUNTING FOR CONVEYANCE - LOSS ONLY**

Where an uncertainly exists as to the recoverability of the cost associated with the retained interest, proceeds from the sale of the partial interest should first be applied to the recovery of the cost associated with that partial Interest and next to the recovery of the cost of the retained interest. When all costs have been recovered, then a gain can be recognized. However, if the proceeds are inadequate to recover the costs of the partial interest sold, a loss should be recognized. Further, the carrying amount of the interest retained is subject to the impairment assessments.
OTHER CONVEYANCES

When there exists a substantial obligation for future performance, initial receipts should be deferred and recognized as the obligation is fulfilled.

a. Other conveyances is a broad category that includes any other “sale” transactions which are not included in the previously discussed categories. Accounting for these transactions will vary based on their substance, the uncertainties involved, and the nature of the property (i.e., individually insignificant or a proved property). The following are a few examples of the more common transactions in this broad category:

(1) Sale of entire interest in an unproved property. If impairment has been assessed individually, gain or loss should be recognized on any sale of an entire interest of an unproved property. If, however, impairment has been assessed on a group basis, neither a gain nor loss is recognized unless the sales price exceeds the original cost of the property, in which case gain is recognized in the amount of the excess sales price.

(2) Sale of entire interest in a proved property. The difference between the sales price and the unamortized cost should be recognized as a gain or loss.

(3) Sale of part of a proved property. This transaction is accounted for as a sale of an asset with the appropriate gain or loss recognized at time of sale, unless the transaction can be shown as a normal retirement which does not significantly affect the unit-of-production amortization rate. Costs are to be apportioned to the interest sold and retained on the basis of fair value.

(4) Sale of part of an unproved property involving cash equivalent with no overriding royalty. The proceeds from the sale are treated as a recovery of the cost due to the uncertainty involved in the recovery of the cost applicable to the retained interest. Again, however, if the sales price exceeds the carrying amount of the property, gain should be recognized for such excess.

(5) Sale of part of a proved property with an overriding royalty. This transaction should be accounted for as a sale of an asset and gain or loss should be recognized on the basis of the fair values of the interests sold and retained.

(6) Sale of proved property subject to a fixed sum of money payable out of Production. If the receipt of the retained production payment is reasonably assured, the present value of that payment should be recorded as the sales price with recognition of gain or loss. If payment is not reasonably assured, the transaction should be accounted for as an overriding royalty as discussed above.

(7) Sale of proved property subject to a variable sum payable out of production. These transactions should be accounted for as overriding royalty transactions as previously discussed.
CHAPTER 5
JOINT INTEREST ACCOUNTING
LEARNING OBJECTIVES

Chapter 5 discusses the various types of joint ventures and presents information relating to the accounting methods used to record the transactions. Studying this chapter should enable you to:

1. Identify and describe the various types of joint ventures.

2. Illustrate the accounting procedures used for accumulation of joint costs in joint interest accounts.

3. Illustrate the accounting procedures used for accumulation of joint costs in operator’s regular accounts.

4. Illustrate the accounting procedures used for material transfer pricing.
JOINT INTEREST ACCOUNTING

Classification of Interests

The mineral interest in a property may be divided into operating (working) interests and non-operating (non-working) Interests. A working interests, however, can be classified as a basic, joint, pooled, or unitized interest. A non-operating interest can be classic as a royalty, overriding royalty, production payment, net profits, or carried interest. These interests can be obtain not only through leasing, but also through purchases or exchanges or through sharing arrangements.

Types of Interests

Basic WI--one WI owner and one lease make up the basic working interest.

Joint WI (JI)--two or more parties each own an undivided fraction of the working interest in a single lease. A joint working interest may result from one of three methods mentioned above, i.e., (1) leases, (2) purchases or exchanges, or (3) sharing arrangements. The joint interest format is very popular because it provides a means of sharing the high risk and high capital investment associated with oil and gas ventures.

One party (usually the party with the largest interest) has the responsibility of developing and operating the property. This party is known as the operator. In a joint interest situation, the parties enter into a joint operating agreement. This agreement specifies the rights and obligations of each party.

Example – Joint WI

U.S. Oil Company and Texas Oil Company together purchased the WI in a 300 acre lease in China. The two companies signed an operating agreement designating U.S. Oil Company as the operator of the lease. The two companies will share equally in the development and operating costs and the revenue from the property.

Pooled WI--two or more properties are combined. They may have the same or different WI owners. The non-WIs may be combined separately at the same time. If the WIs are held by two or more parties, a joint operating agreement is entered into and one of the parties is designated as operator. Pooling, which may be voluntary or mandatory, usually results in more efficient operations and a greater recovery of oil and gas.

Example–Pooling

U.S. Oil Company, Texas Oil Company and ABC Oil Company each own the WIs in small contiguous leases in Azerbaijan. In order to develop and operate the properties efficiently, the three companies decide to pool their leases and enter into a joint operating agreement.
Development and operating costs and revenue are to be allocated based on number of acres contributed to the pool.

**Unitized WI** -- two or more WIs in different properties are combined. The non-WIs are usually combined at the same time. Unitization is similar to pooling, except unitization always involves WIs owned by two or more parties. In addition, unitizations usually occur after the leases involved have been at least partially developed, whereas poolings usually occur before any development of the leases. The purpose of unitization is more economical and efficient development and operation. In particular, a unitization may be necessary to conduct secondary or tertiary recovery operations.

One party, known as the unit operator, has the responsibility of developing and operating the unit.

In a unitization, the parties enter into a unitization agreement. This agreement defines the areas to be unitized and specifies the rights and obligations of each party.

**Example--Unitization**

U.S. Oil Company, Texas Oil Company and ABC Oil Company each own WIs in producing leases that share a common reservoir. Production from the reservoir is declining, and an engineering study recommends waterflooding. In order to waterflood the reservoir effectively, the three companies decide to form a unit and therefore enter into a unitization agreement. The agreement specifies that development and operating costs and revenue from production will be allocated based on the agreed-upon participation factors. The participation factors are based upon the estimated volume of hydrocarbons in place contributed by each party.

**Sharing Arrangements**--an arrangement under which a party makes a contribution to the acquisition, exploration, or development of a mineral property and in return receives as consideration an economic interest in the property. A carried interest and a free-well arrangement are typical sharing arrangements.

**Carried Interest**--an arrangement between two or more WI owners or between two or more parties where one party owns all of the WI. In the latter type of arrangement, which is more common, the non-working interest owner-the carrying party-agrees to drill, equip, and operate one or more wells in return for a fraction of the working interest and the right to recover his costs (or a greater amount) out of the carried party’s share of production proceeds. A carried interest agreement usually results in a joint working interest after payout, i.e., after recoupment by the carrying party of all the agreed-upon costs.

**Example -- Carried Interest**

Texas Company is not financially able to develop a small lease in Houston and so assigns to U.S. Oil Company 60% of the WI in the lease. In exchange, U.S. Oil Company agrees to develop and
operate the lease. The operating agreement signed by both parties specifies that Texas Company is to be carried until development of the lease is completed and that Texas Company has the right to keep 100% of the proceeds from production until all of his costs are recovered. U.S. Oil Company’s cost of development total $500,000. Total revenue from production the first year amounts to $800,000 and operating costs are $150,000. Assuming a 1/8 royalty, the royalty owner will receive $100,000, U.S. Oil Company will recover their development and operating costs, and the remaining $50,000 will be split 60-40 between the two companies.

Free-Well Agreement -- an agreement in which the owner of a WI transfers a fraction of the WI to a second party in exchange for the second party agreeing to drill (and possibly equip) a well free of cost to the first party. The agreement may include more than one well, or the free well may need to be a producing well. A free-well agreement usually results in a joint working interest.

Example—Free Well

Texas Oil Company does not have the financial resources to develop a lease in Canada and so assigns 25% of its 7/8 WI to U.S. Oil Company in return for U.S. Oil Company drilling and equipping one well on that lease free of cost to Texas Company.

Farm-in/Farm-out-- an arrangement in which the owner of a WI assigns the WI to another party for the development and operation of the property and retains an overriding royalty. This term is also used in a broader sense to mean any type of sharing arrangement. In many farm-outs where an ORI is retained, the farm-out agreement specifies that the ORI will become a WI following payout (the point at which the party developing and operating the property recovers all of his costs).

Joint Interest Accounting

A joint working interest exists when two or more parties jointly own the working interest. Most oil and gas exploration and production activities are performed using a joint venture format, i.e., a joint working interest. Each working interest owner receives his share of the revenue from the sale of oil or gas, either directly from the purchaser or from the operator who serves simply as a conduit for the revenue. The operator also pays the costs of development and operation and then bills the non-operators for their portion of the costs. Financial accounting for a joint venture differs from accounting for a partnership in that each WI owner maintains his own accounting records.

In a joint venture, the parties normally enter into a joint operating agreement in which one of the parties is designated as the operator and the other parties are designated as non-operators. Joint interest accounting is conducted in accordance with the operating agreement, which includes agreed-upon accounting procedures.
The operating agreement requires that in most cases the operator pay all costs of developing and operating the joint property and then bill the non-operators for their proportionate share. The major accounting problem relating to joint ventures is the accumulation of these costs under the provisions of the joint operating agreement and their distribution among all of the WI owners. When a joint operating agreement exists, the operator has a choice between the distribution of costs as incurred or the distribution of costs after accumulation.

**DISTRIBUTION OF JOINT COSTS AS INCURRED**

In the following example, which illustrates the distribution of joint costs as incurred, the operator charges his regular (non-joint interest) accounts and recognizes a receivable from the non-operators for their portion of the costs as each transaction occurs.

**Example—Distribution of Joint Costs as Incurred**

U.S. Oil Company owns 60%, Texas Oil Company owns 10% and Alpha Oil Company owns 30% of the joint working interest property 1002. Minor workover costs of $10,000 are incurred. U.S. Oil Company is the operator.

**Entry**

- **Lease operating expenses (60% x $10,000)** .............................................. 6,000
- **Accounts receivable - Gary (10% x $10,000)** ............................................. 1,000
- **Accounts receivable - Lee (30% x $10,000)** ................................................ 3,000
- **Cash** ........................................................................................................... 10,000

Charge $6,000 to lease operating expense. Capitalize $1,000 to accounts receivable - Texas Oil and $3,000 to accounts receivable - Alpha Oil.

The preceding entry format would be used for each transaction. However unless completely computerized, this method would not be practical for joint interest situations involving numerous transactions. Consequently, distribution of costs as incurred has not been commonly used in practice.

**ACCUMULATION OF JOINT COSTS IN JOINT INTEREST ACCOUNTS BY JOINT ACCOUNTING PROCEDURES**

Joint costs may also be accumulated in joint interest accounts according to joint accounting procedures and distributed among the WI owners at the end of each month. Under this method, costs are accumulated in a joint interest control account during the month using subsidiary ledgers. A subsidiary ledger account, is maintained by the operator for each type of expenditures. At the end of the month, the operator closes out the costs in the joint interest account by recognizing a receivable from the non-operators for their portion of the costs incurred during the
month and charging his own regular accounts, i.e., operating expense, wells and related equipment and facilities, etc., for his portion of the costs. The following example illustrates this method of accounting for joint interest costs.

**Example—Accumulation of Joint Costs in Joint Interest Accounts**

U.S. Oil Company incurs the following costs during October 1995 in connection with lease number 1002. Assume the same ownership and operator as in above example.

- Salaries and wages, field employees $5,000
- Contract service, reacidizing 2,500
- Purchase of new valves for Christmas tree 900
- Equipment from operators inventory 600
- Overhead (2 wells at $1,200 per well) 2,400

**Entries** during month by operator

Charge $7,500 ($5,000 salaries and $2,500 service) to Joint interest suspense (JIS) - operating expense.
Capitalize $1,500 ($900 valves and $600 equipment) to JIS-lease and well equipment.
Charge JIS-operating expense for $2,400.

**Entries** at end of month

U.S. Oil Company

<table>
<thead>
<tr>
<th>Description</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lease operating expense (60% x $9,900)</td>
<td>5,940</td>
</tr>
<tr>
<td>Wells and Related E&amp;F (60% x $1,500)</td>
<td>900</td>
</tr>
<tr>
<td>Texas (10% x ($9,000 + $1,500)</td>
<td>1,140</td>
</tr>
<tr>
<td>Alpha (30% x ($9,900 + $1,500)</td>
<td>3,420</td>
</tr>
</tbody>
</table>

Charge $5,940 to lease operating expenses.
Capitalize $900 into wells and related equipment.
Capitalize $1,140 as accounts receivable - Texas Company
Capitalize $3,420 as accounts receivable - Alpha Company

**TEXAS COMPANY**

Reduce JIS account(s) to a zero balance
Charge $990 to lease operating expense.
Capitalize $150 as wells and related equipment.
Record $1,140 as accounts payable - U.S. Oil Company.
ALPHA COMPANY

Charge $2,970 to lease operating expense.
Capitalize $450 as wells and related equipment.
Record $3,420 as accounts payable - U.S. Oil Company.

The actual overhead costs would have been charged to the overhead expenses controlling account when incurred.

As shown in the above example, some costs such as materials and overhead are accumulated during the month in a regular (non-joint interest) controlling account in the general ledger. When material is purchased, a regular account such as materials and supplies is debited; when material is transferred to the joint interest lease, the joint interest suspense (JIS) account is charged.

Overhead costs (non-direct costs) such as administrative, supervision, office services, warehousing costs, etc., are charged to the overhead expense/controlling account as incurred. An overhead charge to the JIS account is generally made at month’s end. This charge is determined by applying the agreed-upon percentage or fixed-rate amount as specified in the accounting procedure. The accounting procedure provides for two different methods for charging overhead to the JIS account: the percentage method and the fixed-rate basis method. The percentage method provides for charging the JIS account a predetermined percentage of development or operating costs incurred during the month. The fixed-rate method provides for charging the JIS account a fixed rate, commonly based upon the number of wells being drilled or produced.

Generally, the overhead controlling account charges will not match the overhead amounts allocated to the JIS operating expense account. An operator may operate several different properties; therefore, only a portion of the total overhead is allocated to each property. Further, the total allocation to all properties may be greater than or less than the actual overhead incurred.

ACCUMULATION OF JOINT COSTS IN OPERATOR'S REGULAR ACCOUNTS

If the operating agreement does not require a joint interest account, transactions may initially be recorded in the operator’s regular accounts rather than in a JIS account. Regular accounts are those accounts normally used by the operator, such as salaries and wages, equipment, and lease operating expense. When this method is used, the regular accounts associated with joint interest properties are identified as such.

As illustrated in the following example, the costs incurred by the operator during the month are initially charged to the operator's regular accounts. At the end of each month, the operator recognizes a receivable from the non-operator(s) and credits his regular accounts for the non-operators’ portion of the costs incurred during the month. The operator’s portion of the costs
incurred during the month are thus left in his regular accounts. In contrast, in the previous example when the JIS subsidiary accounts were closed out, the operator had to charge the appropriate regular accounts to get his portion of the costs on his books.

**Example—Accumulation of Joint Costs in Regular Accounts**

U.S. Oil Company incurs the following costs during October 1985 in connection with lease number 1002. Assume the same ownership and operator as in previous examples.

Salaries and Wages, field employees .............................................. $5,000  
Contract service, reacidizing ................................................... 2,500  
Purchase of new valves for Christmas tree .................................. 900  
Equipment from operator’s inventory .......................................... 600  
Overhead (2 wells at $1,200 per well) ........................................... 2,400

**Entries during month by operator**

Charge lease operating expense, joint lease for $5,000 (wages)  
Charge lease operating expense, joint lease for $2,500 (contract service)  
Charge lease and well equipment, joint lease for $900 (valves)  
Charge lease and well equipment, joint lease for $600 (equipment)

**Entries at end of month**

U.S. Oil Company

Capitalize $1,140 as accounts receivable - Texas Company  
Capitalize $3,420 as accounts receivable - Alpha Company

**Calculation**

Texas Company (10% x $11,400) ......................................................... $1,140  
Alpha Company (30% x $11,400) ..................................................... $3,420

Reduce the joint lease account and the overhead expense controlling account by $4,560.  
Charge lease operating expense for $1,440.

Lease operating expense (60% x $2,400) .............................................. $1,440  
Overhead expense - controlling account .......................................... $1,440

Texas Company

Capitalize wells and related equipment for $150.  
Charge lease operating expense for $990.
Record $1,140 as accounts payable - U.S. Oil Company.

Alpha Company

Capitalize $450 as wells and related equipment.
Charge $2,970 to lease operating expense
Record $3,420 as accounts payable - U.S. Oil Company

POOLED AND UNITIZED WORKING INTERESTS

If the working interests combined in a pooling are held by two or more parties, then a joint operating agreement is entered into. The pooled interest is then a joint working interest situation and is accounted for as described in the previous section.

A unitization is more complicated than a pooling because in a unitization proved reserves are known to exist, whereas in a pooling proved oil or gas reserves are not known to exist. Further, in a unitization the leases are commonly in different stages of development, whereas in a pooling the leases have not been developed. These complications require determination of participation factors and equalization of investment in a unitization.

When several leases are combined into a unit, the percentages owned by the WI owners in each lease are changed to percentage ownership in the unit. The percentage ownership in the unit is determined by participation factors. Participation factors are usually determined based on the estimated volume of hydrocarbons in place contributed by each WI owner.

After the participation factors have been agreed upon, the investment is equalized. Equalization of investment is generally necessary because a WI owner’s percentage ownership (based on the participation factors) of the unit's IDC and equipment is commonly either more or less than the value of the IDC and equipment contributed to the unit by the working interest owner. Equalization of investment is normally accomplished by either paying or receiving cash. A working interest owner, receiving a greater portion of the value of the unit's total IDC and equipment than was contributed by that WI owner, pays cash; a WI owner, receiving less than the amount contributed, receives cash.

After the participation factors have been determined and the investment has been equalized, the unit WI owners enter into a unit operating agreement, and the accounting for the unit is as described in the joint interest section.

Additional Considerations

MATERIAL TRANSFER PRICING
One of the most difficult and challenging problems facing a joint interest operator is the pricing of material transferred to and from the property being operated. COPAS Bulletin No. 21, “Material Pricing Manual” has been prepared to give guidance in this important area. Included in the bulletin are suggested guidelines for pricing material transfers and dispositions in addition to comments on material costs, transportation costs, material preparation expenditures, and loading, hauling, and unloading costs.

Material to be used on a joint property is either hauled from the operator’s warehouse or another property (material transfers) or is purchased directly for the specific property. Purchased material is charged to the property at vendor’s invoice price, less all discounts received, plus transportation charges. Transportation charges include loading, hauling, and unloading costs from the receiving point to the property.

The following example illustrates the purchase of new material for a joint working interest property.

**Example--Transfer of New Material**

U.S. Oil Company purchased 10,000 feet of casing for a joint interest lease at a net price of $100,000. Loading, hauling, and unloading costs from the receiving point to the wellsite were $8,000. U.S. Oil Company is the operator on the lease and has a 60% working interest. Prepare the entry for the transaction.

**Entry**

Capitalize $43,200 (40% x $108,000) as accounts receivable - non-operators.
Capitalize $64,000 (60% x $108,000) as wells in progress.

The above example gives the net result at the end of the month after distribution of joint costs, i.e., the entry charging the JIS account is not shown.

Most joint operating agreements provide for material transferred to a joint property hauled from a warehouse or another property to be priced at published prices on the movement date plus transportation. A standardized pricing method is necessary in pricing transferred material in view of the fact that the transferred material may be in new or used condition. Transferred material to or from a joint property may be classified as being in any one of the following conditions:

- **Condition A** New material
- **Condition B** Used-in sound and serviceable condition without reconditioning
- **Condition C** Used-not in sound and serviceable condition; needs reconditioning
Condition D  Used-no longer usable for original purpose; may be used for other purpose

Condition E  Used-junk

Condition A is new material, and the joint property would normally be charged with the current new price of the material that is in effect at the date of movement. The current new price would include the mill base price plus freight.

(Mill base price is the published price.) In addition, loading, hauling, and unloading costs from the receiving point to the property are also charged to the property as part of the cost of the material.

The following example presents, in part a, the computation of the transfer price of 5,000 feet of casing and, in part b, the entry to record the transfer of the casing from the operator's warehouse to a joint interest lease owned 40% by U.S. Oil Company, the operator. In effect, this transaction represents a sale by U.S. Oil Company of 60% of the casing. The remaining 40% is merely a transfer by U.S. Oil Company from the warehouse to the property and no sale is involved. Thus, in the entry to record the transfer, U.S. Oil Company must recognize a gain or loss on the sale of 60% of the asset and record 40% as wells in progress.

Example—Transfer from Warehouse

Shipment of API oil country tubular goods

-Operator's warehouse in Houston, Texas to a joint interest property, north of Shanghai.
-5,000 ft of 5 1/2-in. casing, Condition A
-Mill base price-Eastern Mill published price, $8.9114/ft.
-Freight, Youngstown, Ohio, to Shanghai, $0.7191/ft.

a. Calculate the total price to be charged to the joint interest property.

\[
\begin{align*}
\text{Mill base price per foot} & \quad 8.9114/\text{ft} \\
\text{Add: Freight per foot} & \quad 0.7191 \\
\text{Price including freight} & \quad 9.6305 \\
\text{Times footage} & \quad \times 5,000 \\
\text{Total price FOB receiving point} & \quad 48,152.50
\end{align*}
\]

b. Give the entry to record the transfer, assuming the material was carried on the operator's books at $42,000 and the operator had a 40% working interest in the

Entry
Capitalize $28,892 ($48,152.50 x 60%) as accounts receivable – non-operators.
Capitalize $16,800 ($42,000 x 40%) as wells in progress.
Record a gain on sale of pipe for $3,692 (60% x [$48,152.40 - $42,000])

Condition B material is material in sound and serviceable condition which may be reused without reconditioning. This material should be charged to a property at 75% of the current new price plus transportation. The following example assumes the same facts as the previous example, except the material is in Condition B rather than A, and the book value is $30,000 rather than $42,000.

Example—Transfer from Warehouse—B

Shipment of API oil country tubular goods, Condition B

- Operator's warehouse in Houston, Texas to a joint interest property north of Shanghai
- 5,000 ft of used 5 1/2-in. casing, Condition B
- Mill base price - Eastern Mill published price $8.9114/ft
- Freight, Youngstown, Ohio, to Shanghai $0.7191/ft

a. Calculate the total price to be charged to the joint Interest property.

\[
\begin{align*}
\text{Mill base price (per foot)} & \quad \$8.9114 \\
\text{Add: Freight per foot} & \quad 0.7191 \\
\text{Price including freight} & \quad 9.6305 \\
\text{Times footage} & \quad \times 5,000 \\
\text{Current new price} & \quad 48,152.50 \\
\text{Condition B adjustment} & \quad 75\% \\
\end{align*}
\]

Total Condition B price FOB receiving point $36,114.38

b. Give the entry to record the transfer, assuming the material was carried on the operator’s books at $30,000 and the operator had a 40% working interest in the joint property.

Entry

Capitalize $21,669 (60% x $36,114.38) as accounts receivable – non-operators.
Capitalize $12,000 (40% x $30,000) as wells in progress.
Record a gain on sale of $3,669 (60% x [$36,114.38 - $30,000])
When material is moved from property, the percentage used in crediting the property depends on the original condition of the material when it was charged to that property. If Condition B material was originally Condition A material when charged to the property, it will be removed at 75% of the current new price. However, if Condition B material was originally Condition B material when charged to the property, it will be removed at 65%. The reduction represents an assumed reduction in service value.

Condition C material is not in sound and serviceable condition and is not suitable for its original use without reconditioning. Condition C material moved to a joint property is charged at 50% of the new price plus reconditioning cost, total cost not to exceed Condition B value. Condition C material moved from a property may be accounted for using two differing methods, depending upon who pays the reconditioning costs.

Condition D material is no longer suitable for its original use but may be used for another purpose. Condition D material is priced on a basis commensurate with its new use.

Condition E material is junk and is priced at prevailing junk prices. Material transferred from a joint property to another property wholly owned or jointly owned by the operator creates complicated accounting situations.

**JOINT INTEREST AUDITS**

The joint operating agreement and accounting procedure typically provide for an audit of the operator by the non-operator(s). The joint interest audit has historically concentrated on the cost and expense side of joint interest operations. The joint interest auditor examines the operator's record-keeping and managerial procedures to determine if the operator is conforming to the provisions of the operating agreement and accounting procedure.

In very recent years, increased emphasis has been placed upon revenue audits. The reason for this increased interest in revenues is the dramatic increase in oil and gas prices from the 1970s to the early 1980s. Two areas of concern are paramount in revenue auditing: verification of volumes and verification of values.

**OFFSHORE OPERATIONS**

Offshore operations are commonly operated by joint working interest ventures because of the large dollar amounts and large amount of risk involved. These operations are conducted on either Federal or state-owned property. Bidding on leases from either the state or the federal government is normally required to obtain a lease. Bidding on offshore federal losses is done by sealed bids, with generally a separate bid for each tract.

**Operating Agreement and the Accounting Procedure**
When a joint interest situation is created, the parties involved, i.e., the operator and non-operators, generally execute an operating agreement and accounting procedure.

The operating agreement delineates the duties and responsibilities of the operator and non-operators. An operating agreement may cover only drilling operations, or it may cover exploration and production activities.

Generally, the operator manages all developing, operating, record keeping and administrative activities pertaining to the joint lease. For major expenditures, such as drilling a well, the operator is generally required to obtain written authority from the non-operator(s) via an AFE. This requirement provides a limit on expenditures without express written authority from the non-operator(s). Periodic reports, which describe the activities performed by the operator, are generally required to be given to the non-operators. The operating agreement normally requires that the operator pay all costs of developing and operating the joint property and bill the non-operators for their proportionate share. However, a provision for requiring advances from the non-operators prior to cost insurance or payment is generally included in the operating agreement.
Doing Business Internationally: Establishing Agreements

In many countries, U.S. oil companies often enter into agreements wherein they become partners with foreign national oil companies, or they act as service partners working with foreign governments or foreign corporations on a contractual basis. Because of the widespread differences in laws, cultures, language and economic parameters found worldwide, it has been impossible to standardize international agreements. However, as discussed in an article by Bell and Sullivan (*Petroleum Accounting and Financial Management Journal*, Summer 1990, pp.89-103), four basic categories of contractual agreements can be found internationally. The types of agreements are concession agreements, joint venture agreements, production sharing agreements, and service contracts.

Concession Agreements

The company entering into this agreement is granted a permit to explore an area for a fixed period. If proved reserves are discovered, the permit is held through the productive life of the area. In traditional concession agreements, the foreign government often received at least half the production after the oil company had recovered development and operating costs. In current concession agreements, the foreign government instead typically receives a bonus and royalties. The foreign government does not usually participate in operations or marketing. The Netherlands, for example, uses a type of concession agreement wherein the government receives both a bonus based on the size of the area involved and royalties of up to 16 percent, depending on the level of annual production. In addition, the foreign company is required to maintain a place of business in the Netherlands from which to manage the day-to-day activities of their operation.

Joint Venture Agreements

The U.S. company becomes a partner or shareholder of a foreign national oil company. The U.S. company usually must bear all exploration costs as well as all the risks. The foreign national oil company shares development and production costs only once production begins. While the oil company is the operator and operates the property, the foreign government, unlike in a concession agreement, does participate in operations through a committee.

Production Sharing Agreements

The U.S. company is required to spend a specified amount of money each year for a specified time period, performing all exploration and assuming all risks. Discovered reserves are owned by the foreign government, with the U.S. company receiving a specified share of production, usually 15 to 20 percent. For example, in Indonesia, a 15 percent production share is common. In the Middle East, production sharing agreements typically provide an even smaller share of production equity – less than 10 percent.
Service Contracts

The U.S. company provides exploration work, and is reimbursed for costs and paid a bonus if reserves are found.

The most important rule for companies contemplating entering into agreements with foreign governments is to research thoroughly every facet of the venture in order to be well prepared to negotiate. This preparation would include learning the type of contracts and terms available, foreign tax rules and regulations, risks involved, etc.

THE ACCOUNTING PROCEDURE

An important part of any operating agreement is the Accounting Procedure. This too can be different in foreign countries. For example, as Richard Yehle describes in his article (“Joint Interest Accounting - A Comparison of UK and US Practices,” *Journal of Petroleum Accounting*, Spring 1987, pp. 73-82), the typical Accounting Procedure in the U.K. differs from the U.S. in the following ways:

1. **Contracts** – In the United States, contracting is left almost totally to the operator. In comparison, operators in United Kingdom contracts are required to consult with nonoperators before entering into any contract in excess of a specified amount of money.

2. **Cash Management** – In the United States, nonoperators are usually billed by operators once a month for their share of costs, with cash advances given only during periods of major construction. In contrast, U.K. joint ventures use a cash advance system where the operator makes a cash call to the nonoperators once a month for anticipated needs. Further, in the United Kingdom, the operator must normally maintain separate bank accounts for each joint venture and currency.

3. **Overhead** – In the United States, overhead costs are charged to nonoperators based on a formula driven by direct costs (usually direct labor costs). In the United Kingdom, actual costs are recoverable and can be quite complex to ascertain.

Accounting Differences

As U.S. companies expand their operations internationally, an understanding of accounting practices in the countries in which they operate is important. There are many reasons for differences in accounting standards around the world. First, the preparers and users around the world are different, with differing education levels. Also, in countries where most industries are government owned, the government is the primary user of accounting information. Second, many cultural factors influence accounting rules, such as the society’s attitude toward secrecy, and their attitude toward business in general. Third, governmental regulation regarding the
reporting of accounting information will differ among nations. Finally, economic conditions, such as the level of economic instability and inflation will influence a nation’s accounting standards.

CONCLUSION

International expansion may be necessary for the survival of many oil and gas companies based in the United States. Ample opportunities exist for these companies in the international arena. However, caution must be exercised before entering into agreements in foreign countries. Both the ability and the intent of foreign governments or foreign companies to honor their agreements should be evaluated. Also, extensive geological and geophysical research should be conducted to carefully assess the region. The future of the U.S. oil and gas industry may lie in international expansion. Many international ventures can be very profitable, provided extra care is taken in establishing international business relationships.