TAX PLANNING FOR OIL AND GAS JOINT OPERATIONS

By

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By

John T. Bradford[1]

I. Introduction

Joint operations for oil and gas exploration and development arise when two or more parties join together to share the working interest costs of jointly exploring, developing and producing an oil and gas property. For example, in the simplest case, joint operations may be undertaken by two or more parties to drill a single exploratory well on one oil and gas lease located in a wildcat area. Or, in a more complex case, joint operations may be undertaken by the parties to develop an oil and gas lease that already has had a discovery well drilled on the lease. And finally, joint operations may be undertaken by owners of individual leases whose leases are unitized under state law to maximize the output from the oil and gas reservoir underlying those leases. In each case, the parties to the joint operation agree to share the risks and rewards of exploring, developing and operating the oil and gas property or properties. Those parties each expect to realize certain federal income tax benefits that flow from the joint operation. It is those tax benefits that are factored into each party's after-tax economics anticipated for the joint operation.

This paper identifies the expected federal income tax results for joint operations in two typical farmout transactions.[2] The first is a more traditional transaction in which

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[2] This paper assumes that the oil and gas properties already have been acquired and therefore does not address the tax consequences to the lessor and lessee on the original acquisition of the oil and gas lease. *See Oil and Gas Federal Income Taxation*,

the consideration provided by the farmee to the farmor is solely the drilling of a well on farmor's property. The second is a transaction in which the farmee agrees to make an upfront cash payment to farmor, drill one or more wells on farmor's property, and carry farmor for a specified dollar amount of farmor's share of the joint exploration and development costs. This latter transaction re-emerged in application in the 2008 – 2009 timeframe and has come to be known as the "cash and carry" type of farmout transaction.

For each farmout transaction, the paper identifies those federal income tax rules that impact the determination of whether the expected results will be realized by the parties. Because an oil and gas tax partnership can play an essential role in realizing the expected tax results of the farmout transaction, the paper defines an oil and gas tax partnership and explains those instances when it can be beneficial for the transaction. Typical tax partnership allocations are analyzed to show how the parties obtain the tax results expected for the particular farmout transaction.

II. A Description of Joint Operations in Traditional Oil and Gas Farmout Transactions

An oil and gas farmout transaction is a time-honored industry transaction that brings together a party who owns a working interest in an oil and gas property and another party with capital who is interested in drilling a well on that property in order to earn an interest in that property.[3] The party owning the oil and gas property is referred to as the "farmor", and it is the farmor who has chosen to engage another party to fund the cost of drilling a well on the farmor's property in exchange typically for a portion of the farmor's working interest in that property. The party with capital to invest in that property is referred to as the "farmee", and it is the farmee who arranges for and pays the cost of the drilling of the well to earn a working interest in farmor's property.

The distinguishing feature of a traditional farmout transaction is that no assignment of a working interest in the subject property is made by the farmor to the farmee unless the farmee drills and pays for a well in accordance with the terms of the farmout letter agreement.[4] The farmout transaction is therefore different from an oil and gas leasing transaction in which the party holding the mineral fee interest in the oil and gas property assigns all or a portion of the working interest to another party in consideration of a payment of lease bonus and the retention of a royalty interest in the property. The farmout transaction likewise is different from an oil and gas subleasing transaction in which the party holding the working interest in the oil and gas property

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¶¶ 103.01 – .06 (Patrick A. Hennessee and Sean P. Hennessee, eds., CCH 2014) for a discussion of these tax consequences. There also are numerous state and local tax issues that can have an impact on the after-tax economics of the joint operation. Those issues, however, are beyond the scope of this paper.

[3] *See* John S. Lowe, *Analyzing Oil and Gas Farmout Agreements*, 41 Sw. L.J. 759 (1987) for a discussion of the structure and analysis of farmout agreements.

[4] *See* Williams and Meyers, *Manual of Oil and Gas Terms* 359 (15th ed. 2012) (definition of "Farmout agreement").

assigns all or a portion of the working interest to another party in consideration of a cash payment and the retention of an overriding royalty interest in the property. In these latter two transactions, the assignees need not drill a well in order to acquire the assigned interest in the property.

There are a number of reasons why the owner of a working interest in an oil and gas property may not desire to undertake the risk and cost of drilling the well on that property and therefore desires to enter into a farmout transaction with a farmee who may be either an industry or financial party. For example, the farmor may not have readily available risk capital to pay for the well. The farmor may lack an understanding of the geology of the property or may not have access to the proper technology to drill and complete the well. Or, the lease on the oil and gas property may be about to expire and the farmor needs a party with access to risk capital and a drilling rig to step in to drill the well to preserve the lease on the property.

The farmee may be interested in drilling the well on the farmor's property because the farmee has access to available risk capital and a more favorable view on the geology of farmor's property. The farmee also may place significant value on the information provided from drilling the well. For example, the geology may be similar to geology for one or more of farmee's inventory of other properties on which to drill. Or, it may be that given the relative bargaining positions of the parties, the farmee simply perceives that it has negotiated a very favorable risk/reward ratio for the investment in drilling the well.

The farmout transaction typically is implemented with several documents. The farmout letter agreement contains the key financial and operating terms for the transaction. The joint operating agreement attached to the farmout letter agreement provides the terms and conditions that will govern all joint operations of the parties should the well be completed and production be obtained. Typically, the parties will use a standard form joint operating agreement such as the A.A.P.L. Model Form 610. Finally, the form of assignment of mineral interest typically is included so that the farmee understands the exact nature of the recordable mineral interest it is earning by drilling the oil and gas well on farmor's property.

Key financial terms specified in the letter agreement include (a) the financial commitment of the farmee, which may be limited to the costs of drilling, completing and equipping a single well or may be a commitment to carry the farmor until a specified dollar amount has been incurred by the farmee with respect to the specified properties, (b) whether the farmee is entitled to complete payout of its investment in drilling the well or paying for the carry, and if so, the specified "pre-payout" and "post-payout" working interest ownership interests and net revenue interests, and (c) the exact manner in which payout of farmee's investment will be computed.

Key operating terms specified in the letter agreement include (a) the oil and gas lease or leases in which the farmee can earn a working interest if the well is drilled, (b) whether farmor or farmee will pay delay rentals required under the oil and gas lease to preserve the lease until the earning well is drilled, (c) whether area of mutual interest provisions[5] and preferential rights to purchase provisions[6] are to be included in the transaction, (d) the location of the well, the geologic formation that is the target for the well and the total depth of the well, (e) whether the assignment of the specified working interest to farmee is contingent solely on drilling the well in accordance with the terms of the letter agreement (a so-called "drill to earn" transaction) or whether the well also must produce oil and gas in paying quantities (a so-called "drill and produce to earn" transaction), and (f) if the agreement contains a complete payout provision, the interest retained, if any, by the farmor during the payout period.

III. The Expected Tax Results for Joint Operations in Traditional Farmout Transactions

In these transactions, the farmor owning the oil and gas lease agrees to assign to the farmee the entire working interest in a portion of the lease designated as the drill site acreage and a working interest in the remaining acreage of the lease in return for the farmee agreeing to incur the costs of drilling and equipping a well. The farmor may retain an overriding royalty interest in the drill site acreage, and that overriding royalty interest may be convertible at the option of the farmor into a fractional working interest in that acreage at some point during the life of the transaction.

The farmee earning the interest in the farmor's oil and gas property will incur costs to drill and equip an oil and gas well. The intangible drilling and development costs ("IDC") incurred by the owner of a working interest in drilling the well are subject to the option to deduct such costs currently pursuant to section 263(c) of the Internal Revenue Code[7] (the "Code") and section 1.612-4(a) of the Treasury regulations (the "Regulations").[8] The farmee contributing cash to pay for the cost of drilling and

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[5] Area of mutual interest provisions are used by the parties to a farmout transaction to protect access to additional oil and gas properties located in the particular geographic area of the oil and gas property that is the subject of the farmout transaction. When protecting such access is important, the parties to a farmout transaction will agree that if one party or the other involved in the transaction acquires an interest in another oil and gas property located within certain specified geographical boundaries, the party so acquiring the interest must offer a specified percentage working interest in the acquired property to the other party.

[6] Preferential rights to purchase provisions are used by the parties to a farmout transaction to provide for the first opportunity to purchase the selling party's interest in the subject oil and gas property by the other party to the farmout transaction. The concept is that the party who has assisted in the creation of the value of the property should have the opportunity to purchase the property before an outsider who has made no previous contribution to the creation of such value.

[7] I.R.C. § 263(c). Unless otherwise noted, all references are to the Internal Revenue Code of 1986, as amended from time to time.

[8] Unless otherwise noted, all references are to the United States Treasury regulations, as amended from time to time. Section 1.612-4 of the Regulations defines IDC to include:

equipping the well will expect to deduct that IDC currently, subject to limitations provided elsewhere in the Code.[9]

To earn an interest in the farmor's oil and gas property, the farmee also likely will incur costs for lease and well equipment necessary to produce the oil and gas. These costs are capitalized pursuant to section 263(a) of the Code and recovered through depreciation pursuant to section 167(a). Depreciation deductions for lease and well equipment are determined under the Modified Accelerated Cost Recovery System ("MACRS") rules provided for in section 168, and those rules generally provide that

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> [W]ages, fuel repairs, hauling, supplies, etc., incident to and necessary for the drilling of wells for the production of oil or gas. . . . Examples of items to which this option applies are all amounts paid for labor, fuel, repairs, hauling and supplies, or any of them, which are used – (1) In the drilling, shooting, and cleaning of wells, (2) In such clearing of ground, draining, road making, surveying, and geological works as are necessary in preparation for the drilling of wells, and (3) In the construction of such derricks, tanks, pipelines, and other physical structures as are necessary for the drilling of wells and the preparation of wells for the production of oil or gas. In general, this option applies only to expenditures for those drilling and development items which in themselves do not have a salvage value.

Treas. Reg. § 1.612-4(a). *See* Exxon Corp. v. United States, 547 F.2d 548 (Ct. Cl. 1976) for a discussion of the history of the IDC deduction.

[9] IDC deductible pursuant to section 263(c) of the Code and section 1.612-4 of the Regulations are subject to additional limitations and computations. Section 291(b)(1)(A) of the Code reduces the amount of IDC otherwise allowable as a deduction to an "integrated oil company" by thirty percent. I.R.C. § 291(b). An "integrated oil company" is defined in section 291(b)(4) by reference to section 613A. *Id*. Section 291(b)(2) provides that the amount not allowed as a current deduction is deducted ratably over a sixty-month period beginning with the month in which such costs are paid or incurred. *Id.* Section 59(e)(1) provides for an option to deduct all or a portion of IDC otherwise currently deductible pursuant to section 263(c) over a sixty-month period beginning with the year the expenditure for such IDC is made. I.R.C. § 59(e)(1). Section 57(a)(2) provides the rules for determining the amount, if any, of IDC that will be considered a "tax preference" for purposes of computing the amount of "alternative minimum taxable income" subject to the alternative minimum tax imposed by section 55. I.R.C. § 57(a)(2). Section 56(g)(4)(D)(i) provides that integrated oil companies (as defined in section 291(b)(4)) must compute their adjustment to alternative minimum taxable income based on adjusted current earnings by using the sixty-month period specified in section 312(n)(2)(A). I.R.C. § 56(g)(4)(D)(i). Finally, section 263(i) provides that IDC incurred outside of the United States may, at the election of the taxpayer, be included in the basis of the oil and gas property for purposes of computing the deduction for depletion allowable under section 611, and if no election is made, deducted ratably over a ten-year period beginning with the taxable year in which such costs are paid or incurred. I.R.C. § 263(i).

depreciation deductions are determined by using the applicable depreciation method, the applicable recovery period, and the applicable convention.[10]

Oil and gas lease and well equipment is seven-year MACRS property for purposes of section 168(e) of the Code, with the applicable depreciation method being the two hundred percent declining balance method with a switch to the straight-line method for the first year that the straight-line method yields a larger allowance as provided for in section 168(b)(1).[11] The farmee contributing cash to pay for the cost of depreciable lease and well equipment will expect to receive the depreciation deductions allowed with respect to such equipment.

The farmee also may incur costs to operate the oil and gas properties once oil and gas production has begun. Such costs generally are deducted as ordinary and necessary business expenses pursuant to section 162 of the Code.[12] The farmee contributing cash to pay for operating costs will expect to receive the section 162 deductions allowed for such costs.[13]

The farmor contributes its working interest in the specified oil and gas property on which the oil and gas well is to be drilled. The farmor's cost to acquire that working interest in the lease generally is capitalized pursuant to section 263(a) of the Code and is recovered through depletion pursuant to section 611 and section 1.611-1 of the Regulations.[14] The farmor's cost to acquire the working interest generally becomes its

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[10] I.R.C. § 168(a).

[11] I.R.C. § 168(b)(1), (e); Rev. Proc. 87-56, 1987-2 C.B. 674. Oil and gas lease and well equipment generally falls into asset class 13.2, which has an asset class life of fourteen years, a recovery period of seven years, and an alternate depreciation system life of fourteen years. Rev. Proc. 87-56, 1987-2 C.B. 674. Certain assets used in offshore drilling for oil and gas, such as a drilling platform, fall into asset class 13.0, which has an asset class life of seven and one-half years, a recovery period of five years, and an alternate depreciation system life of seven and one-half years. *Id.* The half-year convention is used for oil and gas assets, unless a significant portion of the taxpayer's investment for the year is made in the last quarter of the year, in which case the mid-quarter convention must be used. I.R.C. § 168(d)(1), (3). The half-year convention treats all property placed in service during the taxable year as placed in service on the midpoint of such taxable year. I.R.C. § 168(d)(4)(A). The mid-quarter convention treats all property placed in service during any quarter of the taxable year as placed in service on the midpoint of such quarter. I.R.C. § 168(d)(4)(C).

[12] I.R.C. § 162(a).

[13] *Id.*

[14] I.R.C. §§ 263(a), 611(a); Treas. Reg. § 1.611-1(a). Depletion represents the recovery of the taxpayer's investment in the oil and gas property. Section 611(a) of the Code and section 1.611-1(a) provide for the deduction for depletion in the case of oil and gas wells. I.R.C. § 611(a); Treas. Reg. § 1.611-1(a). Section 1.611-1(b) of the Regulations provides that the allowance for depletion is available only to the owner of an "economic interest" in the mineral deposit. Treas. Reg. § 1.611-1(b). An "economic interest" is defined as being "possessed in every case in which the taxpayer has acquired by

basis for the property pursuant to section 1011, and it is that basis upon which the cost depletion deduction provided for in section 612 is computed.[15] The farmor contributing to the cost of the working interest in the oil and gas property involved in the trade will expect to be allocated the depletable tax basis in that property so that the farmor may compute its deduction for cost depletion. Each party to the farmout transaction separately will compute any available percentage depletion deduction.[16]

The farmout transaction also may involve one or more transfers of oil and gas property interests between the parties. For example, in the farmout transaction described above, the farmor may assign a working interest in drill site acreage and other acreage covered by the oil and gas lease in exchange for the farmee bearing the entire cost of the drilling of an oil and gas well on the property. The farmor assigning a working interest in an oil and gas property to another party to the transaction generally will expect to transfer that interest without incurring federal income tax. Similarly, the farmee receiving a working interest in an oil and gas property in return for drilling the earning well generally will expect to receive that working interest without incurring federal income tax.

The joint operating agreement for the farmout transaction typically provides for the parties to take their respective shares of pre-payout and post-payout oil and gas production in kind and separately dispose of such production. There may be instances, however, in which the parties delegate limited authority to the operator designated in the joint operating agreement to sell their respective shares of such production. The farmor and the farmee generally will expect to recognize ordinary depletable income only with respect to the oil and gas production or production income that each party receives. There may be exceptions in instances in which a party has a net operating loss carryforward that is about to expire or otherwise does not have sufficient taxable income in the year in order to be able to utilize fully certain production tax credits.[17]

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investment any interest in mineral in place . . . and secures, by any form of legal relationship, income derived from the extraction of the mineral . . . to which he must look for a return of his capital." *Id.*

[15] *See* I.R.C. §§ 612, 1011(a); Treas. Reg. § 1.612–1 (providing the rules for determining the basis for the allowance for cost depletion); Treas. Reg. § 1.611-2 (providing the rules for determining the amount of the allowance for cost depletion for each year).

[16] *See* I.R.C. §§ 613(d), 613A(b)-(c). Percentage depletion generally is no longer allowed for production of oil and gas pursuant to section 613(d), although there are certain exemptions from the disallowance that are provided for in section 613A, most notably the limited exemption for independent producers and royalty owners. *See* I.R.C. §§ 613(d), 613A(b)-(c). Percentage depletion is computed without regard to tax basis in the oil and gas property, however, so that any available percentage depletion deduction can be claimed by a party irrespective of whether it receives any share of the depletable tax basis in the lease. *See* I.R.C. § 613A.

[17] *E.g.*, I.R.C. § 43 (enhanced oil recovery credit); § 45I (credit for producing oil or gas from marginal wells); § 45K (credit for producing fuel from a nonconventional source).

The farmor and the farmee who each hold an interest in an oil and gas property as a result of the farmout transaction also will expect to be entitled to no less than that interest if and when the joint operation terminates. For example, in the farmout trade described above, the farmee earns a working interest in the drill site acreage and the other acreage covered by the oil and gas lease in exchange for incurring the costs of drilling the earning well. The joint operating agreement covering the farmout transaction typically provides for termination in certain instances. The farmee will expect that if a termination of the joint operation occurs, it will be entitled to both of the working interests earned in the transaction.

Finally, each party to the farmout transaction will expect to minimize the tax complexity and reporting for the transaction. Ideally, no tax partnership agreement would be included in the transaction so that the complexity of administering a tax partnership and the incremental cost of preparing and filing a Form 1065 – partnership income tax return could be avoided.[18]

Any changes in the allocation of production income between the parties in an oil and gas tax partnership will be tested for "substantial economic effect" under section 704(b) of the Code and section 1.704-1(b)(2) of the Regulations. I.R.C. § 704(b); Treas. Reg. § 1.704-1(b)(2). *See Part IV. G. – Using a Tax Partnership to Achieve the Expected Tax Results for the Traditional Farmout Transaction*.

[18] Section 761(a) of the Code provides that parties to the joint operation may elect to exclude the joint operation from the application of subchapter K of the Code if joint operation is conducted through an unincorporated organization and is for the joint production, extraction, or use of property, but not for the purpose of selling services or property produced or extracted, provided that the income of the parties to the joint operation may be adequately determined without the computation of partnership taxable income. I.R.C. § 761(a). Section 1.761-2(a)(3) of the Regulations adds that the parties to the joint operation must own the oil and gas property as co-owners, either in fee or under lease or other form of contract granting exclusive operating rights, must reserve the right separately to take in kind or dispose of their shares of any oil and gas produced, extracted or used, and not jointly sell services or the oil or gas produced or extracted, although each party may delegate authority to sell his share of the oil and gas for the time being, but not for a period of time in excess of the minimum needs of the industry, and in no event for more than one year. Treas. Reg. § 1.761-2(a)(3). Section 1.761-2(a)(3) also provides that the election out of subchapter K is not available to an oil and gas joint operation one of whose principal purposes is cycling, manufacturing, or processing for persons who are not participants in the joint operation. *Id.* Typical oil and gas exploration, development and production joint operating agreements will qualify for the section 761(a) election out of subchapter K. Harold R. Roth et al., *Tax Considerations in Oil and Gas Promotional Agreements*, 13D ROCKY MTN. MIN. L. INST. 2 (1983) ("[T]he Standard Operating Agreement in common use contains a provision electing out of Subchapter K."). However, an oil and gas joint operation that has as one of its principal purposes of organization the processing of natural gas for oil and gas producers who are not parties in the joint operation generally will not qualify for the section 761(a) election out of subchapter K. I.R.C. § 761(a). The impact of using a

IV. Federal Income Tax Rules Impacting the Tax Results for the Parties to the Traditional Farmout Transaction

A. The Fractional Interest Rule

As mentioned earlier, the deduction for IDC incurred in drilling an oil and gas well and the deduction for depreciation for lease and well equipment installed on that well are key components of the expected tax results for the farmout transaction. One of the significant federal income tax rules that impacts the ability of the producer to claim the full benefit of these deductions is the "fractional interest" rule in section 1.612-4 of the Regulations.[19]

As a limitation on the amount of IDC deductible by a producer in drilling a well to earn an assignment in an oil and gas lease, the fractional interest rule provides that:

> "[I]n any case where any drilling or development project is undertaken for the grant or assignment of a fraction of the operating rights, only that part of the costs thereof which is attributable to such fraction interest is within this option. In the excepted cases, costs of the project undertaken, including depreciable equipment furnished, to the extent allocable to fractions of the operating rights held by others, must be capitalized as the depletable capital cost of the fractional interest thus acquired."[20]

The Internal Revenue Service ("Service") provided guidance on how the fractional interest rule should be applied in a series of published rulings beginning in 1969 and carrying through into 1980. In the first ruling, Revenue Ruling 69-332, the Service addressed an oil and gas trade in which the taxpayer agreed to pay for the drilling of a well on another party's oil and gas lease in exchange for an undivided five-eighths of that party's operating interest in the lease.[21] The trade agreement also provided that the taxpayer was to receive from all of the proceeds of production from the well a sum of money equal to the taxpayer's cost of drilling, completing and equipping the well, and the costs of operating the well during the recovery (or payout) period, less

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partnership for the joint operation (rather than making the section 761(a) election out of subchapter K) when it can help keep the after-tax economics intact also is discussed in *Part IV. G. – Using a Tax Partnership to Achieve the Expected Tax Results for the Traditional Farmout Transaction*.

[19] Treas. Reg. § 1.612-4. Section 263(c) of the Code and Section 1.612-4 of the Regulations provide the rules for deducting IDC. I.R.C. § 263(c); Treas. Reg. § 1.612-4. *See supra* note 8.

[20] Treas. Reg. § 1.612-4(a) (as added by T.D. 6836, 1965-2 C.B. 182). The fractional interest rule was included in the original regulation promulgated under the 1939 Code. *See* T.D. 5276, 1943 C.B. 151. *See also* Reg. 111, § 29.23(m)-16 (approved in House Concurrent Resolution 50, 79th Cong., 1st Sess., 59 Stat. 844, 1945 C.B. 545 (1945), in response to F.H.E. Oil Co. v. Comm'r, 147 F.2d 1002 (5th Cir. 1945)).

[21] Rev. Rul. 69-332, 1969-1 C.B. 87.

taxes on the production.[22] Thereafter, production and expenses were to be shared, and all equipment on the lease owned, five-eighths by the taxpayer and three-eighths by the party owning the lease.[23] During the year, the taxpayer drilled the well, a dry hole, and was assigned its agreed interest in the lease.[24]

The question presented to the Service was whether any portion of the IDC incurred in drilling the well had to be capitalized by the taxpayer as the cost of acquiring the leasehold interest pursuant to the fractional interest rule in section 1.612-4(a) of the Regulations.[25] The Service examined the trade agreements and determined that the taxpayer assumed the obligation to pay for the costs of drilling, completing, and equipping the well and the obligation to pay for the entire cost of production during the payout period.[26] The Service also determined that the payout period ended when the gross income from the sale of all of the production from the well attributable to the operating interest equaled all of the costs of drilling, completing, and equipping the well and the costs of operating the well to produce these amounts.[27]

Based on these determinations, the Service concluded that the trade agreement provided for the complete payout of the taxpayer's investment, and that no fraction of the operating interest reverted to the other party prior to complete payout.[28] The Service therefore ruled that the taxpayer was not required to capitalize any amount of IDC incurred in drilling the well because the "complete payout period" test had been met.[29]

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[22] *Id.*
[23] *Id.*
[24] *Id.*
[25] *Id.*
[26] *Id.*
[27] *Id.*
[28] *Id.*
[29] *Id.* The "complete payout period" test, that is, the test of whether the party drilling the well held the all of the operating interest throughout the complete payout period, was included in the regulations proposed for the 1954 Code. *See* Prop. Treas. Reg. § 1.612-4(a)(2), 21 Fed. Reg. 8417, 8446 (Nov. 3, 1956), which provided in part that:

> When more than one person owns an operating mineral interest in an oil or gas well, each owner's share of the total of such interests during the complete payout period shall be the share of the operating net income from the well that he is entitled to receive during the complete payout period. Therefore, each owner may, at his option, deduct a fraction of the total intangible drilling and development costs minus all such costs which are recoverable out of production payments, royalties, and net profits interests not in excess of the lesser of: (i) Such intangible drilling and development costs incurred by him, or (ii) His fractional share of the operating net income that he is entitled to receive during the complete payout period. The "complete payout period" means the period ending

While not applicable in this instance because the well drilled was a dry hole, the Service cautioned that even though no amount of IDC need be capitalized, taxpayers entering into trades otherwise meeting the complete payout period test would be required to capitalize as depletable leasehold acquisition cost a portion of any undepreciated lease and well equipment basis remaining at payout equal to the percentage interest that reverted to the other party at payout.[30]

The Service provided additional guidance on the meaning of the complete payout period test in Revenue Ruling 70-336.[31] In that ruling, the taxpayer agreed to pay all of the costs of drilling, completing, equipping, and operating a well in exchange for an assignment of one hundred percent of the operating interest in the lease owned by the

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> when the operating net income from the well, after payment of all costs of operation, first equals all expenditures for drill and development (tangible and intangible), minus all such expenditures which are recoverable out of production payments, royalties, and net profits interests.

In 1960, the proposed section 1.612-4 regulations were withdrawn and reproposed. Prop. Treas. Reg. § 1.612-4(a)(2), 25 Fed. Reg. 3747, 3761 (April 29, 1960). Prop. Treas. Reg. § 1.612-4(a)(2), as reproposed, provided in part that:

> Where the operator is assigned all the operating rights for the "complete pay-out period" in a well (or wells), he will be considered, for purposes of subparagraph (1) of this paragraph as having the entire operating mineral interest in such well (or wells). Similarly, where the operator is assigned only a fraction of the operating rights for the "complete pay-out period" he will be considered as having such fraction of the entire operating mineral interests in such well (or wells). Where the operator holds all of the operating rights, or a fraction thereof, for less than the complete pay-out period, his share of the total of the operating mineral interests will be determined by reference to his share of such interests immediately after the complete payout period. The "complete pay-out period" means the period ending when the gross income attributable to all of the operating mineral interests in the well (or wells) equals all the expenditures for drilling and development (tangible or intangible) of such well (or wells) plus the costs of operating such well (or wells) to produce such an amount.

Id. These latter proposed regulations were known as the "anti-*Abercrombie*" regulations for their attempt to overrule the result in Comm'r v. Abercrombie, 162 F.2d 338 (5th Cir. 1947). *Abercrombie* later was overruled by the Fifth Circuit in *Cocke*. *See* discussion *infra* note 67. Reference to the "complete payout period" test was not included, however, in section 1.612-4 of the Regulations as adopted. *See* T.D. 6836, *supra* note 20.

[30] *Id*.

[31] Rev. Rul. 70-336, 1970-1 C.B. 145, *modified*, Rev. Rul. 80-109, 1980-1 C.B. 129.

other party to the trade.[32] The taxpayer's operating interest was burdened by an overriding royalty interest retained by the other party, and that party retained the option to convert the overriding royalty interest to a fifty percent operating interest when the cumulative gross production from the well equaled a specified amount.[33] The well was completed as a producing well, and when the specified amount of production was obtained, the other party exercised its right to convert its retained overriding royalty interest into a fifty percent working interest.[34] Conversion occurred prior to the taxpayer obtaining complete payout for the costs it agreed to pay.[35]

In interpreting the fractional interest rule and the complete payout period test, the Service stated that:

> Thus, the limitation in the regulations is operative if the drilling and development project is undertaken '. . . for the grant or assignment of a fraction of the operating rights . . . .' The carrying party [the taxpayer] will have undertaken the drilling and development project for the entire working interest only if he holds the entire working interest through the complete pay-out period. If the carrying party holds the entire working interest for a period that is less than the complete pay-out period he will have undertaken the drilling and development project for the fraction of the operating rights that he receives as his 'permanent' share in the mineral property.[36]

The determination of the complete pay-out period requires an interpretation of the carried interest agreement and the performance of the parties under that agreement. As a general principal, however, the period ends when the gross income attributable to all of the operating mineral interests in the well (or wells, in the case of agreements covering more than a single well) equals all expenditures for drilling and development (tangible and intangible) of such well (or wells) plus the cost of operating the well (or wells) to produce such an amount.[37]

The Service determined that the taxpayer had not held one hundred percent of the operating interest throughout the complete payout period so that the taxpayer's interest failed the complete payout period test.[38] The Service therefore ruled that only the IDC attributable to the fifty percent permanent interest of the taxpayer could be deducted pursuant to section 1.612-4 of the Regulations.[39] The Service further ruled that the remainder of the IDC, and the portion of the investment in otherwise depreciable lease and well equipment not attributable to the taxpayer's fifty percent

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[32] *Id*.
[33] *Id*.
[34] *Id*.
[35] *Id*.
[36] *Id*.
[37] Rev. Rul. 70-336, 1970-1 C.B. at 145.
[38] *Id*.
[39] *Id*.

permanent interest, were attributable to the fraction of the permanent operating interest held by the other party upon exercise of the option, and those amounts had to be capitalized by the taxpayer as depletable leasehold acquisition cost.[40]

The Service provided further guidance in Revenue Ruling 70-657[41], Revenue Ruling 71-206[42], Revenue Ruling 71-207[43], and Revenue Ruling 75-446.[44] Each of these rulings dealt with a different fact pattern and explained how the fractional interest rule and the complete payout period test were to be applied. The final ruling in the series, Revenue Ruling 80-109, involved the drilling of a well on each of two noncontiguous tracts with production for payout of all costs for drilling, completing, equipping and operating the two wells available from both tracts.[45] The Service clarified its ruling in Revenue Ruling 70-336, stating that if the party undertaking the drilling and development of the property will not in all events hold the initial fractional interest through the complete payout period (or the life of the property if it does not pay out), then that party "will be treated as having undertaken the drilling and development for the fraction of the operating rights that are received as the permanent share" and the IDC deduction will be limited to that fractional share.[46] The Service ruled that, notwithstanding the fact that the two tracts were situated on the same prospect and were expected to produce from the same deposit, the complete payout period test was not met in all events because payout for each well on each tract could come from a well on the other tract.[47]

In farmout transactions in which the parties prefer to elect to have the joint operation excluded from the partnership tax rules in subchapter K of the Code to avoid

[40] *Id*.
[41] Rev. Rul. 70-657, 1970-2 C.B. 70 (ruling one-half of IDC deducted and one-half capitalized as leasehold acquisition costs because the agreement failed the complete payout period test).
[42] Rev. Rul. 71-206, 1971-1 C.B. 105 (ruling one-fourth of the IDC deducted and three-fourths capitalized as leasehold acquisition costs because the agreement failed the complete payout period test).
[43] Rev. Rul. 71-207, 1971-1 C.B. 160 (ruling all of the IDC deducted because the agreement met the complete payout period test).
[44] Rev. Rul. 75-446, 1975-2 C.B. 95 (ruling all of the IDC deducted because the taxpayer met the complete payout period test).
[45] Rev. Rul. 80-109, 1980-1 C.B. 129.
[46] *Id*.
[47] *Id.* The facts in the ruling indicate that the two tracts were not contiguous. *Id*. Had the tracts been contiguous, and had the tracts been conveyed in a single conveyance or grant or in separate conveyances or grants at the same time from the same owner to the taxpayer, the tracts would not have been considered separate "tracts or parcels of land" for purposes of the definition of the term "property" in section 614 of the Code and section 1.614-1(a)(3) of the Regulations. *See infra* note 90. As a single tract, the complete payout period test would have been satisfied. In essence, then, Revenue Ruling 80-109 stands for the proposition that the complete payout period test must be applied on a section 614 property-by-property basis. Rev. Rul. 80-109, 1980-1 C.B. 129.

the complexities of negotiating and administering a tax partnership agreement and the filing of a partnership income tax return, the fractional interest rule provides the basis for a producer to deduct all of the IDC it incurs in drilling a well to earn a working interest in another party's oil and gas lease.[48] Thus, where consistent with the business objectives in the trade, producers should structure the trade agreement to provide for a complete payout period consistent with complete payout period test set out in the revenue rulings discussed above. Where that test is met, producers can be confident that the intangible costs incurred in drilling the earning well will be subject to the rules for deducting IDC.[49]

However, producers following these revenue rulings in farmout transactions that elect to have the joint operations excluded from subchapter K of the Code are left with a possible adverse tax impact for the investment in depreciable lease and well equipment. Should the complete payout period be satisfied and the working interests shift prior to the tangible lease and well equipment being fully depreciated, only the depreciable basis remaining at payout attributable to the producer's permanent working interest in the lease would continue to be depreciated under the applicable MACRS rules.[50] The depreciable basis attributable to the portion of the working interest that reverted to the other party no longer would be subject to the rules for depreciation but instead would be capitalized into the depletable basis for the working interest.[51]

To illustrate the impact of following the rulings, if payout were to occur at the end of year two of the farmout transaction, and the taxpayer's permanent working interest in the property were sixty percent, then forty percent of the depreciable basis that remained after two years of depreciation as MACRS seven-year property subsequently would be recovered through depletion. Were the producer to qualify for percentage depletion, this additional depletable basis would be lost, as percentage depletion is allowed regardless of depletable basis. The loss of a tax deduction for this basis would have a significant adverse impact on the net present value of the future tax deductions associated with the investment in the farmout transaction.[52] Were the producer instead able to use only cost depletion, and the oil and gas deposit to have a producing life greater than six years (the remaining recovery period for the depreciable lease and well equipment), then the shift from depreciable basis to depletable basis would have an

[48] Rev. Rul. 69-332, 1969-1 C.B. 87; Rev. Rul. 71-207, 1971-1 C.B. 160. The tax consequences of not making the section 761 election to be excluded from the application of the partnership tax rules in subchapter K of the Code are addressed throughout *Part IV. – Federal Income Tax Rules Impacting the Tax Results for the Parties to the Traditional Farmout Transaction*.

[49] *Id*.

[50] Rev. Rul. 69-332, 1969-1 C.B. 87; Rev. Rul. 71-207, 1971-1 C.B. 160.

[51] *Id*.

[52] *See* I.R.C. §§ 168, 611. In such case, the net present value of the remaining tax deductions attributable to the shift from depreciable basis to depletable basis would be zero. *Id.* Compare that result to the net present value of the remaining tax deductions as seven-year depreciable property had the shift to depletable basis not occurred. *Id.*

adverse impact on the net present value of the future tax deductions.[53] This latter impact would become more and more significant the longer the producing life of the field exceeded the remaining six years of cost recovery for MACRS seven-year property. In either instance, there would be an adverse impact on the after-tax economics of the farmout transaction.

B. The Impact of the Husky Oil and Marathon Oil Cases on the Fractional Interest Rule and the Complete Payout Period Test

As noted earlier, nowhere in the fractional interest rule in section 1.612-4 of the Regulations is there any mention of the complete payout period test in determining IDC and depreciable costs undertaken that are allocable to fractions of the operating rights held by others.[54] That lack of authority for the test in the regulation led the taxpayers to challenge the complete payout period test in *Husky Oil Company v. Commissioner.*[55] In that case, Husky Oil Company ("Husky") entered into an agreement to succeed to the interest of Home-Stake Production Company in an oil and gas investment program that involved public offerings of units of participation representing direct ownership of working interests in oil and gas leases.[56] Husky agreed to act as operator of the subject leases, making all decisions with respect to the properties, including paying operating costs, marketing the oil and gas production, and paying royalties.[57] Husky was entitled to seventy-five percent of the remainder of the proceeds from the sale of the production to reimburse itself for its costs, and the unit holders were entitled to any portion of the seventy-five percent portion in excess of Husky's costs, and all of the remaining twenty-five percent.[58]

Husky also agreed to make all of the capital expenditures for the operation, and for each $750,000 incurred, Husky earned an undivided five percent interest in the rights held by the unit holders.[59] After Husky paid $3,000,000 in capital expenditures, unit holders could elect to begin paying their share of capital expenditures.[60] Amounts paid by Husky for capital expenditures on behalf of unit holders who did not elect to contribute were reimbursed from the balance, if any, of the seventy-five percent portion mentioned above.[61] For each $8,000,000 distributed to participants after the initial $3,000,000 capital investment was made, Husky earned an additional ten percent in the

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[53] *See* Treas. Reg. §§ 1.611–2, 1.612–1. Compare the net present value of recovering the basis that shifts as MACRS seven-year depreciable property with the net present value of recovering that basis through cost depletion over the remaining producing life of the oil and gas deposit.
[54] *See supra* note 29 and accompanying text.
[55] Husky Oil Co. v. Comm'r, 83 T.C. 717 (1984).
[56] *Id.* at 728.
[57] *Id.* at 729.
[58] *Id.*
[59] *Id.*
[60] *Id.*
[61] *Id.* at 730.

rights held by the unit holders, until a maximum of fifty percent interest had been earned.[62]

On its tax returns for the years in issue, Husky deducted all of the IDC and depreciation attributable to its investment, and also claimed an investment tax credit.[63] The Service on audit reduced the IDC and depreciation deductions, and the investment tax credit, to reflect the amounts attributable to Husky's earned participating interest in the properties in the years in question, citing the fractional interest rule in section 1.612-4 of the Regulations.[64]

Husky argued in the United States Tax Court (the "Tax Court") that the agreement had assigned all of the operating rights in the subject leases to Husky and that Husky had a working interest as required to be able to deduct IDC.[65] There was no question that Husky's agreement did not satisfy the complete payout period test, as Husky's reimbursement did not come from one hundred percent of the production during the complete payout period.[66] Husky argued, however, that its position should be sustained based on *United States v. Cocke,*[67] because like the taxpayer in *Cocke*, Husky could look only to the income from the extraction of oil and gas from the subject properties for a return of its investment.[68] The Tax Court agreed with Husky's argument, holding that: "Because petitioner carried the burden of the total working interests and thus had the comprehensive economic interest in Unit Area A during 1975, 1976, and 1977, it is entitled to deduct the intangible drilling and development costs and to claim depreciation and investment tax credits attributable thereto."[69]

On appeal, the Service once again argued that the fractional interest rule in section 1.612-4 did not allow Husky to deduct all of the IDC and depreciation, and claim all of the investment tax credit, because Husky was not entitled to be reimbursed for its investment from one hundred percent of the proceeds of production from the

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[62] *Id.*
[63] *Id.*
[64] *Id.* at 730, 737–738.
[65] *Id.* at 738.
[66] *See id.* at 729.
[67] U.S. v. Cocke, 399 F.2d 433 (5th Cir. 1968), *reh'g denied*, *cert. denied*, 394 U.S. 922 (1969). In *Cocke*, the United States Court of Appeals for the Fifth Circuit addressed whether, under the facts of the carried interest arrangement entered into with Humble Oil and Refining Company, the taxpayer had an economic interest in certain oil in place, so that he could report the income and claim IDC, depreciation, and depletion deductions associated with the interest in that oil. *See id.* at 445. The appellate court held that during the period that Humble was responsible for all exploration, drilling and operating costs for the properties and looked to fifty percent of the income otherwise attributable to the taxpayer's interest in the properties for a return of Humble's investment, the taxpayer had no economic interest in the fifty percent of oil income paid to Humble. *See id.* at 445–46.
[68] Husky Oil Co. v. Comm'r, 83 T.C. 717, 741 (1984).
[69] *Id.*

properties.[70] Husky countered with its argument that it acquired all of the operating rights in the properties, and thus was entitled a deduction and investment tax credit for all of its the costs.[71] Central to Husky's argument was that it could look only to proceeds of oil and gas production for a recoupment of its investment in the properties.[72]

The United States Court of Appeals for the Tenth Circuit agreed with Husky, concluding that Husky acquired all of the operating rights because it assumed the entire burden of operation and further development of the properties, subject only to the options of the other participants to begin paying their shares of capital expenditures after Husky had made its initial $3,000,000 of investment.[73] The appellate court further concluded that when a party acquires the entire operating interest in a property, the fractional interest rule in section 1.612-4 of the Regulations does not apply, even if a percentage of the revenues from production is payable to parties, holding nonoperating interests, who did not incur such costs.[74] The appellate court therefore held that: "[A] party who bears all costs of operation and development and who can only recoup these costs out of oil revenues, has a one hundred percent operating interest."[75]

Husky's IDC and depreciation deductions, and its investment tax credit claimed on its returns for the years in question, thus were sustained.[76]

There was no mention in the appellate court or Tax Court opinions of the rulings that the Service had published regarding the complete payout period test for the

[70] Marathon Oil Co. v. Comm'r, 838 F.2d 1114, 1123 (10th Cir. 1987). Marathon Oil Company was the survivor by merger with Husky, hence the change of case name on appeal. *Id.* at 1116 n.1.
[71] *Id.* at 1123.
[72] *Id.* at 1124.
[73] *Id.*
[74] *Id.* at 1125.
[75] *Id.* Key to the appellate court's decision was its determination that the existence of an unexercised option by the other participants to back into a portion of the operating interest and begin making capital contributions at a specified point did not diminish or otherwise alter Husky's interest in the property during the years in question. *See id*. at 1124 n.7 (citing United States v. Swank, 451 U.S. 571, 585 (1981)). The appellate court relied on *Swank*, a case in which the United States Supreme Court had held that the lessor's ability to terminate a mining lease upon giving a 30-day notice of termination did not prevent the lessee from being considered as owning an economic interest in the mining property and therefore did not prevent the lessee from deducting depletion from its income from the property. *See Swank*, 451 U.S. at 585 & n.25; *see also* Rev. Rul. 83-160, 1983-2 C.B. 99 (following *Swank*, and revoking earlier rulings, the terminability of a mining lease at will or on short notice will not, by itself, prevent a taxpayer from being considered as acquiring an economic interest under section 1.611-1(b)(1) of the Regulations).
[76] *Marathon Oil Co.*, 838 F.2d at 1124-25.

fractional interest rule.[77] Given that the terms of the Husky trade did not meet the test, it can be argued that the courts, with their holdings on the interpretation of the fractional interest rule, implicitly rejected the test. At a minimum, the courts determined that the test was not the appropriate one for the facts in the case.

Thus, where the parties to a traditional farmout transaction prefer to elect to have the joint operation excluded from the application of the partnership tax rules in subchapter K of the Code and the business objectives of the transaction prevent it from being structured to comply with the complete payout period test, a taxpayer willing to rely on the holding in the *Husky/Marathon* decisions may take the position that it is entitled to deduct all of the IDC and depreciation incurred with regard to its investment so long as in the trade the taxpayer owns all of the operating interest when the investment is made and looks only to the proceeds of production for a return of its investment.[78] If that position is sustained, the taxpayer will avoid the adverse impact of deducting less than all of the IDC and depreciation incurred under the farmout transaction. Moreover, even if the transaction is structured to comply with the complete payout period test, a taxpayer willing to rely on these decisions may take the position, contrary to that in Revenue Ruling 69-332, that at complete payout, it need not capitalize the remaining depreciable basis attributable to the portion of the working interest that reverted to the other party into the depletable basis of the working interest retained.[79] If that position is sustained, the taxpayer will avoid the potential adverse impact for the extended recovery (through cost depletion) of post-payout remaining depreciable basis in the lease and well equipment.

C. The Pool of Capital Doctrine Supports Non-Taxable Assignments of Interests in Oil and Gas Leases

As mentioned earlier, the assignment of an interest in an oil and gas lease in exchange for another party drilling a well or providing capital required to drill the well without the party assigning the interest incurring a federal income tax is a key component of the expected tax results for the farmout transaction. Similarly, the receipt of an interest in an oil and gas lease in exchange for providing the service of drilling the well or providing the capital required to drill the well without the party receiving the interest incurring a federal income tax also is a key component of the expected tax results for the transaction. Fortunately, there is long-standing authority for taking these positions so long as the transaction is structured in accordance with the authority.

With regard to the party assigning an interest in an oil and gas lease to another party who has drilled a well on that lease or provided the capital required to drill that well, the Service first ruled in 1925 in Solicitor's Memorandum 3322 that such an assignment did not result in an exchange that was subject to federal income tax.[80] In

[77] *See id.*; Husky Oil Co. v. Comm'r, 83 T.C. 717 (1984).
[78] *See Marathon Oil Co.*, 838 F.2d at 1125; *Husky Oil Co.*, 83 T.C. at 717.
[79] *See* Rev. Rul. 69-332, 1969-1 C.B. 87.
[80] S.M. IV-1 C.B. 112 (1925), obs. Rev. Rul. 70-277, 1970-1 C.B. 280; *see* James A. Lewis Engineering, Inc. v. Comm'r, 39 T.C. 482, 490-91 (1962).

that memorandum, the taxpayer assigned an undivided one-half interest in an oil and gas lease to another company as consideration for the agreement to drill an oil and gas well on the lease.

Two years later, in General Counsel Memorandum 932, the Service ruled that the party who received the interest in an oil and gas lease for drilling a well or providing the capital to drill a well on that lease made a capital investment in the acquired interest in the lease and therefore did not receive income.[81] The Board of Tax Appeals and the United States Court of Appeals for the Fifth Circuit reached a similar result in *Dearing v. Commissioner,* wherein the courts held that the assignee did not realize taxable income on the receipt of an interest in an oil and gas lease in exchange for drilling a well on that lease.[82]

Prior to *Dearing*, the United States Supreme Court in *Palmer v. Bender*[83] had set the stage for what would become known as the Pool of Capital Doctrine. In that case, which involved the determination of whether a sublessor of an oil and gas lease was entitled to a depletion deduction, the Court made reference to oil in the ground representing a reservoir of the capital investment of the various parties.[84]

The Pool of Capital Doctrine formally was established in General Counsel Memorandum 22730.[85] In that memorandum, the Service concluded, *inter alia*, that neither the assignor of an interest in an oil and gas lease nor the assignee of an interest in that lease realized income when the interest was assigned in exchange for capital provided or services provided for the development of that lease. The Service reasoned that the assignee had contributed services or capital to the reservoir or pool of capital investment in the oil and gas in place, and that such a contribution simply did not result in a taxable event to either the assignor or the assignee. Key to the conclusion was that:

> The lessee or assignee, like the lessor or assignor, who retained a share interest in production having a value equivalent to that of the lessor's prior interest but passed on to the lessee the investment obligations and risks that attend development for a share in production, has parted with no capital interest but has merely in turn given another a right to share in production in consideration of an investment made by such other person. If the driller or equipment dealer is making an investment by which he acquires an economic interest in oil and gas in place, expenditure made by him represent capital expenditures returnable tax-free through the depletion allowance rather than by way of expense deduction, and the oil payment rights acquired do not represent payment in property for services rendered or supplies furnished. Similarly, one who, in return for an oil

[81] I.R.S. Gen. Couns. Mem. 932, VI-1 C.B. 241 (1927), made obsolete by Rev. Rul. 67-123, 1987-1 C.B. 383.
[82] Dearing v. Comm'r, 36 B.T.A. 843, 848 (1937), *aff'd*, 102 F.2d 91, 92 (5th Cir. 1939).
[83] 287 U.S. 551, 558 (1933).
[84] *Id.*
[85] I.R.S. Gen. Couns. Mem. 22730, 1941-1 C.B. 214.

> payment right, furnishes money which the lessee is pledged to use in developing the property would be regarded as making an investment representing an addition to the reservoir of capital investments in oil and gas in place . . . . Such a transaction, involving a pledge to use the money furnished in developing the property, is distinguishable from a sale the proceeds of which are unqualifiedly received by the seller.[86]

D. Limitations on the Pool of Capital Doctrine in the Farmout Transaction

For many years thereafter, oil and gas producers participating in trades involving the agreement to drill a well in exchange for an interest in the oil and gas lease on which the well was drilled relied on this general counsel memorandum to take the position that the transfer of an interest in the oil and gas lease to a party who provided services or capital to drill the well on the lease did not result in taxable income to either the assignor or the assignee.[87] Then, in 1977, the Service created uncertainty in the oil and gas exploration and development business when it issued Revenue Ruling 77-

[86] *Id*. at 221-22.

[87] *Id.* There are numerous cases and rulings that interpret the Pool of Capital Doctrine and apply it in various situations. *See, e.g.*, Zuhone v. Comm'r, 883 F.2d 1317, 1323 (7th Cir. 1989) (holding that Pool of Capital Doctrine did not apply to corporate president's receipt of overriding royalty interests from his employer/closely-held corporation in exchange for his services performed in arranging acquisition of certain oil and gas properties); Rev. Rul. 83-46, 1983-1 C.B. 16 (ruling that section 83 applied to include in income overriding royalty interests received by corporate promoter, attorney, and employee of closely-held corporation in exchange for services performed in connection with the acquisition of oil and gas properties without mentioning the Pool of Capital Doctrine); I.R.S. Tech. Adv. Mem. 80-14-024 (Dec. 28, 1979) (advising that Pool of Capital Doctrine did not apply to chief executive officer's receipt of overriding royalty interests from his employer/closely-held corporation in exchange for services performed in connection with the acquisition and development of oil and gas properties); I.R.S. Tech. Adv. Memo. 81-46-006 (Nov. 16, 1980) (advising that Pool of Capital Doctrine did not apply to exploration manager's receipt of overriding royalty interests from his employer/closely-held corporation in exchange for his services performed in connection with securing geological information on oil and gas properties, identifying drilling prospects, and managing well drilling, testing and completion); I.R.S. Tech. Adv. Mem. 81-52-001 (Dec. 28, 1979) (advising that Pool of Capital Doctrine did not apply to land manager's receipt of overriding royalty interests from his employer/closely-held corporation in exchange for his services performed in connection with securing data, analyzing drilling prospects, investigating farmout possibilities, and determining the economics of certain property acquisitions). The key conclusion regarding earning an interest in an oil and gas property by causing a well to be drilled on that property has not been revoked by the Service and therefore remains intact. *See* I.R.M. 4.41.1.2.3.1 (2013).

176,[88] a ruling involving a trade that had broken the assignment of an interest in an oil and gas lease into two component parts.

In that ruling, the party owning the oil and gas lease entered into an agreement with a second party pursuant to which the second party agreed to drill a well on the first party's tract of land. In exchange for drilling the well, the second party was to receive the entire working interest in the drill site acreage, as assigned by the state regulatory body, subject to an overriding royalty interest retained by the first party in such acreage. In addition, the second party received a fifty percent working interest in the remainder of the acreage of the tract of land. The trade further specified that once the second party had recovered all of its costs of drilling, equipping and operating the well out of all of the proceeds from the oil and gas produced from the drill site, the overriding royalty could be converted into a fifty percent working interest therein. The second party drilled and completed the well on the drill site acreage, and, in accordance with the trade agreement, the first party assigned the working interests in the drill site acreage and the remaining acreage to the second party. The issue before the Service was whether either of the assignments resulted in the realization of income to either (or both) of the parties involved in the trade.[89]

The Service first determined that the oil and gas lease was a single section 614 property in the hands of the first party.[90] When the assignment was made, though, the Service determined that two different economic interests had been created and thus each party then had two separate section 614 properties.[91] From the first party's perspective, the Service determined that the first party's retained convertible overriding royalty in the drill site acreage was a property separate from its retained fifty percent

[88] Rev. Rul. 77-176, 1977-1 C.B. 77.
[89] *Id.* Although the ruling does not state that the parties to the agreement made the section 761 election to have the joint operation excluded from the application of the partnership rules in subchapter K of the Code, it can be inferred that such an election was made because the ruling does not address any issues that would have been present under subchapter K. *Id.* The tax consequences to the parties had they not made the section 761 election to have the joint operation excluded from subchapter K are addressed later in this paper.
[90] *Id.* at 79. The term "property" is defined as: "each separate interest owned by the taxpayer in each mineral deposit in each separate tract or parcel of land." I.R.C. §614(a). The term "interest" is defined as: "an economic interest in a mineral deposit . . . . The term includes working or operating interests, royalties, overriding royalties, net profits interests, and, to the extent not treated as loans under section 636, production payments." Treas. Reg. § 1.614-1(a)(2). The term "tract or parcel of land" is defined as: "merely descriptive of the physical scope of the land to which the taxpayer's interest relates." Treas. Reg. § 1.614-1(a)(3). Section 1.614-1(a)(3) provides additional rules for contiguous areas and areas included in separate conveyances or grants. The oil and gas lease involved in the ruling would be a separate tract or parcel of land and thus a single section 614 property.
[91] *Id.*

working interest in the remaining acreage.[92] Likewise, from the second party's perspective, the Service determined that the second party's one hundred percent working interest in the drill site acreage (subject to the retained convertible overriding royalty) was a property separate from its fifty percent working interest in the remaining acreage.[93] No analysis was provided regarding the determinations of these separate section 614 property interests. Particularly lacking was an explanation as to why, in the Service's view, the rules regarding combination of operating interests in a separate parcel or tract of land did not apply to result in a single section 614 property.[94]

The Service next considered whether the Pool of Capital Doctrine from General Counsel Memorandum 22730 applied to the parties' interests in the drill site acreage. The Service determined that the second party's contribution of the drilling of the well had been made to this acreage.[95] As such, the second party's receipt of the working interest in this acreage did not represent payment in property for services rendered or supplies furnished, but instead was a capital interest acquired through the undertaking to make a contribution to the pool of capital.[96] And, the first party's assignment of the working interest upon the completion of the well did not result in the parting with a capital interest but only lessened the first party's required investment and risks in development of the drill site acreage.[97] Accordingly, the Service ruled that pursuant to the Pool of Capital Doctrine, neither party realized income with regard to the assignment of the interest in the drill site acreage.[98]

The Service reached a different result for the parties, however, with regard to the remaining acreage. Applying the Pool of Capital Doctrine on a section 614 property-by-property basis, the Service determined that the drilling of a well on the drill site acreage did not represent a contribution to the pool of capital for the development of the remaining acreage.[99] Since there had been no such contribution with regard to the remaining acreage, the Pool of Capital Doctrine could not apply to the assignment of the interest in that acreage. The Service therefore ruled that the second party had received compensation in the form of property for undertaking the development of the drill site acreage, and must include in its income for the earlier of the year the well was completed or the year the working interest assignment was received, the fair market value of the property interest received, determined as of the date of the transfer.[100]

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92 *Id*.
93 *Id.*
94 *See* I.R.C. § 614(b)(1)(A). Unless the taxpayer elects otherwise, all of the taxpayer's oil and gas operating mineral interests in a separate parcel or tract of land are combined and treated as one section 614 property. *Id*.
95 *Id.*
96 *Id.*
97 *Id.*
98 *Id.*
99 *Id.* at 80.
100 *Id.*

Similarly, the Service ruled that the first party must be treated as if it had sold a fifty percent working interest in the remaining acreage for its fair market value on the date of assignment, and paid the proceeds of the sale to the second party as additional compensation for the drilling of the well on the drill site acreage.[101] The first party had to compute gain or loss on the sale, measured by the difference of the fair market value of the fifty percent working interest assigned and the adjusted tax basis in that interest.[102] The character of the gain or loss (ordinary or section 1231) depended on (1) the first party's holding period on the date of assignment and (2) whether the first party held the oil and gas lease primarily for sale to customers in the ordinary course of its business.[103] The first party was entitled to increase its basis in the retained convertible overriding royalty interest in the drill site acreage by the amount of the fair market value of the fifty percent working interest in the remaining acreage assigned to the second party.[104]

The Service determined that pursuant to the authority in section 7805(b) of the Code, the rulings would not be applied to transfers made prior to April 27, 1977, or to transfers made pursuant to binding contracts entered into before that date.[105]

After Revenue Ruling 77-176, taxpayers who prefer to have the joint operation be excluded from the partnership tax rules in subchapter K of the Code are left with difficult choices in structuring their oil and gas farmout transactions, particularly where the business objectives of the transaction are best served by involving interests in acreage outside of the drill site acreage, whether covered by the same oil and gas lease or another lease.[106] Taxpayers may assert that the positions taken by the Service in the ruling do not represent correct interpretations of the Pool of Capital Doctrine and thus will not be sustained should the trade be challenged on audit.[107] Taxpayers also may

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[101] *Id.*
[102] *Id.*
[103] *Id.*
[104] *Id.*
[105] *Id.*; I.R.C. § 7805(b). *See* I.R.S. Tech. Adv. Mem. 83-11-005 (Nov. 19, 1982) (Service determined that the facts of the oil and gas transaction in issue were analogous to those of the transaction in Revenue Ruling 77-176 but that an adjustment to the taxpayer's return was precluded by the non-retroactive provisions of section 7805(b) of the Code as contained in Revenue Ruling 77-176).
[106] The tax consequences of not having the joint operation make the election to be excluded from the partnership tax rules in subchapter K of the Code are discussed later in this paper. *See infra Part IV. F. - Other Objectives*.
[107] *See, e.g.,* Burke v. Blumenthal, 504 F. Supp. 35 (N.D. Tex. 1980) (challenging positions taken in Revenue Ruling 77-176 in a declaratory injunction proceeding in which the court dismissed the action after concluding that it did not have subject matter jurisdiction). Many tax professionals who have analyzed the ruling believe that a successful challenge to the ruling could be made by attacking the Service's conclusion that the assignment in the transaction created two separate section 614 properties, particularly given the section 614(b)(1)(A) operating mineral interest combination rules

assert that even if the ruling is to be sustained, the ruling is limited to its facts, that is, a transfer in exchange for drilling services rendered rather than in the more common situation today in which the party agreeing to drill the well provides capital to have the well drilled by a drilling company. Or, taxpayers may structure their farmout transactions to minimize the taxable income and gain resulting from the assignment of interests in other than the acreage on which the earning well is drilled, that is, interests outside of the Pool of Capital Doctrine. For instance, the farmout transaction might provide for the assignment of the interests to the farmee at the time the trade is entered into, with those interests outside of the interest in the drill site acreage being valued as of the date of the assignment, presumably at a pre-discovery value rather than a post-discovery value. Or, the trade might be structured so that the farmee, rather than earning an interest in acreage outside of the drill site acreage by drilling a well, earns instead the option to drill another well on specified acreage. In this instance, the option to drill an additional well presumably has a value less than the value of a direct interest in lease acreage. Neither of these structuring alternatives is ideal, but the latter one seems to be more prevalent in use, based on the author's experience.

E. Income Recognition on Gas Sales

The joint operating agreement for the farmout transaction may include as an exhibit an agreement on the rights to produce and market gas, and how gas production will be balanced over the life of the joint operation should at any point in time one party take and dispose of more than its proportionate share of the gas produced. This agreement is known as a "gas balancing agreement." Even if the joint operating agreement does not include provisions regarding gas balancing, the section 761 regulations dealing with electing out of subchapter K of the Code now require taxpayers who elect to have the joint operation excluded from the partnership tax rules in subchapter K to use one of two accepted methods of accounting for how all parties to the trade will recognize income from sales or other taxable dispositions of natural gas.[108] This requirement was added to the section 761 regulations because of the opportunity for taxpayers participating in joint operations to utilize different methods of accounting for gas sales, and thus defer overall recognition of income on gas produced and sold.[109]

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mentioned in *supra* note 86. *See, e.g.*, Lowe, *supra* note 3 at n. 36; OWEN L. ANDERSON ET AL., HEMINGWAY OIL AND GAS LAW AND TAXATION § 12.1 (4th ed. 2004).

[108] Treas. Reg. § 1.761-2(d) (as added by T.D. 8578, 1995-1 C.B. 134). See *Oil and Gas Federal Income Taxation*, *supra* note 2 at ¶ 1603.10 for a discussion of the rules included in section 1.761-2(d) of the Regulations.

[109] *See, e.g.,* I.R.S. Tech. Adv. Mem. 88-09-001 (Oct. 28, 1987). Prior to the promulgation of section 1.761-2(d) of the Regulations, the Service was concerned with the opportunity for whipsaw by the parties. Some producers utilized a method of accounting under which they recognized as gross income the proceeds from all of the gas that they took and disposed of (the "sales method"). Other producers utilized a method of accounting under which they recognized as gross income their proportionate share of the proceeds of gas that was disposed of, regardless of the volume of gas they

Under these regulations, all parties to the trade must utilize the "cumulative" method of accounting for recognizing income on the disposition of gas unless they agree to use the "annual" method of accounting.[110] The cumulative method treats each party to the joint operation as the owner of its percentage share of the total gas in the reservoir, and each party taking and disposing of gas in a period is treated as disposing of its share of the gas in the reservoir so long as the gas remaining in the reservoir is sufficient to satisfy the ownership rights of all parties to the trade. Thus, under the cumulative method, if a party who otherwise is entitled to take and dispose of fifty percent of the gas instead takes and disposes of one hundred percent of the gas during the period, that party will recognize one hundred percent of the income from the disposition of such gas.[111] Under this method, then, there is no opportunity for

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took and disposed of (the "entitlements method"). Thus, if one party who was otherwise entitled to take fifty percent of the gas produced, took one hundred percent of the gas for a period of time (the "overproduced party") and utilized the entitlements method of accounting, that party would recognize only fifty percent of the gross income on the disposition. If the other party who was entitled to the remaining fifty percent of the gas produced but took and disposed of no gas during the period (the "underproduced party") utilized the sales method of accounting, that other party would recognize no gross income on the disposition. Thus, in that situation, even though the entire gas stream was disposed of by the overproduced party, only fifty percent of the proceeds of disposition would be reported as gross income for the period. *See* I.R.S. Tech. Adv. Mem. 88-09-001 (Oct. 28, 1987), (Service ruled that the overproduced party should recognize only its proportionate share of the gross income from the disposition of the gas, even though it took and disposed of more than its proportionate interest in the gas during the period. The ruling indicates that the party who took less than its proportionate interest in the gas should recognize the remaining income).

[110] Treas. Reg. § 1.761-2(d)(2). A party's failure to comply with this requirement generally constitutes an impermissible method of accounting, requiring a change to a permissible method under section 1.446-1(e)(3) of the Regulations. *Id*.

[111] Treas. Reg. § 1.761-2(d)(3)(ii)(A). A party who over time takes and disposes of more than its percentage share of gas in the reservoir continues to recognize income on the disposition, but is entitled to a deduction in the year in which the balancing payment in cash or other property is made to the underproduced party. Treas. Reg. § 1.761-2(d)(3)(ii)(B). The party receiving such a balancing payment takes the payment into income in the year the payment is received. Treas. Reg. § 1.761-2(d)(3)(ii)(C). Operating expenses continue to be taken in accordance with the method of sharing provided in the joint operating agreement. Treas. Reg. § 1.761-2(d)(3)(ii)(D). Each party's depletion allowance and production credits are based on its gas sales not exceeding its percentage share of the total gas in the reservoir. Treas. Reg. § 1.761-2(d)(3)(iii)(A). If a party in good faith erroneously claims a depletion allowance with respect to the other party's percentage share of the gas in the reservoir, the overtaking party must reduce its deduction for the balancing payment made to the underproduced party by any percentage depletion claimed in respect of such gas. Treas. Reg. § 1.761-2(d)(3)(iii)(B). Similarly, any production credits erroneously claimed must be added back to the tax due for the taxable year in which the balancing payment is made. Treas. Reg. § 1.761-2(d)(3)(iii)(C). An anti-abuse rule is included for the cumulative method.

whipsaw. Parties who execute the new A.A.P.L. Form 610 – 2015 Model Form Joint Operating Agreement agree in Article IX thereof that any imbalances will be reported under the cumulative method.[112]

The parties instead may agree to utilize the annual method,[113] but to do so, they must request and obtain permission from the Commissioner of Internal Revenue.[114] They also must strike the standard provision in Article IX of the A.A.P.L. Form 610 – 2015 Model Form Operating Agreement providing for the use of the cumulative method and instead insert a provision for utilization of the annual method. Under the annual method, any gas imbalances must be eliminated annually through either a cash payment, gas produced under the same joint operating agreement, or other property.[115]

Parties to the joint operation can achieve the objective of recognizing ordinary depletable income only with respect to oil and gas production or production proceeds received in the taxable year by utilizing the cumulative method for dispositions of natural gas, while at the same time deferring any required balancing payments until much later in the life of the reservoir. The annual method may be utilized by the parties to address certain special business and tax related needs.[116]

F. Other Objectives

While taxpayers who elect to have the joint operation be excluded from the partnership tax rules in subchapter K take tax risks with regard to the deductibility of IDC and depreciation and with regard to incurring a tax on the assignment of interests outside of the Pool of Capital Doctrine, they do achieve certainty with regard to the interests earned and retained in the farmout transaction should the joint operation terminate under the terms of the joint operating agreement. The termination of the joint operating agreement brings no federal income tax consequences to the parties and each party continues to own the interest it earned or retained as a result of the trade.

Treas. Reg. § 1.761-2(d)(3)(iv). *See* Treas. Reg. § 1.761-2(d)(6), *ex*.4 (for a situation in which the anti-abuse rule will be invoked).

[112] *See* A.A.P.L. Form 610 – 2015, Model Form Operating Agreement, Article IX, which provides, in part, "For federal income tax purposes, the parties agree that any gas imbalances will be reported under the cumulative gas balancing method as defined in Treasury Regulation § 1.761-2(d)(3)."

[113] Treas. Reg. § 1.761-2(d)(4)(i).

[114] *Id*. (providing that rules for obtaining the consent are contained in section 1.761-2(d)(4)(ii) of the Regulations).

[115] Treas. Reg. § 1.761-2(d)(4)(i). Special rules are provided if the parties to the transaction have different taxable years. *Id*.

[116] The annual method might be desired by a producer who expects to have difficulties marketing its share of the gas in the reservoir, and who therefore would like to receive annual balancing payments from a party to the joint operation who is more likely able to market the gas.

Taxpayers who elect to have the joint operation be excluded from the partnership tax rules in subchapter K also achieve the objective of minimizing tax complexity and tax reporting for the trade, as no Form 1065 – partnership income tax return is required.

G. Using a Tax Partnership to Achieve the Expected Tax Results for the Traditional Farmout Transaction

1. Oil and Gas Tax Partnerships

The discussion in this paper so far has centered on farmout transactions in which the parties prefer to have the joint operation excluded from the application of the partnership tax rules in subchapter K of the Code. This preference may be based on a desire to avoid the complexity of administering a tax partnership and the incremental cost of preparing partnership tax returns. This discussion has pointed out, however, that there are instances in which the expected tax results of the joint operation may be adversely impacted by making the election to be excluded from subchapter K of the Code. In those instances, and as discussed below, the parties to the transaction should consider not making the section 761 election, but instead should consider having the joint operation treated as a partnership for federal income tax purposes. This can be accomplished, for example, by striking paragraph IX of the A.A.P.L. Model Form 610 Joint Operating Agreement, which is the paragraph in the joint operating agreement that makes the election to be excluded from subchapter K of the Code, and attaching as an exhibit to the joint operating agreement, an agreement that recognizes that the joint operation will be treated as a partnership for federal income tax purposes.[117]

2. A Historical Perspective on Oil and Gas Tax Partnerships

Oil and gas joint operations have been recognized as creating partnerships for federal income tax purposes for many years. In I.T. 2749, the Service recognized that the co-ownership of oil and gas leases and the undertaking of joint operations to develop those leases in circumstances where the parties either took their respective shares of production in kind and separately disposed of such production or provided for the joint marketing of such production under revocable agency powers should be treated as partnerships in a qualified sense.[118] In I.T. 2785, the Service required that a joint venture characterized as a partnership under I.T. 2749 file only a qualified partnership return, that is, a schedule attached to the Form 1065 that showed the names of the co-owners, their addresses, their percentage interest in the joint operation, the total costs and expenses billed to each owner, and the total revenues distributed to each owner in cases where there were joint sales of production.[119]

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[117] Perhaps the best-known form of tax partnership agreement in the industry is the American Petroleum Institute Model Tax Partnership Agreement (Rev. 1997), hereinafter referred to as the "API Model Agreement". The tax partnership agreement typically is attached as Exhibit G to the joint operating agreement.
[118] I.T. 2749, XIII-1 C.B. 99 (1934), *modified*, I.T. 3930, 1948-2 C.B. 126.
[119] I.T. 2785, XIII-1 C.B. 96 (1934), *modified*, I.T. 3930, 1948-2 C.B. 126.

The Service addressed joint operations conducted by oil and gas producers again in I.T. 3930.[120] In that ruling, the Service concluded that under the tax law in effect at the time, operations conducted under typical joint operating agreements generally providing for the taking in kind of oil and gas production by the parties and their separate dispositions of their shares of production resulted in qualified partnerships for federal income tax purposes, unless the agreements provided for continuity of life and centralized management.[121] In I.T. 3948, the Service clarified that the take-in-kind provision that resulted in a determination of the lack of a joint profit motive for the joint operation (key to the decision that the joint operation was a qualified partnership and not an association taxable as a corporation) still would be satisfied by joint marketing so long as the authority to jointly market was revocable by the party granting it and did not exceed the minimum needs of the industry, but in no event longer than one year.[122]

The Tax Court recognized that joint operations undertaken to explore and develop a jointly-owned oil and gas lease resulted in a partnership for federal income tax purposes in *Bentex Oil Corporation v. Commissioner*.[123] In that case, the taxpayer joined together with other co-owners of an oil and gas lease for the purposes of exploring, developing, and operating that lease. The co-owners shared income and losses in proportion to their respective interests in the joint operation. The taxpayer took the position on its income tax returns for the years 1937, 1938, and 1939 that the joint operation resulted in a partnership for federal income tax purposes, and that it was entitled to deduct its share of the IDC incurred by the joint operation (which had made an election to deduct IDC). The Service challenged the position but the controversy was resolved by a settlement in favor of the taxpayer on the issue. For the years 1944 and 1945, the taxpayer sought to capitalize the IDC incurred by the joint operation, finding that capitalization produced a more favorable result in computing its liability for excess profits taxes levied in those years. The taxpayer argued that the joint operation did not result in a partnership for federal income tax purposes, and that the election to deduct IDC made in the partnership tax returns therefore did not control. The Tax Court, however, had no difficulty in holding that the joint operations conducted for the lease resulted in a partnership for federal income tax purposes. The Service issued two significant rulings in the following year.

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[120] I.T. 3930, 1948-2 C.B. 126, *clarified*, I.T. 3948, 1949-1 C.B. 161.

[121] *Id. See, e.g.*, I.R.S. Priv. Ltr. Rul. 85-47-036 (Aug. 27, 1985) (agreement to undertake oil and gas joint operations resulted in a partnership for federal income tax purposes pursuant to I.T. 3930). The analysis in I.T. 3930 and Private Letter Ruling 8547036 was conducted under law existing at the time. *See* Regulations 111, § 29.3797-2 (1947); *see also* Treas. Reg. § 301.7701-2, T.D. 6503, 1960-2 C.B. 409. *See* Bush #1 c/o Stonestreet Lands Co. v. Comm'r, 48 T.C. 218 (1967), *acq*. 1968-2 C.B. 1 for the Tax Court's approach and analysis under then section 301.7701-2 of the Regulations. Today, the joint operation conducted pursuant to a typical joint operating agreement is considered a partnership for federal income tax purposes under the so-called "check-the-box" regulations unless the parties elect to be treated as a corporation. Treas. Reg. § 301.7701-3(b)(1)(i).

[122] I.T. 3948, 1949-1 C.B. 161.

[123] 20 T.C. 565 (1953).

First, in Revenue Ruling 54-42, the Service, following *Bentex*, ruled that the election to deduct IDC incurred by a partnership was to be made by the partnership.[124] Second, in Revenue Ruling 54-84, the Service ruled that the joint operation conducted pursuant to an agreement among the parties was to be considered a partnership for federal income tax purposes.[125] In that latter ruling, a person with capital, a lawyer, a lease superintendent, and a drilling superintendent entered into an agreement to acquire, explore and develop oil and gas properties.[126] The party with capital agreed to furnish all the tools, finance the project, and bear any losses, and in return, that party was to be reimbursed out of the income from the property for all costs and expenses incurred before the other parties shared in any profit from the operation.[127] The Service determined that the agreement did not provide for the continuity of life and centralization of management characteristic of a corporation, and so therefore the Service ruled that the joint operation was to be considered a joint venture or partnership (rather than a corporation) for federal income tax purposes.[128] Moreover, the Service ruled that the four parties to the agreement were partners in the partnership, even though only the party with capital would bear losses incurred by the partnership.[129]

Then, in 1970, the Service in Revenue Ruling 70-336 made a somewhat confusing statement in a ruling that addressed the application of the fractional interest rule in section 1.612-4 of the Regulations.[130] In that ruling, one party who owned an oil and gas lease agreed with another party for that latter party to drill a well in exchange for one hundred percent of the operating interest in the lease, subject to an overriding royalty interest retained by the owner of the lease.[131] Pursuant to the terms of the agreement, the overriding royalty interest could be converted by the owner to a fifty percent operating interest if cumulative gross production reached a specified amount.[132] When the agreement was entered into, it was uncertain whether the overriding royalty interest ever would be converted to an operating interest, that is, an interest that was responsible for bearing the costs of exploration and development of the lease and thus an interest that would share in profit and loss of the joint operation.[133] The Service stated in the ruling that: "Both parties to the transaction made the proper election for the joint venture to be excluded from the provisions of subchapter K, Chapter 1, Subtitle A of the Internal Revenue Code."[134] The Service then stated that the carrying party completed the well as a producer, and that before the carrying party could recover all of its costs of development and operation of the well, the cumulative production reached

[124] Rev. Rul. 54-42, 1954-1 C.B. 64.
[125] Rev. Rul. 54-84, 1954-1 C.B. 284.
[126] *Id.*
[127] *Id.*
[128] *Id.*
[129] *Id.*
[130] Rev. Rul. 70-336, 1970-1 C.B. at 145.
[131] *Id.* at 145.
[132] *Id.*
[133] *Id.*
[134] *Id.*

the specified amount and the carried party exercised its option to convert the overriding royalty into a fifty percent operating interest.[135]

The quoted language appears prior to presenting the fact that the cumulative production amount was reached and that the non-cost bearing royalty interest was converted into a cost-bearing working interest.[136] By where it was placed in the ruling, the quoted language possibly could be interpreted to mean that the Service concluded that the parties were partners in a partnership from the execution of the farmout agreement, and not just from the point of conversion of the overriding royalty. If the agreement had not resulted in a partnership when it was executed, no election under section 761 to be excluded from the application of the partnership tax rules in subchapter K of the Code would have been effective at that time.[137] If the agreement resulted in a partnership only after the conversion of the royalty interest, then it might have been clearer to include the quoted language after the statement of fact of conversion.

The Service made the same statement regarding whether the parties could make an election out of subchapter K of the Code in Revenue Ruling 75-446.[138] The farmout in that ruling involved a party who owned an oil and gas lease agreeing with another party for that latter party to drill and complete a well on the lease.[139] Pursuant to the terms of the farmout agreement, the party agreeing to drill and complete the well was granted one hundred percent of the operating interest in the lease until it had recovered two hundred percent of the costs of drilling, completing, and operating the well.[140] After payout, the entire operating interest in the lease reverted to the party who originally owned the lease.[141] The Service stated that: "Both parties to the transaction made the proper election under section 761(a)(2) of the Internal Revenue Code of 1954 for the joint venture to be excluded from the provisions of subchapter K, chapter 1, subtitle A of the Code . . . ."[142] In this trade, the party drilling the well owned all of the operating interest before payout, and the party who originally owned the lease owned all of the operating interest after payout, yet the Service referred to the farmout agreement as a joint venture that could elect to be excluded from the partnership tax rules in subchapter

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[135] *Id.*
[136] *Id.*
[137] *See* I.R.C. §761; Treas. Reg. § 1.761-2(a). *See supra* note 18 for a discussion of the election to be excluded from subchapter K. One explanation for the statement is that the possibility of conversion to an operating interest is sufficient to conclude that the owner of the overriding royalty interest was a partner in a partnership from the date of execution of the agreement. Alternatively, the Service may have meant that it was proper to include the election out of subchapter K in the farmout agreement, but that it was effective only when the overriding royalty was converted.
[138] Rev. Rul. 75-446, 1975-2 C.B. 95.
[139] *Id.* at 95.
[140] *Id.*
[141] *Id.*
[142] *Id.*

K of the Code.[143] The statement implies that the agreement resulted in a partnership upon its execution.

Several years later the Service took a different approach to the matter and made clear its views on when a partnership comes into existence when it published Technical Advice Memorandum 8302002.[144] In that memorandum, a party owning certain mineral claims entered into an agreement with another party under which the latter agreed to explore and develop the mineral claims.[145] The party undertaking the exploration and development work was entitled to one hundred percent of the operating interest until it had recovered all of its exploration and development expense.[146] During that period, the party owning the claims retained a five percent royalty interest.[147] Once payout had occurred, the royalty interest converted automatically into a forty-nine percent operating interest, leaving the party who had undertaken the exploration and development work with a fifty-one percent operating interest.[148] Partnership tax returns were filed by the parties for the operation.[149] Among the issues before the Service were whether the agreement resulted in a partnership, whether the special allocations in the agreement were valid, and whether any amount of exploration expenses incurred by the party undertaking the exploration had to be capitalized as mining claim acquisition costs.[150]

The Service first considered whether the agreement resulted in a partnership from the date of its execution.[151] Here, the Service examined case law on the definition of a partnership for federal income tax purposes.[152] It first examined *Commissioner v. Culbertson*[153], a case in which the Supreme Court had stated that the test for the existence of a partnership was:

> [W]hether, considering the all the facts – the agreement, the conduct of the parties in execution of its provisions, their statements, the testimony of disinterested persons, the relationship of the parties, their respective abilities and capital contributions, the actual control of income and the purposes for which it is used, and any other facts throwing light on their true intent – the parties in good faith and acting with a business purpose intended to join together in the present conduct of the enterprise.

143 *Id.*
144 I.R.S. Tech. Adv. Mem. 83-02-002 (Oct. 5, 1981).
145 *Id.*
146 I*d.*
147 *Id.*
148 *Id.*
149 *Id.*
150 *Id.*
151 *Id.*
152 *Id.*
153 Comm'r v. Culbertson, 337 U.S. 733 (1949).

The Service next considered *Luna v. Commissioner*[154], a case involving the issue of whether a lump-sum settlement payment received by an insurance agent was ordinary income or was received on the sale of an interest in a partnership. Citing *Culbertson*, the Tax Court stated that: "[T]he essential question is whether the parties intended to, and did in fact, join together for the preset conduct of an undertaking or enterprise."[155] In making its determination of whether a partnership existed between the insurance agent and the insurance company, the Tax Court considered the following factors:

> The agreement of the parties and their conduct in executing its terms; the contributions if any, which each party has made to the venture; the parties' control over income and capital and the right of each to make withdrawals, whether each party was a principal and co-proprietor, sharing a mutual proprietary interest in the net profits and having an obligation to share losses, or whether one party was the agent or employee of the other, receiving for his services contingent compensation in the form of a percentage of income; whether the business was conducted in the joint names of the parties; whether the parties filed Federal partnership returns or otherwise represented to respondent or to persons with whom they dealt that they were joint venturers; whether separate books of account were maintained for the venture; and whether the parties exercised mutual control over and assumed mutual responsibilities for the enterprise.[156]

The Service applied these factors to the exploration and development agreement and ruled that the agreement did not show intent to form a partnership from the date of its execution.[157] Key to the ruling was the conclusion that the agreement did not provide for a present sharing of profits and losses by the parties.[158] Instead, during the payout period, only the party incurring the exploration and development expenses had an interest in profit and loss, as the party owning the mining claim retained only an overriding royalty interest, which essentially was an interest in gross income, not an interest in profit.[159]

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[154] Luna v. Comm'r, 42 T.C. 1067 (1964).
[155] *Id*.
[156] *Id*. at 1077-78 (The Tax Court ultimately held that there was no evidence of a partnership for federal income tax purposes).
[157] *Id.*
[158] *Id.*
[159] *Id.* Once payout occurred, each of the parties held a working interest, which, as a cost bearing mineral interest, should be considered a present interest in profit and loss. Although the ruling did not address whether a partnership existed beginning with the post-payout period, presumably, under the *Luna* factors, the Service would rule that a partnership existed at that point. See Bruce N. Lemons & Thomas P. Briggs, *Basic Principles of Tax Partnerships for Oil and Gas Operations*, 39 Oil & Gas Tax Q. 428, 442-46 (Mar. 1991) for a discussion regarding Technical Advice Memorandum 83-02-

Revenue Ruling 70-336, Revenue Ruling 75-446, Technical Advice Memorandum 8302002, *Luna,* and *Culbertson* are important authorities to understand. If the parties to the joint operation intend to use a partnership to address tax issues that can have an adverse impact on the expected after-tax economics for the trade, then for the partnership to work as a planning tool, the agreement to conduct the joint operation must result in the existence of a partnership for federal income tax purposes at the time the issue adversely impacting the after-tax economics arises. For example, earlier in this paper, it was pointed out how failure to include a payout provision satisfying the complete payout period test might result in a portion of the otherwise deductible IDC incurred by the party providing capital to drill the well being capitalized as leasehold acquisition cost and recovered through depletion. It was also pointed out that even with a proper payout provision, if payout occurred prior to the recovery of all of the depreciation for the lease and well equipment, a portion of the remaining depreciable basis at payout might have to be capitalized as leasehold acquisition cost and recovered through depletion. Finally, it was pointed out that certain transfers of interests other than the interest in which the party providing capital to drill the well might be outside of the Pool of Capital Doctrine, and thus might cause a tax liability to both the party transferring the interests and the party receiving the interests. The adverse tax results in each of these instances can be addressed through the use of a tax partnership, as explained in *Part IV. G. 4. – Using Partnerships for Farmout Transactions Affected by Revenue Ruling 77-176* and *Part IV. G. 5. – Special Allocations for Oil and Gas Tax Partnerships, including Farmout Transactions Impacted by the Fractional Interest Rule*.

3. Organizing the Oil and Gas Tax Partnership

As mentioned earlier, when the parties to the joint operation conclude that a tax partnership can assist in achieving the after-tax economics of the trade, the parties delete the article in the joint operating agreement that provides for joint operation to elect to be excluded from the partnership tax rules in subchapter K of the Code and instead attach tax partnership provisions as an exhibit thereto.[160] When this approach is taken, the tax results of the formation of the joint operation are determined by provisions in the Code and Regulations, rather than rulings, the Pool of Capital Doctrine, and oil and gas case law. First, the party holding the oil and gas property on which a well will be drilled to earn an interest therein generally is considered to contribute the property to the partnership in exchange for an interest in the partnership. Subject to certain limitations, the contribution generally does not result in the recognition of income or gain to that party.[161] The party's basis in its partnership interest generally

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002 and its impact on whether certain oil and gas transactions result in a partnership for tax purposes.

[160] *See supra* text accompanying note 117.

[161] I.R.C. § 721(a). If the property is burdened by debt and the partnership either takes the property subject to the debt or assumes the debt, then any debt relief to the contributing partner is considered a distribution of cash that first is charged against basis and then any excess is recognized as gain. I.R.C. §§ 731(a)(1), 752(b); *see also*

is the amount of basis it had in the property at the time of contribution.[162] The party's capital account is increased by the fair market value of the property contributed to the partnership.[163] Second, the party contributing capital to drill the well generally is considered to contribute money to the partnership in exchange for an interest in the partnership. This contribution does not result in the recognition of income or gain to that party.[164] The party's basis in its partnership interest is the amount of money it contributed to the joint operation.[165] The party's capital account is increased by the amount of money contributed to the partnership.[166] The parties then are in a position to use the flexibility of subchapter K to specially allocate income, gain, loss, and deduction to achieve the intended after-tax economics of the trade.

To be sustained for federal income tax purposes, however, these special allocations must have a substantial economic effect or be in accordance with the partner's interest in the partnership.[167] The special allocation also can be sustained if the allocation is deemed in accordance with the partner's interest in the partnership, pursuant to one of the special rules contained in the section 704(b) regulations.[168]

Those regulations break down the "substantial economic effect" test into two component parts, one being the "economic effect" test[169] and the other being the "substantiality test."[170] For the allocation to have economic effect, for the full term of the partnership the partnership agreement must provide (1) for the determination and maintenance of capital accounts for the partners in accordance with certain rules,[171] (2) that upon liquidation of the partnership or of a partner's interest, liquidating distributions be made in accordance with the positive capital account balances of the partners, as determined after taking into account certain adjustments within certain periods of time,[172] and (3) that if a partner has a deficit balance in its capital account after all required adjustments have been made, the partner is unconditionally obligated to

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I.R.C. § 707 (classifying certain transactions between a partner and the partnership as a "disguised sale," depending on how the transfer is structured).

[162] I.R.C. § 722.

[163] Treas. Reg. § 1.704-1(b)(2)(iv)(b).

[164] I.R.C. § 721(a).

[165] I.R.C. § 722.

[166] Treas. Reg. § 1.704-1(b)(2)(iv)(b).

[167] *See* I.R.C. § 704(b). A detailed discussion of the section 704(b) regulations and their application to oil and gas partnerships is beyond the scope of this paper, but this topic has been well-covered by other commentators. *See*, *e.g.*, Charles H. Coffin, *et al.*, *Allocating Oil and Gas Partnership Tax Items under the Final 704(b) Regulations*, 64 J. TAX'N 222 (1986).

[168] Treas. Reg. § 1.704-1(b)(1)(i).

[169] Treas. Reg. § 1.704-1(b)(2)(ii).

[170] Treas. Reg. § 1.704-1(b)(2)(iii).

[171] Treas. Reg. § 1.704-1(b)(2)(ii)(b)(1).

[172] Treas. Reg. § 1.704-1(b)(2)(ii)(b)(2).

restore the amount of the deficit to the partnership within certain specified periods.[173] For the economic effect of the allocation to be substantial, there must be "a reasonable possibility that the allocation . . . will affect substantially the dollar amounts to be received by the partners from the partnership, independent of tax consequences."[174]

To meet the economic effect test, the API Model Agreement contains several provisions. First, it contains a general statement that the provisions contained therein are intended to comply with section 1.704-1(b) of the Regulations.[175] Second, it contains provisions for determining and maintaining appropriate capital accounts for the partners.[176] Third, it contains provisions for liquidating distributions in accordance with positive capital account balances.[177] And finally, it contains a capital account deficit makeup provision.[178] While the substantiality test must be analyzed on a case-by-case basis, the speculative nature of the drilling activities generally should provide the basis for meeting the test.[179]

4. Using Tax Partnerships for Farmout Transactions Affected by Revenue Ruling 77-176

As discussed earlier in this paper, Revenue Ruling 77-176, although its facts involved a party providing drilling services, altered the way producers analyze the after-tax economics for oil and gas trades that involve the transfer of both an operating interest in drill site acreage and an additional interest either on the same lease or in another lease in exchange for a party providing the capital to drill a well on the drill site acreage.[180] The formation of a partnership with generally nontaxable transfers of oil and gas leases and money under section 721 of the Code offers the opportunity to achieve the after-tax economics sought by the parties but altered by the limitation on the Pool of Capital Doctrine imposed by Revenue Ruling 77-176 for trades in which the joint operation intended to elect to be excluded from the partnership tax rules in subchapter K of the Code. The partnership alternative achieves the objective of not incurring a tax on the transfer of the oil and gas interests provided that the partnership is recognized from the inception of the trade.

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[173] Treas. Reg. § 1.704-1(b)(2)(ii)(b)(3). If the partnership agreement does not contain an unconditional obligation to restore deficits, the economic effect test can be met by including a "qualified income offset" described in the alternate test for economic effect in section 1.704-1(b)(2)(ii)(d) of the Regulations. Treas. Reg. § 1.704-1(b)(2)(ii)(d).
[174] Treas. Reg. § 1.704-1(b)(2)(iii)(a).
[175] API Model Agreement § 5. An example of the use of the API Model Agreement is *available at http://www.sec.gov/Archives/edgar/containers/fix290/1397516/09/000119312509136182/dex102.htm*.
[176] API Model Agreement §§ 5.1, 5.2.
[177] *Id*. at § 7.7.
[178] *Id*. at § 7.4.
[179] Treas. Reg. § 1.704-1(b)(5), *ex*. 19(ii).
[180] *See supra Part IV. D. - Limitations on the Pool of Capital Doctrine in the Farmout Transaction*.

Farmout transactions involving the transfer of interests outside of the drill site acreage should be recognized as partnerships from the inception of the transaction so long as at the time the trade is entered into, there is some partnership property in which the partners share an interest in profits and losses. Consider, for example, a farmout transaction structured like the one in Revenue Ruling 77-176.[181] Although the party originally owning the oil and gas lease retains a convertible overriding royalty interest in the drill site acreage, it also retains a fifty percent working interest in the remaining acreage in the lease outside of the drill site. The fifty percent working interest in the remaining acreage held by each party is a cost-bearing interest, and with that interest, both parties to the trade should be considered to have a present interest in profit and loss.[182] With a partnership, the effective transfers of operating interests in the oil and gas properties subject to the trade are analyzed under section 721 of the Code, rather than the property-by-property application of the Pool of Capital Doctrine as in Revenue Ruling 77-176. Accordingly, in instances where the partnership is recognized from the inception of the farmout transaction, the income and gain recognition concerns raised by Revenue Ruling 77-176 should not be present.

It may be slightly more difficult to reach a conclusion that a farmout transaction structured with the assignment of a one hundred percent operating interest in the drill site acreage through payout (with a reversionary working interest to the party owning the oil and gas leases involved in the trade) and an option to drill one or more wells on additional tracts to earn operating interests in those tracts should be considered a partnership for federal income tax purposes from the inception of the trade. If this trade is analyzed under the test applied by the Service in Technical Advice Memorandum 8302002, the result may depend on whether there is any initial acreage in which the parties to the trade share an interest in profit and loss. Here, the argument has to be that, contrary to position taken in the technical advice memorandum, the retained reversionary working interest in each tract is a sufficient initial interest in profit and loss. Producers who are uncomfortable with this argument can consider altering the "continuous drilling" trade slightly to provide for a more certain present interest in profit and loss.

Provided that the joint operation is considered a partnership from its inception, the parties then must use special allocations of IDC, depreciation, depletion, operating expense, and gain or loss to achieve the expected tax results for the joint operation, as discussed in the next section below.

5. Special Allocations for Oil and Gas Tax Partnerships, including Farmout Transactions Impacted by the Fractional Interest Rule

[181] *See supra* text accompanying note 89.

[182] *But see* I.R.S. Tech. Adv. Mem. 83-02-002 (addressing a mineral transaction with what must have been a single section 614 property in which the transferor retained only a convertible overriding royalty interest, which overriding royalty interest would not be considered a present interest in profit and loss because the interest is a non-cost bearing interest). *Supra* note 144.

As discussed earlier in this paper, the Service's position is that the fractional interest rule in section 1.612-4 of the Regulations can limit the deductibility of IDC and depreciation in instances where the trade does not have a payout provision or has a payout provision that does not meet the complete payout period test.[183] And, even where the trade does contain a payout provision that meets the complete payout period test, the Service's position is that a portion of the remaining depreciable basis for the lease and well equipment could have be capitalized as leasehold acquisition cost and recovered through depletion, if payout occurs prior to the running of the MACRS cost recovery period for the equipment. The formation of a partnership that contains special allocations of ordinary depletable income to each party who is entitled to the proceeds from oil and gas production and special allocations of IDC, depreciation and operating expense deductions to the party who provides the capital to pay for expenditures for drilling costs, lease and well equipment, and operating expenses, and special allocations of the depletable basis to the party who provides the oil and gas lease offers the opportunity for the parties to achieve their respective objectives of recognizing income and deducting the IDC, depreciation on the lease and well equipment, operating expenditures, and cost depletion. And, once a decision is made to use a tax partnership as an alternative for a trade affected by the limitation on the Pool of Capital Doctrine imposed by Revenue Ruling 77-176, the partnership will have to make those same special allocations to achieve the expected after-tax economics for the trade.

To achieve the objective regarding the recognition of ordinary depletable income, the API Model Agreement provides for the special allocation of actual or deemed income from the sale or other disposition of oil and gas production for capital account and income tax purposes as follows: "Actual or deemed income from the sale, exchange, distribution or other disposition of production shall be allocated to the Party entitled to such production or the proceeds from the sale of such production."[184] Thus, in a farmout transaction in which a party provides the capital to drill, equip, and operate

[183] *See supra Part IV. A. - The Fractional Interest Rule*. Thus, the tax partnership can be used in a promoted transaction where, for example, a party pays one-third of the costs of a well to earn a one-quarter interest in the oil and gas lease, with no payout provision, as well as a transaction in which the reduction of working interest assigned to the party providing the capital to drill the well occurs prior to the complete payout period. *See, e.g.*, Rev. Rul. 70-336, *supra* note 31.

[184] API Model Agreement § 6.1.1 (allocations for capital account purposes). The API Model Agreement provides that unless otherwise provided, allocations for tax return purposes follow the principles of the allocations made under section 6.1. *Id.* at § 6.2.1 (allocations for income tax purposes). Deemed income may arise for capital account purposes with regard to oil and gas production taken in kind by the parties. The production would be deemed sold for its fair market value on the date the production was distributed by the partnership to the partners (that is, taken in kind by the partners). Treas. Reg. § 1.704-1(b)(2)(iv)(e)(1). Deemed income would be added to each taking-in-kind partner's capital account. *Id.* The fair market value of the distributed production would be subtracted from such party's capital account. Treas. Reg. § 1.704-1(b)(2)(iv)(b). Because these entries would offset, tax partnerships may not show the offsetting entries in the capital accounts. *Id.* at § 6.1.1.

a well and is entitled, either under a payout provision or otherwise, to take an amount of oil and gas production or proceeds from the sale of such production that is disproportionate to its permanent working interest percentage, the tax partnership allocates the actual or deemed income from the sale of oil and gas production to the party who is entitled to the proceeds of such production. Similarly, in a farmout transaction in which one party takes and sells an amount of gas production that is disproportionate to its permanent working interest percentage, the tax partnership allocates the income from the sale of such gas production to the party who is entitled to the proceeds of such production. With this allocation, income is recognized by the parties who expected to recognize such income in realizing the expected tax results for the farmout transaction.

To achieve the objective regarding IDC, depreciation, and operating expense deductions, the API Model Agreement provides for the special allocation of IDC and operating costs for capital account and income tax purposes as follows: "Exploration cost, IDC, operating and maintenance cost shall be allocated to each Party in accordance with its respective contribution, or obligation to contribute, to such cost."[185] Similarly, the API Model Agreement provides for the special allocation of depreciation for capital account and income tax purposes as follows: "Depreciation shall be allocated to each Party in accordance with its contribution, or obligation to contribute, to the cost of the underlying asset."[186] Thus, in a trade in which a party provides the capital to drill, equip and operate a well in exchange for an interest in the oil and gas lease and the API Model Agreement is attached as an exhibit, the tax partnership allocates the IDC, depreciation, and operating expense deductions to the party who provides such capital. In this situation, there is no application of the fractional interest rule to the trade. Most importantly, the IDC, depreciation, and operating expense deductions are deducted by the parties who expected to take those deductions in realizing the expected after-tax economics for the trade.

As mentioned earlier in this paper, each party who has invested in the working interest in the oil and gas lease involved in the farmout transaction will expect to receive its pro rata share of the depletable tax basis in that property for purposes of computing its cost depletion deduction.[187] This objective can be met in the partnership alternative by having the tax partnership allocate the depletable tax basis in the property to the party who contributed that property to the partnership. This allocation is made possible by section 613A(c)(7)(D) of the Code, which, because of the possibility that one or more partners in a partnership still may qualify for limited amounts of percentage depletion, while one or more other partners will not,[188] provides that the depletion allowance and

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[185] *Id.* at §§ 6.1.2 (allocations for capital account purposes), 6.2.1 (allocations for income tax purposes).
[186] *Id*. at §§ 6.1.3 (allocations for capital account purposes), 6.2.1 (allocations for income tax purposes).
[187] *See supra* notes 14 - 16 and accompanying text.
[188] *See supra* note 16 and accompanying text.

gain or loss on disposition on the oil and gas property are computed separately be each partner, and not by the partnership.[189]

More importantly, the allocation of depletable basis to the contributing partner, which may not necessarily be viewed in accordance with the partner's interest in capital or income, works because of section 1.704-1(b)(4)(v) of the Regulations, which addresses allocations made under section 613A(c)(7)(D) of the Code and allows such an allocation to be made.[190] Accordingly, to achieve this objective, the API Model Agreement provides that: "The Parties recognize that under Code § 613A(c)(7)(D) the depletion allowance is to be computed separately by each Party. For this purpose,

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[189] I.R.C. § 613A(c)(7)(D) provides in part that:

> In the case of a partnership, the depletion allowance shall be computed separately by the partners and not by the partnership. The partnership shall allocate to each partner his proportionate share of the adjusted basis of each partnership oil and gas property. . . . A partner's proportionate share of the adjusted basis of partnership property shall be determined in accordance with his interest in partnership capital or income and, in the case of property contributed to the partnership by a partner, section 704(c) (relating to contributed property) shall apply in determining such share. Each partner shall separately keep records of his share of the adjusted basis in each oil and gas property of the partnership, adjust such share of the adjusted basis for any depletion taken on such property, and use such adjusted basis each year in the computation of his cost depletion or in the computation of his gain or loss on the disposition of such property by the partnership.

I.R.C. § 613A(c)(7)(D); *See also* Treas. Reg. § 1.613A-3(e). Once the depletable basis is allocated back to the partner contributing the oil and gas property, that partner computes cost depletion for income tax purposes on that basis.

[190] Treas. Reg. § 1.704-1(b)(4)(v) provides in part that:

> Allocations of the adjusted tax basis of a partnership oil and gas property are controlled by section 613A(c)(7)(D) and the regulations thereunder. However, if the partnership agreement provides for an allocation of the adjusted tax basis of an oil or gas property among the partners, and such allocation is not otherwise governed under section 704(c), . . . that allocation will be recognized as being in accordance with the partners' interests in partnership capital under section 613A(c)(7)(D), provided (a) such allocation does not give rise to capital account adjustments under paragraph (b)(2)(iv)(k) of this section the economic effect of which is insubstantial . . . , and (b) all other material allocations and capital account adjustments under the partnership agreement are recognized under this paragraph (b).

Treas. Reg. § 1.704-1(b)(4)(v).

each Party's share of the adjusted tax basis in each oil and gas property shall be equal to its contribution to the adjusted tax basis of such property."[191] In conjunction with this allocation, and in order to comply with the capital account rules, the API Model Agreement provides that:

> Solely for FMV capital account purposes, depletion shall be calculated by using simulated cost depletion within the meaning of Treas. Reg. § 1.704-1(b)(2)(iv)(k)(2), unless the use of simulated percentage depletion is elected in Sec. 9.2 below. The simulated cost depletion shall be determined under the principles of Code § 612 and be based on the FMV capital account basis of each Lease.[192]

Finally, the API Model Agreement provides that: "Simulated depletion shall be allocated to each Party in accordance with its FMV capital account adjusted basis in each oil and gas property of the Partnership."[193] Thus, through the combined operation of these provisions in the tax partnership agreement, the party who invested in the working interest in the oil and gas lease involved in the trade should receive all of the depletable tax basis in that property for purposes of computing its cost depletion deduction.

As mentioned earlier in this paper, each party who holds an interest in an oil and gas property or who earns such an interest as a result of the farmout transaction will expect to be entitled to no less than that interest if and when the farmout and joint operation terminates. In the partnership alternative, with special allocations of IDC, depreciation, depletion and operating expense, the capital account balances of the parties quickly can become disproportionate to the intended ownership interests in the oil and gas property.[194] To meet the objective regarding ownership interests as closely as possible, the API Model Agreement allocates loss, whether on the disposition of the oil and gas property and lease and well equipment, or on the revaluation of the property and equipment[195], for capital account purposes, as follows: "Loss (or simulated loss)

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[191] API Model Agreement § 6.2.2.

[192] *Id*. at § 4.2. Despite section 613A(c)(7)(D), for purposes of maintaining capital accounts for the parties, depletion is computed at the partnership level and therefore is referred to as "simulated" depletion. Treas. Reg. § 1.704-1(b)(2)(iv)(k)(2). Either the simulated cost depletion method or the simulated percentage depletion method can be used by the partnership. *Id*.

[193] API Model Agreement § 6.1.4. This allocation is required by section 1.704-1(b)(2)(iv)(k)(2) of the Regulations.

[194] For example, a party providing the capital to drill a well to earn an interest would have its capital account increased by the money contributed to the partnership and decreased by the IDC allocated to it under the partnership agreement. If all of the money contributed were to be used to pay for IDC, that party would have a zero capital account balance at that point in time, even though it had earned an interest in the oil and gas property included in the tax partnership.

[195] *See* Treas. Reg. § 1.704-1(b)(2)(iv)(f) for the rules regarding the revaluation of partnership property in certain instances and the booking of the deemed gain or loss on

upon the sale, exchange, distribution, abandonment or other disposition of depreciable or depletable property shall be allocated to the Parties in the ratio of their respective FMV capital account adjusted bases in the depreciable or depletable property."[196] The API Model Agreement allocates gain on these assets for capital account purposes as follows: "Gain (or simulated gain) upon the sale, exchange, distribution, or other disposition of depreciable or depletable property shall be allocated to the Parties so that the FMV capital account balances of the Parties will most closely reflect their respective percentage or fractional interests under the Agreement."[197] Thus, each time gain or loss is recognized for capital account purposes, the gain or loss is allocated between the parties in a manner that attempts to keep the capital account balances in line with expected ownership interests.

Recall that gain or loss on the actual disposition of an oil and gas property for tax purposes is computed separately by each partner.[198] To address this computation in the context of the capital account balancing allocation for an actual disposition on liquidation, the API Model Agreement provides that:

> Under Code §613A(c)(7)(D) gain or loss on the disposition of an oil and gas property is to be computed separately by each party. According to Treas. Reg. §1.704-1(b)(4)(v), the amount realized shall be allocated as follows: (i) An amount that represents recovery of adjusted simulated depletion basis is allocated (without being credited to the capital accounts) to the parties in the same proportion as the aggregate simulated depletion basis was allocated to such Parties under Sec. 5.2; and (ii) any remaining realization is allocated in accordance with Sec. 6.1.6.[199]

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the revaluation into the partners' capital accounts. Under these rules, for example, deemed gain or loss would be determined and booked into the partners' capital accounts just prior to distributions in liquidation of the joint operation. Treas. Reg. § 1.704-1(b)(2)(iv)(f)(5)(ii).

[196] API Model Agreement § 6.1.5.

[197] *Id*. at § 6.1.6. Despite the provisions of section 613A(c)(7)(D) of the Code, for purposes of maintaining capital accounts for the parties, gain or loss on the disposition of a partnership oil and gas property is computed at the partnership level and therefore is referred to as "simulated gain or loss". Treas. Reg. § 1.704-1(b)(2)(iv)(k)(2). Rules for increasing the parties' capital accounts for their shares of simulated gain and decreasing their capital accounts for their shares of simulated loss also are provided in section 1.704-1(b)(2)(iv)(k)(2) of the Regulations.

[198] I.R.C. § 613A(c)(7)(D); Treas. Reg. § 1.613A-3(e). *See supra* text accompanying note 189.

[199] API Model Agreement § 6.2.3. In accordance with section 613A(c)(7)(D), for purposes of determining each partner's gain or loss on the disposition of a partnership oil and gas property, amount realized is allocated by the partnership to the partners, except to the extent governed by section 704(c). Treas. Reg. § 1.704-1(b)(4)(v). Generally, amount realized first is allocated to the partner or partners who have simulated basis in the oil and gas property in the amount of that simulated basis. Amounts in excess of simulated basis can be allocated as determined in the partnership

The mechanics of the capital account balancing allocations can be demonstrated through a simple example. Assume that the lease has a fair market value equal to its tax basis on the date of contribution to the partnership. Assume further that the party providing the capital to drill the well has a zero capital account (because of a prior special allocation of the IDC deduction) and the party providing the oil and gas lease has a capital account balance of fifty dollars just prior to the sale of the oil and gas property. Per the terms of the trade, each party expects that it owns fifty percent of the oil and gas lease after the drilling obligation was completed. Assume further that the party providing the oil and gas lease has remaining simulated depletion basis in the property of fifty dollars and remaining depletable basis in the property of fifty dollars. The joint operation is assumed to terminate per the terms of the joint operating agreement and distributions in kind in liquidation of the partners' capital accounts are to be made to the partners. Finally, assume that the property has a fair market value of two hundred dollars just prior to its distribution.

To put the parties' capital account balances in as close to proportion to their expected ownership interests as possible, the one hundred fifty dollar simulated gain on the deemed disposition upon revaluation under section 1.704-1(b)(2)(iv)(f) is allocated one hundred dollars to the drilling party and fifty dollars to the party providing the oil and gas lease.[200] After this allocation, each party's capital account balance is one hundred dollars. In this example, there is sufficient gain for capital account purposes to bring the parties' capital accounts into proportion with their expected ownership interests.

There may be instances, however, in which the gain or loss for capital account purposes is insufficient to achieve this objective. In such case, the API Model Agreement provides that prior to making liquidating distributions to the parties, a party who has a capital account balance that is proportionately less than its expected ownership interest may contribute cash to the partnership to achieve a proportionate capital account balance.[201] This provision and the gain and loss allocation provision

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agreement, provided that such allocation does not give rise to an allocation that is insubstantial and that all other allocations are recognized under section 1.704-1(b). *Id*.

[200] API Model Agreement §§ 7.2, 7.3. The deemed gain is computed as the excess of the $200 assumed fair market value over the $50 assumed simulated depletion basis of the property. Had there been an actual sale of the property for its fair market value of $200, the amount realized of $200 would be allocated to the parties as follows: (i) fifty dollars to the party providing the lease in accordance with that party's remaining simulated depletion basis in the property, and (ii) one hundred dollars to the drilling party and fifty dollars to the party providing the lease in accordance with the gain allocated for capital account purposes. *Id.* at § 6.2.3. As a result, the drilling party would realize one hundred dollars of gain on its disposition of its interest in the oil and gas property (amount realized of one hundred dollars less tax basis of zero in the property) while the party contributing the oil and gas lease would realize fifty dollars of gain on its disposition of its interest in the property (amount realized of one hundred dollars less tax basis of fifty dollars in the property).

[201] *Id*. at § 7.4.

thus provide the means by which a party providing capital to drill the well can achieve its objective of retaining the working interests earned in the trade.

An oil and gas property contributed to the partnership may have a fair market value either in excess of or less than the tax basis of the property on the date of contribution. In such case, the precontribution gain or loss must be allocated to the party who contributed that property to the partnership.[202] The API Model Agreement deals with section 704(c) as follows: "However, the Partnership's gain or loss on the taxable disposition of a Partnership property in excess of the gain or loss under Sec. 6.1, if any, is allocated to the contributing Party to the extent of such Party's precontribution gain or loss."[203]

The Service addressed a 1995 version of the API Model Agreement in Private Letter Ruling 9540034.[204] In that ruling, the Service considered a farmout transaction which was structured substantially similar to the trade in Revenue Ruling 77-176.[205] The trade agreement did not elect to have the joint operation excluded from the partnership tax rules in subchapter K of the Code, and instead attached the pre-1997 version of the API Model Tax Partnership Agreement.[206] The Service concluded that the provisions in the tax partnership agreement met the three requirements for the economic effect test in section 1.704-1(b)(2)(ii)(b).[207] Moreover, the Service concluded that given the speculative nature of the oil and gas joint operations, there was a reasonable possibility that the allocations provided for in the agreement would affect substantially the dollar amounts to be received by the partners, independent of tax consequences, and thus the allocations met the substantiality test in section 1.704-1(b)(2)(iii).[208] Therefore, the Service ruled that the allocations of income, gain, loss and deduction provided for in the tax partnership agreement had substantial economic effect within the meaning of section 704(b) of the Code.[209] The Service also concluded that since (a) no tax basis in the contributed oil and gas property was allocated to a party who did not contribute to the cost of the property, (b) no simulated depletion was allocated to such a party, and (c) any gain recognized on the disposition of the contributed oil and gas property would be recognized by the contributing partner to the

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[202] I.R.C. § 704(c); Treas. Reg. § 1.704-3.

[203] API Model Agreement § 6.2.1. The gain or loss under section 6.1 is the gain or loss for capital account purposes. *Id.* § 6.1. An in-depth discussion of section 704(c) as it relates to oil and gas properties and tax partnerships is beyond the scope of this paper, but this topic has been well-covered by the commentators. *See*, *e.g.*, Barksdale Pennick & Gary Huffman, *The Taxation of Oil and Gas Partnerships*, 2005 Tax Notes Today 181-36 (2005).

[204] I.R.S. Priv. Ltr. Rul. 95-40-034 (July 5, 1995). The 1995 version contained provisions substantially similar to those in API Model Agreement §§ 5, 5.1, 5.2, 7.7, and 7.4.

[205] I.R.S. Priv. Ltr. Rul. 95-40-034 (July 5, 1995). *See supra* text accompanying note 89.

[206] *Id*.

[207] *Id.*

[208] *Id*.

[209] *Id*.

extent of the section 704(c) built-in gain, the method of making section 704(c) allocations was reasonable given the facts and circumstances.[210] Therefore, the Service ruled that the allocations of income, gain, loss, and deduction provided for in the tax partnership agreement constituted a reasonable method for making section 704(c) allocations under section 1.704-3 of the Regulations.[211]

Although the private letter ruling cannot be relied upon by taxpayers other than to whom the ruling was granted, parties using the API Model Agreement as the tax partnership agreement for their farmout and joint operation should be reasonably comfortable that the tax partnership agreement contains the necessary provisions to sustain the allocations of income, IDC, depreciation, depletion, operating costs, and section 704(c) gain or loss, if any.[212]

V. A Description of Joint Operations in the "Cash and Carry" Farmout Transaction

The "cash and carry" farmout transaction has been used in one form or another for many years, but it began to come back into vogue in early 2009 at a time when crude oil and natural gas prices were falling in connection with the global financial crisis. Falling prices for U.S. producers meant reduced cash flows at a time when many of those producers, who had just spent significant sums on acquiring prospective oil and gas properties in shale resource plays such as the Haynesville Shale, the Bakken Shale, the Barnett Shale, and the Eagle Ford Shale, faced extensive drilling obligations on those properties in order to maintain the mineral leases.[213] Meanwhile, bank credit facility borrowing bases were shrinking as oil and gas property values declined, and other sources of traditional debt capital were becoming scarce. Producers needed to act quickly to raise cash to shore up their balance sheets and help meet future drilling obligations.

Given the lack of alternatives, many of these producers returned to the "cash and carry" farmout transaction. In this variation of the farmout transaction, the producer with the oil and gas properties in need of drilling capital seeks out another oil and gas company with a stronger balance sheet and an interest in entering the shale resource play.[214] The parties typically enter into an oil and gas property purchase and sale

[210] *Id.*
[211] *Id*. See also I.R.S. Priv. Ltr. Rul. 2005-30-013 (July 29, 2005) (ruling that partnership allocation provisions similar to those contained in sections 6.1.4, 6.1.5, 6.1.6, 6.2.1, and 6.2.3 of the API Model Agreement had economic effect for purposes of section 1.704-1(b)(2)(ii) of the Regulations and that the allocation provisions were an acceptable method for making allocations under section 704(c) of the Code).
[212] *See generally* API Model Agreement.
[213] Oil and gas leases contain a primary term at the end of which the lessee must begin drilling a well or the lease will terminate. *See* HEMINGWAY OIL AND GAS LAW AND TAXATION § 6.3 (4th ed. 2004).
[214] *See generally* I.R.M. 4.41.1.2.4.8.5 (2013).

agreement and a joint development agreement to execute the transaction.[215] Pursuant to the purchase and sale agreement, the purchasing party agrees to pay a specified amount of cash to the producer in return for the producer's conveyance to the purchaser of a specified working interest in the subject oil and gas properties.[216]

The purchase and sale agreement may also impose certain restrictions on the use of proceeds received by the producer, so that the purchaser obtains some comfort that the producer can meet future obligations. In the joint development agreement, the purchasing party typically agrees to pay the costs of drilling one or more wells on the acquired properties while carrying the producer's working interest share of those costs.[217] However, there is usually no "complete payout" provision included in the joint development agreement. Many of the joint development agreements for these transactions provide for a specified dollar amount, including the amount of the carry, to be expended by the purchaser on the properties over a specified period of time. To summarize, unlike the traditional farmout transaction described earlier in this paper, the cash and carry farmout transaction involves a cash payment from the farmee to the farmor, the assignment of the working interest is made prior to farmee incurring costs to drill one or more wells pursuant to the "carry" provisions, and the carry by farmee of farmor's share of future costs of drilling and development usually extends beyond just the costs of the "earning" well.

VI. Federal Income Tax Rules Impacting the Tax Results for the Parties to the "Cash and Carry" Farmout Transaction

A. Tax Inefficiencies in the "Cash and Carry" Transaction

[215] The purchase and sale agreement conveys ownership of an agreed working interest in the subject oil and gas properties to the purchaser at closing. In this regard, the "cash and carry" farmout out transaction differs from the traditional farmout transaction in that in the latter, no assignment of a working interest in the oil and gas property is made by the farmor to the farmee unless and until the farmee satisfies the requirements for earning an interest in the property.

[216] *See*, for example, section 2.1 of the Purchase and Sale Agreement by and between Exco Operating Company, LP and Exco Production Company, LP (as Seller) and BG US Production Company, LLC (as Buyer), executed on June 29, 2009 but effective as of January 1, 2009 and form of Joint Development Agreement by and between BG US Production Company, LLC, Exco Operating Company, LP and Exco Production Company, LP. The joint development agreement as executed was attached to Exco Resources, Inc. Form 8-K, filed August 17, 2009. The purchase and sale agreement is available at http://www.sec.gov/Archives/edgar/data/316300/000119312509167033/dex25.htm. The joint development agreement is available at http://www.sec.gov/Archives/edgar/data/316300/000119312509176863/dex101.htm.

[217] See, for example, section 2.1 of the Joint Development Agreement by and between BG US Production Company, LLC, Exco Operating Company, LP and Exco Production Company, LP, *supra* note 216.

Both aspects of the "cash and carry" transaction described above can lead to inefficient federal income tax results for both parties to the transaction. As to the "cash" component, the seller of the specified working interest in the subject oil and gas properties typically would recognize gain or loss on the disposition of the working interest in the properties and any lease and well equipment conveyed to the purchaser in the transaction.[218] Gain or loss on the disposition of the working interest in the properties would be measured by the difference of the cash consideration allocated to the properties in the purchase and sale agreement and the properties' adjusted tax basis.[219] If certain holding period and other requirements were met, the gain could be considered a capital gain, subject to the ordinary income recapture rules for prior depletion deductions, if any, and IDC deductions attributable to the subject properties.[220] Any loss on the disposition could be considered an ordinary loss, depending on the tax position of the seller.[221] Similarly, gain or loss on the disposition of the interest in any lease and well equipment included in the disposition would be measured by the difference of the cash consideration allocated to the equipment in the purchase and sale agreement and the equipment's adjusted tax basis.[222] Again, if certain holding period and other requirements were met, the gain could be considered a capital gain, subject to the ordinary income recapture rules for prior depreciation deductions attributable to the equipment.[223] And, any loss on the disposition of an

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[218] Since the seller conveys an undivided working interest in the subject oil and gas properties and does not retain an overriding royalty interest in that property, the disposition is treated as a sale transaction for federal income tax purposes rather than a subleasing transaction. *See* Cox v. United States, 497 F. 2d (4th Cir. 1974).

[219] I.R.C. § 1001(a). The cash consideration allocated to the properties in the purchase and sale agreement would be considered the "amount realized" for purposes of section 1001. It is likely that the purchase and sale agreement would contain a provision allocating the cash consideration among the oil and gas properties and the lease and well equipment involved in the transaction in accordance with section 1060 of the Code.

[220] Working interests in oil and gas properties are considered real property used in a trade or business for purposes of section 1231(b)(1) of the Code. *See* Rev. Rul. 68-226, 1968-1 C.B. 362. Provided that the working interests have been held for more than one year, the gain on the sale of the working interests can qualify as section 1231 gain pursuant to section 1231(a)(3)(A) and can be considered capital gain if the seller's section 1231 gains for the year exceed its section 1231 losses pursuant to section 1231(a)(1). But see I.R.C. § 1231(c) for rules providing for recharacterization of such capital gain as ordinary income to recapture previous "non-recaptured net section 1231 losses". See I.R.C. § 1254 for the rules for determining the amount of ordinary income recapture for depletion and IDC previously deducted with respect to the property.

[221] I.R.C. § 1231(a)(2).

[222] I.R.C. § 1001(a). The cash consideration allocated to the lease and well equipment in the purchase and sale agreement would be considered the "amount realized" for purposes of section 1001.

[223] *See* I.R.C. § 1231(a) – (c). Lease and well equipment on oil and gas properties is considered property used in a trade or business for purposes of section 1231(b)(1) of the Code. Provided that the equipment has been held for more than one year, the gain

interest in any lease and well equipment included in the disposition could be considered an ordinary loss, depending on the tax position of the seller.[224]

From the purchaser's perspective, the amount of cash consideration allocated in the purchase and sale agreement to the working interest in the acquired oil and gas properties will be considered the basis of the oil and gas properties[225] and will be recovered through depletion (cost or percentage, depending on the circumstances) as oil and gas are produced.[226] Amounts allocated to lease and well equipment will be considered the basis of the lease and well equipment[227] and will be recovered through depreciation generally as seven-year MACRS property.[228] Unless the anticipated oil and gas reserves are very short-lived with an anticipated steep decline curve, the purchaser will allocate as much of the cash payment as is supportable under the facts to the equipment, given its faster tax recovery.[229]

As to the "carry" component, as discussed earlier in this paper, in the absence of a complete payout provision, the fractional interest rule in section 1.612-4(a) of the Regulations limits the purchaser's IDC deduction to IDC attributable to the purchaser's working interest.[230] IDC and tangible lease and well equipment expenditures paid for by the purchaser but attributable to the seller's retained working interest are capitalized and recovered through depletion,[231] resulting in a delayed recovery of such expenditures relative to the tax recovery for IDC.[232]

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on the sale of the equipment can qualify as section 1231 gain pursuant to section 1231(a)(3)(A) and can be considered capital gain if the seller's section 1231 gains for the year exceed its section 1231 losses pursuant to section 1231(a)(1). But see I.R.C. § 1231(c) for rules providing for recharacterization of such capital gain as ordinary income to recapture previous "non-recaptured net section 1231 losses". See I.R.C. § 1245 for the rules for determining the amount of ordinary income recapture for depreciation previously deducted with respect to the equipment.

[224] I.R.C. § 1231(a)(2).

[225] I.R.C. § 1012.

[226] *See* I.R.C. § 612 regarding the basis for cost depletion and I.R.C. § 611 for the allowance of depletion with respect to production from oil and gas properties. See I.R.C. § 613 and I.R.C. § 613A for rules regarding the determination of percentage depletion.

[227] I.R.C. § 1012.

[228] I.R.C. §§ 167, 168.

[229]Purchaser will compare the net present value of amounts recovered through cost depletion pursuant to section 611 of the Code with the net present value of amounts recovered under section 168 of the Code for seven-year MACRS property. As stated in the text, unless the oil and gas reserves have a short life and a steep decline curve, the net present value of amounts recovered under section 168 of the Code generally will exceed the net present value of the cost depletion deduction.

[230] Treas. Reg. §1.612-4. *See supra* text accompanying notes 19 – 47.

[231] *See supra Part IV. A. - The Fractional Interest Rule* and note 20.

[232] The assumption at this point is that the parties have elected under section 761 of the Code to be excluded from the application of subchapter K. I.R.C. § 761(a). In *Part VI. B.*

B. Using a Tax Partnership to Enhance the Tax Results for the "Cash and Carry" Farmout Transaction

The parties to the "cash and carry" farmout transaction can enhance the expected tax results by having the "cash and carry" farmout transaction treated as a partnership for federal income tax purposes. This can be achieved by not including an election to be excluded from subchapter K of the Code in the joint development agreement but providing instead that the parties intend that the joint exploration, development and production operations be considered a partnership for federal income tax purposes. Partnership tax provisions similar to those found in the API Model Agreement can be included in the joint development agreement, or the API Model Agreement simply can be referenced in the body of the joint development agreement and attached thereto. Typically, the joint development agreement will contain provisions to the effect that the parties intend that the execution of the purchase and sale agreement and the joint development agreement, taken together, are to be characterized as (1) a contribution by the seller of its working interest in the subject oil and gas properties to the partnership, (2) a contribution to the partnership of the amount of cash paid by the purchaser pursuant to the purchase and sale agreement, (3) an agreement by the purchaser to contribute additional cash to the partnership in the amount of the total carry, and (4) a distribution of the initial cash received by the partnership to seller as a reimbursement, in whole or in part, of seller's expenditures incurred to acquire and develop the working interests in the subject oil and gas properties during the two-year period prior to the contribution of the properties to the partnership.[233]

The expected tax results for the "cash and carry" farmout transaction change significantly if the partnership tax rules are brought into play. First, seller's contribution of the working interest in the oil and gas properties to the partnership and purchaser's contribution of cash to the partnership can be made without incurring federal income tax on either contribution.[234] Second, the IDC deductions paid for by purchaser's agreement to contribute additional cash in the amount of the total carry can be specially allocated one hundred percent to purchaser so that the entire amount of IDC incurred during the carry is deductible as IDC, not just the amount attributable to purchaser's working interest.[235] And, all depreciation deductions from lease and well equipment acquired with cash contributed to the partnership to meet the carry can be specially

– *Using a Tax Partnership to Enhance the Tax Results for the "Cash and Carry" Farmout Transaction*, the benefit of instead treating the operations conducted pursuant to the joint development agreement as a partnership for U.S. federal income tax purposes under section 761 of the Code is demonstrated.

[233] *See*, for example, section 10.1 of the Joint Development Agreement by and between BG US Production Company, LLC, Exco Operating Company, LP and Exco Production Company, LP, *supra* note 216. Section 10.1 provides that the tax partnership provisions are included in Exhibit G to the Joint Development Agreement. *Id.*

[234] I.R.C. § 721.

[235] *See supra* note 185 and accompanying text.

allocated by the partnership provisions to purchaser as immediate deductions rather than only the depreciation attributable to purchaser's working interest.[236]

Finally, to the extent that the seller has incurred qualifying preformation expenditures, the reimbursement of those expenditures can be made without incurring federal income tax on what otherwise might be considered a "disguised sale" under the rules contained in section 707 of the Code and the Regulations promulgated thereunder.[237] Thus, the partnership tax rules in subchapter K of the Code present an opportunity in appropriate circumstances to mitigate the recognition of gain that otherwise would be recognized if the joint development agreement is not characterized as a partnership for federal income tax purposes.

The tax efficiencies of treating the operations conducted pursuant to the joint development agreement as a partnership for federal income tax purposes can be demonstrated through the following example. Suppose that seller owns one hundred percent of the working interest in a ten thousand acre oil and gas lease that has not been developed and that the lease was acquired eighteen months ago. Suppose further that: (1) the fair market value of the working interest in the entire lease is $100 million and that seller's capital costs to acquire the lease are $25 million; (2) seller's adjusted tax basis in the lease is $25 million; (3) seller has $25 million of qualifying section 707(a)(2)(B) preformation expenditures[238]; and (4) purchaser has agreed to pay $50 million to seller and to pay 100 percent of the future joint drilling and development costs on the property until $60 million has been expended in exchange for seller conveying a fifty percent working interest in the lease to purchaser. Finally, suppose that the joint development agreement includes a provision indicating that the seller and purchaser intend for the effect of the purchase and sale agreement and the joint development agreement to be that a partnership has been organized for federal income tax purposes.

Pursuant to section 707 of the Code, this transaction will be treated as a contribution of a portion of the oil and gas property to the partnership by the seller and a

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[236] *See supra* note 186 and accompanying text.

[237] Treas. Reg. § 1.707-4(d).

[238] Section 1.707-4(d) of the Regulations defines qualifying section 707(a)(2)(B) preformation expenditures as expenditures that are incurred by the partner (i) during the two-year period preceding the transfer of the property by the partner to the partnership and (ii) with respect to partnership organization and syndication costs described in section 709 of the Code or property contributed to the partnership by the partner, but only to the extent the reimbursed capital expenditures do not exceed 20 percent of the fair market value of such property at the time of the contribution. Treas. Reg. § 1.707-4(d). Note that this latter 20 percent of fair market value limitation does not apply if the fair market value of the contributed property does not exceed 120 percent of the partner's adjusted tax basis in the contributed property at the time of the contribution. In this example, the capital costs to acquire the mineral lease should qualify as reimbursable preformation expenditures incurred with respect to the property contributed to the partnership.

"disguised sale" of the remaining portion of the property to the partnership.[239] The amount realized with respect to the "disguised sale" is $30 million, determined by subtracting the limited amount of qualifying preformation expenditures of $20 million from the amount of cash paid to seller up front.[240] The amount of seller's adjusted tax basis allocated to the portion of the property sold in the "disguised sale" is $7.5 million[241], leaving a "disguised sale" gain of $22.5 million.[242] Since the portion "sold" is $30 million, the fair market value of the property deemed contributed to the partnership is the remainder, or $70 million. Seller should recognize no gain on this contribution.[243] Seller's capital account initially will be credited with this $70 million contribution.[244] Seller's adjusted tax basis in its partnership interest will be $17.5 million.[245]

The amount of cash received from purchaser that is treated as a distribution to seller is $20 million[246], meaning that seller will recognize gain on the receipt of the

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[239] I.R.C. § 707(a)(2)(B); Treas. Reg. § 1.707-3(a)(1), (b)(1).

[240] Since the fair market value of the contributed property exceeds 120 percent of the adjusted tax basis of such property, the amount of reimbursable preformation expenditures is limited to 20 percent of the fair market value of the contributed property, or $20 million. Treas. Reg. § 1.707-4(d)(ii). This $20 million amount then is subtracted from the $50 million cash payment to arrive at the amount of the "disguised sale", or $30 million. Treas. Reg. § 1.707-4(d).

[241] Recall that the adjusted tax basis of the contributed property is assumed to be $25 million. Since the percentage ratio of the amount of the disguised sale ($30 million) to the fair market value of the contributed property ($100 million) is 30 percent, 30 percent of the adjusted tax basis of the contributed property ($7.5 million) is allocated to the disguised sale for purposes of computing gain or loss on such sale. *See, e.g.,* Treas. Reg. § 1.612-1(a) (in the case of a sale of a portion of a mineral property, the adjusted tax basis of the property is allocated between the part that is sold and the part that is retained (or in this case, contributed). The allocation is based on the relative fair market values of the two properties. *See, e.g.,* Treas. Reg. § 1.614-6(a)(2) (allocation of basis between portion of oil and gas property disposed of and portion retained based on relative fair market values of the two portions).

[242] The amount of gain is the amount realized on the disguised sale ($30 million) less the adjusted tax basis allocated to the portion of the property sold ($7.5 million), or $22.5 million. The oil and gas lease is considered real property used in a trade or business and has been held for more than one year, so the gain can qualify for treatment as capital gain under section 1231 of the Code. See Rev. Rul. 68-226, 1968-1 C.B. 362.

[243] I.R.C. § 721.

[244] Treas. Reg. § 1.704-1(b)(2)(iv)(b).

[245] I.R.C. § 722.

[246] Recall that the amount of cash consideration involved in the "cash and carry" transaction is $50 million. The portion of the cash consideration involved in the "disguised sale" to the partnership is $30 million. *See supra* note 240 and the accompanying text. The balance, or $20 million, is considered distributed by the partnership to Seller.

distribution under section 731 of the Code in the amount of $2.5 million.[247] Total gain recognized by seller equals $25 million, consisting of the $22.5 million gain on the "disguised sale" and the $2.5 million gain on the section 731 distribution. This amount of gain should compared to the $37.5 million of gain that would have been recognized by seller had the parties made the election to be excluded from the partnership tax rules in subchapter K of the Code.[248]

The partnership will take a $17.5 million adjusted tax basis in the portion of the property considered contributed to the partnership[249] and a $30 million adjusted tax basis in the property considered purchased by the partnership in the "disguised sale".[250] The purchaser will be treated as contributing $50 million to the partnership in exchange for a fifty percent interest therein. Purchaser's adjusted tax basis in its partnership interest will be $50 million.[251] Pursuant to the basis allocation rules of section 613A(c)(7)(D), the contributed property rules of section 704(c) and the disguised sale rules of section 707(a)(2)(B), Purchaser will be allocated the entire $47.5 million of adjusted tax basis attributable to the partnership's oil and gas property.[252] Seller and purchaser likely will agree to use the remedial method under section 1.704-3 of the Regulations to allocate an additional $2.5 million of partnership deductions to purchaser and an offsetting amount of $2.5 million of "income" to seller.[253] Seller will be allocated no adjusted tax basis in the partnership's oil and gas property pursuant to section 613A(c)(7)(D) since purchaser was allocated all of that adjusted tax basis. Importantly,

[247] I.R.C. § 731(a)(1) (gain recognized by the distribute partner to the extent that the amount of money distributed exceeds the adjusted tax basis of the partner's interest in the partnership).
[248] In such case, the amount realized would have been $50 million. The adjusted tax basis of the oil and gas property allocated to the 50 percent undivided interest sold would have been $12.5 million. The resulting gain therefore would have been $37.5 million.
[249] I.R.C. § 723.
[250] I.R.C. § 1012. *See* Treas. Reg. § 1.707-3(a)(2) (a transfer that is treated as a sale under the "disguised sale" regulations is treated as a sale for all purposes of the Code).
[251] I.R.C. § 722.
[252] I.R.C. § 613A(c)(7)(D) (section 704(c) shall apply in the case of an oil and gas property contributed to a partnership by a partner); Treas. Reg. § 1.613A-3(e)(5); I.R.C. § 704(c)(1)(A); I.R.C. § 707(a)(2)(B). Recall that the partnership is viewed as having $17.5 million of adjusted tax basis in the portion of the property considered contributed to the partnership and has $30 million of adjusted tax basis in the portion of the property considered purchased by the partnership. Purchaser's $50 million cash contribution for a 50 percent interest in the partnership should entitle it to $50 million of adjusted tax basis in the partnership's assets. Purchaser therefore should be allocated all of the $30 million of "purchased" basis and all of the $17.5 million of "contributed" basis that carried over from seller to the partnership.
[253] Treas. Reg. § 1.704-3(d). The additional $2.5 million of remedial deductions allocated to purchaser, when added to the $47.5 million of adjusted tax basis in the oil and gas property allocated to purchaser, results in purchaser achieving the equivalent of having $50 million of adjusted tax basis in the property.

the tax attributes of the $60 million of future drilling and development costs paid for by purchaser to satisfy the carry obligation will be efficiently realized by the purchaser. Amounts qualifying as IDC pursuant to section 263(c) of the Code will be specially allocated to purchaser by the partnership agreement while amounts expended for the acquisition of lease and well equipment will be capitalized and the resulting annual tax depreciation also will be specially allocated by the partnership to the purchaser.[254] Note that the fractional interest rule discussed earlier in this paper has no application to this latter transaction, so no amounts paid to satisfy the carry will be capitalized and recovered through depletion.

VII. Conclusion

Investments in oil and gas joint operations can generate significant tax benefits for the parties to such transactions. Those parties historically have counted on those tax benefits in determining the after-tax economics of their transactions. Depending on the structure of the transactions, certain federal income tax rules may place limitations on the expected tax benefits, and may even cause adverse tax results to the parties, particularly if the parties elect to exclude the joint operations from the partnership tax rules in subchapter K of the Code. In these cases, the parties can use a tax partnership with provisions like those in the API Model Agreement to address the limitations and adverse tax results, and in so doing keep the expected after-tax economics of the joint operation intact.

[254] What these allocations mean is that the purchaser has used the special allocation of the IDC deductions and accelerated depreciation to recover its indirect investment in the oil and gas property much quicker than if it instead had purchased a 50 percent interest in the property for $50 million and the carry attributable to the seller’s retained interest.