SELECTED ISSUES IN OIL AND GAS TAXATION

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OVERVIEW

The increased production of oil and gas on privately owned property in recent years means that an increasing number of landowners are receiving payments from oil and gas companies. It is important for practitioners to understand the various types of payments that a client may receive and the tax consequences that may apply due to the nature of the income received. The consequences include two relatively new taxes that can apply to payments associated with oil and gas. These new taxes are the additional 0.9% Medicare tax on active income[1] and the additional 3.8% net investment income tax (NIIT) on passive income.[2]

An oil and gas lease is created when the owner of an operating right (working interest) assigns all or a portion of the right to another person and retains a continuing non-operating interest in production. The owner may assign the right either for no immediate consideration or for cash or its equivalent.

Generally, the lease runs for an initial period (e.g., five years), but if the property is placed in production during the initial lease period, the lease generally continues for as long as production continues. The lease is eventually terminated under the terms of the lease or in accordance with local (state) law when production ceases.

The income from the oil and gas property is commonly divided between the mineral interest owner (the royalty owner) and the operator (the working interest owner). In the typical lease arrangement, the royalty owner retains one-eighth (12.5%) and the working interest owner holds the other 87.5% (the balance of the portion of production or income that remains after the royalty interest owner's share is satisfied).[3]

The working interest owner bears the entire cost of exploration for minerals, as well as the development and production costs. The royalty owner bears none of the exploration, development, or operational costs. The funding necessary for the working interest owner to develop the oil and gas property is provided by investors who receive an interest in the activity in exchange for their capital investment. The costs of the activity borne by the working interest owner are allocated to the investors. These include geological survey costs, tangible costs (the drilling equipment and well), and intangible drilling costs (IDC). As discussed later, these costs can be currently deducted rather than capitalized.

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[1] IRC §3101(b)(2).
[2] IRC §1411.
[3] See, e.g., "Mineral Rights, Basic Information About Mineral, Surface, Oil and Gas Rights," located at https://geology.com/articles/mineral-rights.shtml.

This relationship between the working interest owner and the investors is typically a joint venture that is classified as a partnership for tax purposes. Thus, the partnership passes through the costs separately to the investors on Schedule K-1, *Partner's Share of Income, Deductions, Credits, etc.* In the early years of the activity, the partnership typically passes through large losses to the partners. Because the partners are merely investors in the activity, the losses in their hands are passive losses. These losses are limited under the passive loss rules[4] such that they are only deductible to the extent the investor has passive income. The working interest owner (who owns the interest either directly or through an entity that does not limit liability for the interest), however, is treated as being engaged in a nonpassive activity regardless of the participation of the working interest owner.[5] Likewise, for an investor who holds both a general and limited partnership interest, the investor's entire interest in each well drilled under the working interest is treated as an interest in a nonpassive activity regardless of whether the investor is materially participating.

Caution. Investors in the working interest activity, given the broad definition of "partnership" contained in the Code, will likely have income from the activity that is subject to self-employment tax even though they are not materially participating in the activity.[6]

TAX ISSUES FOR LESSORS AND LESSEES

Bonus Payment

The lessee typically pays a lump-sum cash bonus during the initial lease term (pre-drilling) for the rights to acquire an economic interest in the minerals. This is the basic consideration that the lessee pays to the lessor when the lease is executed. The lessor reports the bonus payment on Schedule E, *Supplemental Income and Loss.*

> **Example 1.** Jed owns 160 acres of an oil-contaminated swamp in the Ozarks. Jed enters into a lease with the O.K. Oil Company that gives O.K. the right to drill for oil in the swamp. Jed receives $400,000 as a bonus payment. The lease provides for a primary term of five years and will continue as long as oil is produced on the property. O.K. assumes all development and operating costs and will pay Jed one-eighth of the proceeds when production begins. Jed will report the $400,000 bonus payment as ordinary income, subject to cost depletion (discussed later), on Schedule E.

Tax Consequences to the Lessor. A bonus payment is reported as rent to the lessor in box 1 of Form 1099-MISC, *Miscellaneous Income,* and constitutes net investment income (NII) that is potentially subject to the additional 3.8% NIIT.[7] The lessor reports the payments on Schedule E, *Supplemental Income and Loss,* with the amount then flowing to line 17 of Form 1040. The lessor may be allowed to

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4 IRC §469.

5 Temp. Treas. Reg. §1.469-1T(e)(4)(i). For this purpose, a working interest in oil or gas property is defined in reference to the depletion rules. As a result, for example, the production of fuel from a landfill does not qualify as a working interest in oil and gas property. Also, it is possible for a general partner to be indemnified against liability that exceeds the general partner's capital contribution for any of the partnership's costs and expenses with respect to the general partner's working interest such that the general partner is not deemed to be passive and can deduct IDCs that are passed through without limitation.

6 *See, e.g.,* Methvin v. Comm'r, TC Memo 2015-81 (Apr. 27, 2015).

7 However, the U.S. Court of Appeals for the 9th Circuit has held that a cash bonus received for an oil and gas lease is not a royalty that is treated as passive investment income. Swank & Sons, Inc. v. U.S., 522 F.3d 981 (9th Cir. 1975), *aff'g,* 362 F. Supp. 897 (D. Mt. 1973). The court determined that the payment of a "bonus" upon the execution of an oil and gas lease did not constitute "personal holding company income." The court determined that the terms "bonus" and royalty" had particular meanings in the realm of oil and gas and did not mean the same thing. The court viewed a bonus payment as active income derived from active management of the land and royalty income as entirely passive. The court's holding is contrary to that of the D.C. Circuit and the 5th Circuit.

deduct cost depletion (discussed later) against the bonus payment. Bonus payments are not eligible for percentage depletion (discussed later).

Typically, a bonus payment is ordinary income (rather than capital gain) that is not subject to self-employment (SE) tax. A recent Tax Court case illustrates the difficulty that lessors have in characterizing bonus payments as capital gain. In *Dudek v. Commr*,[8] the petitioner entered into an oil and gas lease agreement with an independent company. Under the agreement, he received an up-front bonus payment of over $800,000 and a royalty payment that equaled 16% of the net profits of oil and gas extracted from his property. The bonus payment was not tied to production. The petitioner reported the payment as long-term capital gain based on his contention that a sale rather than a lease was involved. However, the IRS recharacterized the payment as ordinary income and assessed an accuracy-related penalty. In addition, the petitioner argued for a depletion deduction, which the IRS also disallowed.

The court determined that a lease rather than a sale was involved because the petitioner retained an economic interest in the deposits — he was entitled to a royalty interest equal to a percentage of extracted oil and gas. The court also agreed with the IRS about the treatment of the depletion deduction attributable to the lease bonus income. IRC §613A(d)(5) bars a percentage depletion deduction for income that is payable without regard to production.[9] Although the bonus payment could have been eligible for cost depletion under Treas. Reg. §1.612-3(a)(1), the court held that the petitioner did not provide evidence of the amount of royalties that he expected to receive.

Note. The IRS allows a depletion allowance to an owner of mineral resources (or a taxpayer that has an economic interest in the mineral property) to account for the reduction (production) of the reserves as they are produced and sold. It is a form of cost recovery for the capital investment. There are two ways that a taxpayer may compute the depletion allowance: cost depletion and percentage depletion. Royalty owners can use either approach. Cost depletion allows the taxpayer to deduct the portion of the original capital investment, less prior deductions, equal to the fraction of the estimated remaining recoverable reserves that have been produced and sold during the tax year. The cumulative maximum amount recovered cannot exceed the taxpayer's original capital investment. Percentage depletion, on the other hand, is a deduction that is a fixed percentage of the sales revenue from the sale of the oil or gas. For royalty owners, the deduction is 15% of gross income based on average daily production of crude oil or natural gas up to the depletable oil or natural gas quantity. The deduction is limited to the smaller of 100% of taxable income from the property (computed without the depletion deduction); or 65% of taxable income from all sources (computed without the depletion allowance). With percentage depletion, the cumulative deductions can exceed the capital amount spent to acquire the property. More information on cost depletion and percentage depletion is provided later.

There is authority for claiming cost depletion when it is not possible to reasonably estimate future royalties. This could happen, for instance, in a wildcat area[10] when there is no evidence to indicate that there would be future production during the lease term. In *Collums v. U.S.*,[11] the court held that a zero

[8] Dudek v. Comr, T.C. Memo. 2013-272, *aff'd.,* 588 Fed. Appx. 199 (3d Cir. 2014).
[9] See also Treas. Reg. §1.613A-3(j).
[10] A wildcat area is one that has no concrete historic production records and has been unexplored as a site for potential oil and gas output.
[11] Collums v. United. States, 480 F. Supp. 864 (D. Wyo. 1979); Watnick v. Comr., 90 T.C. 326 (1988)(cash received on execution of lease held to be advance royalty taxable as ordinary income subject to allowance for depletion rather than as capital gain; petitioner failed to show a reasonable prospect that reserved oil payment from lease would be paid off, or that there was any reasonable basis for expecting that it would be. Thus, cash received on assignment of lease to oil company was taxable as an advance royalty subject to depletion. The oil payment extended throughout the economic life of the lease and, thus, was an overriding royalty which qualified as a retained economic interest in the minerals in place).

estimate of future royalties was reasonable and allowed a cost depletion deduction in the year the lease bonus was received equal to the entire basis in the leases at issue. The IRS does not agree with the court's opinion.[12]

Perhaps the taxpayer in *Dudek* could have claimed cost depletion if the transaction had been structured differently and some advance planning had been engaged in. For purposes of claiming cost depletion, the buyer should allocate the cost basis to mineral rights when land and minerals are purchased together. The allocation is useful to the buyer for purposes of claiming cost depletion of the minerals as well as claiming a deduction if the minerals become worthless. Indeed, the IRS asserts that there is no separate cost basis for minerals unless, at the time the minerals were acquired, one of the following conditions exists.[13]

1. The seller's cost included a stipulated amount for the mineral rights.
2. The seller's basis was the result of an estate tax valuation in which the minerals and the surface were separately valued.
3. The seller's cost basis can be properly allocated between surface and minerals because substantial evidence exists of the value attributable to the minerals on the acquisition date.

In any event, the burden is on the taxpayer to prove the basis allocable to minerals.[15]

> **Observation.** It may be advantageous to separate the royalty interest from the working interest, if possible, before negotiations begin with the oil company. The royalty interest could then be transferred to a third party that is related to the transferor. Then, the working interest could be transferred to the developer/explorer subject to the pre-existing overriding royalty interest that the related party holds. The purpose for structuring the transaction in this manner is to provide the taxpayer with an argument that it has "sold" the working interest without retaining an economic benefit from the royalty interest. That could strengthen the argument for capital gain treatment. However, structuring the arrangement in this manner could bring a step-transaction challenge by the IRS unless a legitimate business purpose exists for carving out the royalty interest.

Other related lease expenses — such as attorney fees, land surveying costs, deed or title work, and property taxes — are deductible in the year incurred.

Tax Consequences to the Lessee. For the lessee, a bonus payment is not deductible even if it is paid in installments. It must be capitalized as a leasehold acquisition cost. However, the bonus payment may be subject to cost depletion (discussed later).

> **Note.** If the lessee deducts percentage depletion with respect to the mineral interest acquired (discussed later), the lessee must reduce depletable gross income from the property by a proportionate part of the bonus paid. The reduction is the part of the bonus payment paid in the tax year (or any prior tax year) allocable to the product sold during

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[12] Tech. Adv. Memo. 8532011 (May 7, 1985). The claim of "no future production" is likely synonymous with "no mineral deposit existing" and, thus, cost depletion is not available; taxpayer cannot deduct as cost depletion the entire amount of his basis in each of certain retained overriding royalty interests burdening wildcat leases by virtue of Trea. Reg. §1.612-3(a)(1).
[13] IRM 4.41.1.2.1.2 (Dec. 3, 2013).
[15] Rev. Rul. 69-539, 1969-2 CB 141.

the tax year.[16] Because a bonus payment is considered to be part of the lessor's gross income from the property, the lessee must reduce the gross income from the property by the amount of bonus payments applicable to the oil and gas lease. Thus, to this extent, neither the lessee nor the lessor is entitled to percentage depletion.[17]

Installment Bonus Payments. A bonus payment may be paid annually for a fixed number of years regardless of production. If the lessee cannot avoid the payments by terminating the lease, the payments are termed a **lease bonus payable in installments.** These payments are also consideration for granting a lease. They are an advance payment for oil, and each installment is typically larger than a normal delay rental (discussed next).

A cash-basis lessee must capitalize such payments, and the fair market value (FMV) of the contract in the year the lease is executed is ordinary income to the lessor if the right to the income is transferable or readily saleable.[18] However, if the bonus payments are made under a contract that is nontransferable and nonnegotiable, a cash-basis lessor can defer recognizing the payments until they are received.[19]

Delay Rentals

A delay rental is paid for the privilege of deferring development of the property by extending the primary term to allow additional time for drilling operations to begin. It can be avoided either by abandonment of the lease or by starting development operations (i.e., drilling for oil or obtaining production). A delay rental payment is "pure rent." It is simply a payment to defer development rather than a payment for oil.

Tax Consequences to the Lessor. Delay rentals are ordinary income regardless of whether they are based on production. However, if they are not based on production, they are not depletable gross income to the lessor.[20] **Depletable gross income** for the lessor is the royalty income received. Royalty income is based on production.[21]

Delay rental payments are reported in the same manner as bonus payments. They are reported to the lessor in box 1 of Form 1099-MISC and constitute NII potentially subject to the additional 3.8% NIIT. The lessor reports the payments on Schedule E, with the amount flowing to line 17 of Form 1040.[22]

> **Example 2.** Use the same facts as **Example 1.** Under the lease that O.K. Oil Company enters into with Jed, annual delay rental payments of $5 per acre are payable to Jed. O.K. did not develop the leased property within one year after the lease commenced. Thus, under the terms of the lease, O.K. paid Jed $800 ($5 × 160 acres) for the next year to give O.K. additional time to develop the property. Jed reports the $800 as ordinary income on Schedule E.

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[16] Treas. Reg. §1.613-2(c)(5)(ii).
[17] Although a depletion deduction cannot be claimed on the federal return, some states allow a depletion deduction attributable to lease payments.
[18] Rev. Rul. 68-606, 1968-2 CB 42.
[19] *See, e.g.,* Kleberg v. Comr., 43 BTA 277 (1941), *non. acq.* 1952-1 CB 5.
[20] Treas. Reg. §1.612-3(c)(2).
[21] If the delay rentals paid are not based on production, they do not reduce the lessee's depletable gross income. Treas. Reg. §1.613-2(c)(5). The same applies to "shut-in" rents (royalties paid for acreage surrounding a "shut-in" (nonproducing) well). *See, e.g.,* Johnson v. Phinney, 287 F.2d 544 (5th Cir. 1961); Rev. Rul. 68-361, 1968-2 CB 264.
[22] Because the payments are in the nature of rents, the payments are not subject to depletion.

Tax Consequences to the Lessee. Under Treas. Reg. §1.612-3(c), delay rentals are in the nature of rent that the lessee can deduct as a current expense.[23] However, the IRS maintains that IRC §263A applies to delay rentals, which requires that the payments be capitalized.[24] Under the IRS's view, delay rental payments are paid for periods in which drilling does not occur. In this situation, the delay rentals constitute indirect preproduction period costs. As such they must be capitalized up to the depletable basis of the property to which they relate in accordance with Treas. Reg. §1.263A-2(a)(3)(ii). The only exception to capitalization applies if the taxpayer has credible evidence establishing that the leasehold was acquired for some reason other than development.

> **Note.** Prop. Treas. Reg. §1.612-3(c)(2) indicates that, to the extent the delay rental is **not** required to be capitalized under IRC §263A, the lessee can deduct it or charge it to a depletable capital account under IRC §266.

Royalty Income

A **landowner royalty** is the right to the oil, gas, or minerals "in place" that entitles the owner to a specified percentage of gross production (if and when production occurs) free of the expenses of development and operations. A **royalty interest** is a continuing **non-operating** interest in oil and gas. Thus, a royalty payment is a payment for oil and gas.

Tax Consequences to the Lessor. Royalty payments are payments received for the extraction of minerals from the property that the landowner, as lessor, owns.[26] Royalties are paid as an agreed-upon percentage of the resource extracted (i.e., based on production).

Royalty payments are ordinary income that is reported to the lessor in box 2 of Form 1099-MISC. Royalty payments may be reduced by percentage or cost depletion (discussed later). The lessor reports the royalty income on Schedule E. Beginning in 2013, royalty payments are included in NII and are subject to the additional 3.8% NIIT if the taxpayer's gross income is above the applicable threshold.[27] Royalty payments are not subject to SE tax.

Tax Consequences to the Lessee. The lessee can deduct royalty payments as a trade or business expense. In addition, if the lessee pays the **ad valorem** taxes (taxes based on the property's value) on mineral property, the payment constitutes an additional royalty to the lessor to the extent that income from production covers the tax payment. The payment of such taxes by the lessee is excluded from the lessee's gross income to the extent it is additional royalty income to the lessor. Otherwise, the payment is additional rent that is not subject to depletion.[28]

Advance Royalties. Although it is not commonly included in oil and gas leases, the lease may contain a provision providing the mineral owner with an advance royalty of the operating interest. Thus, an advance royalty is paid before the production of minerals occurs and can be paid to the lessor either in

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[23] The lessee may also opt to capitalize or expense delay rentals on nonproductive properties. IRC §266. This is either a new election every year, or a property-by-property election every year.
[24] See, e.g., Tech. Adv. Memo. 9602002 (Sept. 19, 1995). The IRS maintains that the Code contains a "priority-ordering directive" that dictates that the capitalization provisions take precedence over a specific provision and require that an expenditure be capitalized even when it otherwise might be deemed deductible. Comr. v. Idaho Power Co., 418 U.S. 1 (1974).
[26] The gross amount of royalties received is not reduced by any part of the cost of the rights under which the royalties are received, or by any amount allowable as a deduction in computing taxable income. Treas. Reg. §1.1362-2(c)(5)(ii)(A)(1).
[27] IRC §1411.
[28] Rev. Rul. 72-165, 1972-1 CB 177, *revoking* Rev. Rul. 64-91, 1964-1 CB 219.

a lump sum or periodically until production begins. Once production begins, no additional royalties are paid until the lessee has recovered the advance royalties from the lessor's share of production.[29]

> **Example 3.** Bob enters into a lease with an energy company. The lease, which has a primary term of 10 years, provides that Bob will be paid a one-eighth production royalty. It also specifies that Bob will be paid a royalty of $100,000 at the beginning of each of the first three years of the lease. If, for example, in the first year of the lease, the production royalties are $20,000, then the advance royalty is $80,000 ($100,000 advance royalty − $20,000 production royalty).[30]

An advance royalty occurs when:[31]

1. The lessee is required to pay royalties on a specified number of units of the minerals each year, irrespective of whether the minerals are extracted within the year;

2. The lessee can apply any amounts paid on account of units not extracted during the year against the royalty on the minerals that are later extracted (recoupable from production); and

3. The payment is avoidable (i.e., the lessee can avoid the advance royalty by canceling the lease).

Tax Treatment. The lessee deducts the advance royalty payments in the year in which the mineral production (on account of which it was paid) is sold.[32]

Advance royalties are ordinary income to the lessor, and the lessor is not entitled to percentage depletion on the payments. However, the lessor is entitled to cost depletion in the year the payments are made to the extent they exceed production. Percentage and cost depletion are discussed later.

Advance Minimum Royalties. Advance minimum royalties meet the same conditions as an advanced royalty, but there is also a minimum royalty provision in the contract. This provision requires that a substantially uniform amount of royalties be paid at least annually over the life of the lease or for a period of at least 20 years.

Tax Treatment. The tax treatment to the **lessor** for advance minimum royalties is the same as with advanced royalties.

The **lessee** can deduct the advance royalties from gross income in the year the oil or gas is sold or recovered. The lessee also has the option to deduct the payments in the year they are paid or accrued.[33]

> **Note.** Although advance royalty provisions are rare in oil and gas leases, they are often utilized in leases with longer primary terms such as those involving coal and lignite.

Shut-in Royalties. The lease may provide for payments to be made to the lessor when a well is shut-in (turned off because of lack of market or marketing facilities) but the well is still capable of producing

[29] Treas. Reg. §1.612-3(b).
[30] The example is based on an example contained in IRM 4.41.1.2.2.3.4 (Jul. 31, 2002).
[31] See IRS MSSP, Oil and Gas Industry, May 1996.
[32] See Rev. Rul. 72-165, 1972-1 CB 177. However, advanced royalties resulting from a minimum royalty provision may, at the payor's option, be deducted in the year paid or accrued.
[33] Treas. Reg. §1.612-3(b)(3).

in commercial quantities. The lessee is entitled to deduct the shut-in royalty payment and the lessor must report the payment as income.

Damage Payments

When a well is drilled, the nearby surface area can suffer damages that may entitle the landowner to compensation. To determine the income tax consequences of any payment for surface damages, the governing instrument (lease, etc.) may provide guidance.

Compensatory damages associated with lost profit (e.g., crop damage payments) are taxable as ordinary income (treated as a sale of the crop). To the extent the damage payment represents damages for destruction of business goodwill, the payment is nontaxable up to the taxpayer's basis in the affected property. The amount of the damage payment that exceeds the taxpayer's basis is taxable as IRC §1231 gain. Payments for **anticipated** damages (but when no actual damage occurs) are reported as ordinary income.[34]

Production Payments

Most landowners retain only a royalty interest in minerals. However, landowners who have a working (operating) interest in the production may also receive a "production payment." A **production payment** arises from a transaction in which the owner of an oil and gas interest sells a specific volume of production from an identifiable property until a specified amount of money or minerals has been received. For example, a production payment may require that 80% of production be paid to the holder until $50,000 plus 11% interest is received.[35] A production payment is payable only out of the working interests' share of production.

There are two types of production payments.

- **Retained Production Payments.** Retained production payments result when the mineral interest owner assigns the interest and retains a production payment. The payment is payable out of future production from the assigned property interest.

- **Carved-out Production Payments.** A carved-out production payment is created when an owner of a mineral interest assigns a production payment to another person but retains the interest in the property from which the production payment is assigned.

Tax Treatment. Generally, a **carved-out production payment** is treated under IRC §636 as a mortgage (nonrecourse) loan on the property. As such, it does not qualify as an economic interest in the property. The **lessee** treats the payments as principal repayment and interest expense, and the **lessor** treats the payments received as principal and interest income. Thus, the producer does not recognize taxable income at the time the transaction is entered into. The lessor continues to be treated as the owner of the burdened properties. As the production occurs and is delivered to the holder of the production payment, the lessor is treated as having sold the production for its FMV and having applied the proceeds to repay the principal and interest due to the holder.

As previously mentioned, carved-out production payments are treated under §636 as nonrecourse debt (i.e., a mortgage loan) that is secured by the burdened property. It is not a depletable economic interest in the mineral property. To qualify for loan treatment, the production payment must convey a right to a

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[34] *See, e.g.,* Gilbertz v. U.S., 808 F.2d 1374 (10th Cir. 1987), *rev'g* 574 F. Supp. 177 (Wyo. 1983).
[35] See *Oil and Gas Industry.* IRS, available at[www.irs.gov/pub/irs-mssp/oilgas.pdf.

specified share of the production from minerals in place or the proceeds from such production. It may burden more than one mineral property, but the holder may look only to the production from such burdened properties for payments under the agreement. At closing, the production payment must have an expected economic life of shorter duration than the economic life of one or more of the mineral properties that are burdened.

However, if the consideration given for the production payment is pledged **for development**[37] of the property or if the **production payment is retained** when the property is leased, the payment qualifies as an economic interest. In this situation, the payments that the lessor receives via the production payment agreement are ordinary income that are subject to cost or percentage depletion.[38] The lessee capitalizes the payments.[39]

> **Note.** For a taxpayer to get an advance ruling from the IRS that a contract is a production payment treated as a loan, the taxpayer must show:
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> (1) That it is reasonably expected, at the time the right is created, that it will terminate upon the production of not more than 90% of the reserves then known to exist with respect to the burdened property;
>
> (2) That the present value of the production expected to remain after the right terminates is 5% or more of the present value[40] of the entire burdened property determined at the time the right is created;
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> (3) That the right is limited by a specified dollar amount, a specified amount of mineral, or a specified period of time; and
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> (4) That the right is an economic interest in mineral in place as defined in Treas. Reg. §1.611-1(b), without regard to the application of IRC §636.[41]

The transaction may be treated as the sale of an overriding royalty interest in some instances, however. This can occur, for example, when the production payment is pledged for the exploration and development of the property, if the lease is undeveloped and mineral reserves have not been established and proven in sufficient quantities to generate enough income to retire the production payment (including interest) before the time that the lease is abandoned. In that event, the payment is not classified as either a loan or as a production payment pledged for development.

Treas. Reg. §1.636-3 requires that the life of the production payment be shorter than the life of the property. Thus, for an unexplored property, if no minerals are discovered or the reserves are in such small quantities that they will never pay off the production payment, the production payment's life will

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[37] Treas. Reg. §1.636-1(b) limits the definition of "for development." The proceeds of a production payment are treated as carved out for exploration and development only to the extent the proceeds are required to be used or pledged for use in future exploration or development of the burdened property and may not be used for the exploration or development of any other property or for any other purpose. Payment for the production to the operator reduces the operator's intangible drilling cost deduction or the amount capitalized for equipment. The holder of the production payment does not get a deduction for intangible drilling costs. Expenditures for the exploration and development of burdened property include those to ascertain the existence, location, extent, or quality of a deposit of mineral or those incident to and necessary for the preparation of the deposit for production. They do not include costs relating primarily to production of the mineral.

[38] IRC §636(c); Treas. Reg. §1.636-2(b).

[39] Treas. Reg. §1.636-2(a).

[40] The determination of present value takes into account all the facts and circumstances. Treas. Reg. §1.611-2(e).

[41] Rev. Proc. 97-55, 1997-2 CB 582.

exist until the lease is abandoned. Once the lease is abandoned, the transaction is treated by the lessee as a purchase of an overriding royalty interest. It is capitalized by the lessee and treated as capital gain by the lessor.

> **Note.** The burden of proof is on the taxpayer that the production payment will be retired before the time the lease is abandoned. That is a near impossibility before a producing well has been drilled on the lease.

Payments for "Shooting Rights"

In some situations, an operator may not want to incur the costs of entering into a lease on the property (to avoid lease bonuses, for example). Consequently, the operator may enter into a contract with the landowner to pay a smaller amount under a contract that gives the operator a right to enter onto the property to conduct exploration activities. The contract does not grant any drilling or production rights. The payments that the landowner receives under this type of arrangement are reportable as ordinary income.

Expenses

Most lessors are only able to claim a depletion expense deduction associated with the royalty amount that is received. If a lessor also has a working (operating) interest in the production of oil or gas, then additional expenses are deductible. The common expenses that are either currently deductible or must be capitalized by the working interest owner include the following.

- **Geological and Geophysical Expenses.** These are expenses incurred that are associated with acquiring and maintaining properties for oil/gas exploration and development. Usually, these costs must be capitalized.

- **Intangible Drilling and Development Costs.** These are necessary and incidental expenses that are incurred in preparing wells for production and for the drilling of wells. Such expenses include wages, fuel, repairs, hauling, and supplies. These expenses are usually deducted in the tax year if which they are incurred.

- **Operating Expenses.** These currently deductible expenses include labor, maintenance, repairs, supplies, utilities, auto expenses, taxes, insurance, depreciation of operating equipment, and lawyers and accountants' fees.

> **Note.** Depreciation of drilling equipment for the working interest owner is discussed more fully later.

Depletion Deduction

Owner-lessors and operator-lessees can claim depletion associated with the production of oil and gas. Although conceptually similar to depreciation, the depletion deduction differs in significant ways from depreciation. The depletion deduction is based on the depletion of the mineral resource, whereas depreciation is based on the exhaustion of an asset that is used in the taxpayer's trade or business.

> **Note.** When a lease of minerals is involved, the depletion deduction must be equitably apportioned between the lessor and the lessee.[42] If a life estate is involved (the property is held by one person for life with the remainder to another person), the deduction is allowed to the life tenant but not the

[42] IRC §611(b).

remainderman. For property held in a trust, the deduction is apportioned between the income beneficiaries and the trustee in accordance with the terms of the trust. If the trust instrument does not contain such provisions, the deduction is apportioned on the basis of the trust income allocable to each. For a decedent's estate, the deduction is apportioned between the estate and the heirs on the basis of the estate income allocable to each.

Requirements for the Deduction. To claim a depletion deduction, the taxpayer must have:

1. An economic interest in the mineral property, and

2. The legal right to the income from the oil and gas extraction.[46]

If these two requirements are met, the deduction is allowed upon the sale of the oil and gas when income is reported. For the owner-lessor, the deduction can offset royalty payments but not bonus lease payments (because the deduction is allowed only when oil or gas is actually sold and income is reportable). For the operator-lessee, the depletable cost is the total amount paid to the lessor (the lease bonus) and other costs that are not currently deducted such as exploration and development costs as well as intangible drilling costs.

Note. Conceptually, the taxpayer is entitled to a deduction against the revenue received as the income tax basis in the mineral property is depleted. For the owner-lessor, a cost basis in the minerals must have been established at the time basis in the taxpayer's property (surface and mineral estate) was established. This may have occurred as part of an estate tax valuation in which the minerals and surface were separately valued or upon allocation of the purchase price at the time of acquisition. For the operator-lessee, depreciation is tied to the operator's historical investment cost (explained later).

Computation Methods. There are two methods available for computing the depletion deduction: the **cost depletion method** and the **percentage depletion method.** A comparison should be made of the two methods and the one that provides the greater deduction should be used.

Cost *Depletion*. For the owner-lessor, the cost depletion method is a units-of-production approach that is associated with the owner's basis in the property. Cost depletion, like depreciation, cannot exceed the taxpayer's basis in the property. The basis includes the value of the land and any associated capital assets (e.g., timber, equipment, buildings, and oil and gas reserves).[47] Basis also includes any other expenses that were incurred in acquiring the land (e.g., attorney fees, surveys, etc.).[48] Basis is allocated among the various capital assets and is determined after accounting for the following items.

1. Amounts recovered through depreciation deductions, deferred expenses, and deductions other than depletions

2. The residual value of land and improvements at the end of operations

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[46] Treas. Reg. §1.611-1(b).
[47] See IRC §612, which refers to IRC §1011 for adjustments to basis. Included in basis are the purchase price of the property, lease bonus payments, incidental costs, capitalized intangible drilling and development costs (except for the election under IRC §59(e)), and capitalized carrying charges.
[48] Mineral property can be acquired via purchase (purchase price basis), inheritance (basis equals the property's FMV at the time of the decedent's death) or gift (carryover basis from the donor).

3. The cost or value of land acquired for purposes other than mineral production

Note. Landowners without an established cost basis may be able to claim percentage depletion (discussed later). It is common for a landowner to **not** allocate any part of the property's basis to the oil and gas reserves. Thus, percentage depletion may be the only depletion method available.

Under the cost depletion approach, the taxpayer must know the total recoverable mineral units in the property's natural deposit and the number of mineral units sold during the tax year. The **total recoverable units** is the sum of the number of mineral units remaining at the end of the year plus the number of mineral units sold during the tax year.[49] The number of mineral units sold during the tax year depends on the accounting method that the taxpayer uses (i.e., cash or accrual). Many taxpayers, particularly landowners, are likely to be on the cash method. Thus, for these taxpayers, the units sold during the year are the units for which payment was received.

Under the cost depletion approach, the basis applicable to the mineral property is computed annually by dividing the unrecoverable depletable cost at the end of the year by the estimated remaining recoverable units at the beginning of the year. The cost per unit is then multiplied by the number of units sold during the year.

Example 4. Billie Jo's father died in 2014. His will devised a 640-acre tract of land to Billie Jo. The value of the tract as reported on Form 706, *United States Estate (and Generation-Skipping Transfer) Tax Return,* for estate tax purposes was $6.4 million. Of that amount, $1 million was allocated to the mineral rights in the tract.

In 2015, a well drilled on the property produced 300,000 barrels of oil. Geological and engineering studies determined that the deposit contained 2 million barrels of usable crude oil. In 2015, the 300,000 barrels produced were sold. Billie Jo's cost depletion deduction for 2015 is $150,000 and is calculated as follows.

$$\frac{\text{Unrecoverable depletable cost at the end of the year}}{\text{Estimated remaining recoverable units at the beginning of the year}} \times \begin{array}{l}\text{Number of units}\\ \text{sold during the year}\end{array}$$

$$\frac{\$1{,}000{,}000}{2{,}000{,}000} \times 300{,}000 = \$150{,}000$$

Billie Jo deducts the $150,000 on his 2015 Schedule E. Billie Jo's adjusted basis in the mineral deposit for 2016 that is eligible for cost depletion is $850,000 ($1 million − $150,000).

Example 5. Acme Drilling Corporation paid Bubba $300,000 to acquire all of the oil rights associated with Bubba's land. The $300,000 was Acme's only depletable cost. Geological and engineering studies estimated that the deposit contains 800,000 barrels of usable crude oil.

In 2015, 200,000 barrels of oil were produced and 180,000 were sold. Acme's cost depletion deduction for 2015 is $67,500 and is calculated as follows.

$$\frac{\text{Unrecoverable depletable cost at the end of the year}}{\text{Estimated remaining recoverable units at the beginning of the year}} \times \begin{array}{l}\text{Number of units}\\ \text{sold during the year}\end{array}$$

[49] The landowner must estimate or determine the recoverable units of mineral product using the current industry method and the most accurate and reliable information available. A safe harbor can be elected to determine the recoverable units. Rev. Proc. 2004-19, 2004-10 IRB 563. The mechanics of the computation are contained in Treas. Reg. §1.611-2.

$$\frac{\$300{,}000}{800{,}000} \times 180{,}000 = \$67{,}500$$

Percentage Depletion. As noted previously, the amount allowed as a depletion deduction is the **greater of cost or percentage depletion** computed for each property[51] for the tax year.[52]

Under the percentage depletion method, the taxpayer (owner-lessor or a producer that is not a retailer or refiner) uses a percentage of gross income (presently set at 15%) from the oil/gas property,[53] which is limited to the **lesser** of the following.

- 100% of the taxable income from the oil/gas property; or
- 65% of the taxable income of the taxpayer from all sources[55]

Note. For percentage depletion purposes, total taxable income is a function of gross income. Gross income from the property includes, among other things, the amount received from the sale of the oil or gas in the immediate vicinity of the well.[56] Gross income does not include lease bonuses, advance royalties, or other amounts payable without regard to production from the property.[57]

Any amount not deductible due to the 65% limitation can be carried over to the following year, subject to the same limitation. Any amount carried over is added to the depletion allowance before any limits are applied for the carryover year. IRC §613A and the underlying regulations set forth a detailed multi-step process that is utilized to compute percentage depletion allowed to independent producers and royalty owners.

Observation. A production limit also applies. For partnerships, all depletion is computed at the partner level and not by the partnership.[58] The partnership must allocate the adjusted basis of its oil and gas properties to its partners in accordance with each partner's interest in capital or income.

Example 6. In 2015, Rusty received $50,000 of royalty income from a well on his farm. His taxable income from all sources in 2015 is $432,000. Of that amount, $300,000 is income from crops and livestock. He has $82,000 of income from other sources.

Rusty computes his percentage depletion deduction by multiplying his $50,000 gross income from the oil/gas property by 15%, which is $7,500. His taxable income from the property is $8,000. His taxable income from all sources is $432,000, and 65% of that amount is $280,800.

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[51] **Property** is defined in IRC §614(a) as each separate interest owned by the taxpayer in each mineral deposit in each separate tract or parcel of land. Under IRC §614(d), a **separate interest** is an operating mineral interest in which the production costs must be taken into account for purposes of computing the taxable income limitation of percentage depletion. An operating interest is always separate from a non-operating interest owned in the same property. IRC §614(b)(1)(B) and Treas. Reg. §1.614-8(a).

[52] IRC §§613 and 613A and Treas. Reg. §1.611-1(a).

[53] For an operator-lessee, this is defined as gross income from the property less expenses attributable to the property other than depletion and the production deduction but including an allocation of general overhead.

[55] IRC §613A(d). This amount is computed without taking into account any depletion on production, any IRC §199 deduction, NOL carryback to the taxable year or capital loss carryback to the taxable year.

[56] Treas. Reg. §1.613-3.

[57] IRC §613A(d)(5).

[58] Prop. Treas. Reg. §1.613A-3(e).

Thus, Rusty's depletion deduction is the lesser of $7,500, $8,000 or $280,800. Rusty can claim the $7,500 deduction on line 18 (depreciation expense or depletion) of his 2015 Schedule E.

Example 7. Hammerhead Drilling Co. leases land from Jed for a one-eighth royalty interest. In 2015, Hammerhead Drilling Co. realized a total of $500,000 in sales proceeds from the well (of which $62,500 was paid to Jed as a royalty) and incurred $200,000 of operating expenses. Hammerhead's depletion deduction for 2015 is determined as follows.

Gross receipts from the property:	$500,000
Less royalty paid to Jed:	62,500
Gross income:	$437,500
Less production expenses:	220,000
Taxable income:	$217,500

Depreciation

Oil and gas property is subject to the normal MACRS rules of IRC §168 with the recovery periods and class lives specified in Rev. Proc. 87-56. Thus, most oil and gas property is classified as 7-year property subject to the 200% declining balance method and an applicable depreciation convention of either mid-year or mid-quarter.[59]

IRC §179 expense-method depreciation is available for oil and gas property.

Oil and gas property is also eligible for bonus depreciation if it has a recovery period of 20 years or less and the original use begins with the taxpayer.[60] An election can be taken to accelerate the minimum tax credit and the research credit in lieu of deducting bonus depreciation (when available).

The taxpayer can also elect to depreciate oil and gas property under the unit-of-production method or any depreciation method not expressed in terms of years. This election applies to lease and well equipment and can be made on a property-by-property basis. In essence, the election gives the taxpayer flexibility in determining the depreciation deduction for a particular property without affecting the recovery allowances claimed on all other eligible property the taxpayer may place in service in a given year. The calculation is similar to that used for cost depletion.

Domestic Production Activities Deduction

From 2005 through 2017, the IRC §199 domestic production activities deduction (DPAD) was 6% of domestic production gross receipts (DPGR) from oil and gas activity (production, refining, processing, transportation, or distribution, but not income from the sale of land or leasehold rights).[61]

[59] Natural gas gathering lines are also depreciable over seven years. *Duke Energy Natural Gas Corp. v. Comm'r,* 172 F.3d 1255 (10th Cir. 1999), *non. acq,* 1999-47 IRB 573. See also *Saginaw Bay Pipeline Company v. U.S.,* 338 F.3d 600 (6th Cir. 2003); *Clajon Gas Co., L.P. v. Comm'r,* 354 F.3d 786 (8th Cir. 2004).

[60] IRC §179 expense method depreciation is tied to the taxpayer's tax year, but bonus depreciation is tied to the calendar year.

[61] CCA 201208029 (Dec. 1, 2011). However, income from the sale of the well is DPGR as are intangible drilling costs if the intangible drilling costs were capitalized.

The DPAD was limited to 50% of Form W-2 wages paid that are attributable to qualified production activities. The DPAD was also limited to the lesser of qualified production activities income (QPAI) or taxable income. Thus, the DPAD was limited to the lesser of QPAI or taxable income, or 50% of W-2 wages paid. For partnerships, QPAI and W-2 wages are calculated at the partnership level except for qualifying in-kind partnerships, which include oil and gas partnerships.[62] For tax years beginning after 2017, the DPAD was replaced with the Qualified Business Income Deduction (QBID) of I.R.C. §199A through 2025.

Uniform Capitalization Rules

IRC §263A applies a uniform set of capitalization rules to all costs incurred in manufacturing or constructing property or in purchasing and holding property for resale. Costs relating to real or tangible personal property produced by the taxpayer and the purchasing and holding of property for resale are subject to uniform capitalization (UNICAP) rules.

Produced Property. The rules in §263A generally apply to construction of assets used, or to be used, in a trade or business. These rules also apply to IRC §1231 assets.

> **Note.** Rev. Rul. 68-226[64] defines an oil and gas leasehold as an interest in real property. This ruling supports the IRS's position that, historically, a mineral interest is real property. Thus, a taxpayer who acquires and develops oil or gas properties is engaged in a developmental activity within the meaning of IRC §263A.

Produced property[65] can include geological and geophysical data, acquiring and developing the leasehold mineral interest, constructing tangible and surface well equipment, and carrying oil and gas inventory (barrels of oil and MCF (thousand cubic feet) of gas). It does not include acquiring undeveloped leases.

Predevelopment Expenses. Many oil operators maintain inventories of undrilled leases for resale to others or transfer to limited partnerships. Exploration, drilling, and development activities could be construed as activities that improve property.

> **Note.** The Tax Court has held in various decisions[67] that exploration and developmental drilling could not be distinguished for intangible drilling cost purposes. However, it has been held that exploration is considered a separate activity from development and production.[68]

Intangible drilling costs are specifically exempt from the UNICAP rules of §263A, but the rules may apply to oil production if an inventory of oil is on hand at the end of the year. An appropriate share of indirect costs should be allocated to geological and geophysical activities. Treas. Reg. §1.263A-1(b) lists costs that are excepted from the UNICAP rules.

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[62] See Rev. Proc. 2007-34, 2007-23 IRB 1345 and Treas. Reg. §1.199-3(i)(7).
[64] Rev. Rul. 68-226, 1968-1 CB 362.
[65] The term **produce,** as described in IRC §263A(g), means construct, build, install, manufacture, develop, or improve. Historically, IRC §341(b) also contains this same language: "manufacture, construction, or production of property." Rev. Rul. 57-346, 1957-2 CB 236, holds, under IRC §341(b)(1) (since repealed), that a corporation engaged in acquisition and development of oil properties is considered to be involved in the construction or development activities that increased the value of the properties.
[67] *See, e.g.,* Sun Company, Inc. & Subs. v. Comr., 74 TC 1481 (1980), *aff'd* 677 F.2d 294 (3rd Cir. 1982), *acq.* 1983-2 CB 1.
[68] Shell Oil Co. v. Comr., 89 TC 371 (1987), *rev'd* 952 F.2d 885 (5th Cir.1992).

There are additional §263A costs. These include the following.

- **Direct costs** are labor and material that are directly related to a property. Direct materials are those that are a part of the property or consumed in the activity. Direct labor costs are labor costs, including fringe benefits, that are associated with the property or activity. These costs have traditionally been capitalized.

- **Indirect costs** are all other costs that directly benefit production or are incurred because of the production activity. If they benefit more than one activity, they should be allocated on a reasonable basis to the activities involved.[69]

  Note. The Code and Treasury Regulations do not specify **how** the indirect costs are to be allocated, just that the allocation must be reasonable. The regulations provide several "simplified" methods that are available to the taxpayer. In essence, the indirect costs should be matched with the activities that benefit from the incurred costs. The taxpayer should use the same method for allocating overhead. The allocation method should be used consistently and for all federal tax purposes.

- **Mixed service costs** are costs of administrative, service, or support departments or activities that benefit more than one activity. These costs must be allocated, on a reasonable basis, to the activities that benefitted from them.

- **Interest costs** incurred to finance the production of property must be capitalized if the property produced is:

  1. Real property;

  2. Personal property with a MACRS life of 20 years or more;

  3. Personal property with an estimated production period of more than two years; or

  4. Personal property with an estimated production period of more than one year and the estimated production cost exceeds $1 million.

Interest Capitalization. Treas. Reg. §1.263A-13 sets forth the interest capitalization rules. The interest to be capitalized is the interest that would have been avoided if the production expenditures relating to the property or activity had not been made, and the funds were used to repay the taxpayer's debts. Debt that can be traced specifically to an activity is allocated to that activity. If the production expenditures relating to an activity exceed the debt traced to the activity, other debt must be allocated to the activity. Interest on debt allocable to leasehold costs should be capitalized during the production period because mineral leases are real property.

For onshore activities, the production period for a unit begins on the first date physical site-preparation activities are undertaken for that unit (for example, building an access road, leveling a site for a drilling rig, or excavating a mud pit). For offshore activities, the production period for a unit begins on the first date physical site preparation activities (for example, drilling to drive the piles), other than activities undertaken with respect to expendable wells, are undertaken. An expendable well is a well drilled solely

[69] Treas. Reg. §1.263A-1(e)(3)(ii) has an extensive list of indirect costs that must be capitalized.

to determine the location and delineation of hydrocarbon deposits. The production period ends when the well is ready to produce.

> **Note.** Intangible drilling costs are excluded from the application of interest capitalization. However, if a taxpayer uses their own drilling equipment (rather than a contract driller), the basis of the drilling equipment (but not depreciation on the equipment) is included in the accumulated production expenditures and is subject to interest capitalization.

An exception from the interest capitalization rule applies when the production period does not exceed 90 days. In addition, a de minimis exception applies when the total production expenditures do not exceed $1 million divided by the number of days in the production period.

SUBSURFACE MINERAL RIGHTS RETAINED IN CONSERVATION EASEMENT REQUIRE FURTHER FACT DEVELOPMENT[70]

In this case, the taxpayer granted a conservation easement over 245 acres of a 260-acre parcel located in Louisiana. The easement deed barred "the exploration for . . . or extraction of minerals, oil, gas, or other hydrocarbons, soils, sands, clays, gravel, rock, or other materials on or below the surface of the Property." Applicable regulations under section 1.170A-14 prevent a deduction for a conservation easement "when there is a retention by any person of a qualified mineral interest . . . if at any time there may be extractions or removal of minerals by any surface mining method." In such a case, the property is not deemed to be protected in perpetuity.

The IRS sought summary judgment against the Taxpayers on the matter of protecting the property in perpetuity. Although the IRS could not allege that Taxpayers retained any right to surface mining, it alleged instead that the Taxpayers retained subsurface rights associated with over 3000 acres surrounding this parcel, including the right to 75 percent of "all oil, gas, or other minerals of any kind or character whatsoever." According to the court, the term "other minerals" was ambiguous under Louisiana law. Extrinsic evidence admitted from the Taxpayer included an affidavit from the grantor that this reservation was intended only to cover "liquid and gaseous minerals", not clay. Moreover, the easement expressly restricted the extraction of oil and gas from unit wells located on the property but permitted extraction of oil and gas through directional drilling from wells located on other lands. This was sufficient to produce a fact issue that would have to be resolved at trial.

> **Observation:** It is not clear that the retention of oil and gas rights would limit the value of the conservation easement, given that the usage of the property would not be affected. Those with oil and gas interests associated with conservation land may want to follow this case.

[70] North Donald LA Property, LLC v. Commissioner, T.C. Memo 2023-50; petitioner's motion for partial summary judgment on claim that civil fraud penalty did not apply denied, No. 24703-21, 2024 U.S. Tax Ct. LEXIS 884 (U.S. Tax Ct. Apr. 10, 2024)