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subject: Section 1341 and Oil & Gas Royalties

This Chief Counsel Advice responds to your request for assistance. This advice may not be used or cited as precedent.

LEGEND

Taxpayer =

Production Company =

Lessor =

Period 1 =

Period 2 =

Month 1 =

Date1 =

Date 2 =

Date 3 =

Year 1 =

A year period =

ATime =

State A Court =

Transshipment Point 1 =

Transshipment Point 2 =

Shipment Mode 1 =

Shipment Mode 2 =

$A =

$B =

$C =

Market A =

Market B =

ISSUES

(1) Do damages for underpaid oil royalties constitute a disgorgement of gross income or an inventory cost recoverable through cost of goods sold?

(2) Do damages which constitute additional costs of goods sold qualify for the tax benefits of section 1341?

CONCLUSIONS

(1) More factual development is needed in this case. If the damages for underpaid royalties were based on the net proceeds that Taxpayer received from the sale of the royalty oil, then the damages constitute a disgorgement of gross income. Otherwise, the damages for underpaid royalties constitute an inventory cost recoverable through cost of goods sold.

(2) Damages which constitute additional cost of goods sold do not qualify for the tax benefits of section 1341.

FACTS

Taxpayer[1], as well as others, obtained oil and gas leases from Lessor. The first oil produced from the leased land for commercial purposes was delivered to Transshipment Point 1 beginning during Period 1. Hereafter, oil or gas produced from the leases at issue will be referred to as lease oil or lease gas.

Except for oil or gas unavoidably lost or used on the land for production and development, the standard lease used in the leasing transactions provided for a 12.5 percent royalty in amount or value of lease oil or gas produced. Lessor could take the royalty in kind or value but opted to take the bulk of the royalty in value. If Lessor opted to take royalty in kind, the lease required the lessee to provide free storage for the Lessor’s share of the oil for Atime. However, the lease required the Lessor to bear its share of the costs of dehydrating or cleaning any oil or gas taken in kind.

The royalty in value clause required the lessee to pay Lessor royalty based on the field market price or value at the well of all royalty oil or gas, due on or before the last day of the calendar month following the month of production. However, pursuant to the “price” paragraph of the lease the field market price or value of royalty oil could not be less than the highest of the following three amounts: (1) the posted field price, (2) the price actually paid or agreed to be paid to Taxpayer at the well by the purchaser of the oil if any, or (3) the prevailing price received by other producers in the field at the well for oil of like grade and gravity at the time such oil was removed from the land or run into storage. Because of certain legal restrictions on the disposition of the oil and physical challenges unique to the production and marketing of the oil produced, no economically significant market developed for the oil at the field. Consequently, there was no posted field price for the oil. Instead, the lease oil was transported to and sold in various markets remote from the field.

From the beginning of commercial production, both Lessor and the various lessees recognized the existence of uncertainty regarding the proper method to calculate royalties pursuant to the value clause. Shortly after starting commercial production, the various lessees and Lessor entered into written agreements in which the parties recognized this uncertainty. Pursuant to these agreements, the parties formally recognized that this uncertainty might eventually have to be resolved through litigation

[1] Taxpayer consists of a consolidated group of corporations that filed consolidated returns for the taxable years at issue. For the period covered by the settlement agreement, it appears that various production company members of this group including their successors or predecessors, or companies that subsequently became members of the group through corporate reorganizations, actually entered into the oil or gas leases at issue. To simply the discussion, unless the context requires otherwise, we will refer to all the relevant production companies as Taxpayer.

absent a consensual resolution. In the meantime, the parties agreed that the lessees would make and Lessor would accept, royalty amounts calculated by the lessees without any prejudice to the parties' rights to have the royalty amounts subsequently adjusted for overpayments or underpayments together with interest. In addition, the parties agreed that an oil or gas lease would not be terminated for failure to make proper royalty payments prior to the resolution of the royalty issues so long as the lessee made royalty payments under the lease in good faith in accordance with its legal position.

Upon removal from the ground, the lease oil is piped to facilities for treatment to remove certain gases, water, and various impurities. After treatment, the lease oil is piped to Transshipment Point 1. The treatment and other costs in getting the oil from the wellhead to Transshipment Point 1 are known as field costs.

From Transshipment Point 1 the lease oil moves via Shipment Mode 1 with the bulk of it being delivered to Transshipment Point 2. From there the bulk of the oil moves by Shipment Mode 2 to various remote markets where it is sold. During the relevant period, the netback price for the oil, that is the actual selling price for the oil less the costs to transport the oil to market, differed among the various markets[2].

On Date 1, Lessor filed a declaratory judgment action in State A Court, naming various lessees as defendants including Taxpayer (the defendants), seeking a declaratory judgment regarding the proper method to compute lease oil royalties. Lessor's complaint asserted that field costs should not be deducted from the value of oil in computing royalty amounts, a position contrary to that of the lessees. Defendants asserted that royalties should be based on the "price or value at the well", a point at which the quality of the crude oil had not been improved by the incurrence of any field costs. Assuming that field costs constituted an allowable deduction in calculating royalties, Lessor asserted that the lessees were improperly allocating or calculating such costs or were otherwise deducting costs that did not qualify as deductible field costs. It appears that most of the field cost issues, at least to the extent such costs relate to the production of oil, were settled prior to execution of the primary settlement agreement discussed below.

Subsequent to the filing of the original complaint, additional lands leased by various lessees, including Taxpayer, were brought into commercial production for which Lessor was entitled to royalty payments. During the A year period following the filing of the

[2] In a smoothly functioning free market in which no seller has a pricing advantage, provided there are means to eliminate or greatly reduce the risk of adverse price changes or other risk factors during shipment from one market to another, it would be expected that netback price differences in various markets for the same commodity would provide arbitrage opportunities. See PETER ELLIS JONES, OIL A PRACTICAL GUIDE TO THE ECONOMICS OF WORLD PETROLEUM 131 (1988). Traders taking advantage of such opportunities would tend to eliminate the netback price differentials. The documents we examined in preparing this Chief Counsel Advice did not explain why these netback price differences existed for the lease oil. However, there appears to be general agreement that such differences did exist for the period at issue.

original complaint, Lessor filed several amended complaints. Therein, in addition to various other assertions, Lessor claimed that the defendants had used improper values in computing lease oil royalties. Based on these assertions, Lessor asserted substantial claims against Taxpayer and other lessees for underpaid lease oil royalties. In addition, asserting claims for exemplary damages, Lessor alleged that some of the defendants, including Taxpayer, defrauded Lessor by making intentional misrepresentations in its royalty reports regarding the true price or value of lease oil.

The defendants responded to these claims with denials of liability. In addition, the defendants asserted counterclaims against Lessor for overpaid royalties. The rationale for these counterclaims essentially was as follows. The leases imposed no obligation on defendants to transport lease oil to locations remote from the point of production for marketing. Rather, for royalty computation purposes, Lessor's entitlement only extended to a portion of the value of the lease oil at the well. By incurring costs to transport the oil and market it at remote locations, the defendants incurred risk not born by Lessor and used their expertise to enhance the value of the lease oil by amounts in excess of the cost incurred. Consequently, Lessor had been paid royalties based on an enhanced value to which it was not entitled.

Recognizing the absence of a market for lease oil at the field, both Lessor and the defendants agreed that royalties had to be computed based on netback pricing. The parties differed, however, as to methodology. The parties agreed that the lease oil was being sold in various markets at different netback prices. Lessor contended that the proper netback price should be based on actual sales prices to third parties in the various markets. In contrast, the defendants advocated for a royalty value derived from the market yielding the lowest netback price. In defendants' view, this price represented the "market clearing" price", apparently under the theory that all of the oil could have been sold at that price. Under defendants theory, to the extent they were able to sell lease oil at netback prices in excess of the market clearing price, this added value was attributable to defendants' efforts rather than to the intrinsic value of the lease oil. Consequently, Lessor was not entitled to any royalty based on this enhanced value and in fact had received royalties substantially in excess of amounts to which it was entitled.

During Month 1, Lessor and Taxpayer entered into a written settlement agreement, effective Date 2, which resolved the bulk of the matters at issue in the litigation. The settlement agreement required Taxpayer to pay to Lessor a total of $A by Date 3. This amount consisted of $B of net underpaid lease oil royalties for Period 2 plus net interest of $C on the net underpaid lease oil royalties. Pursuant to the settlement agreement, Lessor also withdrew its fraud allegations against Taxpayer, and the parties agreed that no part of the liability extinguished by the settlement payment was attributable to fraud The ultimate question that must be addressed by this memorandum is whether Taxpayer is entitled to the tax benefits of section 1341 for making the $B payment to Lessor for underpaid royalties.

For each month of the period subject to the litigation, the settlement agreement sets forth royalty settlement values, prior to any deduction for field costs, for the crude oil produced from a particular area. Two settlement values are listed for each month, one value for Market A and one value for Market B. In addition, the settlement agreement lists the barrels of crude oil placed in the respective markets each month from each producing area. The settlement amount for a given month for a particular producing area equals the weighted average of the Market A and Market B settlement values, weighted according to the amount of oil placed in each market. The royalty amount that would have been due based on the settlement values is compared to the royalty actually paid to determine if there was a royalty overpayment or underpayment for a producing area for a particular month. The settlement agreement then provides for an interest charge to Taxpayer for royalty underpayments, or interest credits for royalty overpayments, in determining the net amount of settlement due.

For the post-settlement period, the settlement agreement provides a detailed method for determining the values of the crude lease oil in the various markets in which the oil is sold. In contrast, although the settlement agreement provides numerical detail regarding the computation of the settlement amount, the agreement does not specify the method used to determine the Market A and Market B royalty settlement values

LAW AND ANALYSIS

Whether Taxpayer qualifies for the tax benefits of section 1341 for the settlement payments it made to Lessor (excluding interest) constitutes the ultimate issue to be resolved. Section 1341 allows a taxpayer to pay the lesser of: (1) the normal income tax for the year in which excess income is restored by the taxpayer with a deduction for the amount restored or (2) a tax computed with a reduction in the amount that the tax for the year in which the taxpayer received the excess income would have been decreased if the amount restored had been excluded from income in that year.

To qualify for the tax benefits of section 1341 the taxpayer must satisfy the following three requirements of section 1341(a):

> (a)(1) the taxpayer must have included an item in gross income for a prior taxable year (or years) because it appeared that the taxpayer had an unrestricted right to the item,
>
> (a)(2) a deduction must be allowable to the taxpayer for the current taxable year because it was established after the close of the taxable year (or years) of income inclusion that the taxpayer did not have an unrestricted right to the item or portion thereof, and
>
> (a)(3) the amount of the deduction must exceed $3,000.

Even if a deduction satisfies the requirements of section 1341(a)(1)-(3), that deduction does not qualify for the tax benefits of section 1341 if the "inventory rule" of section 1341(b)(2) applies. With an exception not relevant here, the inventory rule denies the tax benefits of section 1341 to any deduction allowable "with respect to" an item which was included in gross income by reason of the sale or other disposition of stock in trade, inventory, or other property held primarily for sale to customers in the ordinary course of the taxpayer's trade or business.

Part I- Ordinary Deduction, Inventory Cost, or Splitting of Gross Income

Initially, the crucial questions in this case require determining whether the payments at issue constitute (1) a deduction for a trade or business expense for which the taxpayer was liable in one or more prior taxable years, (2) an additional inventory cost, or (3) a disgorgement of an amount previously included in gross income.

Expenditures falling into the first category clearly do not qualify for the tax benefits of section 1341. Such amounts do not constitute disgorgements of amounts previously included in gross income as required by the statute. See e.g. *Cal-Farm Insurance Co. v. United States*, 647 F. Supp. 1083 (E.D. Cal. 1986), *aff'd,* 820 F.2d 1227 (9th Cir. 1987) (deduction to reimburse others for taxpayer's share of expenses mistakenly borne by them in prior taxable years did not qualify for section 1341); *First National Bank of Elkhart County v. United States,* 330 F.Supp. 975 (N.D. Ind. 1971) (deduction in current taxable year for employee's salary underpaid in prior taxable years did not qualify for section 1341). Likewise, as discussed in more detail in Part II of this memorandum, notwithstanding some contrary authority, the Service takes the position that section 1341 does not apply to additional inventory costs. On the other hand, if the royalty agreement provides for a division of the gross income from the sale of the crude oil between Taxpayer and Lessor, section 1341 applies to damages for underpaid royalties if the other substantive requirements of the statute are met.

A. Authorities Treating Royalties Like Rents

Section 162(a) provides a deduction for ordinary and necessary expenses paid or incurred during the taxable year in carrying on any trade or business. These expenses include rentals or other payments required to be made as a condition to the continued use or possession, for purposes of the trade or business, of property to which the taxpayer has not taken or is not taking title or in which he has no equity. Section 162(a)(3). If oil and gas royalty payments simply constitute a rental charge for the right to use Lessor's land, it follows that damages for underpaid royalties are not a disgorgement of gross income as required by section 1341.

Black's Law Dictionary (8th Ed. 2004) defines rent in part as "consideration paid usu. periodic, for the use or occupancy of property". Some cases have analogized lessee payments to lessors, pursuant to oil and gas leases, to rent. See e.g. *Burnet v. Harmel*, 287 U.S. 103, 108 (1932)[3]; *Burton-Sutton Oil Co. v. Commissioner*, 328 U.S. 25 (1946);

Mobil Oil Corp. v. Federal Power Commission, 42 F.P.C. 164 (1969), *rev'd,* 463 F.2d 256 (D.C. Cir. 1971), *cert. denied*, 406 U.S. 976 (1972). In *Mobil Oil*, the court dealt with the question of whether, pursuant to the Natural Gas Act (NGA), the Federal Power Commission (FPC) had jurisdiction to regulate the amount of royalties paid to lessors by lessees pursuant to leases for the extraction of natural gas. For the FPC to have jurisdiction, the lessors had to be engaged in the sale in interstate commerce of natural gas for resale.

Owners of royalty interests, asserting that the FPC had no power to regulate royalties, contended that a mineral lease constitutes a simple transaction in real estate and in no way constitutes a sale in interstate commerce by the landowner. They argued that the royalty payment comprises only a small part of the lease which in fact constitutes only a rental of the land for various considerations. The FPC rejected these arguments. Finding that the royalty owners retained a percentage economic interest in the gas sold in interstate sales, the FPC concluded that the royalty owner had joined the other interest owners in such sales. Therefore, the FPC had jurisdiction under the NGA to regulate royalty rates.

On appeal, the United States Court of Appeals for the District of Columbia Circuit reversed the FPC. The court quoted *Burnet v. Harmel* for the principle that payments by lessees to lessors under mining leases do not constitute a conversion of capital, as upon a sale of capital assets, but instead constitute income to the lessor, like payments of rent. The court concluded that the royalty owner neither under state law conceptions nor in common parlance would be considered to be engaged in any sale of gas. The court noted that all possessory interests to the extracted gas vested in the lessee upon its extraction[4]. The court apparently accepted the lessors' arguments that they could not be engaged in the sale of the gas because they had no gas to sell. In the court's

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[3] After reviewing relevant prior authority, the *Burnet* Court stated:

> [These cases] established, for purposes of defining "income" in a tax measured by it, that payments by lessees to lessors under mining leases were not a conversion of capital, as upon a sale of capital assets, but were income to the lessor, like payments of rent. 287 U.S. at 108.

[4] State legislatures and courts have adopted divergent views regarding the proper characterization of property interests in the context of oil and gas properties. However, where a lease provides for royalty to the lessor based on a percentage of market value, market price, or proceeds, it is generally held that title to the severed mineral is vested in the lessee. *See* RICHARD W. HEMININGWAY, LAW OF OIL AND GAS 61 (3d Ed. 1991).

view, retention of an economic interest in gas did not qualify the lessors as sellers of natural gas for purposes of the NGA[5]:

> While the lease by the landowner provides for a royalty in the event of the discovery and sale of gas, typically he has no control over any incident of such sale either as to the quantity to be sold, the price to be paid, the identity of the purchaser or whether it shall be sold in interstate or intrastate commerce. To refer to the royalty owner as engaging in the sale is to depart from the common understanding of the words used …
>
> The Commission's approach was this, that when a landowner executes a 'proceeds' or 'value' lease 'he has contracted to retain an economic interest in interstate sales by the producer,' and 'has joined the other interest owners in such sales and he has become a seller of natural gas.' But an economic interest in the proceeds of a sale, unaccompanied by authority to determine the incidents of the sale, does not make one a seller. The developer of a shopping center does not become a seller of food because he leases to a supermarket on percentage rental terms. … Nor does the lessor become a seller of an article merely because the article was produced on or from the land that he leased. An owner of farmland leased to a farming tenant does not become a seller of produce raised because his rent may be a fraction of the price received for the crops. An owner of a mine leased to an operator does not become a seller of the ore produced because the stipulated compensation for the lease is a fixed fraction of the price received for the ore produced.

463 F.2d at 262, 263. In the above quote the court focuses on the lessors' status, or lack thereof, as sellers of natural gas. Nevertheless, the court appears to equate the payment of mineral royalties to the payment of percentage rents in other contexts.

If for federal income tax purposes the payment of oil royalties constitutes payment of rent for the use of property, damages for underpaid royalties cannot qualify for the tax benefits of section 1341. This would be true regardless of whether such rents constitute amounts immediately deductible under section 162(a) (see *Cal-Farm* and *First National Bank of Elkhart County)* or, as discussed in Part II below, whether such payments constitute a production cost that must be treated as an inventory cost under section 263A or Treas. Reg. § 1.471-11 for pre-section 263A taxable years. Consequently, assuming that the royalties should be treated as rents for all federal income tax purposes, it is not necessary for us to address the immediately deductible/ inventory cost issue here.

B. Percentage Depletion Statute, Legislative History, and Regulations

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[5] The court indicated, in footnote 10 of the opinion, that it was not addressing the case of a landowner taking a share of the gas in kind and then selling it.

Section 61(a) generally provides that gross income means all income from whatever source derived, including but not limited to fifteen specifically enumerated items. Among the specifically enumerated items are (1) gross income derived from business, (2) gains derived from dealings in property, and (3) royalties.

When Congress repealed the percentage depletion deduction for oil for integrated oil companies in the Tax Reduction Act of 1975, and for most of the taxable years during which the royalty underpayments occurred, section 613(a) provided in part:

> In the case of the mines, wells, and other natural deposits listed in subsection (b), the allowance for depletion under section 611 shall be the percentage, specified in subsection (b), of the gross income from the property excluding from such gross income an amount equal to an amount equal to any rents or royalties paid or incurred by the taxpayer in respect of the property. Such allowance shall not exceed 50 percent of the taxpayer's taxable income from the property (computed without allowance for depletion). … In no case shall the allowance for depletion under section 611 be less than it would be if [cost depletion were used].

This language providing for the exclusion of gross income from the property for any rents or royalties paid or incurred by the taxpayer traces its origins to the Revenue Act of 1932. In the Revenue Act of 1926, because of myriad problems encountered in applying discovery value depletion, Congress replaced that method of depletion for oil and gas with depletion equal to a flat percentage of the gross income (percentage depletion) derived from the oil or gas extracted from the property.

The 1926 Act contained no language specifically directing that a taxpayer, in computing the taxpayer's percentage depletion deduction, exclude from gross income from the property rents or royalties paid or incurred by the taxpayer. The 1926 Act did, however, require in the case of leases for the depletion deduction to be equitably apportioned between the lessor and lessee. Sections 234(a)(8) and 214(a)(9) of the 1926 Act. The 1926 Act placed the language providing for the actual percentage of gross income to be used in calculating the depletion deduction, as well as certain net income limitations on that deduction, in section 204(c)(2) of the 1926 Act, a section other than those providing for equitable apportionment of the deduction between lessors and lessees.

In *Helvering v. Twin Bell Oil Syndicate*, 70 F.2d 402 (9th Cir.), *rev'd*, 293 U.S. 312 (1934), the taxpayer produced and sold oil making the taxpayer liable for royalties in cash or kind. The taxpayer argued that its gross income from oil sales, for purposes of predecessors to section 61, equaled the entire gross proceeds from such sales without reduction for royalties and that section 204(c)(2) of the 1926 Act itself provided for a percentage depletion deduction without regard to the equitable apportionment sections. The taxpayer's position would have allowed it to claim percentage depletion on the entire proceeds from the sale of the oil as well as allowing the royalty owners to claim percentage depletion on a total of one quarter of such proceeds.

The Ninth Circuit Court of Appeals sided with the taxpayer. First, relying in part on *Comar Oil.Co. v. Burnet,* 64 F. 2d 965 *(8th Cir.),*[6] *cert. denied,* 290 U.S. 652 (1933), the court determined that the entire gross proceeds from the oil sales constituted the taxpayer's gross income. The Ninth Circuit concluded that the royalties that the taxpayer paid were deductions from that gross income. The court treated the royalties like rentals or other payments required as a condition to the continued use of possession of the leased property. 70 F.2d at 409. The court further found the taxpayer to be entitled to a percentage depletion deduction based on the entire gross income from the oil sales.

The Supreme Court reversed. The Court concluded that section 204(c)(2) of the 1926 Act provided no authority for a percentage depletion deduction but simply provided the method for computing the deduction. The Court found actual authority for the deduction in those sections which also required an equitable apportionment of the deduction between lessee and lessor. The Court concluded that for percentage depletion purposes there was a single measure of gross income from the property, namely, the gross income from the oil produced from the land and not all of the gross income attributable to the land. This was the case irrespective of whether the lessee paid the royalty in kind or instead sold all the oil and paid the royalty in cash. The Court further found that the gross income from the property had to be apportioned among the lessee and lessor[7] in accordance with the economic interest of each in the oil. The Court did not specifically address the question of whether, pursuant to predecessors of section 61, the proceeds from the oil sales were also split between lessee and lessor or instead only constituted gross income of the lessee.

In reaching its conclusion, the Ninth Circuit found it significant that unlike prior acts the Revenue Act of 1932 specifically required the exclusion of rents or royalties paid or incurred by a taxpayer from the taxpayer's gross income in computing the taxpayer's percentage depletion deduction. In contrast, the Supreme Court accepted the government's argument that the language added in the 1932 Act "was merely clarifying in purpose and declaratory of the existing law as administered." 293 U.S. at 322. The

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[6] In *Comar Oil,* pursuant to the terms of assignments of various oil and gas leases, the assignee was required to make payments to the various assignors out of portions of the production of oil or gas from the assigned properties, such payments being limited to specified maximum amounts. The taxpayer, the assignee, contended that the amounts paid, found to be overriding royalties by the Eighth Circuit, should be excluded from its gross income. The Eighth Circuit rejected this argument, finding amounts paid either as royalties or overriding royalties on oil and gas to be paid out of the gross income of the payor. As noted below, the Supreme Court rejected this reasoning in *Thomas v. Perkins,* 301 U.S. 655 (1937).

[7] To simplify the discussion, we are assuming a simple arrangement involving only one lessor entitled to royalties and a single lessee solely responsible for producing and selling the oil produced from the leased land. In actual practice, multiple parties may have production responsibilities and multiple parties may have economic interests in the oil entitling them to a portion of the percentage depletion deduction. However, the same principal applies for percentage depletion purposes. There is one gross income amount which much be apportioned among those parties for purposes of determining the amount of their percentage depletion deduction.

1932 Act's legislative history provides no guidance regarding whether the splitting of gross income between lessee and lessor for purposes of computing percentage depletion also applies for purposes of section 61.

No definitive inferences may be drawn from section 613(a)'s language and the implementing regulations (Treas. Reg. § 1.613-2(c)(5)(i) and § 1.613-3(a)) regarding whether gross income from the sale of oil or gas is split between the lessor and lessee for both section 61 and percentage depletion purposes. In computing a taxpayer's percentage depletion deduction, section 613(a) requires gross income from the property to be computed by excluding from such gross income an amount equal to any rents or royalties paid or incurred by the taxpayer in respect of the property. If gross income from oil and gas sales is split between the lessee and lessor for section 61 purposes, arguably the language requiring the exclusion from gross income of amounts of rents and royalties paid or incurred by the taxpayer would be unnecessary. There would seem to be no need to exclude, for purposes of computing percentage depletion, rents or royalties paid or incurred by the taxpayer if such amounts are not otherwise includable in the taxpayer's section 61 gross income. Therefore, one can argue that section 613(a)'s language supports the view that royalty payments do not constitute a division of gross income between lessee and lessor.

This argument would be quite compelling if the amount for which the oil or gas were sold and the base for the computation of the royalties were always the same. This is not always the case. Under section 613(a) gross income from the property for percentage depletion purposes may be a hypothetical gross income based on what the crude oil would have sold for if sold in the immediate vicinity of the well rather than the actual gross income from the sale of the oil. For example, the lessee may refine the oil into finished products to sell or may transport and sell the crude oil in a different market. Thus, the lessee's actual gross income may be substantially different from the gross income for section 613(a) purposes. It is the hypothetical gross income, reduced by rents and royalties paid, that the lessee uses to calculate the depletion deduction. Thus, this hypothetical gross income only exists as a step in the computation of percentage depletion. It serves no other purpose. Therefore, section 613(a)'s requirement to exclude rents or royalties from gross income from the property for percentage depletion purposes does not give rise to a conclusive inference that there cannot also be a splitting of gross income between lessee and lessor for section 61 purposes.

C. Authorities Supporting Treatment of Royalty Payments as a Splitting of Gross Income

Although section 613(a)'s language and implementing regulations provide no definitive answer to the question of whether gross income for section 61 purposes is split between the lessee and the lessor, a rationale exists for such a split, at least in certain circumstances. Namely, the oil and gas lease, rather than being a contract whereby the lessor simply compensates the lessee for the use of the latter's property, actually constitutes a form of cooperative venture pursuant to which both the lessor and lessee recognize gross income from the sales of their respective interests in the extracted resource.

In *Berg v. Commissioner,* 6 BTA 1287 (1927), *aff'd,* 33 F2d 641 (D.C. Cir.), *cert. denied*, 280 U.S. 598 (1929), the Board of Tax Appeals confronted the question of whether bonuses paid to the taxpayer-lessors to obtain oil and gas leases from them resulted in ordinary income or capital gains from the sale of the mineral in place. In concluding that the payments constituted ordinary income, the Board of Tax Appeals made the following statements:

> [The] language [of the lease] does not comport with the term "sale" as that term appears to have been used in [the provision dealing with gains from the sale of capital assets]. The proceeds of minerals, and by minerals we include oil and gas, obtained from mining operations constitute gross income to the owner of the leased premises, and this is true where the minerals are leased. The result of an ordinary mining lease, such as we have here, is merely to transfer the cost of operations from the owner to the lessee. The operation remains the same and the *proceeds of the operation are divided between the lessee and lessor, the portion of the minerals and amounts paid to the lessor pursuant to the lease usually being termed "royalty."* [emphasis supplied].

Id. at 1292. Likewise, in *Shamrock Oil and Gas Corp. v. Commissioner*, 35 T.C. 979 (1961), *aff'd*, 346 F.2d 377 (5th Cir.), *cert. denied*, 382 U.S. 892 (1965) the Tax Court made the following comments regarding oil and gas royalties:

> Unlike rent, it represents a division or sharing of the production or its proceeds. GCM 22730, 1941-1 C.B. 214. Such a royalty is gross income taxable in the hands of the lessor upon which he is entitled to a reasonable allowance for depletion. The lessee, on the other hand, does not include the lessor's royalty in his own gross income, nor does he include the royalty in the "gross income from the property" upon which his own statutory depletion allowance is based.

35 T.C. at 1040. This quoted language indicates that gross income is split for purposes of both section 61 and the computation of percentage depletion, at least where the royalty is based on a share of production or proceeds from its sale. Nevertheless, the Tax Court made this statement in setting forth a general framework for the taxation of oil and gas as part of its introductory discussion pertaining to a lessee's proper tax treatment of bonuses paid to obtain oil and gas leases. A conclusion regarding the issue of whether royalty payments constitute a splitting of gross income for section 61 purposes was not crucial to resolving those issues.

Palmer v. Bender, 287 U.S. 551 (1933) involved two partnerships, of which the taxpayer was a partner, in which each partnership was a lessee under an oil and gas lease. After the discovery of oil on the leased premises, each partnership transferred some or all of its interests in the property that it leased to a different oil company in return for various consideration, including cash and royalties in kind. The government contended that the partnerships had sold interests in the leases making the partnerships ineligible to claim depletion after the transfers. The taxpayer countered that depletion should be allowed to the transferor if as consideration for the transfer the transferor retained an interest in the "fruits of the land as they may be produced". 287 U.S. at 555.

The Supreme Court rejected the government's position. The Court focused on the economic attributes of the taxpayer's interests:

> The language of the statute is broad enough to provide, at least, for every case in which the taxpayer has acquired, by investment, any interest in the oil in place, and secures, by any form of legal relationship, income derived from the extraction of the oil, to which he must look for a return of his capital. …
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> [T]he lessor's right to a depletion allowance does not depend upon his retention of ownership or any other particular form of legal interest in the mineral content of the land. It is enough if, by virtue of the leasing transaction, he has retained a right to share in the oil produced. If so he has an economic interest in the oil, in place, which is depleted by production.
>
> When the two lessees [the partnerships] transferred their operating rights to the two oil companies, whether they became technical sublessors or not, they retained, by their stipulations for royalties, an economic interest in the oil, in place, identical with that of a lessor. [citations omitted]. Thus, throughout their changing relationships with respect to the properties, the oil in the ground was a reservoir of capital investment of the several parties, all of whom, the original lessors, the two partnerships and their transferees, were entitled to share in the oil produced. Production and sale of the oil would result in its depletion and also in a return of a capital investment to the parties according to their respective interests.

Several commentators have taken the position that the payment of oil and gas royalties results not only in a splitting of gross income for percentage depletion purposes, but also a splitting of gross income for section 61 purposes, at least where the royalty is paid in kind or as a portion of the proceeds of sale. See e.g. Alexander J. Bruen ET. AL., FEDERAL INCOME TAXATION OF OIL AND GAS INVESTMENTS, ¶6.02 (2d ed. 1989), wherein the authors make the following statement:

> For federal income tax purposes, each owner of each interest in an oil or gas deposit underlying a given tract of land is regarded as receiving his respective share of production and marketing it himself or as having it marketed for his account. Accordingly, each owner includes in his gross income the proceeds from the sale of his share of production, and on such share of production, each owner separately computes his depletion allowance. Thus,

> although the owner of the operating interest may in the first instance come into physical possession of all the oil or gas produced from the tract and although he may sometimes market the shares for some of the owners of non-operating interests, accounting to them merely for the proceeds, he excludes from his gross income the amount that he delivers or pays over, in kind or in money, to the owners of the nonoperating interests. Thus, all payments made by way of royalties, by way of overriding royalties, and in respect of net profits interests are excluded from the gross income of the operating interests.

See also JOHN S. DZIENKOWSKI & ROBERT J. PERONI, NATURAL RESOURCE TAXATION PRINCIPLES AND POLICIES 71 (1988) ("The payor of the royalty does not include the portion of production used to discharge the royalty in gross income from the property for section 61 or percentage depletion purposes.").

The analysis in the Bruen treatise is based in part on *Thomas v. Perkins*, 301 U.S. 655 (1937), *aff'g,* 86 F.2d 954 (5th Cir. 1936). In that case, owners of oil and gas leases assigned their interests in such leases to the taxpayers in part for cash and notes. In addition, the assignors were entitled to a payment of $395,000, only payable out of ¼ of the oil produced from the property, if, as, and when produced. The taxpayers had no personal liability to pay the $395,000 which was to be paid directly to the assignors by the pipeline company or other purchaser of the oil as the oil was run. The taxpayers did not include these amounts in their gross income and did not claim percentage depletion with regard to such amounts.

The Service took the position that the amounts paid to the assignors to satisfy the $395,000 obligation constituted the taxpayers' gross income. The Service's theory was that the payments constituted consideration for the transfer of leasehold interests. The Ninth Circuit disagreed:

> Whosesoever may be the technical title to the oil in the ground or that produced and saved until sold, it is plain that the transferors have an economic interest in both, and a right to specific performance of the agreement to sell and pay over a fourth of the proceeds of oil produced.
> … .
> Looking to the whole instrument, and noting especially that the proceeds of one fourth of the oil saved is never to be paid by the buyer to the transferee-producer, but is to be paid direct to the transferor, and that the transferee owes no money debt, but only the duty to sell the oil and submit to a division of the proceeds by the purchaser of the oil, we think it clear that for taxing purposes this share of the proceeds received by the transferor is his income alone.

86 F.2d at 957.

The Supreme Court granted certiorari. The Court stated the issue as "whether respondents' gross income should include moneys paid to assignors by purchasers of the oil." 301 U.S. at 658. The Court noted that the $395,000 was payable out of oil only and did not constitute a personal obligation of the assignees and that the payments to the assignors were made directly to the assignors by the purchasers of the oil pursuant to terms of the assignment. Based on the terms of the assignment, the Supreme Court concluded that the assignors intended to withhold from the grant to the taxpayers ¼ of the oil to be produced and saved in an amount sufficient to yield $395,000. Because the assignors were required to look to the extraction of the oil for the return on their investment, based on *Palmer,* the Court concluded that the assignors were entitled to percentage depletion on the ¼ share payment made to them. The Supreme Court concluded as follows:

> As … the assignors in this case would be entitled to an allowance for depletion in respect of the oil sold out of their share, the income from that interest is not chargeable to [the taxpayers]. It follows that the Commissioner erred in including in their income the payments made by purchasers to assignors for their share of the oil.

Id. at 663.

D. Conclusions—Splitting of Gross Income or Inventory Cost

We have found no authority directly on point that addresses the question of whether, pursuant to an oil and gas lease, there is a splitting of gross income from the property for section 61 purposes between the lessor and lessee where resolution of that question proved crucial to the tax issue to be resolved.[8] As noted above, the authorities that appear to be relevant to this question offer conflicting inferences.

<u>Royalties are not Equivalent to Production Expense Rents</u>

Despite the various characterizations of royalties as analogous to rents, we do not believe that a royalty payment primarily serves to compensate the lessor for the lessee's use of its property. Rather, the royalty payment primarily compensates the lessor for its property interest in the extracted resource, irrespective of how that property interest may be characterized under state law. Where the obligation to pay royalties depends on production, no royalties will be due absent such production, irrespective of how much use the lessee makes of the lessor's land. Consequently, while the lessee's use of the lessor's land may be necessary to find and produce oil or gas, such use is ancillary to royalty's primary function, that is, to compensate the lessor for its interest in any oil or gas commercially produced.

Although the Court of Appeals for the District of Columbia may have been correct in *Mobil Oil Corp. v. Federal Power Commission* that royalty payments were not subject to

[8] In *Thomas v. Perkins*, the Court could have reached the same tax result by concluding that the payments at issue were includible in the taxpayers' gross income for section 61 purposes but were deductible as royalty payments.

regulation by the FPC under the NGA, we disagree with the court's conclusion that such payments are analogous to percentage rents paid by a store operator to the owner of a shopping center. The owner of a shopping center generally has no property interest, save for perhaps a lien to secure the payment of the rent, in the articles sold. The shop operator generally pays the landlord a base rent plus a percentage of sales. But there is no doubt that the shop operator is paying to use the shopping center owner's property as a business premise. Although rents will be higher if sales are higher, these higher rents reflect the value of that use rather than a sale of property by the shopping center owner. In contrast, for federal income tax purposes the royalty compensates the lessor for its interest in the extracted resource.

Likewise, the same distinction generally applies to percentage rents paid by a farm tenant to the farm's owner. The tenant pays for the use of the land to grow crops and the percentage rents reflect the relative value of that use. Granted, where there is no base rent and rents are based solely on a percentage of crop sales, a complete crop failure, like a failure to find oil or gas in quantities justifying commercial production, results in no payment obligation. However, where a liability to pay rents or royalties does arise, in the case of oil or gas the lessor has an existing property interest in the resource when the lease is entered into whereas the farm owner has no existing property interest in crops that have not yet been created. Of course, pursuant to the lease the landowner might become the actual owner of a portion of the crops grown. However, in that case there might be a splitting of gross income between the farmer and the landowner.

Finally, we note that where the courts have analogized royalties to rentals, the primary issue before the courts was whether the income at issue constituted gain from the sale of the land or ordinary income. Income from the extracted resource, which has been considered to be from "the fruits of the land" is considered to be one of the income incidents of the land as is rental from the use of the land. In analogizing the royalties to rentals the courts were primarily interested in establishing that royalty income, like the operator's income from the sale of the extracted resource, constituted ordinary income. We do not think that the courts' conclusions require treating royalties as ordinary rentals for all purposes. Consequently, we conclude that the damages for underpaid lease oil royalties at issue in this case do not constitute costs of producing the oil.

Did Taxpayer Puchase the Royalty Oil?

Even if royalties do not constitute one of the lessee's costs of producing the oil, royalties may still be treated as a lessee inventory cost if it is appropriate to treat the royalty as payment by the lessee to acquire the lessor's share of the oil. For example, irrespective of the type of royalty clause, if the lessee also refines the oil into finished products for sale, the royalties paid constitute part of the lessee's cost of acquiring a raw material, crude oil, for refinement into finished products. In such a case the lessee would be the purchaser of the lessor's share of the crude oil.

If the crude oil is sold to a third party, the analysis becomes more complicated. For federal income tax purposes, both lessee and lessor are considered to have a property interest in the extracted resource. Whether provided for explicitly in the lease, or pursuant to the implied covenant to market, the lessee generally must make a good faith effort to market the extracted resource under reasonable terms. Nevertheless, these obligations on the lessee do not require a finding that the payment of royalties where the crude oil is sold to a third party always results in a splitting of gross income between lessor and lessee.

There may be significant differences among lease royalty clauses. The three primary classifications of interest are (1) royalties paid in kind, (2) royalties based on the actual proceeds of sale (proceeds leases)[9], and (3) royalties based on the market value of the oil (market value leases). If royalties are paid in kind, there is a physical division of the extracted oil between the parties, and the lessor assumes all the benefits and burdens of ownership regarding its share upon receipt. If the lessor sells its royalty share of the oil, the gross income derived from such sales belongs to the lessor for all federal income tax purposes. In this case the lessee incurs no inventory cost, that is, cost of acquiring, the lessor's share of the oil.

For proceeds or market value royalty leases, the benefits and burdens analysis becomes more complicated. Whether lessee assumed enough benefits and burdens with regard to the royalty oil to cause that oil to be treated as sold by the lessor to the lessee for federal income tax purposes constitutes a question of fact which must be ascertained from the intention of the parties as evidenced by the written agreements read in light of the attending facts and circumstances. *See Haggard v.* Commissioner, 24 T.C. 1124, 1129 (1955), *aff'd*, 241 F.2d 288 (9th Cir. 1956).

In determining whether there has been a sale of property by one party to another, courts have examined various factors including but not limited to: (1) whether legal title passes, (2) whether the right to possession and control is vested in the purported purchaser, (3) which party bears the risk of loss or damage to the property, (4) whether the contract creates a present obligation on the purchaser to make payments (5) whether the purported purchaser acquires an equity in the property and which party receives the profits from the sale of the property, *See Grodt & McKay Realty, Inc. v. Commissioner*, 77 T.C. 1221 (1981). Likewise, whether or not a party assumes the credit risk associated with the property constitutes a factor in determining whether that party has purchased the property. *See e.g. In re Golden Plan of California, Inc.* 829 F.2d 705 (9th Cir. 1986) (where party purportedly purchasing notes assumed risk that obligors would not pay on notes, this factor contributed toward characterization as purchase rather than a loan secured by an unperfected security interest in the notes).

[9] Royalties may also be payable on "net proceeds", that is, gross proceeds less the cost of transporting the extracted resource to market. To simplify the discussion, unless specifically stated otherwise the term "proceeds lease" is to be understood as referring to leases requiring the payment of royalties on either the gross proceeds or net proceeds from the sale of the extracted resource

Before conducting a benefits and burdens analysis for the leases in this case, we must first consider the effect of the Supreme Court's decision in *Thomas v. Perkins*. The Supreme Court did not need to address the section 61 gross income question in that case to determine if the payments at issue were for the transfer of leases or were ordinary income subject to depletion in the hands of the assignors. Nevertheless, the actual holding in that case is a gross income holding. Likewise, although the fact pattern in *Thomas v. Perkins* involved a production payment rather than a pure royalty, we believe the pertinent facts in that case are close enough to a pure royalty to make the court's conclusions applicable to royalty clauses. In *Thomas v. Perkins*, in essence the assignors were entitled to a ¼ royalty limited to a total of $395,000. The Court concluded that no part of that royalty was includible in the taxpayers' [the assignees'] gross income. There is no reasonable basis to conclude that the Court's conclusion on the gross income issue would have been different if the ¼ royalty interest had been for the life of the lease rather than being limited to $395,000.

We recognize that in *Thomas v. Perkins* the purchasers of the oil made payments directly to the assignors pursuant to terms of the assignment. Ultimately, the obligation to pay royalties depends on the terms of the lease and the variance in these terms is limited only by the imagination of the drafters. However, we view *Thomas v. Perkins* as establishing a presumption that if royalty oil is sold to an independent third party pursuant to a proceeds lease, the proceeds from such sales only constitute the section 61 gross income of the lessor.

The instant case involves a modified form of market value lease. Because royalties paid pursuant to proceeds leases involve a splitting of gross income for section 61 purposes, to determine if royalties paid pursuant to a market value lease result in the incurrence of an inventory cost or a section 61 splitting of gross income, benefits and burdens of ownership common to both types of leases should be disregarded.

We have found only two categories of benefits and burdens of ownership that differentiate proceeds leases from market value leases with regard to royalty oil: (1) credit risk and (2) price risk and benefit.

(1) <u>Credit Risk</u>

The royalty clause in *Sondral v. Placid Oil Co.,* 23 F.3d 1341 (8th Cir. 1994) required the lessee to pay a royalty to the lessors equal to a percentage of the proceeds received for gas sold from each well where gas only was found[10]. The lessee sold the extracted wet gas to a processor. After processing, a utility company purchased the processed gas

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[10] The lease also provided for royalty based on market value at the well of gas used off the premises. In starting its analysis the Eighth Circuit stated that "[t]he crux of this dispute is whether the 'proceeds' clause or the 'market value' clause applied to the gas… ." Prior to analyzing the application of the proceeds clause, the court rejected the lessors' argument that the market value royalty clause applied to the gas. Had the court concluded that the market value clause applied, it would have found the lessee to be liable for royalty on the market value of the gas placed in storage prior to its actual sale.

from the processor pursuant to a gas purchase contract. Pursuant to its agreement with the lessee, the processor paid the lessee 75 percent of the proceeds received from gas sales less processing and fuel costs (net proceeds). The lessee paid royalty to the lessors based on a percentage of these net proceeds.

When the market value of natural gas fell, the utility company defaulted on its payment obligations under the gas purchase contract. Gas not paid for was placed in storage to the credit of the lessee. The lessee eventually resold this gas for less money than it would have brought had the utility company not defaulted on its payment obligation. The lessors objected to being paid royalties based on the proceeds received from the sale at the lower resell price. They argued that for purposes of the royalty clause "proceeds" included not just cash paid to the lessee but the "credit" the processor gave the lessee for the gas placed in storage. The Eighth Circuit disagreed. Although recognizing that in a proper case "proceeds" might not be limited to cash, the court concluded that the "credit" given to the lessee simply amounted to a bookkeeping entry whereby the processor indicated that it had received the stored gas from the lessee but had not yet paid for it. Such a credit did not constitute proceeds for purposes of the royalty clause. Consequently, in *Sondral*, both the lessee and the lessors bore the loss arising from the utility company's failure to pay.

Likewise, although not technically a royalty case, *Calpine Producer Services, v. Wiser Oil Co.,* 169 S.W.3d 783 (Tex. Ct. App 2005) supports the position that where one party is obligated to pay another party an amount based on the proceeds received from the sale of property, both parties bear the risk that the purchaser of the property will fail to pay for it. In *Calpine,* a party owning or controlling natural gas produced from certain properties (the producer) entered into a contract with another party (the reseller). Pursuant to the contract the reseller obtained the sole and exclusive right to purchase the gas from the producer. As consideration for such purchases, the reseller agreed to pay the producer a percentage of the proceeds received by the reseller in reselling the gas. The reseller sold some of the producer's gas to Enron which subsequently filed for bankruptcy before paying for it. Only a portion of the debt arising from the gas sale to Enron was satisfied.

A portion of the contract between the producer and reseller directed that the amount of each payment to the producer be determined by multiplying a percentage, reduced as the volume of gas sold increased, to the amount of money "received" by the reseller from the third-party purchaser for the gas sold. The Texas court concluded that the reseller had no obligation to pay the producer for gas not paid for by Enron.

If a lessee has obligated itself to pay royalties based on the value of the extracted resource, provided that such value can be established, there appears to be no argument for releasing the lessee from this obligation if the party to which it sells the extracted resource fails to pay for it. On the other hand, based on the above authorities, we conclude that if a lease obligates the lessee to pay a royalty based on a percentage of the proceeds received from the sale of the oil or gas, the lessor bears the risk that the purchaser will fail to pay for the royalty portion of the oil or gas sold. Consequently, the lessee's bearing of the credit risk with regard to the royalty portion of the oil sold to third parties constitutes a burden of ownership that differentiates market value royalty clauses from proceeds royalty clauses.

(2) Price Risk and Benefit

For crude oil sold to third parties, the ability to retain the proceeds from such sales constitutes a benefit of ownership. If a lease requires the lessee to turn over the proceeds from the sale of royalty oil to the lessor, the lessee derives no economic benefit and suffers no economic detriment based on the price at which the royalty oil is sold. This is true regardless of whether the relationship between lessee and lessor is that of agent and principal or of debtor and creditor.

On the other hand, as exemplified by several of the market value gas royalty cases, if the lease requires royalties based on the value of the extracted resource, the values for royalty computation purposes may differ from the amounts for which the extracted resource is actually sold or could be sold. In such a case the lessee may benefit from selling the royalty oil at prices in excess of its royalty value but also assumes the risk of being required to pay royalties based on values that exceed the actual sales prices.

Consequently, if royalties are based on the value of the extracted resource, we believe there should be a rebuttable presumption that the lessee assumes enough of the benefits and burdens of ownership regarding the royalty portion of the extracted resource to treat the lessee as the owner of that portion for federal income tax purposes. Thus, royalties paid by the lessee under market value royalty clauses should be presumed to constitute an inventory cost.

In a market value lease, the lessee may sell the extracted resource in the same type of transactions that are considered in computing the value of the resource. In such a case the proceeds derived from the sales may approximate the value of the resource sold. One might argue that in this situation royalties paid pursuant to the market value lease should be treated the same as royalties paid pursuant to a proceeds lease. However, in a market value lease, the lessee, without breaching its contract with the lessor, has the right to sell the extracted resource in transactions other than the transactions from which the value of the resource is determined. It is this right which distinguishes a market value lease from a proceeds lease.

Nevertheless, in evaluating the lessee's ability to sell the extracted resource for amounts differing from its royalty value, unavoidable realities of the marketplace should be taken into account. For example, if a lease requires royalties based on the value of oil produced, but for the period in question all of the oil may only be sold at regulated ceiling prices, as a practical matter the lessee could not derive any benefit from the royalty oil sold. The lessee's legal right to sell the oil at prices lower than the regulated prices, an economically irrational choice, should be disregarded. Despite the lease's call for royalties based on value, the imposition of ceiling prices ensures that in paying royalties the lessee will simply turn over the proceeds from the royalty oil's sale, less allowable expenses, to the lessor. Under these circumstances the market value lease has effectively been converted into a proceeds lease and should be treated as such for royalty characterization purposes.

Although the settlement agreement in the instant case provides royalty settlement values for each month at issue for each producing area, it fails to specify how those values were determined. Consequently, further factual development will be required regarding how those values were calculated to determine if Taxpayer's payment of royalties pursuant to the settlement agreement constituted an inventory cost or a disgorgement of gross income. Although it requires some speculation on our part, we will attempt to provide some guidance on the conclusions to be reached based on what we anticipate may have been the methods for calculating the royalty settlement values.

Determination of royalty values requires a two-step process. First, it is necessary to determine the per barrel value of the oil at its delivery point (destination value). Second, costs of getting that oil (hereinafter referred to as transportation costs) to market must be subtracted from the destination value to determine the royalty value. According to the litigation documents submitted, Lessor asserted that royalty values should be determined based on the following methodology. First, destination values should be based on actual prices paid in actual transactions[11] in the actual markets in which the royalty oil was sold. Second, Lessor asserted that destination values should be based on the average market level for the period during which a particular month's production would reach a particular destination market. To reduce the destination value to a royalty settlement value, Lessor contended that it was proper to deduct the weighted average transportation costs per barrel incurred by all lessees marketing lease oil in each destination market.

Because substantial amounts of lease oil were refined by the producers of that oil or their affiliates, we anticipate that royalty values were determined by reference to arms-length sales to unrelated third parties. If you discover that Taxpayer's royalty settlement values were determined based solely on Taxpayer's actual sales to unrelated third parties and Taxpayer's actual costs of transporting the oil to market, Taxpayer's damages for underpaid royalties should be treated as a disgorgement of gross income rather than an inventory cost. Although the leases at issue provide for royalty based on value, a strong argument may be made that the price paragraph established a net

[11] The submitted litigation documents do not specify the relevant characteristics that these actual transactions would have to satisfy to be taken into account in determining royalty values. For example, it is not clear whether all sales contracts for a particular month's production, which might include forward contracts entered into months earlier, would be taken into account in determining destination values or whether only contracts entered into after production would be taken into account. Likewise, it is not clear if sales of lease oil between the producing parties would be accorded special treatment because of the potential for price manipulation (for example, a "spinning" transaction in which reciprocal sales of oil are made between parties at artificially low prices).

proceeds floor on the royalty base. In light of the long-standing disagreement between Taxpayer and Lessor regarding royalty computation, it would not be surprising to find the settlement values based on net proceeds.

You may determine that Taxpayer's royalty settlement values were determined based solely on Taxpayer's actual sales to third parties but based on the weighted-average transportation costs of all lessees marketing lease oil to the particular market for the period at issue. This is a difficult situation because the settlement value determined reflects neither an average market value of all the oil sold nor the actual net proceeds realized by Taxpayer from its sales. However, provided that the weighted average transportation costs of all lessees marketing lease oil appears to reasonably approximate Taxpayer's actual transportation costs for the period, we would treat damages for underpaid royalties in this case as a disgorgement of gross income rather than an inventory cost.

On the other hand, if you determine that Taxpayer's royalty settlement values were determined with reference to the weighted average price of lease oil sold by all lessees marketing such production to a particular market for a particular period, Taxpayer's damages for underpaid royalties for that period should be treated as an additional inventory cost. Finally, if you are unable to determine the theory upon which the royalty settlement amounts were determined, the settlement values must be assumed to be based on a compromise with regard to the proper value of the oil. In such a case, damages for underpaid royalties should be treated as an additional inventory cost.

Part II Application of Section 1341 to Inventory Costs

To the extent the royalty payments at issue constitute additional inventory costs, such costs do not qualify for the tax benefits of section 1341 for several reasons.

A. The Item

To qualify for the tax benefits of section 1341, pursuant to section 1341(a)(1) Taxpayer must have included an item in gross income for a prior taxable year (or years) because it appeared that the taxpayer had an unrestricted right to the item. Service position is that section 1341 applies only to <u>items</u> of gross income subject to the common law claim of right doctrine, i.e., <u>total</u> <u>receipts</u> or "gross income" as defined in Treas. Reg. § 1.61-1(a). Taxpayer may satisfy the requirements of section 1341(a)(1), only if the gross income referred to in that section means "gross income" as defined in Treas. Reg. § 1.61-3(a) (net taxable income). The Service reads the statutory language's reference to inclusion, "taxpayer must have included an item in gross income," as an indication that section 1341 applies to all items includible in income (essentially total receipts), not to income reduced by cost of goods sold (COGS). The case law is nearly unanimous (with the exception of *Pennzoil-Quaker State Co. v.. United States*, 62 Fed Cl. 689 (2004), *government appeal pending* (Fed. Cir.) and *Reynolds Metals Co. v. United States*, 389 F.Supp.2d 692, (2005), as defining gross income for section 1341(a) purposes as total receipts within the meaning of Treas. Reg. § 1.61-1(a). *Pennzoil* involved underpayments for crude oil. *Reynolds* involved the incurrence of environmental remediation expenses.

Some taxpayers have argued that the incurrence of expenses, that, if had they been incurred in prior taxable years would have been included in inventory costs recoverable through COGS, means they included an item in gross income under an apparent claim of right within the meaning of section 1341(a)(1). These taxpayers equate their subsequent payments of additional COGS with the repayment of items that they included in income in earlier years. To convert COGS expenditures into receipts eligible for section 1341 treatment, the taxpayers substitute the definition of net taxable income of a business for the definition of total income, or gross receipts, contemplated in section 1341(a)(1).

In *Pennzoil*, interpreting the “remedial” scope of section 1341 very broadly, the Court of Federal Claims agreed with this position. We think that the court misapprehended the purpose of section 1341 and seriously misinterpreted the legal authority mandating the government’s position. The court’s legal errors were as follows.

Section 1341(a)(1) allows a recalculation only for the return of income items, not for subsequent adjustments to net taxable income

The Court of Federal Claims’ fundamental error was applying the net taxable income concept of Treas. Reg. § 1.61-3(a) to section 1341(a)(1). That definition serves a very specific and limited purpose: to ensure that businesses are not taxed on their gross receipts. Section 1341 has a very different purpose, i.e., recomputing income when a taxpayer later returns or “restores” an item of income received in a previous year. Section 1341 allows a recomputation for the return of an item of gross income defined in Treas. Reg. § 1.61-1(a). Section 1341 is not applicable to adjustments of net taxable income under Treas. Reg. § 1.61-3(a).

The Internal Revenue Code taxes all items of income unless specifically excluded from the definition of income or otherwise excepted from taxation. Section 61 implements this broad policy of inclusion by defining gross income as “all income from whatever source derived.” The courts have unequivocally embraced the all-inclusive definition of gross income embodied in section 61. The Supreme Court has instructed other courts to apply this broad definition of income. *Commissioner v. Glenshaw Glass Co*., 348 U.S. 426, 429-30 (1955). Treas. Reg. § 1.61-1(a) adopts this broad definition of gross income when it states that the Code taxes all “income realized in any form, whether in money, property, or services [emphasis added].” For individuals, that means “gross receipts.”

However, a business is not taxable on all its receipts, because a business does not realize that gross amount. A business realizes income on its gain: gross receipts [or sales] less the costs of producing that income [or COGS], i.e., net taxable income.

Treas. Reg. § 1.61-3(a) simply reiterates that fundamental economic principle: "In a manufacturing, merchandising, or mining business, 'gross income' means the total sales, less the cost of goods sold, plus any income from investments and from incidental or outside operations or sources." That definition means net taxable income, despite the regulation's unfortunate use of the phrase "gross income" that has a much broader meaning in other contexts.

To obtain the benefits of a section 1341 recomputation, taxpayers have conflated the different meanings of the term "gross income" in Treas. Reg. §§ 1.61-1 and 3. They have argued that the term "gross income" appearing in section 1341 must include the net taxable income concept, because both Treas. Reg. § 1.61-3(a) and section 1341 use the same term, "gross income." The law and the overwhelming authority are otherwise. As used in section 1341, "items included in gross income" means total or gross receipts defined in Treas. Reg. §1.61-1(a), not net taxable income defined in Treas. Reg. § 1.61-3(a). *Pennzoil* and *Reynolds* [12] are the only exceptions in the long line of cases adopting the gross receipts concept. *See North American Oil Consolidated v. Burnett* and its progeny, *supra; see also United States v. Skelly Oil Co*., 394 U.S. 678, 682 (1969)("Nevertheless, it is clear that Congress did not intend to tamper with the underlying claim-of-right doctrine; it only provided an alternative for certain cases in which the new approach favored the taxpayer."); *Chernin v. United States*, 149 F.3d 805, 816 (8th Cir. 1998)("legislative history is replete with references to repayment, restoration, and restitution"); S. Rep. No. 1622, 83d Cong. 2d Sess. 118; H.R. Rep. No. 1337, 83d Cong. 2d Sess. 86; Treas. Reg. § 1.1341-1(a)(1).

The Service's position is thoroughly consistent with the case precedent and legislative intent. Rev. Rul. 72-28, 1972-1 C.B. 269, holds that "claim of right" doctrine applies only to gross receipts. The revenue ruling concluded that a public utility's COGS is ignored in determining whether payments from customers had been included in gross income for section 1341 purposes. Rev. Rul. 2004-17, 2004-1 C.B. 516, concluded that environmental remediation payments similar to those in *Reynolds* were not income or proceeds from sales but were subsequent adjustments to the taxpayer's costs of production; therefore, the payments were not items included in income for section 1341(a) purposes.

Section 1341(a) does not apply to expenditures

To the extent the underpaid royalty damages Taxpayer paid constitute additional inventory costs, the amounts that Taxpayer paid to Lessor (not customers) were not "items" included in taxpayer's income in an economic sense or for purposes of section 1341. Rather, the payments were merely expenditures used to compute Taxpayer's net taxable income. Any cost subtracted from gross income to compute net taxable income

[12] The *Reynolds* court found that Reynolds did not restore income to its customers, even under *Pennzoil*'s definition of "gross income", when it incurred the environmental remediation expenses that were the subject of that litigation. 389 F.Supp.2d at 701.

is an expenditure. An expenditure is definitionally an outlay not an item of income. See *Colony, Inc. v. Commissioner*, 357 U.S. 28 (1958), in which the Supreme Court held that a taxpayer who overstated its COGS had not "omit[ted] from gross income an amount properly includible therein" for purposes of determining whether the Service had additional time to assess taxes. In *Colony*, the Court held that "the statute is limited to situations in which specific receipts or accruals of income items ***are left out*** of the computation of gross income." 357 U.S. at 33 (emphasis added). Colony's overstatement of its COGS to compute net taxable income under Treas. Reg. § 1-61-3(a) did not result in the omission of an item from "gross income" for purposes of extending the normal assessment period. The inverse is also true. By understating COGS, a taxpayer ***did not include*** any item in gross income. The payments that taxpayer realized from sales to its customers were the "items" that it included in gross income. Taxpayer's subtraction of its COGS (paid to its suppliers) from those items of income did not constitute the return of income items to the payers (customers). Taxpayer did not return any items of income held under a "claim of right" within the contemplation of section 1341(a).

The Court of Federal Claims' rationale in *Pennzoil* is puzzling. The court seemed to lump purchases from the taxpayer's suppliers with sales to the taxpayer's customers into a single transaction. We have great difficulty understanding how a taxpayer can repay or 'restore' sales proceeds to customers by paying COGS to suppliers (unrelated to the customers) who never bought anything from the taxpayer.

In *Reynolds Metals Co. v. United States,* the court declined to follow the Pennzoil court's "shaky" speculation as to how production cost payments could be returns or "restorations" of income items eligible for section 1341 treatment. *See* 389 F.Supp.2d at 701. The *Reynolds* court correctly concluded that Reynolds' environmental remediation costs were not returns of income items received in earlier years and thus did not qualify for section 1341 treatment. *Accord*, *Alcoa, Inc. v. United States,* 406 F.Supp. 2d 580 (W.D. Pa. 2005), *taxpayer appeal pending (3d* Cir).

B. Cost of Goods Sold is Not a Deduction

Section 1341(a)(2) contains a separate requirement for section 1341 relief. That section requires the taxpayer to be entitled to a "deduction" in the current year for the amount of income it repays or restores in the latter year. If the damages for underpaid royalties constitute an additional inventory cost, Taxpayer fails to meet this condition.

Section 1341 applies to the return of items in a later year if the return would have otherwise been deductible under the Code in the later year. Section 1341 does not itself make an item deductible. *National Life & Accident Ins. Co. v. United States*, 244 F. Supp. 135 (M.D. Tenn. 1965), *aff'd*, 271 F.2d 832 (6th Cir. 1967; *Wood v. United States,* 863 F.2d 417, 420 (5th Cir. 1989); *MidAmerican Energy Co. v. Commissioner*, 114 T.C. 570, 583 (2000), aff'd, 271 F.3d 740 (8th Cir. 2001); see also Treas. Reg. §

1.1341-1(a)(1). Therefore, to qualify for section 1341 treatment, Taxpayer must be entitled to deduct the settlement payments it made for underpaid royalties.

The deductibility or other tax treatment of payments made in litigation flows from the character of the underlying claim. *See Arrowsmith v. Commissioner*, 344 U.S. 6 (1952) (taxpayers incurred capital loss from a capital transaction); *United States v. Skelly Oil Co., 3*94 U.S. 678 (1969) (any deduction for repayment of natural gas had to be reduced by 27.5% depletion allowance taxpayer took upon receipt of income). In settling the suit filed by Lessor, if the royalties are inventory costs, Taxpayer agreed to pay additional amounts for its previous purchases of crude oil that Taxpayer processed, held in inventory, and resold to customers in the ordinary course of its business. Such payments were inventory costs both under section 263A, to the extent applicable, and section 471, as in effect for pre-263A years. See section 263A(a)(1)(A), Treas. Reg. § 1.263A-1(e)(2)(i)(A); Treas. Reg. 1.471-11(a) and (b)(2). Inventory costs are recovered only through adjustments to COGS. See Treas. Reg. § 1.263A-1(c)(4).

When a business computes its net taxable income by subtracting COGS from gross receipts, the adjustments are not deductions. See e.g. *Max Sobel Wholesale Liquors v. Commissioner,* 630 F.2d 670 (9th Cir. 1980) (§ 162(c)(2) prohibition on "deducting" illegal payments did not preclude taxpayer from subtracting the cost of extra liquor shipped to its customers in violation of state law from gross receipts; the extra liquor costs were additional COGS, not a "deduction"); *B.C. Cook & Sons, Inc. v. Commissioner,* 65 T.C. 422 (1975), *aff'd*,584 F.2d 53 (5th Cir. 1978) (mitigation provisions do not apply where taxpayer receives double tax benefit from deducting an item twice in computing taxable income; there was no double deduction when one adjustment was COGS, because COGS is not a deduction). Consequently, if the royalty payments constitute additional inventory costs, such payments do not constitute deductions as required by section 1341(a)(2) and cannot qualify for the tax benefits of section 1341.

C. Inventory Rule

Assuming that the payment of damages for underpaid royalties constitute additional inventory costs, even if Taxpayer did satisfy all of the requirements of section 1341(a)(1)-(3), the "inventory rule" of section 1341(b)(2) would preclude the tax benefits of section 1341 to such payments. With an exception not relevant here, this rule denies the tax benefits of section 1341 to any deduction allowable "with respect to" an item which was included in gross income by reason of the sale or other disposition of stock in trade, inventory, or property held primarily for sale to customers in the ordinary course of business.

Applying the inventory rule requires determining which deductions are allowable "with respect to" an item which was included in gross income by reason of the sale of inventory. In this context, Treas. Reg. § 1.1341-1(f)(1) interprets "with respect to" as meaning “attributable to.” It follows that the deduction must be for an amount previously included in income “attributable to” or generated by, the sale of an inventory item.

In this case, Taxpayer recognized gross income from the sale of inventory, namely oil. Taxpayer now has a legal obligation for underpaid royalties owed to the lessor for oil sold in prior years. If it is determined that the damages for underpaid royalties is an inventory cost and that Taxpayer is entitled to a deduction for the damages, then the deduction should be treated as allowable with respect to an item that was included in gross income by reason of the sale of inventory. Inventory costs, as a cost of goods sold (COGS), is essential to the determination of gross income under Treas. Reg. § 1.61-3(a). Taxpayer had already engaged in the transaction giving rise to a legal liability for underpaid royalties when this income was recognized. Therefore, the obligation to pay additional royalties and the resulting deduction is directly related to the inclusion of the item in gross income. Accordingly, assuming the Taxpayer was entitled to a deduction for underpaid royalties that would have constituted an inventory cost if paid when originally due, the inventory rule would disqualify that deduction for the tax benefits of section 1341.

Part III Sales of Lease Oil to Other Members of the Consolidated Group

Production companies in the Taxpayer’s consolidated group may have sold crude lease oil to other members of the group, for example, the sale by a production company within the group to a refiner within the group. This raises the question of whether such sales should be characterized the same as independent sales to third parties for characterization of the royalties relating to such oil or whether the separate corporate entities should be disregarded for this purpose.

In contrast to the current consolidated return regulations, which generally attempt to characterize transactions between members of a consolidated group as if the group members were divisions of the same corporation[13], the consolidated return regulations applying to the taxable years covered by the settlement period took a different approach. These regulations generally determined the character and source of any deferred gain or loss attributable to a deferred intercompany transaction at the time of the transaction by treating the transaction as if it had not occurred during a consolidated return year. Treas. Reg. § 1.1502-13(c)(4). In other words, character and source were generally determined as if the transaction occurred between unrelated entities. Consequently, if a producing company within Taxpayer’s consolidated group sold lease oil to another member of the group, for example, a transportation company or a refiner, such a sale would be treated for royalty characterization purposes the same as if were to an independent third party.

CASE DEVELOPMENT, HAZARDS AND OTHER CONSIDERATIONS

[13] See Treas. Reg. § 1.1502-13(a)(2)

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