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Accounting for Intangible Drilling and Development Costs of Oil and Gas Wells

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The drilling of oil and gas wells gives rise to an interesting series of accounting problems for which petroleum accountants have been called upon to devise solutions. A discussion of these problems should be of interest to cost accountants generally. Large numbers of persons have invested in securities of oil companies or in oil and gas ventures. An understanding of the alternative methods of accounting for intangible drilling and development costs is essential to the understanding of financial statements issued by oil companies as well as to the understanding of the methods by which taxable income from oil and gas properties is determined.

THE NATURE OF DEVELOPMENT COSTS

Intangible drilling and development costs, which are more commonly referred to as development costs, represent expenditures made to sink a hole in the earth's crust to reach a reservoir of oil or gas. Development costs are to be distinguished from leasehold costs, which represent bonuses and other costs incurred to obtain the right to exploit the oil and gas reserves, and from the cost of well and lease equipment installed on the property for the purpose of producing oil or gas. Development costs are also to be distinguished from the purchase price of reserves on which the development has already occurred, which is generally classified as leasehold cost.

A more technical definition of the term "development costs" is to be found in the Federal income tax Regulations.(1) Under these Regulations and the Internal Revenue Code(2), each taxpayer is granted an election with respect to such costs. A taxpayer may elect to capitalize development costs or to deduct them from taxable income in the taxable year in which paid or accrued (depending on the method of accounting used). If the taxpayer elects to capitalize development costs, he is entitled to a second election which permits him to deduct the development costs of dry holes. The election with respect to development costs must be made by the taxpayer in his return for the first year in which such costs are paid or accrued, and the election with respect to dry holes must be made in the first year in which such a well is completed. The elections so made are irrevocable.

Because of the importance of these elections, accounting for development costs in the books of account is in many respects based on the income tax Regulation and the related rulings and decisions. Any comprehensive discussion of accounting for development costs must, therefore, include a consideration of both the financial accounting and the income tax aspects of the subject.

The Regulations generally define development costs as expenditures which are "incident to and necessary for the drilling of wells and the preparation of wells for the production of oil or gas", and which "in themselves do not represent items which have a salvage value".

A partial list of items which may be included in development costs follows:

I. Preparatory costs:

1. Geological and geophysical work in selection of well site (to be distinguished from geological and geophysical work in connection with acquisition of or evaluation of acreage).
2. Surveying and staking the well location.
3. Clearing and grading the well location.
4. Building roads and bridges to move drilling equipment to well location.
5. Installing temporary lines, tanks, etc. for water or fuel to be used in drilling.
6. Moving drilling equipment to the well site.
7. Erecting drilling equipment.
8. Building temporary racks for drill pipe, casing, and tubing.
9. Digging slush pits.

II. Drilling costs:

1. Labor (and related taxes and insurance).
2. Drilling supplies.
3. Maintenance and repairs of drilling equipment.
4. Bits and reamers.

5. Fuel, power, and water.
6. Mud and chemicals.
7. Depreciation of drilling equipment.
8. Overhead applicable to drilling operations.

III. Completion costs:

1. Well surveys and testing.
2. Cementing surface casing.
3. Shooting, acidizing, casing perforating, etc.
4. Cores, samples, etc.
5. Transportation of casing, tubing, and other sub-surface equipment to well location.
6. Installation of casing, tubing, and other sub-surface equipment in hole.

IV. Late charges:

1. Dismantling drilling equipment and clearing location.
2. Filling slush pits and grading location.
3. Damages to landowner's property.
4. Plugging the well (if a dry hole).

It should be borne in mind that in most instances oil and gas wells are drilled by independent contractors whose services are furnished at a flat rate per foot of hole drilled plus a day-work charge for time spent in testing, etc. Well surveys, cementing, acidizing, and similar services also are usually furnished by independent contractors. In some instances, wells are drilled and equipped under turnkey contracts. Here the well is drilled and equipped by the contractor for a lump sum. In such situations the portion of the total contract price allocable to intangibles, as compared with tangible equipment, is subject to the development costs option.(1)

The option with respect to development costs applies not only to the cost of drilling wells but is also applicable to workover jobs in which existing wells are deepened or plugged back to a shallower formation.

The cost of drilling wells to provide water for drilling operations is generally considered to be covered by the option. There is one decision which lends support to the position that input wells drilled for the purpose of injecting water into the oil-producing sand to increase production in water flooding projects are within the option.(3) Salt water disposal wells and water supply wells drilled in connection with lease operations are not accepted by the Internal Revenue Service as being covered by the option.

Development costs are to be distinguished from installation costs of surface equipment. The Regulation states that the "option applies only to those drilling and developing items which in themselves do not have a salvage value".[1] Thus, casing and tubing are equipment and not development costs. The Regulation, however, provides that "for the purposes of this option labor, fuel, repairs, hauling, supplies, etc. are not considered as having a salvage value, even though used in connection with the installation of physical property which has a salvage value".[1] Accordingly, the costs of hauling, labor, cement, etc. used in the installation of subsurface equipment are classified as development costs.

The Internal Revenue Service, however, has taken the position that the option ceases to apply to installation costs when the Christmas tree (valves, fittings, and connections) has been installed on the top of the casing. It has held that installation costs of pipe lines, tanks, separators, salt water disposal equipment, and the like are not development costs because they relate to lease equipment and are not necessary for drilling or the preparation of wells for the production of oil or gas.[4]

DIVISION OF DEVELOPMENT COSTS AMONG CO-OWNERS

Because of the great financial risks which are involved in the drilling of oil and gas wells, joint operations are common in the petroleum industry. Drilling and development are the obligation of the owners of the operating, or working interest, as contrasted with the owners of royalty, overriding royalty (an additional royalty carved out of the working interest), or production payment interests (an amount of money or quantity of oil or gas payable solely from oil or gas produced), which interests are not burdened with such obligations. The options with respect to development costs are available only to the co-owners of the working interest, that is, the owners of the operating rights.[1] A great variety of arrangements for spreading the financial risk have been devised. Some of the more common arrangements are briefly discussed in the paragraphs which follow.

The most common of these is the joint operating agreement. As an illustration, assume that A owns the entire working interest in a lease. He sells 37-1/2% to B and 12-1/2% to C. A is designated as operator. B and C are referred to as non-operating co-owners. A undertakes to develop the property. All expenditures made by him are charged to the joint account and monthly billings are rendered to B and

C for their 37-1/2% and 12-1/2% of the charges, respectively. Such an arrangement ordinarily provides that each co-owner may take his share of production in kind and traditionally has not been regarded as a partnership for Federal income tax purposes. Under the 1954 Code and related Regulations such classification may be avoided by providing in the joint operating agreement that the venture for development and operation is not a partnership and is not to be taxed as such.[5] Under the arrangement just described, each co-owner may record his share of the development costs in accordance with his established accounting policies. One might use the cash basis, and another might use the accrual basis. One might capitalize, and another might write off development costs.

A second type of arrangement is the farm-out agreement. As an illustration, assume that A owns the working interest. He assigns 50% to B upon the latter's agreement to drill the first well free of cost to A. In such a case, 50% of B's development costs would be subject to the option, whereas the remaining 50% would be capitalized and regarded as leasehold cost to him.[1] A would not be regarded as the recipient of income in this arrangement and no development costs of the obligation well would appear on his books. The leasehold is regarded as a pool of capital to which A has contributed his investment in the undeveloped lease whereas B has contributed the cost of drilling a well.

A variation of the farm-out arrangement would also involve the assignment to B of an interest in leaseholds other than the one on which the drill site was located. In this situation, some advocate the allocation of B's development costs among the properties based on their fair market value prior to the drilling of the well. In the illustration given, the development costs allocable to the drill site would be subject to the option to the extent of 50%. Others regard the development costs as attributable only to the drill site and suggest that the fair market value of the other leases be recorded as income received by B.

Somewhat similar to the farm-out arrangement is the plan whereby A would sell 50% of the working interest to B for cash. At the same time A would agree to drill the first well and B's 50% of such costs would be fixed in advance at an agreed amount. If this amount was substantially in excess of the development costs and related overhead incurred by A with respect to B's 50% interest, the Internal Revenue Service would probably take the position that a portion of B's payment equal to the excess represented leasehold cost and would not be subject to the option.

Another arrangement is the carried interest. To illustrate, A assigns the entire working interest to B who undertakes to develop and operate the property free of cost to A. It is agreed that when and if the accumulated income from the property has equalled the costs expended by B, a 50% interest will revert to A, who thereafter will participate in the income and pay his share of costs incurred. Although an early decision holds that in certain carried-interest agreements the carried party (A) would be taxed on the income and entitled to the development costs deduction with respect to the 50% carried interest[6], it now appears that most carried-interest arrangements are distinguishable from this case and that the Internal Revenue Service would in such cases attribute all income and deductions to B during the pay-out period.[7] A would have no investment in development costs incurred during the pay-out period.

Another arrangement is called the net-profits interest. As an example, assume that A assigns the entire working interest to B with the agreement that he will receive 50% of the net income from the property payable solely from the proceeds of oil or gas when and if produced. In this situation A's leasehold cost becomes his investment in the net-profits interest. All development costs are incurred by B and are subject to the option. His net profit payments to A serve to reduce his gross income from the property because they are in the nature of royalties.[8]

SHARING ARRANGEMENTS WITH OTHER PARTIES

Risk-sharing arrangements are not necessarily limited to co-owners of the oil and gas leashold.

The owner of a leasehold who proposes to drill a wildcat well, that is, a well in an unproven area, may obtain contributions from owners of surrounding leases the value of whose properties will tend to be proved or disproved by the well. Dry-hole contributions are made only if the wildcat well is dry. Bottom-hole contributions are made upon reaching the agreed depth of the well, whether it is a producer or a dry hole. Contributions may be made in cash or in undeveloped acreage. In either event, the contribution is a reduction of the driller's development costs or an item of income to him. Dry-hole contributions are deductible by the contributor. Bottom-hole contributions are required to be capitalized if the well is productive as an addition to leasehold cost.

Another arrangement involves the use of a payment solely from oil or gas, when, as, and if produced. To illustrate, A owns the working interest in a lease. B, an independent drilling contractor, undertakes to drill a well on the lease. He is to receive a production payment of agreed amount (in dollars or in quantity of product) as compensation for his services. Under this arrangement, A has no development costs nor is he considered to be in receipt of income. B's drilling costs are not subject to the development costs option but are to be capitalized as his depletable investment in the production payment received.(9) If both cash and a production payment are received, B must allocate his drilling costs between the cash and the production payment based on fair market value.(10)

ACCOUNTING FOR THE USE OF OPERATOR'S EQUIPMENT

As has been previously stated, most wells are drilled and many related services are furnished by independent contractors. In those instances where the well is drilled or services are furnished by the operator of the property, however, additional accounting problems arise.

Joint operating agreements with respect to oil and gas properties ordinarily permit the operator to charge the joint account for services rendered and facilities used at the prevailing rate for such services and equipment in the locality. As a consequence, when a well is drilled by the operator, he stands somewhat in the position of an independent contractor. Development costs are charged to the joint account and drilling income is credited at the rate per foot and per day which an independent contractor would charge. The actual cost of drilling is charged to appropriate contract drilling cost accounts. The operator's profit or loss on the well usually is regarded as a profit or loss from drilling operations. However, his share of the charges to the joint account properly may be reduced or increased to actual cost, if desired.

Accounting for the use of the operator's automobiles, trucks, spudders, etc. is made in similar fashion, using rates per mile, per hour, or per day equivalent to the rates charged by independent contractors.

OVERHEAD AS AN ELEMENT OF DEVELOPMENT COSTS

General and administrative overhead is ordinarily included in development costs in the books only to the extent of the fixed charge per month, per well, which is ordinarily provided for in joint operating agreements among the co-owners of oil and gas properties.

For the purpose of computing the tax allowance for depletion based on a percentage of income, an allocation is made of the general and administrative expenses applicable to drilling and development activities (either separately or as a part of overhead applicable to all production activities). The Federal Regulations prescribe that the allocation to drilling and development activities shall be based on the ratio of the direct operating expenses of the various types of business activities carried on by the taxpayer and the overhead allocable to drilling and development activities is in turn to be allocated to specific properties taking into account their relative production.[11] Other equitable methods have been accepted by the Internal Revenue Service, one being the allocation of drilling and development overhead to specific properties based on direct development costs incurred.

District expense, which represents the salaries and expenses of personnel supervising or serving a group of leases in a given geographical area, is ordinarily allocated to individual properties in the books and for the purpose of billing non-operating co-owners. A commonly used basis for this allocation is the number of wells in the district. To give recognition to the fact that the drilling of a well requires more activity on the part of district equipment and personnel than does the operation of a producing well, a drilling well is weighted at, say, the equivalent of four producing wells in making the monthly district expense allocation.

THE CONTROL OF DEVELOPMENT COSTS

In many oil companies drilling of oil and gas wells is conducted under an annual capital expenditures budget which defines the aggregate amounts to be expended for development costs during the period. The budgeted amount may be broken down according to geographical areas, monthly or quarterly periods, etc.

When the drilling of a specific well is planned, it is the better practice to issue a properly approved authorization for expenditure describing the well to be drilled and including an itemized estimate of the costs to be incurred. Competitive bids are obtained for drilling and other major services. Actual development costs are accumulated by authorizations for expenditure and by appropriate sub-classifications so that variations over and under the preliminary estimates may be noted and investigated for report to management upon completion of the well. Such records also form a basis for future estimates and comparisons.

Where the authorization for expenditure system is used, wells in progress at the balance sheet date will appear as an asset similar to construction in progress. For Federal income tax purposes, however, development costs are to be deducted (if the taxpayer has so elected) in the year in which such costs are paid or accrued, even though the well is not completed.(12) Advance payments to contractors are not deductible where the drilling has not been performed.(13)

DEVELOPMENT COSTS - CAPITAL OR EXPENSE

For purposes of financial reporting, as contrasted with accounting for income tax purposes, three practices with respect to development costs appear to be in general use. The lack of uniformity in this respect is probably attributable to the influence of long-established income tax accounting concepts on financial accounting and the natural conservatism of companies whose operations involve a high degree of financial risk.

A survey of the published reports of major oil companies indicates that the great majority of such companies capitalize the intangible drilling and development costs of productive wells and recover the same through depletion or amortization charges. Considering the nature of development costs whose benefits extend over the productive life of the well, this is unquestionably the preferred treatment.

A few of the major companies capitalize development costs of productive wells and immediately provide a reserve equal to the amount thereof with the result that the costs are charged against income in the year in which paid or accrued. This method is conservative but is subject to the theoretical objection that development costs are not matched against the revenue derived from the well.

Among the smaller companies, partnerships, and individuals there is a strong tendency to charge development costs directly against income in the year in which paid or accrued. This method, likewise, is subject to the theoretical objection that there is not a proper matching of costs against revenues. This method is subject to the further objection that the balance sheet does not disclose the accumulated investment in development costs. Proponents of this method cite the arguments of conservatism, of conformity to income tax accounting, and the fact that balance sheet values based on cost rarely bear any relation to fair market values of property in the petroleum industry.

Development costs of dry holes are generally charged to income as paid or accrued, although the cost of dry holes drilled on producing properties is capitalized by some companies.

In view of the alternative methods of accounting for development costs which are in general use, the reader of oil company financial statements should give careful attention to the method used in the statement before him. Where development costs are not capitalized and amortized over the productive life of the property, the following should be taken into account in making comparisons with statements in which the preferred method is used:

1. Income tends to be depressed in the early years of a property's life when drilling and development expenditures occur. In a growing company this tendency will be reflected in the income statement during the growth period. When development slows down or ceases, a tendency toward overstatement of earnings appears.
2. Income for any given year may be increased or decreased by reason of the management's decisions as to the extent of the drilling program to be carried on during the period.
3. Where sales of the properties occur relatively early in their productive life, the gains are usually materially greater or the losses are materially less than would be the case if development costs were capitalized and amortized over the life of the properties.

AMORTIZATION OF DEVELOPMENT COSTS

Among the companies which capitalize development costs, at least two alternative methods of amortization appear to be in general use (in addition to 100% amortization in the year in which paid or accrued as previously described).

Under the unit-of-recovery method, the estimated recoverable reserves of oil or gas to be obtained from the completed wells on each property are divided into the accumulated development costs on the property to provide a unit rate which is multiplied by the quantities of oil or gas recovered during the year to arrive at the amortization for the period. Estimates of recoverable reserves are revised at periodic intervals based on the actual experience with the property. Ordinarily these revisions are retroactive only to the beginning of the year of the change.(14)

In some instances, development costs are amortized by the straight-line method, using rates comparable to those used in the depreciation of leasehold equipment.

The Federal income tax Regulations require that capitalized development costs be recovered through depletion except for the portion of development costs which represents the installation costs of equipment, which portion is recoverable through depreciation.[1]

ALLOCATION OF INCOME TAXES

A common practice in the petroleum industry is to capitalize development costs for purposes of financial reporting and to deduct these costs in the year incurred for Federal income tax purposes. In this situation the theorist will ask if provision is made in the year the well is drilled to cover income taxes which will be paid in future years when the financial provision for amortization of development costs does not have a corresponding income tax deduction. A provision for deferred income taxes or for additional amortization equal to such taxes is not ordinarily made.

If an enterprise drilled only one well or developed only one lease, failure to provide for deferred income taxes would undoubtedly result in an overstatement of income in the year when the drilling occurred and taxes were reduced by the deduction for development costs and would produce an understatement of income in all future years when the amortization of development costs on the books produced no income tax deduction. This, however, is a situation which rarely prevails in the petroleum industry. The continuous need for the discovery of underground reserves to replace those being depleted by production leads most producing companies to engage in annual programs of drilling and development throughout the life of the enterprise. As a result, petroleum accountants are inclined to regard the development costs deduction as one of those "differences between the tax return and the income statement" which "will recur regularly over a comparatively long period of time" and which are exempted from the application of the deferred taxes provision by the terms of the bulletin of the American Institute of Accountants.[15]

The thinking of petroleum accountants is undoubtedly conditioned by the fact that in a producing oil company there are numerous and important differences between commercial net income and taxable net income. The analyst finds that the provision for taxes bears no fixed relationship to income as reported in the financial statements and the effective tax rate for future years is a matter of conjecture. Delay rentals on undeveloped leaseholds may be capitalized for financial reporting purposes and they are almost invariably expensed for tax purposes. Geological and geophysical expenditures must be capitalized for tax purposes where acreage is acquired or retained and these costs are often expensed in their entirety in the books of account. Undeveloped leasehold costs may be amortized in the books, but this is not permissible for tax purposes. Income from the sale of production payments is reported in the year of sale for tax purposes and may be deferred over the period of production in the books. Percentage depletion, a tax deduction whose amount is greatly influenced by the amount of development costs expended on the property during the year, differs materially from the provision for depletion which is ordinarily recorded in the books. Faced with this multiplicity of recurring differences between commercial and taxable income, the petroleum accountant is not inclined to single out development costs for special treatment.

At least one major company, however, has recognized that the development cost deduction may produce a distortion in income despite the recurring character of the difference between commerical and income tax accounting. In its 1951 report to stockholders The Texas Company included the following note:

> "Since 1934, the Company has capitalized the costs of drilling productive wells and has amortized such costs by charges to the income account on a straight-line basis, except in Illinois, Indiana, and Kentucky, where the costs are fully amortized as incurred. For Federal income tax purposes, however, the Company continued to deduct all intangible drilling costs in the year incurred. As a result, there is an immediate tax deduction for drilling costs capitalized in the current year which costs will be amortized by charges to income in future years. This affects the income account in a way which becomes more significant in periods like the present one in which there are heavy drilling activities and very high taxes.
>
> In recognition of this situation, the Company, beginning in 1951, has adopted the policy of providing an additional reserve for amortization of intangible development costs equivalent to the reduction in taxes applicable to the excess of current drilling costs incurred over regular amortization charges. In 1951, such additional amortization amounted to $13,680,796."

Although this report was published several years ago, the writer has not observed instances in which other companies have adopted the practice just described. This merely serves to emphasize what has previously been stated, namely, that the alternative methods of accounting for development costs which are used within the petroleum industry are such that the reader of financial statements issued by oil companies should take note of the practices employed in any set of statements in making comparisons between companies.

List of Citations:

(1) Regulations 118, Sec. 39.23(m)-16.
(2) Internal Revenue Code of 1954, Sec. 263(c).
(3) Page Oil Co. v. Commissioner, 41 BTA 952 (non acquiesence).
(4) Mimeograph 6754, 1952-1 Cumulative Bulletin, page 30.
(5) Proposed Regulations, Sec. 1.761-1(b) (3).
(6) J. S. Abercrombie Co. v. Commissioner, 162F(2d)338, 35 AFTR 1467.
(7) Manahan Oil Company 8 TC 1159 and Herndon Drilling Company, 6 TC 628.
(8) Kirby Petroleum Company v. Commissioner, 34 AFTR 526.
(9) G.C.M. 22730, 1941-1 Cumulative Bulletin, page 214.
(10) G.C.M. 22332, 1941-1 Cumulative Bulletin, page 228.
(11) Regulations 118, Sec. 39.23(m)-1(g).
(12) Great Western Petroleum Corporation, 1 TC 624.
(13) Revenue Ruling 170, 1953-2 Cumulative Bulletin, page 141.
(14) Regulations 118, Sec. 39.23(m)-9(b).
(15) Restatement and Revision of Accounting Research Bulletins, page 87.