PART X: OIL AND GAS

7790. How do individuals invest in oil and natural gas?

Because exploration for, and production of, oil and natural gas requires large amounts of capital and technical expertise and involves a high degree of risk, few individuals are willing to "go it alone" in an oil or gas project. As a result, the normal practice in an oil and gas project is for individuals, groups of individuals, and even corporations to combine efforts and capital in some type of joint organization. The forms of organization commonly used for this purpose are:

. . .corporations, including S corporations;

. . .trusts;

. . .partnerships;

. . .limited partnerships; and

. . .joint ventures.

Sometimes a combination of these forms is used, particularly where considerations apart from the actual exploration and production of oil or gas are important to some or all of the investing parties. (For example, an individual may more effectively be able to limit liability in an oil and gas venture by incorporating the individual's interest and then having the corporation become a member of the oil and gas limited partnership).

Traditionally, the most commonly used method available to individual investors for investing capital in an oil and gas venture has been the purchase of an interest in an oil and gas limited partnership. Such partnership interests were often tradable, if at all, only on informal secondary markets or to the partnership itself. In the 1980s there was a growth in partnerships that are traded on established securities markets or are readily tradable on a secondary market (or the substantial equivalent thereof), referred to in the IRC as publicly traded partnerships. A master limited partnership that is publicly traded would fall within this definition. However, in taxable years beginning after 1987, a publicly traded partnership is taxed as a corporation unless 90 percent of the partnership's income is passive-type income. In general, "passive-type income" for this purpose includes income and gain from certain mineral or natural resource activities, as well as interest, dividends, real property rents, gain from the sale of real property, and gain from the sale of a capital or IRC Section 1231 asset. A grandfather rule is in effect for tax years after 1997 for electing 1987 partnerships (that agree to a 3.5 percent tax on their gross income); such a partnership otherwise operates as a passthrough entity.[1] Taxation as a corporation would defeat the "passthrough" feature of a limited partnership. (See Q 7699 on publicly traded partnerships). So long as investors are interested in limiting their liability and do not wish to materially participate in the oil and gas investment, limited partnerships that

1. IRC Sec. 7704.

manage to avoid taxation as a corporation should remain popular. In general, there are now two types of passthrough limited partnerships: regular (see Q 7703) and electing large partnerships (see Q 7704).

7791. Why are oil and gas limited partnerships attractive to individual investors?

There is no single answer to this question. Because oil and gas programs (i.e., limited partnerships) come in several varieties (see Q 7792), each offering different benefits and risks, an investor may choose a program that suits the investor's needs. In general, however, some of the more common attractions of an oil and gas limited partnership, other than a publicly traded partnership taxed as a corporation (see Q 7790), are as follows:

Small investment. Although the dollar amount needed to purchase a partnership interest in oil and gas limited partnership would be considered large by many individuals, it is in fact quite modest when compared to the capital required to complete an oil and gas venture.

High front-end deductions. In many oil and gas programs, the investor will be able to take first year income tax deductions for the intangible drilling and development costs associated with drilling the wells. Because a high percentage of the investor's initial investment goes to pay these intangible costs, these deductions are substantial, often exceeding 60 percent of the initial investment (see Q 7798 to Q 7801). However, for certain limitations on the use of deductions, see Q 7795.

Continuing tax shelter. As most investors will be permitted to take deductions for percentage depletion on producing wells, otherwise taxable income (whether in the form of cash distributions from the oil and gas program or income from other sources of the taxpayer) will be "sheltered" to the extent of those deductions (see Q 7806). For limitations on the use of losses to offset income outside the oil and gas program, see Q 7795.

Striking it rich. Although not always an economic reason for investing in oil and gas, the fact remains that many investors hope to "strike it rich" by hitting a "gusher." A successful exploratory well can produce a 10 to 1 (or even greater) profit on the investor's capital investment. Even development wells often produce in the area of a two to one profit.

Liquidity. Although not as liquid as many other investments, an informal secondary market and provisions in many partnership agreements providing for periodic offers from the general partner to purchase interests of the limited partners, or permitting a limited partner to exchange the partnership interest for the stock of the general partner (assuming the general partner is a corporation), create a small degree of liquidity.

Limited liability. An investor who purchases a limited partnership interest is generally liable for partnership liabilities only to the extent of capital contributions to the partnership (including contributions the investor has agreed to make in the future).

Allocations of income, deductions, and credits. Within the limitations imposed by the federal income tax law, the limited partnership form of organization allows the participants (i.e., the general and limited partners) to specially allocate items of income and costs (including corresponding deductions and credits) among the limited and general partners in a manner that is disproportionate to their ownership (capital) interests.

7792. What are the basic types of oil and gas drilling programs?

The four basic types of oil and gas drilling programs are the following: (1) exploratory programs; (2) development programs; (3) income programs; and (4) combination programs.

In *exploratory* drilling programs, wells are drilled far from areas of proven production or, at best, on the periphery of a proven field. As a result, the likelihood of drilling successful wells (versus "dryholes") is reduced and the risk that little or no return on invested capital will be realized is increased. In addition, because exploratory wells are often drilled in remote locations, the drilling and marketing costs are likely to be higher. On the other hand, the return on investment in the case of successful exploratory programs is generally much greater than on successful development or income programs.

In *development* drilling programs, wells are drilled in proven areas. Thus, development programs are less risky than exploratory programs, but because the costs of acquiring drilling rights in a proven area are greater than in an unproven (exploratory) area, the return on investment is likely to be less also.

An *income* purchase program purchases the reserves of proven wells that have already been drilled. As a result, income programs involve the least investment risk. (Previously, income programs were generally not considered to be "tax shelters" because deductions for percentage depletion and intangible drilling and development costs were generally not available. However, percentage depletion may now be available to those who participate in these programs (See Q 7798, Q 7806).

Combination drilling programs combine the exploratory, development, and income type activities into a single, diversified program. Although the major reason for utilizing a combination program is to offer investors a reduced risk of loss of capital, public programs tend to emphasize exploratory drilling within the combination and participate in income purchase activities to only a very small extent.

7793. Does an individual recognize any gain or loss at the time the individual purchases a limited interest in an oil or natural gas limited partnership?

No.[1]

7794. What tax deductions and credits are available through an oil or gas limited partnership?

The two deductions that are particular to oil and gas programs (and certain other extractive industries) and which provide the major incentives for investing in an oil or gas limited

1. IRC Sec. 721(a); Treas. Reg. §1.721-1.

partnership are (1) the deductions for intangible drilling and development costs (see Q 7798 to Q 7801), and (2) depletion (See Q 7802 to Q 7816). Of course, subject to certain limitations (see Q 7795 to Q 7797), deductions for interest, taxes, depreciation, and operating expenses *may* be passed through and deducted by the limited partner.

See Q 7704 regarding electing large partnerships.

7795. What limits apply to the deductibility of a limited partner's share of partnership losses in an oil and gas partnership?

Three different limitations may result in the total or partial disallowance of a deduction by a limited partner for the share of partnership losses. These limitations *must* be applied separately since they are completely independent of each other. The limitations are as follows:

Partnership basis. A limited partner may deduct the limited partner's share of partnership losses (including capital loss) only to the extent of the limited partner's adjusted tax basis in the partnership interest (determined at the end of the tax year, but before reduction for partnership losses for the year). However, any amount disallowed by this rule may be carried forward to succeeding years and deducted to the extent that the partner's adjusted tax basis in his partnership exceeds zero at the end of that tax year.[1]

Where a limited partner's share of partnership losses exceeds that partner's adjusted tax basis of the partnership interest, the amount of the limitation (i.e., the partner's tax basis) must be allocated among several categories (e.g., long-term capital loss, short-term capital loss, IRC Section 1231 loss, etc.) according to the proportion that the loss in each category bears to the total loss. Furthermore, if there is taxable income rather than loss in any category (e.g., short-term gain), the limitation amount (i.e., the partner's tax basis) will be increased by the amount of that income before the limitation is allocated among the categories in which there is a loss.[2]

> *Example*: At the end of the tax year, limited partner C has the following distributive shares of partnership items: long-term capital loss, $4,000; short-term capital loss, $2,000; "bottom line" income, $4,000. Partner C's adjusted tax basis in his partnership interest at the end of the year, but before adjustment for any of the foregoing items is $1,000. Adjusted as described in the text above, C's tax basis is increased from $1,000 to $5,000 at the end of the year. C's total distributive share of partnership loss is $6,000. Since without regard to losses, C has a tax basis of only $5,000, C is allowed only 5/6th ($5,000/$6,000) of each loss–$3,333 of his long-term capital loss and $1,667 of his short-term capital loss. C must carry forward $667 as long-term capital loss and $333 as short-term capital loss.[3]

Amount at risk. A limited partner in an oil or natural gas program may deduct the limited partner's share of partnership losses only to the extent the limited partner is "at risk" with respect to the interest in the partnership. For further explanation of this "at risk" limitation, see Q 7796, and Q 7912 to Q 7917.

1. IRC Sec. 704(d); Treas. Reg. §1.704-1(d)(1).
2. See Treas. Regs. §§1.704-1(d)(2), 1.704-1(d)(4), Ex. (3).
3. See Treas. Reg. §1.704-1(d)(4), Ex. (3).

Passive loss rules. Application of the passive loss limitation to an investment in an oil or gas program depends on the form in which the investment is made and the material participation of the investor in the activity (See Q 7797).

7796. How do the "at risk" rules affect a limited partner's interest in an oil and gas program?

In preparing income tax returns for any tax year, a limited partner is permitted to offset the allocated share of tax deductions generated by the partnership against the allocated share of income of the partnership. This is permitted regardless of the limited partner's "amount at risk" in the partnership. However, should the share of tax deductions (including the share of any partnership loss) exceed the share of partnership income (if any), the limited partner will be permitted to offset the excess of such deductions (i.e., the losses) against the income received from other sources only to the extent the limited partner is "at risk" in the partnership at the close of the year[1] (See Q 7914). If an individual owns limited interests in more than one oil and gas partnership (or owns limited interests in other types of tax shelters), each partnership interest must be treated separately for purposes of the at risk limitations; no aggregation of "amounts at risk" in different partnerships is permitted.[2] However, until otherwise provided, a partnership is permitted to aggregate its oil and gas properties for purposes of the at risk limitation[3] (See Q 7915).

Basically, a limited partner is "at risk" with respect to an interest in a tax shelter partnership to the extent of the sum of cash or property the limited partner has contributed plus the amount of debt incurred in connection with the partnership and for which the limited partner is personally liable. An individual is not at risk with respect to amounts that are protected against loss through nonrecourse financing, guarantees, stop loss agreements, repurchase agreements, or other similar arrangements[4] See Q 7913). Oil and gas limited partners were considered "at risk" at the end of each year to the extent the partners assumed liability for annual accruals of the partnerships' minimum annual royalties and annual license fees.[5]

If a limited partner's "amount at risk" in an oil and gas partnership falls below zero, the limited partner will generally be required to recognize income to that extent. See Q 7916 for details.

For a detailed analysis of the "at risk" provisions and their application, see Q 7912 to Q 7917.

Percentage Depletion

It is not completely clear whether the "at risk" rules will ever operate to disallow the percentage depletion deduction. Some authorities suggest that percentage depletion is deductible regardless of an individual's amount at risk. These authorities point out that the conference committee report and effective date provisions of the Tax Reform Act of 1976 specifically

1. IRC Sec. 465; Prop. Treas. Reg. §1.465-45.
2. IRC Sec. 465(c)(2)(A).
3. Notice 89-39, 1989-1 CB 681.
4. IRC Sec. 465(b).
5. *Krause v. Comm.*, 92 TC 1003 (1989).

mentioned depreciation and amortization, but omitted any reference to depletion. Furthermore, Proposed Treasury Regulation Section 1.465-1 provides that a taxpayer's amount at risk in an oil and gas limited partnership is to be increased by the excess of the deductions for depletion over the basis of the property subject to depletion. As this appears to allow percentage depletion even if the taxpayer has no other amount at risk, the authorities question whether a deduction for percentage depletion should also be allowed in early years when percentage depletion does not exceed the basis of the property and the taxpayer has no other amount at risk in the partnership.[1]

7797. How do the "passive loss" rules affect investment in an oil and gas program?

Application of the passive loss rules to an investment in an oil or gas program depends on the form in which the investment is made and the level of participation of the investor in the activity.[2] Investment in an oil or gas activity of a C corporation, other than a personal service corporation or closely held corporation, is not subject to the passive loss rules. Apparently, a publicly traded partnership taxed as a C corporation is also not a taxpayer subject to the passive loss rules.[3] (However, investment in a C corporation does not permit items of income and deductions to flow through to the shareholder-investor). Also, a working interest in an oil or gas property that the investor owns directly or through any entity that does not limit the liability of the investor with respect to the interest is not a passive activity (see below).[4] Otherwise, an oil or gas program will be subject to the passive loss rules, unless the investor materially participates in the program.[5] Thus, an investor who wants the tax benefits of an oil or gas investment to flow through to him or her, but does not wish the oil and gas investment to be passive, must either forgo limited liability or materially participate in the venture. As a result, the typical investor in an oil or gas program will be subject to the passive loss rules (see Q 7918, Q 7919).

For purposes of the working interest exception, an entity is considered to limit liability if the taxpayer's interest is in the form of (1) a limited partnership interest (unless the taxpayer is also a general partner), (2) stock in a corporation, or (3) any other interest in which the potential liability of a holder of such an interest is limited under state law to a determinable fixed amount, such as the taxpayer's capital contribution. However, the following protections against loss are not taken into consideration in determining whether the entity limits liability: (1) an indemnification agreement, (2) a stop loss arrangement, (3) insurance, (4) any similar arrangement, or (5) any combination of (1) through (4).[6] A husband and wife are treated as separate taxpayers for purposes of the working interest in an oil or gas property exception.[7]

1. See, e.g., Haft, *1984 Tax Sheltered Investment Handbook* (Clark Boardman Company, Ltd.), at 5-6.
2. IRC Sec. 469.
3. IRC Sec. 469(a).
4. IRC Secs. 469(c)(3), 469(c)(4).
5. IRC Sec. 469(c)(1).
6. Temp. Treas. Reg. §1.469-1T(e)(4).
7. Temp. Treas. Reg. §1.469-1T(j)(2)(iii).

In general, the passive loss rules limit the amount of the taxpayer's aggregate deductions from all passive activities to the amount of the taxpayer's aggregate income from all passive activities; passive credits can be taken only against tax attributable to passive activities. The rules are applied separately in the case of a publicly traded partnership; aggregation is permitted only within the partnership.[1] The rules are intended to prevent taxpayers from offsetting income in the form of salaries, interest, and dividends with losses from passive activities. However, the benefit of the disallowed passive losses and credits is generally not lost forever, but rather is postponed until such time as the taxpayer has additional passive income or disposes of the activity (see Q 7918 to Q 7929).

With respect to the working interest exception above, gross income from an oil or gas property is not treated as income from a passive activity if any loss from such property in a prior taxable year beginning after 1986 was treated as other than a passive loss solely by reason of the working interest exception, and not by reason of the taxpayer's material participation in the activity.[2]

7798. What are "intangible drilling and development costs"?

Intangible drilling and development costs (more commonly referred to as "intangible drilling costs" or "IDCs") are expenditures made by an operator in the development of an oil or natural gas property for wages, fuel, repairs, hauling, supplies, etc. Thus, intangible drilling costs generally include all amounts paid for labor, fuel, repairs, hauling, and supplies that are incurred in drilling, shooting, and cleaning wells; in clearing ground, draining, road making, surveying, and geological work necessary to prepare a site for drilling; and in constructing derricks, tanks, pipelines, and other physical structures necessary for drilling and the production of oil or natural gas.

On the other hand, intangible drilling costs do *not* include expenditures made to acquire tangible property ordinarily considered to have a salvage value. Thus, the costs of the actual materials in structures constructed in the wells or on the property and the cost of drilling tools, pipes, casings, tubings, tanks, engines, boilers, machines, etc. are *not* intangible drilling costs. However, wages, fuel, repairs, hauling, supplies, etc. are not considered to have salvage value even though they are incurred in connection with the installation of physical structures that themselves have salvage values.[3]

Expenditures for wages, fuel, repairs, hauling, supplies, etc. incurred in connection with equipment, facilities, or structures that are *not* incident to or necessary for the drilling of wells (including expenditures for storing and drilling) are *not* intangible drilling costs. (These items must be capitalized and depreciated).[4] Expenditures for drilling wells solely to obtain geological information and not for the production of oil or natural gas are not intangible drilling costs.[5]

1. IRC Sec. 469.
2. Treas. Reg. §1.469-2(c)(6).
3. Treas. Reg. §1.612-4(a).
4. Treas. Regs. §1.612-4(c)(1).
5. Rev. Rul. 80-342, 1980-2 CB 99.

Expenditures for labor, fuel, repairs, hauling, supplies, etc. incurred in connection with the actual operation of wells and other facilities on the property for the production of oil or natural gas are *not* intangible drilling costs, but must be treated as expenses.[1]

Expenditures for labor, fuel, repairs, hauling, supplies, etc. incurred in connection with the drilling of an injection well, or the conversion of a producing or nonproducing well to an injection well, are treated as intangible drilling costs.[2]

If drilling and development work is done by a contractor under an agreement with the operator, intangible drilling and development costs do not include those amounts that are payable to the contractor out of production or proceeds from production if such amounts are depletable income in the hands of the contractor, or amounts that are properly allocable to the cost of depreciable property. Otherwise, any type of contract (including a turnkey contract) between the operator and contractor may be used without jeopardizing the classification of expenditures as intangible drilling costs.[3]

Numerous rulings and cases have considered the eligibility of specific expenditures to be treated as intangible drilling and development costs and the special problems encountered in the case of offshore wells.[4]

7799. How are intangible drilling and development costs treated for purposes of the federal income tax?

Intangible drilling and development costs (IDCs) are capital in nature; however, the IRC and regulations provide alternatives for treatment of such costs. The individual or entity that holds the working or operating interest in the oil or gas property (i.e., the operator) may elect to (1) capitalize the IDCs or (2) deduct them as expenses for the taxable year in which they are paid or incurred.[5] (With respect to oil or gas property located outside the United States, intangible drilling and development costs paid or incurred after 1986 must be (1) capitalized, or (2) deducted ratably over 10 years. This, however, does not apply to a nonproductive well).[6]

If intangible drilling costs are capitalized, they may be recovered through depreciation or depletion (See Q 7809, Q 620).

In the case of certain enhanced oil recovery projects (generally referred to as tertiary recovery projects) begun or expanded after 1990, the operator may, instead of expensing or

1. Treas. Reg. §1.612-4(c)(2).
2. GCM 39619 (3-19-87), TAM 8728004.
3. Treas. Reg. §1.612-4(a).
4. See Rev. Rul. 89-56, 1989-1 CB 83; Rev. Rul. 88-10, 1988-1 CB 112; Rev. Rul. 78-13, 1978-1 CB 63; Rev. Rul. 70-414, 1970-2 CB 132; TAMs 8406006, 8141028; Let. Ruls. 7924101, 7837004, 7834002; *Texaco, Inc. v. U.S.*, 84-2 USTC ¶9866 (S.D. Tex. 1984); *Standard Oil Co. (Ind.) v. Comm.*, 77 TC 349 (1981), acq. in result, 1989-1 CB 1; *Sun Co., Inc. v. Comm.*, 74 TC 1481 (1980), aff'd, 677 F.2d 294 (3d Cir. 1982); *Gates Rubber Co. v. Comm.*, 74 TC 1456 (1980), aff'd per curiam, 82-2 USTC ¶9702 (10th Cir. 1982); *Standard Oil Co. (Ind.) v. Comm.*, 68 TC 325 (1977); *Miller v. U.S.*, 78-1 USTC ¶9127 (C.D. Cal. 1977); *Exxon v. U.S.*, 212 Ct. Cl. 258 (1976); GCM 39085 (12-1-83) (revoking GCM 37359 dated 12-28-77).
5. IRC Sec. 263(c); Treas. Reg. §1.612-4.
6. IRC Sec. 263(i).

capitalizing IDCs, claim a tax credit generally equal to 15 percent of qualified enhanced oil recovery costs (See Q 7817).

In the case of the typical oil and gas limited partnership, it is the partnership that holds the working interest in the oil or gas property and undertakes the drilling and development expenditures. Thus, the election to capitalize or expense intangible drilling costs is made at the partnership level by the general partner.[1] The general partner's intent as to this election is normally stated in the prospectus provided to potential investors by the oil and gas program; however, good faith reliance on the prospectus and general partner (or promoter) will not sustain a deduction if there is a failure by the partnership to satisfy the requirements for deduction.[2]

As to how individual limited partners treat their allocated shares of intangible drilling and development costs after the partnership has made its election to capitalize or expense, see Q 7800 and Q 7801.

Nonproductive Wells

If a limited partnership (i.e., the operator) has elected to capitalize intangible drilling and development costs, the regulations provide an additional option with respect to intangible drilling and development costs incurred in drilling a nonproductive well. Intangible drilling costs incurred with respect to individual nonproductive wells may be taken as a deductible loss for the first taxable year in which such nonproductive well is completed. Apparently, once this election is made, it is binding for all subsequent years and must be applied to all nonproductive wells completed after the election.[3]

7800. If the limited partnership elects to capitalize intangible drilling costs, how does a limited partner treat the allocated share of such costs?

If the limited partnership has elected to capitalize intangible drilling and development costs, each limited partner must treat the allocated share of such costs as a capital expenditure. Subsequently, each limited partner may recover a share of these capital expenditures on the income tax return through depletion or depreciation.[4] In the case of an electing large partnership, see below.

A limited partner may recover the limited partner's share of the cost of a particular item of intangible drilling costs that is *not* represented by physical property through the allowance for depletion (See Q 7802). Expenditures for clearing ground, draining, road making, surveying, geological work, excavation, grading, and the drilling, shooting, and cleaning of wells are considered *not* to be represented by physical property and thus may be recovered through depletion.[5]

1. Treas. Reg. §1.703-1(b).
2. See, e.g., *Puscas v. Comm.*, TC Memo 1978-73.
3. Treas. Reg. §1.612-4(b)(4).
4. Treas. Reg. §1.612-4(b).
5. Treas. Reg. §1.612-4(b)(1).

Amounts of intangible drilling and development costs capitalized and represented by physical property may be recovered by depreciation (See Q 620). Thus, a limited partner will capitalize and depreciate an allocated share of expenditures paid for wages, fuel, repairs, hauling, supplies, etc. used in the installation of casing and equipment and in the construction on the property of derricks and other physical structures.[1]

If intangible drilling costs are incurred under a drilling contract (e.g., a turnkey contract), the intangible drilling costs under the contract must be allocated between depletable and depreciable classes of costs for purposes of calculating depletion and depreciation at the partner level.[2]

As to how intangible drilling and development costs incurred with respect to a nonproductive well (i.e., a dryhole) are treated by a limited partner, see Q 7799.

Electing Large Partnerships

An electing large partnership generally calculates depletion and depreciation deductions (including those representing capitalized intangible drilling costs) at the partnership level. In the case of a limited partnership interest, these deductions are generally aggregated with other items of income or loss from passive loss limitation activities of the partnership and are considered one passive activity.[3] In the case of a general partnership interest, deductions allocable to passive loss limitation activities are generally taken into account separately to the extent necessary to comply with the passive loss rule.[4] However, in the case of a partner who is a disqualified person, items of income, gain, loss, deduction, or credit from oil and gas property are treated under the regular partnership rules discussed above. A disqualified person is a retailer or refiner of crude oil or natural gas (see Q 7806) or any other person whose average daily production of domestic crude oil and natural gas exceeds 500 barrels.[5] See Q 7704 regarding electing large partnerships; see Q 7918 regarding the passive loss rules.

7801. If the limited partnership elects to expense intangible drilling costs, how does a limited partner treat allocated shares of such costs?

If the limited partnership elects to expense intangible drilling and development costs, each limited partner has a choice as to how to treat an allocated share of intangible drilling costs for federal income tax purposes. The limited partner may (1) deduct the share of intangible drilling costs, or (2) elect to amortize the share of such costs ratably over a 60-month period.[6] In the case of an electing large partnership, see below.

Election to Amortize Costs

If the limited partner makes this election, the limited partner may deduct each year on his or her income tax return a ratable portion of the allocated share of intangible drilling costs

1. Treas. Reg. §1.612-4(b)(2).
2. Treas. Reg. §1.612-4(b)(3).
3. IRC Sec. 772(c)(2).
4. IRC Sec. 772(f).
5. IRC Sec. 776(b)(2)(B).
6. IRC Secs. 263(c), 59(e); Treas. Reg. §1.612-4.

over the 60-month period beginning with the month in which such amounts were expended by the partnership.[1]

If a limited partner elects to amortize intangible drilling costs over the 60-month period, any amount of intangible drilling and development costs covered by the election will *not* be treated as an item of tax preference for purposes of the alternative minimum tax.[2] See Q 7819.

In the case of a disposition of a limited partner's interest in an oil and gas limited partnership, deductions taken under the amortization method may, like expensed intangible drilling costs, be required to be recaptured as ordinary income.[3]

Deduction of Expensed Costs

If a limited partner does not elect to amortize the allocated share of intangible drilling costs, the limited partner will deduct (within the limits described in Q 7795) the amount on his or her federal income tax return.[4]

Assuming the limited partnership has elected cash basis tax accounting (as is usually the case), the limited partner will deduct the allocated share of intangible drilling and development costs with respect to a particular well in the year they are paid by the partnership if (1) the cash basis partnership (or more specifically, the general partner) drills the well and incurs the intangible drilling costs itself, or (2) the drilling is performed by a drilling contractor and the well is drilled in the same (or previous) calendar year that the drilling fees are paid by the partnership.[5] However, where the drilling contractor is paid by the partnership in a year prior to the year in which the drilling services are performed under the contract (i.e., where the intangible drilling costs are "prepaid"), the IRC and the courts have limited the ability to take the deduction in the earlier year.

If intangible drilling costs with respect to a particular well are prepaid and the drilling of that well commences *within 90 days* after the close of the calendar tax year (including where the drilling commenced but had not been completed during the earlier year), the limited partner may deduct the entire allocated share of the intangible drilling costs with respect to that well in the earlier year *if* (1) the expenditure (i.e., the payment of fees under the drilling contract) is a *payment* rather than a refundable deposit, (2) there is an adequate business purpose for prepaying the drilling fees, and (3) the deduction of such costs in the year of prepayment does not result in a material distortion of income. However, in such case, the portion of the intangible drilling costs attributable to drilling commencing within 90 days after the close of the earlier year is deductible only to the extent of the limited partner's *cash basis* in the

1. IRC Sec. 59(e).
2. IRC Sec. 59(e)(6).
3. IRC Secs. 59(e)(5), 1254.
4. IRC Sec. 263(c); Treas. Reg. §1.612-4.
5. See IRC Secs. 706(a), 461.

partnership.[1] (A limited partner's "cash basis" in the partnership is his or her adjusted basis in the partnership determined without regard to (1) any liabilities of the partnership, (2) any borrowings of the partner that were arranged by the partnership or an organizer or promoter of the partnership, and (3) any borrowings of the partner that were secured by any assets of the partnership.[2] See Q 7708.)

> *Example 1*: A limited partner purchases an interest in an oil and gas partnership in December 2014. The partnership hires a drilling contractor to drill the well under a contract that requires payment in December. Drilling is commenced on February 1, 2015. Assuming that the requirements with respect to adequate business purpose, payment rather than deposit, and nondistortion of income are met, the limited partner's entire share of prepaid IDC is deductible for the 2014 taxable year, but only to the extent of his or her *cash* basis in the partnership.

> *Example 2*: Assume the same facts as in *Example 1*, except that drilling begins in December 2014 and continues until February 1, 2015. The limited partner's entire share of prepaid IDC is deductible for the 2014 taxable year; however, the limited partner's share of the portion of intangible drilling costs that are attributable to drilling prior to the end of 2014 is not subject to the "cash basis" limitation discussed in the text above. (The limited partner's share of intangible drilling costs attributable to drilling after 2014 is, however, subject to this "cash basis" limitation).

If the drilling of the well does not commence within 90 days after the close of the calendar tax year in which the intangible drilling costs were prepaid, then the deduction of amounts that constitute intangible drilling costs can be taken only as economic performance occurs with respect to such costs (i.e., only as the drilling services are actually provided to the partnership).[3]

For purposes of determining if an expenditure is a payment rather than a deposit and whether a business purpose exists for a prepayment, the following principles and holdings should be considered: To the extent amounts prepaid pursuant to a footage or daywork contract may be recovered by way of a refund under a work stoppage provision in the contract, the amounts are deposits rather than payments.[4] Turnkey contracts fulfill a substantial business purpose and therefore do not distort income.[5] Where a turnkey drilling contract required payments on completion of each well, the Tax Court found that a valid business purpose existed for payments made after substantial drilling services had been performed but before any wells had been completed.[6] Where prepayments of intangible drilling costs were made to a general contractor who was the parent company of the general partner, the Service ruled that the deductions could *not* be taken for any year before such contractor actually contracted with and paid a drilling contractor.[7] But where prepayments were made under a turnkey-type contract to a corporation related to the general partner, the Tax Court held that limited partners could deduct their shares of intangible drilling costs in the year the fees were prepaid, even though the related corporation would contract

1. IRC Sec. 461(i). See General Explanation – TRA '84, pp. 279-282; *Keller v. Comm.*, 79 TC 7 (1982), aff'd 84-1 USTC ¶9194 (8th Cir. 1984), acq. 1984-1 CB 1.
2. IRC Sec. 461(i)(2). See General Explanation – TRA '84, p. 279.
3. IRC Secs. 461(i), 461(h); See General Explanation – TRA '84, p. 280.
4. *Keller v. Comm.*, above.
5. *Keller v. Comm.*, above.
6. *Levy v. Comm.*, TC Memo 1982-419, aff'd 84-1 USTC ¶9470 (9th Cir. 1984).
7. Rev. Rul. 80-71, 1980-1 CB 106.

for, rather than perform, the drilling services.[1] In Revenue Ruling 73-211,[2] the Service allowed a deduction for prepaid intangible drilling costs under a turnkey drilling contract with a drilling contractor controlled by the operator, but only to the extent such costs would have been incurred in an arm's length transaction. Where the drilling contract provided that drilling fees were payable when the well reached a predetermined depth, the Service ruled that a voluntary partial prepayment made in a year prior to the year in which the wells were drilled could *not* be deducted in the year paid; instead, the prepayment was deductible in the year the well reached the predetermined depth.[3]

When an interest in an oil or natural gas property (including a limited interest therein) is disposed of, all or part of the intangible drilling costs that were expensed rather than capitalized by the operator must be recaptured as ordinary income.[4]

Electing Large Partnership

An electing large partnership generally calculates intangible drilling and development costs at the partnership level. In the case of a limited partnership interest, these deductions are generally aggregated with other items of income or loss from passive loss limitation activities of the partnership and are considered one passive activity.[5] In the case of a general partnership interest, deductions allocable to passive loss limitation activities are generally taken into account separately to the extent necessary to comply with the passive loss rules.[6] However, in the case of a partner who is a disqualified person, items of income, gain, loss, deduction, or credit from oil and gas property are treated under the regular partnership rules discussed above. A disqualified person is a "retailer" or "refiner" of crude oil or natural gas (see Q 7806), or a person whose average daily production of domestic crude oil and natural gas exceeds 500 barrels.[7] See Q 7704 regarding electing large partnerships; see Q 7918 regarding the passive loss rules.

7802. What is the depletion allowance?

The depletion allowance is a formula for computing and excluding (i.e., by way of income tax deductions) from the proceeds of mineral operations the portion of the proceeds which represents a tax-free return of an investor's capital.[8] In other words, the depletion allowance is an income tax deduction that compensates the owner of wasting mineral assets (e.g., oil or gas) "for the part exhausted in production, so that when the minerals are gone, the owner's capital and his capital assets remain unimpaired."[9] Depletion is similar in concept to depreciation (see Q 620).

1. *Jolley v. Comm.*, TC Memo 1984-70.
2. 1973-1 CB 303.
3. Rev. Rul. 71-579, 1971-2 CB 225. See also, *Stradlings Building Materials, Inc. v. Comm.*, 76 TC 84 (1981); *Pauley v. U.S.*, 11 AFTR 2d 955 (S.D. Cal. 1963); Rev. Rul. 71-252, 1971-1 CB 146.
4. IRC Sec. 1254.
5. IRC Sec. 772(c)(2).
6. IRC Sec. 772(f).
7. IRC Sec. 776(b).
8. See *Jefferson Lake Sulphur Co. v. Lambert*, 133 F. Supp. 197 (E.D. La. 1955), aff'd, 236 F.2d 542 (5th Cir. 1956).
9. *Paragon Jewel Coal Co., Inc. v. Comm.*, 380 U.S. 624 (1965).

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7803. Who is eligible to take deductions for depletion?

Depletion allowance deductions are allowed only to individuals or entities that own an "economic interest" in the mineral deposit (i.e., the oil or gas in place).[1] Essentially, an individual or entity has an economic interest in a mineral deposit if (1) he, she, or it has acquired by investment any interest in a mineral in place, *and* (2) the individual or entity secures income through the extraction of the mineral.[2] However, it is not required that the taxpayer invest cash or property in acquiring the interest; an economic interest may be acquired by gift, inheritance, personal effort, etc. "The test of the right to depletion is whether the taxpayer has a capital investment in the [mineral] in place which is necessarily reduced as the [mineral] is extracted."[3]

"Economic interests" include working or operating interests, royalties, overriding royalties, net profits interests, and, to the extent not required to be treated as a loan, production payments.[4]

Where a limited partnership owns an economic interest in an oil or gas deposit (or other mineral interest), each individual partner (including any limited partner) is considered as owning an "economic interest" in the deposit.

7804. In the case of a limited partnership, who calculates the depletion allowance?

In the case of a limited partnership, each partner (both general and limited) computes the partner's depletion allowance separately from the partnership and other partners. (The partnership, however, often computes a tentative depletion allowance for its partners which, depending on the circumstances of the individual partner, may or may not need revising).[5] In the case of an electing large partnership, see below.

To ensure that a partner is able to make these calculations, the partnership is required to allocate to each partner his or her proportionate share of the tax basis of each partnership domestic oil or gas property. The partner's proportionate share will generally be determined in accordance with the partner's proportionate interest in partnership capital at the time of the allocation, unless (1) the partnership agreement provides for an allocation based upon the partner's proportionate interest in partnership income, and (2) at the time of the allocation it is reasonably expected that such interest will remain unchanged other than to reflect changes in ownership of the partnership. Each partner is charged with maintaining records of his or her share of the tax basis of each property and is further charged with making and keeping a record of the appropriate adjustments to such bases during the time he or she is a partner. The basis of each property is generally reduced as depletion is taken. Also, basis is generally reallocated upon a contribution to the partnership by a new or existing partner, or upon the withdrawal of a partner or a decrease in a partner's interest in the partnership.[6]

1. Treas. Reg. §1.611-1(b). See *Helvering v. Bankline Oil Co.*, 303 U.S. 362 (1938).
2. Treas. Reg. §1.611-1(b).
3. *Kirby Petroleum Co. v. Comm.*, 326 U.S. 599 (1946). See *Anderson v. Helvering*, 310 U.S. 404 (1940).
4. Treas. Reg. §1.614-1(a)(2).
5. IRC Sec. 613A(c)(7)(D); Treas. Reg. §1.613A-3(e)(1). See IRS Pub. 535 (2011), p. 35.
6. IRC Sec. 613A(c)(7)(D); Treas. Reg. §1.613A-3(e). See Treas. Reg. §1.704-1(b)(4)(v).

Electing Large Partnerships

An electing large partnership generally calculates depletion at the partnership level. In the case of a limited partnership interest, these deductions are generally aggregated with other items of income or loss from passive loss limitation activities of the partnership and are considered one passive activity.[1] In the case of a general partnership interest, deductions allocable to passive loss limitation activities are generally taken into account separately to the extent necessary to comply with the passive loss rules.[2] However, in the case of a partner who is a disqualified person, items of income, gain, loss, deduction, or credit from oil and gas property are treated under the regular partnership rules discussed above. A disqualified person is a retailer or refiner of crude oil or natural gas (See Q 7806) or any other person whose average daily production of domestic crude oil and natural gas exceeds 500 barrels.[3] See Q 7704 regarding electing large partnerships; see Q 7918 regarding the passive loss rules.

7805. How is the depletion allowance calculated?

The IRC provides two different methods for calculating a limited partner's individual depletion allowance. The first method is "cost depletion." Cost depletion essentially involves recovery of a portion of the taxpayer's adjusted basis each year, based on the amount of oil or gas recovered for that year and the total anticipated production. The second method is "percentage depletion." Percentage depletion is determined based on a percentage of the taxpayer's gross income from the property during the year, subject to certain limitations.[4] Assuming that a partnership and partners own a depletable interest in an oil or natural gas property (see Q 7803), there are no further restrictions as to who may use cost depletion. Percentage depletion is available only with respect to domestic oil or natural gas, and only certain individual limited partners are eligible to use the percentage depletion method (see Q 7806).[5]

If a limited partner is not eligible to use the percentage depletion method, the limited partner must use cost depletion to determine the total allowable deduction for depletion. If the limited partner is eligible to use percentage depletion, the limited partner must each year calculate a depletion allowance for each oil or gas property of the partnership using both the cost and percentage depletion methods, select the greater amount for each property, and deduct the sum of the selected amounts as the total depletion allowance.[6] (Unless an election has been made, interests in a single tract or parcel of land are treated as one property. Interests in different tracts or parcels are treated separately.[7] The election to treat interests in a single tract or parcel is made, if at all, by the partnership; individual partners cannot make this election).[8]

In the case of an electing large partnership (see Q 7704), depletion is generally calculated at the partnership level (See Q 7804).

1. IRC Sec. 772(c)(2).
2. IRC Sec. 772(f).
3. IRC Sec. 776(b).
4. See IRS Pub. 535 (2013), pp. 33-35.
5. IRC Secs. 611, 613, 613A.
6. IRC Sec. 613(a); Treas. Regs. §§1.611-1(a), 1.613-1.
7. IRC Sec. 614(a).
8. Rev. Rul. 84-142, 1984-2 CB 117.

7806. Who is eligible to use the percentage depletion method?

Percentage depletion is generally available to individuals (including limited partners) who qualify as "independent producers or royalty owners" (i.e., certain "small producers") and to individuals who own a depletable interest in (1) certain domestic regulated natural gas, (2) domestic natural gas sold under certain fixed contracts, and (3) certain domestic natural gas produced from geopressured brine.[1] (See Q 7804 regarding calculation of depletion in the case of an electing large partnership). The IRC formerly prohibited certain transferees of an interest in a "proven" oil or gas property from using the small producer's percentage depletion method; however, for transfers occurring after October 11, 1990, this limitation generally does not apply.[2] (See Treasury Regulation Section 1.613A-3(i)(2) regarding "transfers" and "transferees" in the context of "proven" properties and, also, for examples illustrating the effects of the old and new rules on the transfer of such properties).

Percentage depletion is available under IRC Section 613(b) with respect to certain minerals (other than oil and gas) recovered from an oil or gas well, without regard to the restrictions on oil and gas contained in IRC Sections 613(b)(7) and 613A.[3]

7807. What are the rules applicable to independent producers and royalty owners who are eligible to use the percentage depletion method with respect to oil and gas properties?

This is currently the most common basis for allowing an individual to claim percentage depletion.

A limited partner is eligible as an "independent producer or royalty owner" (i.e., as a "small producer") to use percentage depletion if: (1) the limited partner owns a depletable interest in a domestic oil or natural gas property (See Q 7803); and (2) is not a "retailer" or a "refiner" of crude oil or natural gas, as described below.[4]

A taxpayer is a "retailer" if (1) the taxpayer directly or through a related entity sells oil or natural gas (other than certain bulk sales to commercial or industrial users), or any product derived from oil or natural gas (other than certain bulk sales of aviation fuels), through any retail outlet owned, leased, controlled, or operated by the taxpayer or a related entity, or to any person who has agreed to use the trademark, service mark, etc. owned by the taxpayer or a related entity, and (2) the combined gross receipts of all retail outlets taken into account exceed $5,000,000 for the tax year.[5]

For tax years ending after August 8, 2005, a taxpayer is a "refiner" if the taxpayer and one or more related entities have an "average daily refinery run" for the year of more than 75,000 barrels. The average daily refinery run is determined by dividing the aggregate refinery run for

1. IRC Secs. 613A(b), 613A(c); Treas. Reg. §1.613A-3.
2. IRC Sec. 613A(c)(9), prior to amendment by OBRA '90.
3. *Louisiana Land and Exploration Co. v. Comm.*, 90 TC 630 (1988), nonacq. at 1995-2 C.B. 1 (IRS 1995).
4. IRC Sec. 613A(d); Treas. Regs. §§1.613A-4(b), 1.613A-4(c), 1.613A-7.
5. IRC Sec. 613A(d)(2).

the tax year by the number of days in the tax year.[1] For tax years ending before August 9, 2005, a taxpayer was a "refiner" if the taxpayer and any related entities together refined more than 50,000 barrels of crude oil on any day during the tax year.[2]

For purposes of the above rules, an entity is "related" to the limited partner if the limited partner owns a significant interest in such entity (5 percent or more in value of the outstanding stock of a corporation; 5 percent or more interest in the profits or capital of a partnership; 5 percent or more of the beneficial interests in an estate or trust). In determining such ownership interests, an interest owned by or for a corporation, partnership, trust, or estate is considered to be owned directly both by itself and proportionately by its shareholders, partners, or beneficiaries.[3]

7808. What are the rules applicable to transferees of "proven" properties that are eligible to use the percentage depletion method with respect to oil and gas properties?

For transfers occurring after October 11, 1990, the "proven property" prohibition for use of percentage depletion was repealed.

For transfers occurring prior to October 12, 1990, the IRC prohibited use of percentage depletion for certain transferees of "proven" properties. Generally, a limited partner who acquired a depletable interest in a "proven" oil or natural gas property after 1974 did not qualify as an independent producer or royalty owner and thus could be prohibited from using the percentage depletion method *unless* the interest was acquired (1) by a transfer at death, (2) from the limited partner's spouse or minor children, (3) from the limited partner's parents if he or she was a minor child at the time of the transfer, (4) as a result of certain changes in the beneficiaries of a trust, or (5) by reversion (in total or in part) of an interest with respect to which the limited partner was previously eligible to use the percentage depletion method.[4]

If a partner was eligible to use the percentage depletion method at the time he or she transferred a proven oil or natural gas property to the partnership, that partner was not treated as a transferee with respect to any retained or reversionary interest in the property. A partner who did not have an interest in a proven property prior to the time it was transferred to the partnership was not eligible for percentage depletion.[5]

Where an individual transferred his depletable interest in a producing oil and gas property to a Clifford Trust that provided for the maintenance of a depletion reserve, the "proven" property rule did not prohibit the transferor from claiming deductions for percentage depletion either during the period of the trust or after the interest was returned to the transferor.[6]

1. IRC Sec. 613A(d)(4).
2. IRC Sec. 613A(d)(4), prior to amendment by ETIA 2005.
3. IRC Sec. 613A(d)(3).
4. IRC Sec. 613A(c)(9), prior to amendment by OBRA '90.
5. Let. Rul. 8723073.
6. Rev. Rul. 84-14, 1984-1 CB 147.

An oil or natural gas property was considered "proven" if at the time of the transfer the principal value of the property had been demonstrated by prospecting, exploration, or discovery work.[1]

7809. How is cost depletion calculated?

Cost depletion is calculated on each oil or gas property by a unit of production method using the following formula:[2]

$$\begin{matrix}\text{Cost depletion} \\ \text{for tax year}\end{matrix} = \frac{\text{Basis of property}}{\text{Units remaining as of tax year}} \times \text{Units sold during year}$$

Basis. For this purpose, "basis" is the adjusted tax basis (including adjustments reflecting prior years' depletion deductions) of the oil or gas property (i.e., excluding the basis of any land or depreciable improvements) that would be used to determine the gain on a sale of the property.[3] If an election has been made to capitalize intangible drilling and development costs, some of those costs may be reflected in the individual's adjusted tax basis (See Q 7800).[4] In the case of limited partners in an oil or natural gas program, the partnership will allocate to each limited partner the limited partner's proportionate share of the tax basis in each property[5] (see Q 7804). In the case of community property interests, a surviving spouse's basis for calculating cost depletion on property representing the surviving spouse's one-half share of the property will be stepped up or down to reflect the property's estate tax value in the decedent spouse's estate (generally, fair market value at the date of death). But see Q 598.[6]

Units. For purposes of the formula, mineral deposits remaining and amounts sold are determined using the unit customarily paid for in the type of mineral sold. In the case of oil, the unit is "barrels"; in the case of natural gas, the unit is "thousands of cubic feet."[7]

Units remaining. The number of units remaining as of the tax year is the number of units of mineral remaining at the end of the year to be recovered from the property (including units recovered but not yet sold) *plus* the number of units sold during the year.[8] For this purpose, if the number of recoverable units remaining at the end of the prior year (or years) has been estimated and there have been no known changes that would affect such estimate, the number of recoverable units as of the tax year is the number remaining from the prior estimate.[9]

Units sold. In the case of a cash basis taxpayer, the number of units sold during the tax year includes units for which payments were actually received during the year, even if such units were

1. IRC Sec. 613A(c)(9)(A), prior to amendment by OBRA '90. See Treas. Reg. §1.613A-7(p).
2. Treas. Reg. §1.611-2(a).
3. IRC Sec. 612; Treas. Regs. §§1.611-2, 1.612-1(a).
4. Treas. Reg. §1.612-1(b)(1).
5. Treas. Reg. §1.613A-3(e)(1).
6. Rev. Rul. 92-37, 1992-1 CB 195.
7. Treas. Reg. §1.611-2(a)(1).
8. Treas. Reg. §1.611-2(a)(3).
9. Treas. Reg. §1.611-2(c)(2).

sold or produced in a prior year. Units sold but not paid for in the tax year are not counted in that year.[1]

In the case of natural gas, where the annual production is not metered and is not estimable with reasonable accuracy, cost depletion for the tax year may be calculated by multiplying the adjusted tax basis of the property (see "Basis" above) by a fraction, "the numerator of which is equal to the decline in rock pressure during the tax year and the denominator is equal to the expected total decline in rock pressure from the beginning of the tax year to the economic limit of production."[2]

Once an individual's adjusted tax basis for a mineral property has been reduced to zero through reductions for allowable depletion deductions (or otherwise), cost depletion is no longer available with respect to such property; however, if eligible, the individual may continue to use percentage depletion. (See Q 7810).[3]

7810. How is percentage depletion generally calculated on oil or gas properties?

Unlike cost depletion, percentage depletion is not based on the investor's tax basis in each oil or gas property; instead, the percentage method provides for a deduction of a specified percentage of the *gross income* derived from the property (after reduction for rents or royalties paid or incurred by the investor with respect to the property).[4] The applicable percentage rate and various limitations depend on the reason for the investor's eligibility for percentage depletion.[5] See Q 7804 regarding the calculation of depletion in the case of an electing large partnership.

The deduction for percentage depletion for oil and gas properties may offset up to 100 percent of the taxpayer's taxable income from the property (computed without allowance for depletion).[6] The percentage rate to be used in calculating percentage depletion is to be determined in the year that oil and gas income is reported and not in the year that the oil or gas is extracted.[7]

For purposes of calculating percentage depletion, "gross income" is defined as the amount for which the oil or gas is sold in the immediate vicinity of the well. If the oil or gas is not sold on the premises, but is manufactured or refined prior to sale, or transported from the premises prior to sale, gross income generally is the representative market or field price of the oil or gas prior to conversion or transportation.[8]

1. Treas. Reg. §1.611-2(a)(2).
2. Treas. Reg. §1.611-2(a)(4).
3. See Treas. Reg. §1.611-2(b)(2).
4. IRC Sec. 613(a); Treas. Reg. §1.613-2(c)(5). See Rev. Rul. 81-266, 1981-2 CB 139; Rev. Rul. 79-73, 1979-1 CB 218. See also *Comm. v. Engle*, 84-1 USTC ¶9134 (U.S. 1984).
5. See IRC Secs. 613(b), 613(e).
6. IRC Sec. 613(a).
7. *Potts v. Comm.*, 90 TC 995 (1988).
8. Treas. Reg. §1.613-3.

7811. How is percentage depletion calculated on oil or gas properties for independent producers and royalty owners?

In the case of an individual who qualifies as an independent producer or royalty owner (often referred to as a "small producer" (See Q 7806)), percentage depletion is available using a rate of 15 percent. However, in this case, percentage depletion is calculated only on so much of the individual's average daily production of crude oil or natural gas as does not exceed the individual's maximum daily depletable quantity.[1] In the case of crude oil, an individual's "maximum daily depletable quantity" is generally 1,000 barrels.[2] In the case of natural gas, an individual's maximum daily depletable quantity equals the amount determined by multiplying 6,000 cubic feet by the number of barrels by which the individual has elected to reduce his or her maximum daily depletable quantity of crude oil. (In other words, one barrel of crude oil is deemed to equal 6,000 cubic feet of natural gas, and an individual's maximum daily depletable quantity must be allocated between crude oil and natural gas such that the total daily depletable quantity is the equivalent of 1,000 barrels of crude oil).[3] If an individual's spouse or minor children own depletable oil or gas interests, the maximum daily depletable quantity must be allocated among such family members in proportion to their respective production of crude oil during the year.[4] An electing large partnership (See Q 7704, Q 7804) calculates its percentage depletion without regard to these production limitations.[5]

An individual's "average daily production" of crude oil or natural gas is determined by dividing the aggregate production from all oil or gas interests, as the case may be, during the tax year by the number of days in that year. A limited partner's annual production of oil or natural gas from specific properties is determined by multiplying the total production of each property by the limited partner's percentage participation in the revenues from that property.[6] A taxpayer holding a "net profits interest" determines the taxpayer's annual production by multiplying the total production of the property by the taxpayer's percentage participation in the revenues from the property.[7]

If an individual's average daily production of crude oil exceeds the individual's maximum daily depletable quantity, the amount of percentage depletion allowable with respect to each domestic property is determined using the following formula:

$$\begin{array}{c}\text{Percentage}\\ \text{Depletion}\end{array} = \frac{\text{maximum daily depletable quantity}}{\text{average daily production (all properties)}} \times 15\% \times \begin{array}{c}\text{gross income from}\\ \text{property in tax year}\end{array}$$

This formula may also be used to determine allowable percentage depletion on natural gas production when an individual's average daily production of natural gas exceeds the maximum daily depletable quantity.[8]

1. IRC Sec. 613A(c)(1).
2. See IRC Sec. 613A(c)(3).
3. IRC Sec. 613A(c)(4); Treas. Regs. §§1.613A-3, 1.613A-5, 1.613A-7(i).
4. IRC Sec. 613A(c)(8)(C); Treas. Regs. §§1.613A-3(h)(3), 1.613A-3(h)(4)(i).
5. IRC Sec. 776(a)(2).
6. IRC Sec. 613A(c)(2).
7. Rev. Rul. 92-25, 1992-1 CB 196.
8. IRC Sec. 613A(c)(7).

Special rules apply to the percentage depletion rate for marginal properties held by small producers. During any year in which the reference price for crude oil for the preceding calendar year drops below $20, the percentage depletion rate of 15 percent is increased by one percentage point for each whole dollar by which such reference price falls below the $20 level. However, the percentage depletion rate cannot exceed 25 percent.[1] The applicable percentage for 2001 through 2014 is 15 percent.[2] For tax years beginning after 1997 (except 2008) and before 2012 the limit of percentage depletion to 100 percent of the taxable income from the property (computed without allowance for depletion) did not apply to marginal properties.[3] "Marginal properties" for this purpose refers only to stripper wells or wells that produce heavy oil.[4]

Certain tertiary recovery projects begun or expanded after 1990 may qualify for a special tax credit; see Q 7817.

An additional limitation applies to percentage depletion for small producers. The aggregate deduction for percentage depletion of a small producer's oil and gas properties (i.e., not including percentage depletion on domestic regulated natural gas, etc. – see below) may not exceed 65 percent of the individual's taxable income; however, for this purpose, taxable income is calculated without regard to (1) certain depletion deductions, (2) any net operating loss carryback, and (3) any capital loss carryback. If this 65 percent limitation acts to disallow a portion of the percentage depletion deduction, the disallowed amount is allocated among the producing properties in proportion to the percentage depletion otherwise allowable (but for the 65 percent limitation), and the reduced percentage depletion deduction is compared to the cost depletion allowance on a property-by-property basis to finally determine whether cost or percentage depletion is greater (for each property). Any amount disallowed by reason of the 65 percent limitation may be carried forward to the following year in which it again will be subject to the 65 percent limitation.[5] An electing large partnership (See Q 7704) calculates its percentage depletion without regard to the 65 percent of taxable income limitation.[6]

7812. How is percentage depletion calculated on oil or gas properties in the case of regulated natural gas and natural gas sold under a fixed contract?

The applicable percentage in the case of a depletable property that qualifies as "regulated natural gas" or "domestic gas sold under fixed contract" (See Q 7806) is 22 percent.[7] Thus, 22 percent of the "gross income" received from the property is the amount allowable as percentage depletion.[8] Remember, however, that the amount which must be deducted as the

1. IRC Sec. 613A(c)(6)(C).
2. Notice 2012-50, 2012-2 CB 121.
3. IRC Sec. 613A(c)(6)(H).
4. IRC Sec. 613A(c)(6)(D).
5. IRC Sec. 613A(d)(1); Treas. Reg. §1.613A-4.
6. IRC Sec. 776(a)(2).
7. IRC Sec. 613A(b)(1).
8. IRC Sec. 613(a).

depletion allowance on a specific property is the *greater of* the percentage depletion or cost depletion (See Q 7805).[1]

7813. How is percentage depletion calculated on oil or gas properties in the case of natural gas from geopressured brine?

In the case of "natural gas from geopressured brine" (see Q 7806), the applicable percentage rate is 10 percent.[2]

7814. Is percentage depletion available with respect to advance royalties or lease bonuses?

No. Percentage depletion is not available with respect to advance royalties or lease bonuses.[3] Prior to TRA '86, gross income received in the form of advance royalties or lease bonuses was eligible for percentage depletion by a "small producer" (see Q 7810) even though no oil or natural gas had as yet been extracted from the ground.[4] According to the Service, however, this depletion deduction had to be taken in the year in which the lease bonus or advanced royalty payment was includable in the gross income of the taxpayer.[5]

If the economic interest in the property expires, terminates, or is abandoned before income has been derived from production (in the case of a lease bonus), or before the royalty has been recouped from production (in the case of an advanced royalty), the taxpayer is required to adjust the capital account by restoring any excess depletion deduction taken under the *Engle* rule and to include the excess in income in the year the expiration, termination, or abandonment occurs.[6]

7815. Does depletion affect a limited partner's tax basis in a partnership interest?

Yes, in two ways. First, a limited partner's tax basis in the partnership interest is *increased* by the excess of the deductions for depletion over the basis of the property subject to depletion. (This can occur only when percentage depletion is taken).[7] However, Treasury Regulation Section 1.705-1(a)(2) provides that the previous rule does not apply in the case of oil and gas property the basis of which is allocated to and computed separately by the partners of the partnership owning such property under IRC Section 613A(c)(7)(D) (See Q 7804). Second, the limited partner's tax basis in the partnership interest is *reduced* (but not below zero) by the amount of allowable depletion deductions for each tax year.[8] The basis is not reduced due to depletion deductions calculated at the electing large partnership level (See Q 7704).[9]

1. IRC Sec. 613(a).
2. IRC Sec. 613A(b)(2).
3. IRC Sec. 613A(d)(5).
4. *Comm. v. Engle*, 84-1 USTC ¶9134 (U.S. 1984).
5. Treas. Reg. §1.613A-3(j)(2).
6. Treas. Regs. §§1.612-3(a)(2), 1.612-3(b)(2).
7. IRC Sec. 705(a)(1)(C); Treas. Reg. §1.705-1(a)(2).
8. IRC Sec. 705(a)(3); Treas. Reg. §1.613A-3(e)(6)(ii).
9. IRC Sec. 776(a)(3).

7816. How is gain from the disposition of an interest in an oil or natural gas property treated if depletion deductions have been taken?

Gain from the disposition of an interest in an oil or natural gas property is treated as ordinary income ("recaptured") to the extent that depletion deductions reduced the adjusted basis of the oil and natural gas property.[1] Taxation of the recaptured amount may be deferred through use of an installment sale. However, income (other than interest) from an installment sale of an oil or natural gas property is treated as recaptured IRC Section 1254 gain until all such gain is reported, and any remaining income is then treated as other than IRC Section 1254 gain.[2]

7817. What is the enhanced oil recovery credit?

The enhanced oil recovery credit is a credit equal to 15 percent of a taxpayer's qualified enhanced oil recovery costs in connection with certain certified enhanced oil recovery projects (generally referred to as tertiary recovery projects).[3] Because of the phase out tied to the "reference price" of crude oil, discussed below, this credit has not been important in recent years.

The credit is, in form, generally available for projects utilizing one or more qualified tertiary recovery methods located in the United States and begun after December 31, 1990.[4] Qualified enhanced oil recovery costs include amounts paid or incurred for tangible depreciable (or amortizable) property, intangible drilling and development costs, and qualified tertiary injectant costs.[5] Costs paid for acquisition of an existing qualified enhanced oil recovery project are not eligible for the credit.[6]

But the credit is phased out as the "reference price" for crude oil (the estimated average annual wellhead price per barrel for domestic crude oil, determined under IRC Section 45K(d)(2)(C)) exceeds $28 (adjusted by an inflation adjustment factor for taxable years beginning after 1991). The phaseout is equal to an amount that bears the same ratio to the amount of the credit as the amount by which the reference price for the calendar year preceding the calendar year in which the taxable year begins exceeds $28 (as adjusted for inflation) bears to $6.[7] Because of the reference price and inflation adjustment factor, the credit was phased out completely in calendar years 2006 through 2013.[8]

> *Example*: In 1993, F, the owner of an operating mineral interest in a property, incurred $100 of qualified enhanced oil recovery costs. The 1992 reference price was $34, and the 1993 inflation adjustment factor was 1.10. F's credit in 1993 determined without regard to the phaseout for crude oil price increases was $15 ($100 × 15%). In determining F's credit, $30.80 (1.10 × $28) was substituted for $28, and the credit was reduced by $8 ($15 × ($34 - $30.80)/6). Accordingly, F's credit was $7.[9]

1. IRC Sec. 1254.
2. Treas. Reg. §1.1254-1(d).
3. IRC Sec. 43.
4. IRC Sec. 43(c)(2).
5. IRC Sec. 43(c)(1).
6. Treas. Reg. §1.43-4(e)(2).
7. IRC Sec. 43(b).
8. See Notice 2013-50, 2013-2 CB 134.
9. Treas. Reg. §1.43-1(c)(3), Ex. 2.

Any deduction otherwise allowable for items such as tangible depreciable property and intangible drilling and development costs taken into account in computing the enhanced oil recovery credit must be reduced by the amount of enhanced oil recovery credit attributable to the expenditure. Also, any increase in basis attributable to qualified enhanced oil recovery costs is reduced by the amount of credit claimed.[1] Partners and S corporation shareholders must reduce the basis of their interests in a partnership or S corporation (but not below zero) to the extent any deduction is disallowed or any basis is reduced under the preceding rules in this paragraph.[2]

7818. How does the enhanced oil recovery credit work in conjunction with the general business credit?

The enhanced oil recovery credit is a component of the general business credit. The amount of the enhanced oil recovery credit is aggregated with other credits, including the low-income housing credit (see Q 7754) and the rehabilitation credit (See Q 7965).[3] The sum of these credits (the general business credit) may not exceed the excess (if any) of the taxpayer's net income tax over the *greater of*:

(1) the taxpayer's tentative minimum tax (as calculated without reduction for the alternative minimum tax foreign tax credit or the taxpayer's regular tax liability), *or*

(2) for most credits, 25 percent of the amount by which the taxpayer's net regular tax liability exceeds $25,000.[4]

"Net income tax" means the *sum of* the taxpayer's regular *and* alternative minimum tax liabilities, *reduced by* the sum of the nonrefundable personal credits, the foreign tax credit, certain energy credits, and the Puerto Rico economic activity credit. "Net regular tax liability" means the taxpayer's regular tax liability reduced by the sum of the nonrefundable personal credits, the foreign tax credit, certain energy credits, and the Puerto Rico economic activity credit.[5] For these purposes the taxpayer's regular tax liability does not include certain specified taxes, such as the alternative minimum tax and certain penalty taxes on premature distributions from qualified plans or ordinary annuity contracts.[6] See Q 653 on the alternative minimum tax.

The $25,000 amount applies to the individual partners and not to the partnership. Similarly, the $25,000 amount applies to the S corporation shareholder and not to the S corporation. Estates, trusts, and controlled groups of corporations must apportion the $25,000 amount. For married taxpayers filing separately, $12,500 is substituted for $25,000, unless the spouse of the taxpayer has no general business credit for the year. REITs, RICs, and certain banking organizations apply a ratable share of the $25,000 amount.[7]

1. IRC Sec. 43(d).
2. Treas. Reg. §1.43-1(f).
3. IRC Sec. 38(b).
4. IRC Sec. 38(c).
5. IRC Sec. 38(c)(1).
6. IRC Sec. 26(b).
7. IRC Sec. 38(c)(5).

The amount of the general business credit that exceeds the above limitation (i.e., the unused general business credit) for any taxable year generally may be carried back to the preceding year and carried over to the succeeding 20 years.[1] (For credits arising in tax years beginning before 1998, credits could be carried back to the preceding three years and carried over to the succeeding 15 years). However, there are limitations on certain carrybacks.[2]

Where a portion of the general business credit remains unused at the end of the carryover period, the taxpayer may deduct from adjusted gross income in the first taxable year following the last carryover year available the amount of the unused credit remaining in the case of the qualified business credits, including the enhanced oil recovery credit and the rehabilitation credit (See Q 7761), with respect to which a basis adjustment was required.[3] If a taxpayer dies or ceases to exist before the end of the carryover period, any such allowable deduction is taken in the taxable year in which death or cessation occurs.[4]

The order in which the various general business credits are treated as used, or carried back or forward, is determined by the order in which they are listed in IRC Section 38(b) at the end of the year in which the credits are used.[5]

The allowable general business credit that is attributable to a passive activity may offset tax liability attributable only to passive activities[6] (See Q 7831).

7819. What items of tax preference (for purposes of the alternative minimum tax) are unique to an oil and gas program?

Two items that are unique to oil or gas investments and that may give rise to tax preferences for purposes of the alternative minimum tax are the following: (1) intangible drilling and development costs; and (2) percentage depletion.

Intangible drilling costs. The amount (if any) by which "excess intangible drilling costs" exceeds 65 percent of the limited partner's net income from oil and gas (determined without consideration of such "excess intangible drilling costs") for the tax year is a tax preference item for purposes of calculating the limited partner's alternative minimum tax for the year. "Excess intangible drilling costs" for a tax year is the amount by which the limited partner's allowable deduction for intangible drilling and development costs in the tax year on productive wells exceeds the amount that would have been deducted had the costs been capitalized by the partnership and the limited partner's allocated share amortized over a 120-month period or recovered through cost depletion (i.e., through a straight-line recovery method).[7]

However, only those intangible drilling and development costs (IDCs) that both the partnership and limited partner elect to expense (and deduct) may give rise to a tax preference

1. IRC Sec. 39(a).
2. IRC Sec. 39(d).
3. IRC Secs. 196(a), 196(c).
4. IRC Sec. 196(b).
5. IRC Sec. 38(d).
6. IRC Secs. 469(d)(2), 469(a).
7. IRC Sec. 57(a)(2).

amount. IDCs that the partnership elects to capitalize and IDCs that the limited partner elects to amortize over 60 months (see Q 7801) will not create tax preferences for purposes of calculating the limited partner's alternative minimum tax.[1]

Intangible drilling costs on nonproductive wells are never tax preference items.[2] A well is nonproductive if it was plugged and abandoned without ever having produced oil or natural gas in commercial quantities for any substantial period of time.[3] A well that is temporarily shut down is not "nonproductive" for this purpose.[4]

This preference does not apply in the case of taxpayers who are not "retailers" or "refiners" of crude oil or natural gas (See Q 7806). However, this exception is not available to the extent that it reduces the taxpayer's alternative minimum taxable income by more than 40 percent of the amount of the taxpayer's alternative minimum taxable income calculated without regard to the exception and the alternative tax net operating loss deduction.[5]

For treatment of electing large partnerships, see below.

Percentage Depletion. If a limited partner's deduction for depletion with respect to a specific oil or gas property is greater than his or her share of the adjusted tax basis of that property (determined at the end of the year and without regard to the depletion deduction for that year), the amount of the difference is a tax preference item for purposes of the partner's alternative minimum tax. This preference does not apply in the case of "independent producers and royalty owners" (See Q 7806).[6] For this purpose, adjusted basis includes intangible drilling and development costs but not unrecovered tangible (depreciable) drilling costs.[7] Thus, once a limited partner's adjusted tax basis in a property has been reduced to zero (on account of previous depletion deductions, etc.), any percentage depletion deductions with respect to the property will generally create a tax preference item.

Of course, as cost depletion may not be taken once a limited partner's adjusted tax basis in a property is reduced to zero, deductions for cost depletion can never result in a tax preference amount (See Q 7809).

Electing Large Partnerships

An electing large partnership generally calculates alternative minimum tax preferences (including those regarding excess IDCs and percentage depletion) at the partnership level. In the case of a limited partnership interest, these preferences are generally aggregated with other items of tax preference from passive loss limitation activities of the partnership and are considered one passive activity.[8] In the case of a general partnership interest, tax preferences

1. IRC Secs. 57(a)(2), 59(e)(6).
2. IRC Sec. 57(a)(2)(B).
3. S. Rep. No. 1236, 94th Cong., 2d Sess. 426 (1976), 1976-3 (Vol. 3) 807, 830.
4. Rev. Rul. 84-128, 1984-2 CB 15 (as modified by Ann. 84-127, 1984-53 IRB 27).
5. IRC Sec. 57(a)(2)(E).
6. IRC Sec. 57(a)(1).
7. *U.S. v. Hill*, 506 U.S. 546, 93-1 USTC ¶50,037 (U.S. 1993).
8. IRC Sec. 772(c)(2).

allocable to passive loss limitation activities are generally taken into account separately to the extent necessary to comply with the passive loss rules.[1] However, in the case of a partner who is a disqualified person, items of tax preference from oil and gas property are treated under the regular partnership rules discussed above. A disqualified person is a retailer or refiner of crude oil or natural gas (see Q 7806) or any other person whose average daily production of domestic crude oil and natural gas exceeds 500 barrels.[2] See Q 7704 regarding electing large partnerships; see Q 7918 regarding the passive loss rules.

For an explanation of the alternative minimum tax, see Q 653.

1. IRC Sec. 772(f).
2. IRC Sec. 776(b).