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THE INCOME TAX UPON OIL AND GAS INTERESTS

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INTRODUCING THE TAX PATTERN *

The tax law has been getting out of hand. Text writers and the tax services have been struggling valiantly to condense, interpret and correlate the mass of material which nowadays comprises that law. There have been, in moderate number, sound analyses, brilliant criticisms and competent summaries. But to the general practitioner the tax law has become the mysterious domain of the tax specialist. Yet, the general practitioner has become increasingly aware of the impact of taxation upon the subject matter of his practice. He knows that he may not draw a trust or a will, nor prepare or foreclose a mortgage, nor organize or liquidate a corporation, without potential tax consequences. These consequences he must ferret out from an Internal Revenue Code which is primarily an instruction book for the preparation of a tax return—an accountant's handbook. The Code presents a numerical sequence of "items" of income, deductions, credits, exclusions and exemptions, with no pretence of a subject-matter correlation. The synthesis of these items into a complete tax picture for his own transaction is a formidable task for any lawyer. Because the texts and services have uniformly followed the statutory pattern, the lawyer's principal guide to his problem is a labyrinth of confusing indices.

The tax pattern technique is the product of considerable experimenting with the "subject-matter" approach. It has been developed

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with three major aims: (1) a reallocation of the tax law to coincide with the lawyer's understanding of subject-matter division; (2) a visual summary and coordination of the various tax aspects of each major subject-matter; and (3) annotations keyed to the summaries for complete discussion of each point involved.

The present article is a representative example of the method. The traditional approach to the problem—the chapter on royalty income, the chapter on depletion deductions, the chapter on capital gains and losses—has been scrapped. It is too clear to require demonstration that no one of the tax aspects of an oil and gas lease relationship may be understood without an understanding of its correlative aspects. The specific tax rules, therefore, have been subordinated to the relationships themselves: lessor-lessee, assignor-assignee, producer-drilling contractor, producer-investor, etc. The tax rules thus summarized within each box of the chart assume a coherence which is but faintly perceptible in the statute itself.

I. THE LEASEHOLD RELATIONSHIPS

There are several factors which contribute to the complexity of the tax law relating to oil and gas income. One is the varying nature of the tax issues themselves. Another is the unique concept pervading the cases of "interests in the oil and gas in place", and the consequences of the gradual exhaustion of such interests. The most complicating factor, however, is the number and the variety of the interests which participate in the production of the income.

Let us take a simple case. Mr. Farmer owns a modest ranch for which, many years ago, he paid \$10,000. Oil is discovered a few miles away, and Mr. Farmer is visited by Mr. Speculator. The resulting deal is a lease of the oil, gas, and mineral rights of the ranch to Mr. Speculator, for which Mr. Farmer receives a \$50,000 cash "bonus", plus a "royalty" equal to $\frac{1}{8}$ of the gross selling price of the oil to be produced during the term of the lease.

The oil fields a few miles away develop better than expected, and Mr. Speculator is ready to turn over a profit. He visits Mr. Promoter, and another deal is made. He assigns his leasehold interest (subject, of course, to Mr. Farmer's $\frac{1}{8}$ royalty) and receives from Mr. Promoter \$80,000 in cash, and an "oil payment" of $\frac{1}{16}$ of the gross oil to be produced until he shall have received an additional \$200,000. Mr. Speculator has thus come out of the transaction with \$30,000 net cash, plus a $\frac{1}{16}$ oil payment right to the extent of \$200,000. Mr. Promoter, at a cost of \$80,000 has acquired a $\frac{7}{8}$ "working interest", subject to a $\frac{1}{16}$ oil payment.

I. THE LEASEHOLD RELATIONSHIPS

In the chain of transactions leading up to production of oil and gas income, a variety of relationships may be created: lessor-lessee, assignor-assignee, investor-producer, and producer-drilling contractor.

Each of these relationships may be involved in fixed cash payments, royalty rights, oil payment rights, and other contingent interests in production.

Each such transfer or payment may involve also interest-related tax questions: income realization-recoupment of cost, depletion allowance, capital gain, cost recovery-depletion, and deduction of income—payment of purchase price.

III. "SALE" BY LESSOR OR ASSIGNOR

When the consideration received for the lease or assignment of an interest in oil or gas property is in not an economic interest, but is a sale, the income is not an economic interest. Such income is not ordinary income derived from the property and therefore is not subject to depletion. While generally a right to share in the oil produced is an "economic interest," this rule does not apply to guaranteed or secured production payments, nor to a share in the net profits of production.

IV. RESERVATION OF ROYALTIES BY LESSOR OR ASSIGNOR

Since a right to royalties is an "economic interest" in the oil and gas property, it is ordinary income and is subject to depletion. If the lessor or assignor reserves, in addition to the depletion allowance, fixed annual bonuses, or a lump-sum cash payment, these amounts, like royalty income, are ordinary income subject to depletion. "Delay rentals," while ordinary income, are not subject to depletion.

V. RESERVATION OF OIL PAYMENTS BY LESSOR OR ASSIGNOR

When the lessor or assignor has retained the right to a fixed sum payable only out of oil production, such amounts are not subject to depletion. Where, however, a cash payment is received in addition to such an oil payment right, the majority of the cases hold that the cash payment represents the selling price of an interest "sold," and is therefore subject to the capital gain provisions, and is not subject to depletion. Cost is allowed for the cash payment, and the oil payment right. The cost allocable to the latter is recoverable only through depletion.

X. THE INVESTOR AND PRODUCTION RIGHTS

If the investor acquires "an economic interest in the oil and gas in place," payments received by him from production represent ordinary income subject to depletion, not a return of capital. Upon the sale or exchange of royalty, payment or other production rights, capital gain or loss may be realized. It is noted that the fair market value of the proceeds is determinable.

IX. PRODUCTION RIGHTS GRANTED BY PRODUCER

In the case of a producer there can be no question as to his right of depletion with respect to his own operating income. Consequently the producer will assign a participating interest in an oil well to an investor for an advance production or in return for drilling the well. If the investor receives only the completed well, or if in return for an investment he gives up production rights in the specific well, no income is realized by the producer. But if the investor's income is realized without restriction, such money is taxable to the investor. The producer of an interest in the property, not as income from the property subject to depletion.

XI. THE DRILLING CONTRACTOR AND PRODUCTION RIGHTS

To the extent that the drilling contractor acquires an "economic interest," his drilling costs represent a capital investment. The return from this interest is ordinary income subject to depletion. A cash payment received by the driller represents ordinary business income reduced by the portion of his drilling costs allocated to the cash payment. The return from this interest is not subject to economic interest, to be recovered by depletion deductions.

VI. PRODUCTION PAYMENTS AND THE ECONOMIC INTEREST OF THE PRODUCER

The principal question for the producer is whether royalties are income to him or to the assignor. If the assignor is his own income. If the lessor or assignor has retained an "economic interest in the oil and gas in place" sufficient to derive ordinary income and obtain the depletion allowance, such income is not taxable to the producer and is excluded in determining his "gross income from the property" for purposes of percentage depletion.

VII. BONUS PAYMENTS BY PRODUCER

A producer, or any other transferee, who makes a lump-sum payment to acquire an "economic interest in the oil and gas in place" is entitled to a depletion deduction for the payment. Such cost is recoverable only through the depletion allowance, though it serves no tax purpose to the percentage depletion taxpayer. Moreover, in determining the percentage depletion allowance for production years, the taxpayer is required to reduce his "gross income from the property" by the portion of the bonus allocable to such production.

VIII. PRODUCTION PAYMENTS AS PRODUCER'S COST

Production payments to a lessor or assignor which do not flow from an "economic interest" represent his selling price of the interest conveyed. Conversely, such payments are the producer's income, taxable to him as income from the property. In some cases, they may be included in the producer's "initial cost"; in others, they may be added annually to his basis. In the latter case, the annual cost depletion deductions would increase disproportionately to production.

Mr. Promoter now calls upon The Big Gusher Development Co., and another assignment of the Farmer lease is effected. Mr. Promoter recoups his \$80,000 cash investment, and acquires a $\frac{1}{8}$ royalty interest plus a \$100,000 oil payment to be paid out of $\frac{1}{16}$ of the oil produced. The development company, at a cost of \$80,000, is now the owner of a $\frac{3}{4}$ working interest, subject to two separate $\frac{1}{16}$ oil payments.

At long last the property is in the hands of a company interested in actual production. But The Big Gusher Development Co. is not equipped for drilling a well, so there is a conference with The Deep Drilling Co. The latter estimates that it will cost \$20,000 to drill a well on the property, and would like to charge \$30,000 for the job. Big Gusher counters with the proposition of \$10,000 in cash, and a speculative \$50,000 to be paid out of $\frac{1}{16}$ of the oil to be produced. Another paper is signed, and the oil presses anticipatorily against its enclosing rock.

There may still, however, be the problem of development capital. Big Gusher obtains \$50,000 from The Oil Finance Co. in return for a $\frac{1}{16}$ "participating interest" in gross production for the life of the lease. By this time the interest remaining to the development company is an $\frac{11}{16}$ working interest, subject to $\frac{3}{16}$ oil payments aggregating \$350,000.

Up to this point, remember, not one drop of oil has been produced. Yet, there have been many taxable transactions; and, anomalously, considerable "income from the property" has been realized, and "depletion" deductions have been incurred. Suppose now that the various investors turn out to be the victims of wildcat optimism. A complete set of tax problems results. Or, more happily, the property produces. For every barrel of oil, there may be a tankload of tax complications. Our sextet above is not a fantastic example. It could easily be worse. Mr. Speculator may want to realize on his \$200,000 $\frac{1}{16}$ oil payment in advance of production, by selling a one-half interest for \$50,000 in cash. Mr. Promoter, somewhat skeptical of the Farmer property, trades his $\frac{1}{8}$ royalty interest for an oil payment right in an adjoining property. Deep Drilling Co., having finished its job, liquidates; the stockholders receive their pro rata share of its \$50,000 $\frac{1}{16}$ oil payment as a liquidating dividend. Mr. Farmer dies, and his heirs inherit his $\frac{1}{8}$ royalty interest. Big Gusher Development Co., to utilize the anticipated gas production, contracts with a casinghead gasoline plant for the removal and processing of the gas in return for a percentage of the gross income from gasoline and dry gas. The tax cases contain all of these—and others.

And thus the cases come before the Treasury, the Board of Tax Appeals, and the courts. What part of Mr. Farmer's \$50,000 is subject to tax? Is Mr. Speculator's profit ordinary income or is it capital gain? Mr. Promoter spent and received \$80,000 in cash; does he pay tax because he received also a speculative interest in an unopened well? Does The Big Gusher Development Co. obtain taxable income when The Deep Drilling Co. opens the well? Or when Oil Finance Co. pays it \$50,000 for development? Does The Deep Drilling Co. have a \$10,000 expense, or does it have a capital investment in the property? And after production begins, the problems multiply. The Big Gusher Development Co. receives all of the production income, and passes it to the various $\frac{1}{8}$'s and $\frac{1}{16}$'s along the line; must it pay tax on any part of the money it does not keep? The Deep Drilling Co. gets back the balance of its \$20,000 drilling cost; does it have taxable income, or may it offset its expense? May Oil Finance Co. recoup its \$50,000 out of the first production, or must it await depletion deductions? And then interests are sold and exchanged and devised; and the interests must be evaluated and apportioned. The stratum of tax problems exceed those of the rock in the geologist's notebook.

There are few fields in the tax law where the allocation of the tax burden appears so difficult. Income from both speculation and production must be determined in relation to the varying kinds and amounts of investment, and to the values of the interests retained in the property. Most complicating of all, the income must be measured with a gauge recording the exhaustion of the property. For, on some not entirely predictable date, the property which produced the gusher will inevitably be just a piece of land with a big hole. Theoretically, the tax law is designed to have that date coincide with the last of a series of reasonable depletion deductions. Since that deduction is an integral part of every oil and gas tax problem, a brief summary of the "mechanics" of depletion would seem appropriate, before it is considered in connection with the various relationships comprising an oil and gas lease.

II. THE DEPLETION DEDUCTION

The depletion allowance is intended primarily to compensate the taxpayer for the exhaustion of the contents of his well. Fundamentally,¹ the taxpayer is entitled to a reasonable annual allowance based

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1. "Fundamentally" the taxpayer is entitled to no such deduction, since all deductions are a matter of legislative grace. Depletion is no exception. *Burnet v. Thompson Oil & Gas Co.*, 283 U. S. 301 (1931); *Stanton v. Baltic Mining Co.*, 240 U. S. 103 (1916); see *Von Baumbach v. Sargent Land Co.*, 242 U. S. 503, 525 (1917). Perhaps this is too glib a statement. There is some justification for the contention that deduc-

upon cost, or other statutory basis. The equivalent of this allowance in the case of deteriorating assets, as distinguished from depleting assets, is the depreciation deduction.² This compensating deduction for the decline in the content of oil and gas wells resulting from production and sale is known as "cost depletion". But Congress, concerned first with encouraging the pioneer and wildcatter in the oil and gas industry (and in certain phases of the mining industry), and disturbed later by the "everlasting accounting" problem in computing the depletion allowance, evolved as an alternative to cost depletion the "percentage depletion" method, and permitted the oil and gas taxpayer to use this latter method if it produced a greater deduction in any year.³ Thus "tax gravy" was discovered as a new by-product of oil and gas.⁴ To date no Congressional attack has gathered sufficient strength to shake this subsidy out of the statute. Incidental to the depletion allowance is the problem of recovering the cost, or other basis, of improvements and equipment not attributable to the well itself.⁵

The three factors applied in determining cost depletion are "basis", "units sold" and "remaining units". The basis used is the same as the basis for computing gain, which in turn is cost, or other statutory basis, adjusted for depletion.⁶ There is excluded from the amount

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tions designed to accomplish the tax-free return of a taxpayer's capital are inherently necessary as a matter of computation to arrive at income. *Davis v. United States*, 87 F. (2d) 323 (C. C. A. 2d, 1937), *cert. denied*, 301 U. S. 704 (1937). So far as depletion is concerned the "gross income concept" is academic, for the statute since 1913 has authorized a deduction for this factor.

2. "In essence, the deduction for depletion does not differ from the deduction for depreciation." *United States v. Ludey*, 274 U. S. 295, 303 (1927). One is quantitative, the other qualitative.

3. See SEIDMAN, *LEGISLATIVE HISTORY OF FEDERAL INCOME TAX LAWS* (1938) 352, 583-586. The percentage depletion alternative was first incorporated in § 204 (c) (2) of the Revenue Act of 1926 as a substitute for the "discovery depletion" method, which was then presenting difficult problems of application and valuation. Discovery depletion is now applicable only in the case of mines, other than metal, coal or sulphur, where the discovery was made by the taxpayer after February 28, 1913, and the resulting fair market value became disproportionate to cost. INT. REV. CODE § 114 (b) (2); U. S. Treas. Reg. 103, § 19.23 (m)-3.

4. Percentage depletion was to be the rule of thumb designed to replace the complicated accounting involved in cost depletion. As a practical matter taxpayers compute both cost and percentage depletion to be sure of securing the greater deduction. But the odds seem to be in favor of percentage depletion. "The estimated annual loss of revenue due to this source alone is about \$75,000,000". Tax Evasion Message of President Roosevelt, June 1, 1937. Moreover, cost depletion computations are a prerequisite to a determination of adjusted basis for gain or loss. See note 6 *infra*.

5. This deduction is in addition to and apart from the depletion deduction. See note 28 *infra*.

6. INT. REV. CODE § 114 (b) (1); U. S. Treas. Reg. 103, § 19.23 (m)-2. For basis other than cost, see INT. REV. CODE § 113 (a). Cost, or other statutory basis, of the depletable property must be adjusted for cost depletion to the extent allowed, but not less than the amount allowable. In addition, where percentage depletion was deducted in the taxable year 1932 or subsequent years, the basis must be further adjusted for any excess over cost depletion. INT. REV. CODE § 113 (b) (1) (B). The Bureau has ruled that depletion deductions beginning with 1932 in excess of the cost basis of any well, are applicable to the reduction of the basis of other wells on the property, even if drilled in a subsequent year. G. C. M. 22239, 1940-2 CUM. BULL. 105. The cost of

of the basis the cost or value of the land not used for oil or gas production, the amount recoverable through depreciation and through deductions other than depletion, and the residual value of other property at the end of operations,⁷ but there is included those amounts of capitalized "intangible drilling and development expenses" which are recoverable through depletion.⁸ If the basis used is "cost", it must be shown to have been incurred in a bona fide purchase and sale.⁹ If basis is dependent upon fair market value, such value must be determined in the light of an assumed transfer, as of the date of valuation, between a willing seller and a willing buyer.¹⁰ In the absence of fair market value factors, value may be determined by "analytical appraisal" methods.¹¹

The Treasury Regulations recognize a borderline class of expenditures, commonly known as "intangible drilling and development expenses".¹² Generally, these are the items incurred in drilling wells and preparing them for production which do not in themselves have any salvage value, such as the expenditures for wages, fuel, repair,

drilling nonproductive wells may at the taxpayer's option be deducted for the year in which the well is completed, or may be capitalized and recovered through the depletion (and depreciation) allowance on the property. U. S. Treas. Reg. 103, § 19.23 (m)-16 (a) (2). As to the meaning of the term "property", see note 21 *infra*.

7. U. S. Treas. Reg. 103, § 19.23 (m)-2. The purpose of these exclusions is to limit the basis for depletion to the portion of cost, or other basis, attributable to the well itself. Adjusted basis for gain or loss, as distinguished from the basis for depletion, requires the determination of the basis of the entire property, with additional adjustments for depreciation (to the extent allowed or allowable, whichever is greater) and for items chargeable to capital account. INT. REV. CODE §§ 113 (b) (1) (A), (B).

8. "Intangible drilling and development expenses," discussed in the next paragraph, are not properly chargeable to capital account if previously deducted in computing net income. U. S. Treas. Reg. 103, § 19.113 (b) (1)-1.

9. U. S. Treas. Reg. 103, § 19.23 (m)-6.

10. U. S. Treas. Reg. 103, § 19.23 (m)-7. No revaluation is permitted, during the continuance of the ownership under which the value was determined, except for misrepresentation, fraud, or gross error as to any facts known on the date as of which the valuation was made, and then only with the consent of the Commissioner. U. S. Treas. Reg. 103, § 19.23 (m)-8; see *Lucky Tiger-Combination Gold Mining Co. v. Crooks*, 95 F. (2d) 885, 889 (C. C. A. 8th, 1938); cf. *Rust-Owen Lumber Co. v. Com'r*, 74 F. (2d) 18 (C. C. A. 7th, 1934); *Cape Henry Syndicate*, 30 B. T. A. 794 (1934). This revaluation must be distinguished from the revision of estimated recoverable units for the purpose of redetermining the depletion unit (not the depletion basis). See note 17 *infra*.

11. U. S. Treas. Reg. 103, § 19.23 (m)-7.

12. U. S. Treas. Reg. 103, § 19.23 (m)-16. Costs which must be capitalized are those by which the taxpayer acquires tangible property ordinarily considered as having a salvage value, such as the cost of actual materials in those structures which are constructed in the wells and on the property, and the cost of drilling tools, pipe, casing, tanks, engines, boilers, machines, etc. Costs which must be expensed include operation and production expense, general overhead expense, taxes, and depreciation of drilling equipment, though incurred during development. U. S. Treas. Reg. 103, §§ 19.23 (m)-16 (c) (1), (2). But see *New Quincy Mining Co.*, 36 B. T. A. 376 (1937). In computing excess profits net income for base period years, deductions for intangible drilling and development costs are disallowed to the extent of the excess over 125% of the average of such deductions for the four prior years, or the excess over the deductions of that class for the taxable year, whichever excess is less. INT. REV. CODE § 711 (b) (1) (I).

hauling, supplies, etc.¹³ The taxpayer may elect either to deduct these items as current expense or to capitalize and recover them through subsequent depletion and depreciation deductions.¹⁴ Of these items, those applicable to clearing ground, draining, road making, surveying, geological work, excavation, grading, and drilling, shooting and cleaning of wells are recoverable by depletion. Those for labor, fuel, repairs, hauling and supplies applicable to the installation of casing and equipment and in the construction on the property of derricks and other physical structures are recoverable by depreciation.¹⁵ Therefore, the "basis" factor used in determining cost depletion is the adjusted cost, or other statutory basis, attributable to the well, plus that portion of capitalized intangible drilling and development expenses recoverable through depletion.

The annual cost depletion deduction is computed by first distributing the basis among the units (barrels of oil, or thousands of cubic feet of natural gas) remaining in the well as of the taxable year. This provides the depletion unit. The depletion unit so determined is then multiplied by the units sold within the taxable year. The result is the cost depletion for the taxable year. The "number of units sold

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13. Expenditures for wages, fuel, repairs, hauling, supplies, etc., in connection with equipment, facilities, or structures, not incident to or necessary for the drilling of wells, such as structures for storing or treating oil or gas, are capital items recoverable through the depreciation deduction. U. S. Treas. Reg. 103, § 19.23 (m)-16 (c) (2). When the taxpayer contracts with an independent driller for a completed well under a "turnkey contract", the amount paid to the driller is a capital cost, and no part of the cost may be deducted at the option of the taxpayer. *Hughes Oil Co. v. Bass*, 62 F. (2d) 176 (C. C. A. 5th, 1932), *cert. denied*, 289 U. S. 726 (1933); *Harris Co. v. Com'r*, 112 F. (2d) 76 (C. C. A. 6th, 1940); *E. C. Laster*, 43 B. T. A. 159 (1940). The optional deduction is permitted, however, where the driller is in the employ of the taxpayer, *W. D. Ambrose*, 42 B. T. A. 1405 (1940); or where the expenses "are incurred under a contract providing for the drilling of a well to an agreed depth, or depths, at an agreed price per foot or other unit of measurement". U. S. Treas. Reg. 103, § 19.23 (m)-16 (a) (1). The Treasury recently proposed an amendment to the Regulations regarding drilling costs. The producer is to capitalize his costs whenever drilling is performed by an independent contractor, even on a footage basis. Vigorous protest from the industry compelled a temporary postponement of this proposed amendment. See Release, November 3, 1941, 413 C. C. H. Fed. Tax Serv. ¶6580. As to the requirement that the drilling contractor capitalize costs which result in his obtaining an "economic interest" in the oil or gas in place, see Section XI *infra*.

14. The election must be made on the first return, and is binding for all subsequent years. U. S. Treas. Reg. 103, § 19.23 (m)-16 (d). The propriety of granting this election, as well as the reasonableness of requiring a binding election, has been approved. *Vinton Petroleum Co. of Texas v. Com'r*, 71 F. (2d) 420 (C. C. A. 5th, 1934), *cert. denied*, 293 U. S. 601 (1934); *Boone County Coal Corp. v. United States*, 37 F. Supp. 327 (D. W. Va. 1941), *aff'd*, 121 F. (2d) 988; *California Coast Oil Co.*, 25 B. T. A. 902 (1932); *Fort Ring Oil & Gas Co.*, 30 B. T. A. 307 (1934). But the taxpayer may show that no binding election was intended or effected in its return. *Lucas v. Sterling Oil & Gas Co.*, 62 F. (2d) 951 (C. C. A. 6th, 1933); *Callie E. Robertson*, 28 B. T. A. 635 (1933).

15. The distribution of these expenses between depreciable and depletable items depends upon whether the amounts capitalized are represented by physical property or not. U. S. Treas. Reg. 103, §§ 19.23 (m)-16 (b) (1), (2); see *United States v. Dakota-Montana Oil Co.*, 288 U. S. 459 (1933). As to the importance of segregating depreciable items where percentage depletion is being used by the taxpayer, see page 392 *infra*.

within the taxable year," in the case of a taxpayer reporting on the cash receipts and disbursements method, includes units for which payments were received within the taxable year although produced and sold prior to the taxable year, and excludes units sold but not paid for in the taxable year. Sales, not payment, is the factor for the taxpayer on the accrual basis. In neither case does the phrase "number of units sold within the taxable year" include units with respect to which depletion deductions were allowed or allowable prior to the taxable year. The number of units "remaining as of the taxable year" is the number of units at the end of the year still to be recovered from the property (including units recovered but not sold) plus the number of units sold within the taxable year.¹⁶ The determination of the content of the well may be revised from year to year if warranted by development work or operations.¹⁷

As already stated, the taxpayer in oil and gas cases is not confined to cost depletion. He may, if it produces a larger deduction, use the percentage depletion method.¹⁸ No permanent election is required of the taxpayer, and he may adopt each year the method most advantageous to him.¹⁹ This method permits a deduction in an arbitrary amount equal to 27½% of the "gross income from the property". In no case, however, may the deduction exceed 50% of the "net income from the property".²⁰

"Gross income from the property" is the selling price of the crude oil or gas in the immediate vicinity of the well.²¹ If the taxpayer

16. U. S. Treas. Reg. 103, § 19.23 (m)-2. In the case of gas wells, where the annual production is not metered and is not capable of a reasonably accurate estimate, the "decline in rock pressure" method is permitted. *Id.*

17. The estimate of total recoverable units must be made according to the method current in the industry. U. S. Treas. Reg. 103, § 19.23 (m)-9. The statute authorizes the revision of the estimated recoverable units, for determining depletion for subsequent years, where such revised estimate is ascertained as a result of operations or of development work. INT. REV. CODE § 23 (m). "Subsequent years" includes the year in which the revision is made. U. S. Treas. Reg. 103, § 19.23 (m)-9, as amended by T. D. 5054, 1941-1 CUM. BULL. 227. Significantly, the statute provides that such revised estimate will not, however, affect "the basis for depletion." The result is that a revision of the estimated recoverable reserve will require an upward or downward revision of the depletion unit, but no change in the basis recoverable through depletion. *McCahill v. United States*, 1941 Fed. Tax Serv. 4 ¶ 9634. (D. Minn. 1941); *American Sulphur Royalty Co. of Texas*, 34 B. T. A. 439 (1936); *cf. McCahill v. Helvering*, 75 F. (2d) 725 (C. C. A. 8th, 1935). As to the revision of basis where predicated on value, see note 10 *supra*.

18. Percentage depletion may be taken though the taxpayer has no basis for gain or loss or for cost depletion. *Louisiana Iron & Supply Company, Inc.*, 44 B. T. A. 1244 (1941); *cf. Second Carey Trust*, 41 B. T. A. 800 (1940), where percentage depletion was allowed though no evidence of cost depletion was introduced.

19. INT. REV. CODE §§ 114 (b) (3); 23 (m); U. S. Treas. Reg. 103, § 19.23 (m)-4. As to the information required to be attached to the return of a taxpayer who claims percentage depletion, see U. S. Treas. Reg. 103, § 19.23 (m)-13.

20. INT. REV. CODE § 114 (b) (3).

21. The taxpayer's interest in each separate mineral property is a separate "property". *Vinton Petroleum Co. of Texas v. Com'r*, 71 F. (2d) 420 (C. C. A. 5th, 1934), *cert. denied*, 293 U. S. 601 (1934). The term "property" means each separate interest owned by the taxpayer in each separate tract or parcel of land, whether sepa-

transports or processes the product, the representative "field price" of the crude oil or gas, or in the absence of such field price the portion of the selling price applicable to the crude oil or gas at the well, is used.²² Rents and royalties paid by the taxpayer are deducted in determining gross income from the property.²³ Advance royalties, if deducted from income for the taxable year, are deducted also for this purpose.²⁴ In addition, there is deducted the portion of any bonus paid which is allocable to the product sold during the taxable year.²⁵ "Net income from the property" is the "gross income from the property" less allowable deductions attributable or fairly allocable to the mineral property, but not including depletion.²⁶ Intangible drilling and development costs optionally deducted from income by the taxpayer are deducted in determining net income from the property.²⁷

Irrespective of the method of depletion adopted by the taxpayer, he is permitted to recover the cost, or other basis, of improvements and equipment. This recovery is accomplished through the deprecia-

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rated geographically or by conveyance. It means also each different interest of the taxpayer in the same tract, G. C. M. 22106, 1941-1 CUM. BULL. 245. But two or more mineral properties included in a single tract or parcel of land may be considered to be a single property, provided such treatment is consistently followed. Jewel Mining Co., 43 B. T. A. 1123 (1941). A "mineral property" is the mineral deposit, the development and plant necessary for its extraction, and so much of the surface of the land necessary for purposes of mineral extraction. U. S. Treas. Reg. 103, § 19.23 (m)-1 (b). As used in the Regulations the term "minerals" includes oil and gas, but the term "mine" does not include oil and gas wells. U. S. Treas. Reg. 103, §§ 19.23 (m)-1 (d), (e).

22. "In the case of oil and gas, if the crude mineral product is not sold on the property but is manufactured or converted into a refined product or is transported from the property prior to sale, then the gross income from the property shall be assumed to be equivalent to the market or field price of the oil or gas before conversion or transportation". U. S. Treas. Reg. 103, § 19.23 (m)-1 (f). "Gross income from the property" does not include costs of production defrayed by the purchaser of the product. *Helvering v. Mountain Producers Corp.*, 303 U. S. 376 (1938).

23. U. S. Treas. Reg. 103, § 19.23 (m)-1 (f).

24. See Section VI *infra*.

25. See Section VII *infra*.

26. The allowable deductions include overhead and operating expenses, depreciation, taxes, losses sustained, etc., but exclude any allowance for depletion. U. S. Treas. Reg. 103, § 19.23 (m)-1 (g). These deductions have been held to include interest on loans for development and equipment (*Mirabel Quicksilver Co.*, 41 B. T. A. 401 (1940)); interest on loans to purchase producing property (*St. Marys Oil & Gas Co.*, 42 B. T. A. 270 (1940)); state income tax applicable to production (*Grisson Oil Corp.*, 42 B. T. A. 1117 (1940)); full interest on income tax deficiencies, where the taxpayer had other sources of income but no other "business" (*Holly Development Co.*, 44 B. T. A. 51 (1941)); cost of geological and land departments where deducted as expense (G. C. M. 22689, 1941-1 CUM. BULL. 225). The percentage depletion allowance, as well as the net income limitation thereon, must be computed for each depletable economic interest or property held by the taxpayer. G. C. M. 22956, 1941 INT. REV. BULL. No. 46 at 2. As to the meaning of the term "property," see note 21 *supra*. For taxable years beginning after December 31, 1940, the excess profits tax is deductible in computing net income. Presumably, the portion of this tax allocable to the property is deductible in computing "net income from the property". For the purpose of the excess profits tax, however, the limitation is based upon the net income without reduction by the excess profits tax. INT. REV. CODE §§ 711 (a) (1) (G), 711 (a) (2) (I), both added by the Rev. Act of 1941 § 202 (d).

27. U. S. Treas. Reg. 103, § 19.23 (m)-1 (g); *Helvering v. Wilshire Oil Co. Inc.*, 308 U. S. 90 (1939). As to the option to capitalize or deduct these costs, see note 14 *supra*.

tion allowance.²⁸ It has already been noted that the portion of capitalized intangible drilling and development expenses attributable to casing and equipment and in the construction on the property of derricks and other physical structures is recoverable through depreciation.²⁹ Segregation of depletable and depreciable property is particularly advantageous to the taxpayer when percentage depletion is employed, since otherwise the depreciation of improvement costs would be merged in the depletion allowance.³⁰ In general, the depreciation allowance is spread over the life of the equipment or improvement, or the life of the depletable property, whichever is shorter.³¹

The application of these depletion formulæ present little theoretical difficulty, although a detailed and sometimes involved accounting analysis may be required. The difficulty arises in determining who obtains the depletion deduction, and when. If producing oil were generally a one-man proposition, the judicial eye could be kept on the entire venture and the depletion allowance could be easily relegated to its correct relationship with the other parts. But the traffic in oil and gas interests produces income which has no connection with actual production. The depletion deduction must often be anticipated as well as distributed. In such cases, the "who" and "when" of the depletion deduction must be considered in connection with the income aspects of the oil and gas relationships.

III. "SALE" BY LESSOR OR ASSIGNOR

When the owner of an interest in oil or gas property sells, leases, subleases, or assigns such interest, or a part thereof, he immediately acquires a set of tax problems. (The latent tax problems of his vendee, lessee, sublessee, or assignee are reserved for subsequent discussion.) If there is a taxable transaction, what is the measure of the income? Is it ordinary income or is it capital gain? Is a depletion deduction allowable?

Of the many factors which determine these answers, the most important (and most troublesome) is whether or not the taxpayer retained an "economic interest in the oil and gas in place." If the taxpayer makes an outright sale of his entire oil and gas interest,

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28. As to the deduction for depreciation (and obsolescence generally, see U. S. Treas. Reg. 103, §§ 19.23 (1)-1 to (1)-10, inclusive. This deduction covers the physical property, such as machinery, tools, equipment, pipes, etc. U. S. Treas. Reg. 103, § 19.23 (m)-18.

29. See note 15 *supra*.

30. See *United States v. Dakota-Montana Oil Co.*, 288 U. S. 459 (1933).

31. The basis is equitably distributed over the useful life of the property so as to bring such property to its true salvage value when no longer useful. But where the reasonable expectation of the economic life of the oil or gas deposit is shorter than the normal useful life, the deduction may be based upon the length of life of the deposit. U. S. Treas. Reg. 103, § 19.23 (m)-18.

there is one set of answers. If he leases or assigns his interest, but retains a fractional interest in the gross production for the life of the lease, there is another set of answers. Between the two lies a twilight zone in which the lines are still in the process of demarcation: the retention of "oil payments" to be paid out of gross production, but only until such time as a fixed aggregate of such payments is received.

A sale or exchange of property is ordinarily a taxable transaction, provided that the income therefrom is "realized" within the taxable year. If the owner of an oil and gas interest sells his entire interest for a fixed amount, his gain or loss is the difference between that amount and the "adjusted basis" of the property in his hands.³² Suppose, however, that the selling price consists of a speculative interest in the future production of the property. The accepted measure of taxability upon an exchange is the "fair market value" of the property or right received in exchange; but if such value is indeterminate, the realization of income, or of gain or loss, is postponed until a subsequent realization upon the property or right acquired.³³ The courts have been reluctant to apply a "fair market value" test to oil and gas interests.³⁴ Whether such valuation is grounded upon engineers' estimates or upon actual purchase and sale figures, the attitude is understandable. There are few commodities with the inherent uncertainties and fluctuations of an interest in oil property. To require an immediate tax on a "gain" so essentially speculative is patently harsh. In the long run, there is no prejudice to the revenues, and the courts are disposed to require the Treasury to join the taxpayer in his gamble.

Will the same result follow if the taxpayer receives a cash payment in addition to a speculative interest in production or profits? On

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32. INT. REV. CODE § 111. As to adjustment of basis for depletion allowed or allowable, see note 6 *supra*.

33. *Burnet v. Logan*, 283 U. S. 404 (1931); *Helvering v. Tex-Penn Oil Co.*, 300 U. S. 481 (1937); *Gould Securities Co. v. United States*, 96 F. (2d) 780 (C. C. A. 2d, 1938). As to gain realized by a taxpayer on the cash basis, see *Helvering v. Nibley-Mimnaugh Lumber Co.*, 70 F. (2d) 843 (App. D. C. 1934); *I. T.* 3485, 1941-1 CUM. BULL. 240.

34. *Columbia Oil & Gas Co.*, 41 B. T. A. 38 (1940), *aff'd*, 118 F. (2d) 459 (C. C. A. 5th, 1941) cited note 52 *infra*; *E. C. Laster*, 43 B. T. A. 159 (1940), *appeal pending* C. C. A. 5th, cited note 75 *infra*; *Kay Kimbell*, 41 B. T. A. 940 (1940), cited note 83 *infra*; *Com'r v. Edwards Drilling Co.*, 95 F. (2d) 719 (C. C. A. 5th, 1938), *aff'g* 35 B. T. A. 341 (1937), cited note 87 *infra*; *cf. Midfield Oil Co.* 39 B. T. A. 1154 (1939), cited note 83 *infra*. In *Robert J. Boudreau*, 45 B. T. A. No. 70 (Oct. 21, 1941), the Board held, with four dissents, that a stockholder's gain on the liquidation of a corporation includes the fair market value of oil payments received in the liquidation. In *Champlin Refining Co. v. Com'r*, 123 F. (2d) 202 (C. C. A. 10th, 1941), the taxpayer corporation was allowed a cost basis for depletion measured by the value of its stock given in payment for the oil interest, which value was in turn predicated upon the value of the interest. This conclusion was reached in the face of the court's prior decision that a stockholder had realized no gain upon the receipt of that corporation's stock, since the stock had no "fair market value" on account of pending litigation over title to the property. *Champlin v. Com'r*, 71 F. (2d) 23 (C. C. A. 10th, 1934).

the one hand, it does not seem entirely equitable that he should receive a tax-free recovery of his entire cost before any part of the cash is taxable. On the other hand, there seems no justification for a different tax classification of a future indeterminate profit merely because it is received together with cash. The Board and the courts have not quite emerged from their tussle with this problem, but the results seem clearly foreshadowed. The taxability of such a transaction depends primarily upon the nature of the speculative interest. There is one result if the taxpayer retains a royalty interest. There is another if the taxpayer retains a right to oil payments. And there is still a third if the taxpayer retains no "economic interest in the oil and gas in place." In the first case, all of the cash is income (subject to depletion); in the second, the taxpayer's basis is allocated between the interest "sold" and the interest "retained"; in the third, the full basis of the taxpayer's interest is set off against the realized payments before there is any taxable gain from the transaction.

This is only one of the differences effected by the retention or non-retention of an "economic interest in the oil or gas in place." Dependent upon the holding period of the asset, gain realized upon a sale or exchange may be taxed at the more favorable rates applicable to capital transactions.³⁵ This rule would apply to the sale of an oil or gas interest for a fixed amount. But, again, the answer is not so simple when the taxpayer receives an interest in production or profits. It becomes further complicated when cash is received in addition to such an interest. If a royalty interest is retained, both the cash and the royalty constitute ordinary income. If an oil payment is reserved, gain on the cash received is capital gain, whereas the income realized as oil payments is ordinary income. Where no "economic interest" is retained, the gain on the entire consideration would seem to be subject to the capital gain limitations.

There is still a third difference attributable to an "economic interest" retained or not retained by the taxpayer. If an amount received by the taxpayer represents income derived from the property (as distinguished from income derived from a disposition of the property) he is entitled to a depletion allowance with respect to such income. This means that the taxpayer is not entitled to set off the entire cost of his interest against the first income realized. It means also, however, that a taxpayer with little or no cost may still be entitled to the

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35. INT. REV. CODE § 117. As to the special limitation upon individual surtax in the case of a sale of oil or gas property, or any interest therein, where the principal value of the property has been demonstrated by prospecting or exploration or discovery work done by the taxpayer, see INT. REV. CODE § 105.

arbitrary subsidy of the deduction for percentage depletion. If a royalty interest is retained, both the royalties and a cash bonus are entitled to depletion deductions. If an oil payment is reserved, the income realized on the oil payments is subject to depletion, but a cash payment is not. If no "economic interest" is retained, the taxpayer's income is the full amount realized in excess of his basis.

In view of the issues summarized above, it is not strange that taxpayers and the Treasury are continuously shifting position on what constitutes an "economic interest". In one case, a taxpayer will argue that he did not retain an interest, and is therefore entitled to a tax-free recovery of cost. In a second case, the taxpayer is seeking the advantage of the capital gain rates. In a third case, the taxpayer who has no cost basis may be willing to forego the advantages of capital gain in favor of a percentage depletion deduction.

With characteristic disregard of nomenclature, the tax law may view a lessor as a vendor, and an assignor as the holder of an "economic interest". The Supreme Court has stated that the consequences of a lease or assignment are affected neither by state law,³⁶ nor by "the formalities of the conveyancer's art."³⁷ In commenting upon the quality of a lessor's interest required for a depletion allowance, the court negatived the importance of the retention of ownership or any 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."³⁸ And a lessee may retain an "economic interest" upon his assignment of the leasehold interest, if by the assignment he withheld a right to a fraction of the oil to be produced.³⁹ From these early pronouncements, there were grounds for belief that a sale was effected only when the consideration was a fixed cash payment, and that any lessor or assignor who acquired a right to payment dependent upon the operation of the property retained an "economic interest in the oil and gas in place." The Supreme Court has since announced two important departures from such a rule. No "economic interest" is retained by a person who conveys

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36. *Burnet v. Harmel*, 287 U. S. 103 (1932). In that case it was argued that a lease under Texas law constituted a sale of the oil and gas prior to severance from the soil, and that a lump-sum payment received upon such a "sale" was subject to the capital gain provisions. The court held that the retention by the lessee of an interest in production precluded such interpretation, since the economic consequences were the same as those of a lease in which title to the oil and gas did not pass before severance.

37. *Anderson v. Helvering*, 310 U. S. 404, 411 (1940), cited note 41 *infra*.

38. *Palmer v. Bender*, 287 U. S. 551, 557 (1933), cited note 46 *infra*.

39. *Thomas v. Perkins*, 301 U. S. 655 (1937), cited note 60 *infra*.

his interest for a share in the net profits of production,⁴⁰ nor by a person who reserves an interest in the fee as security for oil payments.⁴¹

Whether the exceptions in the last two cases produce a "workable rule" is open to question. Each of these cases was a government victory. In one, a depletion deduction was denied to the transferor. In the other, the payments were taxed as the transferee's income, on the theory that the amounts turned over to the transferor represented the cost of the transferee's interest. Conversely, then, the payments represent selling price to the transferor. It is somewhat anomalous that such income should be subject to the capital gain limitations. With the tremendous advantage which the capital gain rates afford today, there may be, notwithstanding the Supreme Court's abjuration, a high premium upon the "conveyancer's art". The plight of the transferee in such a case will be more fully discussed in a later section. Meanwhile, it is only fair to note that a tax-conscious transferee will be represented by his own conveyancer.

IV. RESERVATION OF ROYALTIES BY LESSOR OR ASSIGNOR

Of the various types of interests which may be reserved by a transferor, two result in the retention of an "economic interest in the oil and gas in place." For tax purposes, the "royalty" interest is the simpler. The "oil payment" interest will be discussed in the next section.

A royalty is a fractional interest in the gross production of the oil or gas. This is the interest customarily reserved by the owner of the property when he leases the mineral rights. It is unlimited in amount, and operates for the life of the lease. By its terms, the royalty owner is not required to share in drilling or development costs, nor in the costs of operation. The royalty interest is generally collected by the ultimate producer of the oil and gas, and turned over to the

40. *Helvering v. Elbe Oil Land Development Co.*, 303 U. S. 372 (1938); *Blankenship v. United States*, 95 F. (2d) 507 (C. C. A. 5th, 1938). The same conclusion was reached in *Helvering v. O'Donnell*, 303 U. S. 370 (1938), where there was the additional factor that the cash and percentage of net profits were received by the taxpayer as consideration for stock of a corporation which owned the producing property. See G. C. M. 22730, 1941-1 CUM. BULL. 214, 223-224, disapproving *Reynolds v. McMurray*, 60 F. (2d) 843 (C. C. A. 10th, 1932), *cert. denied*, 287 U. S. 664 (1932).

41. *Anderson v. Helvering*, 310 U. S. 404 (1940). The transferor, noted the court, "is not dependent entirely upon the production of oil for the deferred payments; they may be derived from sales of the fee title to the land conveyed. . . . It is similar to the reservation in a lease of oil payment rights together with a personal guarantee by the lessee that such payments shall at all events equal the specified sum. . . . In the interests of a workable rule, *Thomas v. Perkins* must not be extended beyond the situation in which, as a matter of substance, without regard to formalities of conveyancing, the reserved payments are to be derived solely from the production of oil and gas". *Anderson v. Helvering*, *supra* at 412-413. Cf. *E. C. Laster*, 43 B. T. A. 159 (1940), *appeal pending*, C. C. A. 5th, holding that a lien against production is not equivalent to a lien against the property.

lessor; but it may be paid directly by the purchaser of the product to the lessor. The royalty is usually stated as a percentage of the gross value of production, but may even be fixed as a fraction of the oil in kind, at the surface of the well. Generally, the term "royalty" is restricted to the interest retained by the lessor, but a similar interest (an "overriding royalty") may be retained by the lessee, or by his sublessee or assignee, in subsequent conveyances of the oil and gas interest.⁴²

Royalty income is ordinary income, essentially the same as rental income from property. The important difference between the two, however, is that the royalties are paid with respect to a depleting interest in the oil and gas in place. The royalty recipient, therefore, is entitled to a depletion deduction as an offset against his income. Where cost depletion is employed, the deduction represents a pro rata return of the taxpayer's cost attributable to the producing property. Where percentage depletion is more advantageous, the effect is to subject but 72½% of the royalty income to tax, regardless of the taxpayer's cost.

In the same category as royalties are "advance royalties" and fixed bonuses which are payable each year regardless of production.⁴³ But such payments differ from "delay rentals" paid by a lessee or assignee for the privilege of postponing development beyond the date fixed in the lease. The latter payments are taxable as ordinary income to the lessor or assignor, but are not subject to depletion.⁴⁴

If a lessor or assignor receives a lump-sum cash payment in addition to the royalty right, such a bonus is treated as an "advance royalty", despite the fact that the amount of the bonus is not to be deducted from the amount of the royalties. The amount of the bonus, therefore, is ordinary income in the hands of the lessor or assignor,

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42. A somewhat confusing cross-current of definitions has been recognized for personal holding company surtax liability. "Personal holding company income" includes, within certain limitations, "mineral, oil, or gas royalties." INT. REV. CODE § 502 (h). Overriding royalties are not included in this provision, nor are they included in "royalties (other than mineral, oil, or gas royalties)." U. S. Treas. Reg. 103, § 19.502-1 (3), (11). A true "advance royalty" chargeable against future production is a "mineral, oil, or gas royalty." Logan Coal and Timber Association, 42 B. T. A. 529 (1940). But a bonus or rent payable regardless of production is not. J. Howard Porter, 42 B. T. A. 681 (1940); I. T. 3401, 1940-2 CUM. BULL. 166. The term includes only amounts received for an interest *reserved* by a taxpayer, not a "participating interest" acquired in consideration of the furnishing of drilling equipment. Kiesau Petroleum Corp., 42 B. T. A. 69 (1940).

43. The Regulations require that depletion be taken against advance royalties in the year in which payment is received, not in the subsequent year in which the production occurs. U. S. Treas. Reg. 103, § 19.23 (m)-10 (b). As to fixed annual bonuses not chargeable against future production, see Alice G. K. Kleberg, 43 B. T. A. 277 (1941).

44. J. T. Sneed, Jr., 33 B. T. A. 478 (1935). This rule has been applied to "extension payments" received prior to production, although identical amounts were to be paid as "advance royalties" upon the commencement of production. Continental Oil Co., 36 B. T. A. 693 (1937).

not proceeds of a "sale".⁴⁵ Since the bonus is treated as derived from the transferor's remaining interest in the property, the bonus is subject to a depletion deduction.⁴⁶ In the computation of depletion on the cost method, the deduction consists of the portion of the taxpayer's basis allocable to the bonus; the taxpayer is not permitted to set off his entire cost against the bonus.⁴⁷

If to his advantage, the taxpayer is entitled to deduct percentage depletion from bonus income.⁴⁸ In allowing this deduction, the Supreme Court overruled the Bureau's position that percentage depletion on a bonus was allowable only if there was actual production within the taxable year, or if "future production was practically assured because of nearby wells and geological indications."⁴⁹ The government has since won a partial and roundabout victory on this issue. If the lease is subsequently terminated without any oil having been produced, percentage depletion (in excess of cost) allowed in a prior year on account of a bonus must be reported as income in the year the lease is terminated.⁵⁰ Nevertheless, if there has been some production (apparently, no matter how small), the deduction need not be restored to income upon the termination of the lease.⁵¹ Granted that the Treasury and the courts are understandably tempted to whittle

45. *Burnet v. Harmel*, 287 U. S. 103 (1932).

46. *Palmer v. Bender*, 287 U. S. 551 (1933). To acquire the characteristics of an "advance royalty", a bonus must be received in connection with the transaction by which a royalty interest was reserved. Thus, in *Badger Oil Co.*, 42 B. T. A. 521 (1940), *aff'd*, 118 F. (2d) 791 (C. C. A. 5th, 1941), *rehearing denied*, May 10, 1941, *cert. denied*, 62 Sup. Ct. 67 (1941), depletion was denied with respect to a lump sum received by a lessee upon the assignment of the lease, although the lessee had previously acquired a share of the lessor's royalty rights.

47. The portion of the taxpayer's basis allocable to the bonus is measured by the ratio which the amount of the bonus bears to the sum of the bonus and the royalties expected to be received. U. S. Treas. Reg. 103, § 19.23 (m)-10 (a). Where at the time the bonus is received there is no showing that the bonus plus expected royalties will exceed the taxpayer's basis, the full bonus is applied in recoupment of cost. In such a case, the practical effect of the bonus is the same as though it represented the proceeds of a "sale". Where a lessor has thus recouped his cost, he may not thereafter claim any part of such cost as a basis for cost depletion against the royalties. *Murphy Oil Co. v. Burnet*, 287 U. S. 299 (1932).

48. *Herring v. Com'r*, 293 U. S. 322 (1934).

49. G. C. M. 11384, XII-1 CUM. BULL. 64.

50. "If for any reason any grant of mineral rights expires or terminates or is abandoned before the mineral which has been paid for in advance has been extracted and removed, the grantor shall adjust his capital account by restoring thereto the depletion deductions made in prior years on account of royalties on mineral paid for but not removed, and a corresponding amount must be returned as income for the year in which such expiration, termination, or abandonment occurs". U. S. Treas. Reg. 103, § 19.23 (m)-10 (c); *Sneed v. Com'r*, 119 F. (2d) 767 (C. C. A. 5th, 1941), *rehearing denied*, 121 F. (2d) 725 (C. C. A. 5th, 1941), *aff'd* 40 B. T. A. 1136 (1939); *Lamont v. Com'r*, 120 F. (2d) 996 (C. C. A. 8th, 1941); *Grace M. Barnett*, 39 B. T. A. 864 (1939). Whether such income is reportable where the taxpayer derived no tax benefit from the deduction in the prior year (e. g. where other deductions exceeded the gross income) seems still an open question. See *National Bank of Commerce of Seattle*, 40 B. T. A. 72 (1939). *Contra*: G. C. M. 22163, 1940-2, CUM BULL. 76.

51. *Dolores Crabb*, 41 B. T. A. 686 (1940), *aff'd*, 119 F. (2d) 772 (C. C. A. 5th, 1941), *remanded on other issue*, 121 F. (2d) 1015 (C. C. A. 5th, 1941). The Circuit Court noted that the Commissioner had not appealed on this issue, and expressly withheld opinion as to the rule.

away the subsidy which Congress has granted, the shavings should be somewhat more substantial—and somewhat less absurd.

V. RESERVATION OF OIL PAYMENTS BY LESSOR OR ASSIGNOR

In the last two sections we have detailed the consequences of a "sale", and the consequences of a retention of an "economic interest in the oil and gas in place." We come now to the hybrid subject of oil payments.

An "oil payment" reserved by a lessor or assignor is similar to a royalty, in that it represents a fractional interest in the gross production from the property. Its point of difference is that it is payable only until a fixed aggregate of money or oil has been received. If the transferor reserves an oil payment as consideration for the transfer, and does not receive any lump-sum payment, his status is the same as that of a royalty owner.⁵² The payments, when realized, are ordinary income and are subject to a deduction for depletion. The taxpayer is not entitled to recoup his entire cost from the first payments received.⁵³

The complications arise when the lessor or assignor receives a lump-sum payment, together with the right to oil payments. If he reserves a royalty as well as an oil payment, a lump-sum payment is taxable as any other bonus received in connection with the reservation of a royalty.⁵⁴ But if the only interest retained is an oil payment, the lump-sum payment is divorced from the "economic interest" still held by the taxpayer. One Circuit Court has refused to distinguish between a royalty and any other interest in this respect,⁵⁵ and the Su-

52. *Thomas v. Perkins*, 301 U. S. 655 (1937); cf. *Helvering v. Elbe Oil Land Development Co.*, 303 U. S. 372 (1938), cited note 40 *supra*; *Anderson v. Helvering*, 310 U. S. 404 (1940), cited note 41 *supra*. As in the case of other contingent payments out of production (whether royalties, oil payments, or "selling price"), the present value of the right is not income when it is acquired; income is realized only when the production occurs. *Columbia Oil & Gas Co.*, 41 B. T. A. 38 (1940), *aff'd*, 118 F. (2d) 459 (C. C. A. 5th, 1941); see note 34 *supra*.

53. *T. W. Lee*, 42 B. T. A. 1217 (1940); see *E. C. Laster*, 43 B. T. A. 159 (1940), *appeal pending*, C. C. A. 5th, holding that the realization of oil payment rights was income subject to depletion, and that the taxpayer was not entitled to recoup the value of the rights as of the date he received them in the liquidation of a corporation; cf. *Com'r v. Laird*, 91 F. (2d) 498 (C. C. A. 5th, 1937), and *O. Kenneth Hickman*, 44 B. T. A. 1242 (1941), holding that the estate tax value of oil payment rights transmitted to the taxpayer by death may be recouped from the first proceeds, although royalties are taxable income subject only to a depletion deduction.

54. *Marrs McLean*, 41 B. T. A. 565 (1940), *aff'd*, 120 F. (2d) 942 (C. C. A. 5th, 1941). In *Cullen v. Com'r*, 118 F. (2d) 651 (C. C. A. 5th, 1941), *rev'g* 41 B. T. A. 1054 (1940) and in *Com'r v. West Production Co.*, 121 F. (2d) 9 (C. C. A. 5th, 1941), *rev'g* 41 B. T. A. 1043 (1940), the Board had found an indivisible assignment of various leases reserving oil payments, in some of which royalties had also been reserved. The Board held, therefore, that depletion was allowable against all cash payments received by the taxpayer. The reversal was based upon the court's conclusion that the leases should have been segregated.

55. *Elbe Oil Land Development Co. v. Com'r*, 91 F. (2d) 127 (C. C. A. 9th, 1937), *rev'd*, 303 U. S. 372 (1938), cited note 40 *supra*, on the ground that the re-

preme Court has not yet passed upon the issue. Nevertheless, the Bureau, the Board and two Circuit Courts have established what may safely be regarded as the prevailing rule. This rule recognizes the oil payment as an "economic interest in the oil and gas in place," so that the income realized from the oil payments themselves is ordinary income, subject to depletion. On the other hand, it recognizes a "sale" of that part of the transferor's interest not represented by the oil payment right, so that the lump-sum payment is not ordinary income and is not subject to depletion.⁵⁶ In other words, an oil payment by itself (or in conjunction with a royalty) has all of the tax characteristics of a royalty; but, because of the ceiling on the aggregate return, it is not a strong enough "economic interest" to impart its own characteristics to a bonus. As a makeshift compromise of the perplexing distinction between "sale" and "income", perhaps this is as logical as any other result. Yet, it seems hardly in consonance with sound tax philosophy to construct a rule which permits a taxpayer, without materially altering his transaction, to shift the tax consequences to his own advantage.⁵⁷

The remaining question, then, is the formula for computing the gain or loss represented by the lump-sum payment. Since part of the transferor's original interest is still represented by the oil payment right retained, he may not apply his entire cost against the lump-sum payment. He is entitled, however, to recover out of that payment the entire depreciated cost of any physical equipment sold by him in the transaction.⁵⁸ His remaining basis is then allocated between the portion of that interest which he "sold", and the portion of that interest which he "retained". This allocation is in the ratio of the respective values of those interests at the time of the transaction.⁵⁹

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served interest itself did not constitute an "economic interest". In *Heep Oil Corp. v. United States*, 32 F. Supp. 762 (Ct. Cl. 1940), the court held that an assignor claiming cost depletion on its oil payments must concede prior depletion on the cash payment received.

56. *Com'r v. Fleming*, 82 F. (2d) 324 (C. C. A. 5th, 1936); *Mamie S. Hammonds*, 38 B. T. A. 4 (1938), *aff'd on this issue*, 106 F. (2d) 420 (C. C. A. 10th, 1939); *G. C. M.* 22730, 1941-1 CUM. BULL. 214.

57. For example, if a transferor who would ordinarily reserve a royalty wishes to obtain a capital gain with respect to a bonus, he need merely convert the royalty into an oil payment by setting a limit upon his return—a limit which is safely in excess of the expected return. See *Eaton, Taxation of Oil Payments* (1941) 19 *Taxes* 661, 664. Of course, the fixing of a fantastic sum would probably result in the disregard of the distinction, but an amount within the upper limits of possible production would be difficult to ignore. It may be noted that here is the perfect opportunity for the unilateral functioning of the "conveyancer's art", since the transferee's tax liability cannot be adversely affected by the result (compare text page 403 *infra*).

58. *Thomas v. Peckham Oil Co.*, 115 F. (2d) 685 (C. C. A. 5th, 1940); *Columbia Oil & Gas Co.*, 41 B. T. A. 38 (1940), *aff'd*, 118 F. (2d) 459 (C. C. A. 5th, 1941).

59. *Columbia Oil & Gas Co.*, 41 B. T. A. 38 (1940), *aff'd*, 118 F. (2d) 459 (C. C. A. 5th, 1941). In that case the taxpayer attempted to increase the basis attributable to the cash payment by employing a ratio based on quantities of oil. It allocated to the reserved oil payments only a sufficient number of barrels to satisfy the oil pay-

The discussion of transferor's income may be best concluded by reverting to the lessor and assignors of our example. Mr. Farmer leased the mineral rights of his ranch for \$50,000 cash plus a $\frac{1}{8}$ royalty. The \$50,000 is taxable as ordinary income, but is subject to a 27½% depletion allowance.

Mr. Speculator assigned his $\frac{7}{8}$ interest for \$80,000 in cash plus a \$200,000 oil payment out of $\frac{1}{16}$ of production. The \$80,000 is not income from the property, nor is his gain limited to the \$30,000 cash profit. If we assume that the oil payment has a present value of \$40,000, his \$50,000 investment must be allocated in the ratio 80:40. His basis for computing gain on the \$80,000 cash received is therefore only two-thirds of \$50,000, or \$33,333.33, and the resulting profit is \$46,666.67. The remaining basis of \$16,666.67 is theoretically recoverable via cost depletion, although that deduction will more probably be computed by the percentage method.

Mr. Promoter assigned the $\frac{7}{8}$ interest (less the $\frac{1}{16}$ oil payment) for \$80,000 (the same amount that he invested) plus a $\frac{1}{8}$ royalty and a \$100,000 oil payment out of $\frac{1}{16}$ of production. Because he retained a royalty as well as an oil payment, the \$80,000 is ordinary income. No part of the \$80,000 investment may be deducted from such income, except by way of the depletion deduction. The remaining investment is still available for cost depletion against the royalties and oil payments.

And so we pass to the ultimate owner of the working interest, and to the converse of the problems discussed above.

VI. PRODUCTION PAYMENTS AND THE PRODUCER

The tax pattern for the oil producer is shaped very largely by the interests of his various predecessors in title. As we have seen, the oil and gas rights of a parcel of land may reach the ultimate holder of the working interest in an extremely fractional state. He has probably given a cash payment and some form of an interest in production to his immediate assignor. In addition, he may be the conduit for various production rights retained by vendors, lessors, sublessors and assignors in the chain of title. These rights may fall within or without the magic phrase "economic interest in the oil and gas in place."

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ments; the remainder of the estimated quantity of oil in place was allocated to the interest sold. The Board rejected this formula, and adopted an allocation based upon values. For the value of the entire property, it accepted a value stipulated by the parties; for the value of the interest sold, it took the actual cash payment received by the assignor for his interest. In *Com'r v. Roeser and Pendleton, Inc.*, 118 F. (2d) 462 (C. C. A. 5th, 1941), the court pointed out that an allocation was impossible where the facts did not disclose a basis for valuation; the employment of the face-amount of the oil payment was held improper.

Let us first consider the royalties and oil payments which The Big Gusher Development Co. passes on to Messrs. Farmer, Speculator and Promoter. From the latter, it will be recalled, the company acquired a $\frac{3}{4}$ working interest, subject to two $\frac{1}{16}$ oil payments. For the moment we may disregard the \$80,000 lump-sum payment, as well as the various payments to the drilling contractor and to the investor. Assume that the gross production of oil for the taxable year is \$320,000. Of this amount, a \$40,000 royalty is paid to Mr. Farmer, a \$20,000 oil payment to Mr. Speculator, and a \$40,000 royalty and a \$20,000 oil payment to Mr. Promoter. Does the company's gross income include any part of the \$120,000 thus paid? As has been demonstrated above, each of these payments is with respect to an "economic interest in the oil and gas in place." The income is treated as derived directly from the property by the ultimate payees. The conclusion, therefore, is that the income is not that of the producer merely because it happened to flow through his hands.⁶⁰ And from this it follows that the producer's "gross income from the property" does not include these payments for the purpose of computing percentage depletion.⁶¹

A peculiar status is accorded "advance royalties" by the Regulations. So far as the payee is concerned, such payments are concededly income from the property, subject to a depletion allowance. If the analogy to ordinary royalties were followed in the case of the producer, the production income attributable to the advance royalty would constitute an *exclusion* from gross income in the year such income was realized. Instead, the Treasury terms the payment a *deduction* from gross income, and offers the taxpayer an election as to the year when that deduction may be taken. The item may be deducted on the return for the year in which the advance was paid or accrued; or, if no election is expressed in the return, the item is deductible when the product with respect to which the royalty was paid is sold.⁶² The latter treatment is unquestionably the more con-

60. *Thomas v. Perkins*, 301 U. S. 655 (1937). A dissenting opinion by Justices Stone and Cardozo insisted that an oil payment made to the assignor was taxable to the assignee; the payment represented merely purchase price for the assignee's interest, whatever might be the tax effect upon the assignor. See *Anderson v. Helvering*, 310 U. S. 404 (1940), cited note 41 *supra*. In *American Liberty Oil Co.*, 43 B. T. A. 76 (1940), *appeal pending*, C. C. A. 5th, oil payments made to the lessor and lessee by the producer were held not taxable income to the producer, where an intervening assignee-assignor reserved a lien on the leasehold equipment. The Board pointed out that the payments in question were not made to that person, but to persons who retained no rights except from oil production.

61. *Helvering v. Twin Bell Oil Syndicate*, 293 U. S. 312 (1934).

62. U. S. Treas. Reg. 103, § 19.23 (m)-10 (e). This election was required to be made in the return for the first taxable year ending on or after December 31, 1939, and such election is binding for all future years. For years ending prior to December 31, 1939, the Treasury apparently recognized the "deduction" only in the year of the production against which the advance royalty was chargeable.

sistent. Yet, the election to treat the payment as a fixed periodic deduction, in the nature of rent, is a privilege to which a realistic taxpayer seems justifiably entitled.⁶³ For the purpose of the percentage depletion deduction, "gross income from the property" is reduced by the amount of advance royalties in the year in which they are deducted by the taxpayer.⁶⁴

VII. BONUS PAYMENTS BY PRODUCER

It has been noted that a lump-sum payment received by a lessor or assignor may be taxed either as ordinary income or as capital gain in his hands. So far as the transferee is concerned, however, the tax consequences are the same in either case. "In the case of the payor any payment made for the acquisition of an economic interest in a mineral deposit or standing timber constitutes a capital investment in the property recoverable only through the depletion allowance."⁶⁵ There can be no quarrel with this statement, though its ending might more informatively have been: "recoverable, if at all, only through the depletion allowance." For it is clear that a taxpayer to whom percentage depletion is more advantageous will not derive a dollar's worth of tax benefit from a \$100,000 bonus payment.

The Treasury, however, has not been content to leave such a taxpayer in *status quo*. It actually penalizes him for the original cost which he incurred in obtaining his interest, if that cost was a depletable "bonus" in the hands of the transferor. In determining "gross income from the property" for percentage depletion, the taxpayer is required to deduct the portion of the bonus allocable to the product sold during the taxable year.⁶⁶ That portion of the bonus, it is said, is equivalent to a royalty paid to the transferor; and a royalty is concededly deductible from production income in computing the producer's "gross income from the property." The proof of such equivalence is that the bonus was taxable as ordinary income to the transferor, and was subject to a depletion deduction in his hands.

Thus, if The Big Gusher Development Co. had paid Mr. Promoter only \$40,000 as the cash consideration for the assignment, its future income taxes would be lower than they will be as a result of the \$80,000 payment. If this perverse conclusion is correct, then the tax law has indeed lost touch with reality. The error, of course, is in the

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63. See *Burnet v. Hutchinson Coal Co.*, 64 F. (2d) 275 (C. C. A. 4th, 1933); *Com'r v. Jamison Coal & Coke Co.*, 67 F. (2d) 342 (C. C. A. 3d, 1933).

64. U. S. Treas. Reg. 103 § 19.23 (m)-1 (f).

65. U. S. Treas. Reg. 103, § 19.23 (m)-10 (a).

66. U. S. Treas. Reg. 103, § 19.23 (m)-1 (f); *Quintana Petroleum Co.*, 44 B. T. A. 624 (1941).

false analogy. A producer is denied depletion on production income paid over as royalties because such income is not taxable to him.⁶⁷ It is another matter to deny depletion on production income, taxable to the producer, merely because he has paid out his own money. No deflection of income accompanied such payment, nor was any other tax advantage derived therefrom. That a cost of this type should adversely affect all subsequent depletion deductions of the taxpayer is a result which requires prompt correction.

VIII. PRODUCTION PAYMENTS AS PRODUCER'S COST

We have seen that not all payments from production constitute income from the property in the hands of a lessor or assignor. A "secured" oil payment, for example, is taxable to the assignor as the selling price of his interest. Conversely, then, the payment represents purchase price to the assignee. The production income which the assignee devotes to such a payment is taxable to him.⁶⁸ Physically, of course, he may be merely a conduit for such income, in precisely the same manner as he is a conduit for royalties and true oil payments. Nevertheless, the income is his own, with a depletion deduction as the only offsetting item. Since the payments constitute a capital investment, there can be no deduction for these payments as an "ordinary and necessary business expense."⁶⁹

It would be pleasantly simple to dismiss the producer's problem at this point. The rulings and cases appear to find no difficulty with such a dismissal: the producer's taxable income which he turns over to an assignor represents cost to him, and such cost is recoverable by depletion deductions spread over the life of the property. In the first place, of course, this cost affects the depletion deduction only if depletion is computed by the cost method. Otherwise, this cost is merged in the percentage depletion deduction, and the tax originally paid on such cost is a complete loss to the taxpayer. For this reason alone, a producer should be wary of entering into any contract wherein his predecessors obtain a share of production but not an "economic interest in the oil and gas in place."

In the second place, the effect of such payments upon cost depletion is not easily predictable. The result may depend upon a further

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67. *Helvering v. Twin Bell Oil Syndicate*, 293 U. S. 312 (1934), cited note 61 *supra*.

68. *Anderson v. Helvering*, 310 U. S. 404 (1940), cited note 41 *supra*.

69. *Quintana Petroleum Co.*, 44 B. T. A. 624 (1941). Minimum royalties commonly payable in mining leases are usually deductible as expenses (see note 63 *supra*); but where the taxpayer lessee had the option to apply such royalties against "purchase price", the deduction was disallowed. *Goldfields of America, Ltd.*, 44 B. T. A. 200 (1941); see *Virginia Iron Coal & Coke Co. v. Com'r*, 99 F. (2d) 919 (C. C. A. 4th, 1938); cf. *Jordan Creek Placers*, 43 B. T. A. 131 (1940).

analysis of the type of payment in question. If the payments are true "guaranteed" oil payments, the producer's cost basis at the date of the assignment should include the face amount of his obligation, since that amount would seem to be the equivalent of a purchase money mortgage issued by any purchaser of property. In that case, of course, the payments are merely in discharge of the initial obligation, and produce no annual change in the depletion basis. The difficulty arises, however, in cases where there is no "obligation" of the producer which may be considered a "cost" at the inception of his interest.⁷⁰ Suppose, for example, that the interest reserved by the assignor is a share of the net profits of production. It is unlikely that the producer would be permitted to capitalize the assignor's estimated share of such net profits at the time of the assignment, and thus to compute his annual cost depletion allowances on such a highly speculative basis. The producer's only alternative, apparently, is to increase his cost basis, year by year, as these payments of "purchase price" are made. This result, however justified by the niceties of tax logic, creates a fantastic distribution of the depletion deduction over the life of the property. The producer obtains an increasing cost against a depleting capital asset. As the oil and gas is extracted, the producer's cost increases, with the result that the maximum cost basis is obtained precisely in time for the final depletion allowance.

A simple hypothetical case will illustrate this conclusion. Let us take first an owner-producer whose producing property costs \$100,000 and has an estimated yield of 1,000,000 barrels. If this property produces 200,000 barrels per year, the \$100,000 cost will be recovered (disregarding percentage depletion) in five annual depletion deductions of \$20,000 each. Now let us take the same producer and the same property, but add the factor of a production payment to an assignor who retains no "economic interest". For simplicity we will assume that each barrel is sold for one dollar and that twenty-five cents of each dollar is paid to the assignor. Our producer, then, is paying tax on \$50,000 each year which he is turning over to his assignor. Again disregarding percentage depletion, how does he recover that \$250,000 additional "cost"? If this \$50,000 is added to the remaining cost basis as of the beginning of each year in which the payment is made, the five annual depletion allowances on that cost would be, roughly, \$10,000, \$22,000, \$40,000, \$64,000, and \$114,000. It is

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70. In *Anderson v. Helvering*, 310 U. S. 404 (1940), for example, the oil payment right of the assignor was "secured", but not "guaranteed" by the assignee. There is considerable doubt whether such an "obligation" may constitute cost for depreciation or depletion prior to the actual payments thereon. See *Midtown Tower, Inc.*, 40 B. T. A. 116 (1939).

difficult to imagine a more preposterous distribution of deductions against a constant income.

The tax inequities of such a computation are too plainly evident. The producer is paying tax in the early years on income which has never really been his, and obtains the compensating depletion allowance in the later years when the deduction probably exceeds his net income. Moreover, if the actual mineral content of the property falls short of the estimate, he has accumulated a large cost basis to be written off as a loss in a year when there is no production income. On the other hand, this discrepancy may not operate entirely against the taxpayer. In the example above, percentage depletion was disregarded. In his first two years, the producer might advantageously take his deduction of $27\frac{1}{2}\%$ of the \$200,000 gross income from the property. To the extent, therefore, that the inadequate cost depletion in those years is covered by percentage depletion, the producer has preserved a potential cost depletion deduction for later years.

This then, is the *reductio ad absurdum* of a perfectly plausible chain of tax logic. The fault would seem to lie in the "workable rule" by which the courts have distinguished between income and selling price. By the standards of plain common sense, the receipt of income which does not belong to the taxpayer is not a realization of taxable income. Exceptions to that rule of common sense should be sparingly applied. A proper exception is where such income is devoted to the acquisition of a capital asset. But where the asset being "purchased" is a depleting asset, and where the "cost" is paid from the very production income which causes the depletion, the purchase theory is at best artificial, and at worst pernicious. An overhauling of this concept, however, is a staggering undertaking. It affects the measure of income of both transferor and transferee; it affects the distinction between ordinary income and capital gain; and it affects the depletion deduction. It is safe to predict that the structure will be preserved, and that the props of equity, if not of consistency, will in time be pressed against the more vulnerable joints.

IX. PRODUCTION RIGHTS GRANTED BY PRODUCER

Up to this point there have been considered the conventional oil and gas relationships of vendor-vendee, lessor-lessee, and lessee-assignee. The "economic interests" have been limited to those *reserved* by the lessor and intermediate owners of the lease. To be entitled to depletion, those persons are apparently required to retain the right to a share of the gross proceeds of production. Obviously, however, this

test is not applicable to the "economic interest" of the producer. The latter is the person who occupies and operates the producing property, and incurs the cost of production; it is unimportant whether he is denominated a lessee or a contractor, so long as he has the right to extract the mineral from the ground and to retain a share of the proceeds.⁷¹ But the producer is not necessarily at the end of the chain of "economic interests". Without relinquishing his status, the producer may contract for a partial operation of the property by another. An example which has at least twice reached the courts is that of the casinghead contractor, whose function is to remove wet gas at the casingheads, or "traps" at the mouth of the well, and to separate that gas into its components of gasoline and dry gas. In both cases, the contractor was to share the production income with the producer. In the first case, the contractor was allowed depletion against its share of the wet gas production, based upon its right to enter upon the land and to assist in the actual extraction.⁷² In a subsequent case, the Supreme Court denied depletion to the contractor on the ground that its status was that of a "processor", not a producer; a mere "economic advantage" from production is insufficient.⁷³ The producer's own computation has not been before the courts. It would seem, however, that the contractor's share of the gas production would not be included in the producer's "gross income from the property."⁷⁴ The result, therefore, is that something less than 100% of the production income from the property is subject to percentage depletion.

Two groups of cases involving the granting of production rights by the producer have been frequently in litigation. The drilling of wells is commonly performed by an independent contractor, and the

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71. "... the Oil Company, whether technically it became a sub-lessee or not, acquired an economic interest in the oil and gas in place identical with that of a lessee ... Though referred to in the agreement as a "contractor", the Oil Company was not ... a mere contractor for hire. It had the right to, and did, occupy the leased property and produce oil and gas therefrom. It had the right to, and did, receive and retain as its own 61 2/3% of the net proceeds of the oil and gas so produced. ... The possessor of such rights cannot be regarded as a mere hireling." *Spalding v. United States*, 97 F. (2d) 697, 700 (C. C. A. 9th, 1938).

72. *Signal Gasoline Corp. v. Com'r*, 66 F. (2d) 886 (C. C. A. 9th, 1933). The various factors recited by the court "make the conclusion inevitable that the petitioner was to have an interest, not only in such gas as might naturally rise and be caught in the casing heads, but that this right extended to all the gas that petitioner might be able to reduce to possession by drawing it to the surface and into its plant". *Signal Gasoline Corp. v. Com'r*, *supra* at 889.

73. *Helvering v. Bankline Oil Co.*, 303 U. S. 362 (1938). The court carefully omitted any reference to the *Signal* case, but said, "Respondent had the right to have the gas delivered, but did not produce it and could not compel production. The pipe lines and equipment, which respondent provided, facilitated the delivery of the gas produced but the agreement for their installation granted no interest in the gas in place. ... Undoubtedly, respondent through its contracts obtained an economic advantage from the production of the gas, but that is not sufficient". *Helvering v. Bankline Oil Co.*, *supra* at 368. For a thorough differentiation of the facts in the two cases, see the Board opinion at 33 B. T. A. 910, 914 (1936).

74. U. S. Treas. Reg. 103, § 19.23 (m)-1 (f).

latter's payment is often an oil payment right or a "participating interest" in the property. Or, drilling and development are financed by outside capital, with an interest in production as the consideration for the money. The producer's fundamental problem in both cases is whether the nature of the transaction is such that income is realizable.

Where all that the producer receives is a completed well, the resulting enhancement of the producer's interest is not taxable income.⁷⁵ This conclusion is in line with the general unwillingness of the courts to anticipate production income: there is time to exact the tax when production actually occurs. A similar result obtains where the producer receives cash for the purpose of drilling a well, provided that the investor receives his production rights in the specific well to be developed with that cash.⁷⁶ In that case, the money is regarded as a contribution to the "reservoir of capital" in the producing property. In the absence of this restriction, however, the money may constitute a payment to the producer as a taxpaying entity, rather than to the joint investment. What is the measure of the producer's income in such a case, and what is its nature?

It will be recalled that a lessor or assignor who reserves a royalty and receives a cash bonus is deemed to receive the bonus as ordinary income from the property, subject to depletion. The producer who transfers a production right for cash would seem to be in the same position. In both cases, the transferor has retained an economic interest, and in both cases the transferor's potential income from production has been reduced by the transfer. The income of the lessor or assignor is considered an advance payment attributable to the interest retained by him, rather than proceeds from the sale of the interest conveyed. The producer, on the other hand, is held to have received the investor's money as the proceeds of a sale.⁷⁷ The result is that the amount received in excess of the cost allocable to the interest sold is taxable as capital gain.⁷⁸

75 E. C. Laster, 43 B. T. A. 159 (1940), *appeal pending*, C. C. A. 5th. As to the nondeductibility of drilling costs under a "turnkey contract", see note 13 *supra*.

76 Transcalifornia Oil Co., 37 B. T. A. 119 (1938).

77. Rogan v. Blue Ridge Oil Co., 83 F. (2d) 420 (C. C. A. 9th, 1936), *cert. denied* 299 U. S. 574 (1936). In that case, the taxpayer financed the drilling of a well by the sale of an undivided interest in that well. The full amount received was held taxable, since there was no showing as to the amount actually used for drilling, nor could the court find an obligation on the part of the taxpayer to use the funds for the benefit of the investors or to return any unused balance to them. In United States v. Knox-Powell-Stockton Co., 83 F. (2d) 423 (C. C. A. 9th, 1936), the taxpayer proved that the amounts it received were used for drilling various wells, but income was held realized because there was no proof that the amounts were used in proportion to each investor's interest in each well. In Rawco, Inc., 37 B. T. A. 128 (1938), income was held realized where the financing occurred after the well had been drilled.

78. Ortiz Oil Co. v. Com'r, 102 F. (2d) 508 (C. C. A. 5th, 1939), *aff'd* 37 B. T. A. 656 (1938), *cert. denied*, 308 U. S. 566 (1939); Majestic Oil Corp., 42 B. T. A. 659 (1940), *on app.* C. C. A. 8th. The formula adopted in the Ortiz case for the allocation of cost was disapproved in Columbia Oil & Gas Co., 41 B. T. A. 38 (1940), *aff'd*,

In our example, therefore, The Big Gusher Development Co. has a \$10,000 capital investment in the well (recoverable through depletion and depreciation deductions) and has given up a share of its future production income. It realizes no income by reason of the increase in the value of the property attributable to the well. But its receipt of \$50,000 development capital from The Oil Finance Co. in exchange for a $\frac{1}{16}$ participating interest is a taxable transaction, since no restriction was placed upon the use of the money for the drilling of a particular well. Its gain (or, presumably, its loss) is measured by the difference between the \$50,000 received and the portion of its investment in the property attributable to the $\frac{1}{16}$ participating interest. The \$50,000 does not represent ordinary income from the property, subject to depletion.

Is there any justification for treating Big Gusher's deal with the finance company any differently from Mr. Farmer's deal with Mr. Speculator, or from Mr. Promoter's deal with Big Gusher? It is difficult to reconcile the "bonuses" of the latter two with the "selling price" of the former. If any distinction is warranted, it would seem to be in the opposite direction. The money received by the producer seems more nearly an anticipation of production income than the money received by a lessor: the producer's transaction is both physically and temporally closer to the actual production of oil than is the original reservation of a highly speculative production interest by the lessor. The same conclusion would seem to follow if we compare the two transactions from the standpoint of "sale". The lessor conveys a $\frac{5}{6}$ or a $\frac{7}{8}$ working interest, whereas the producer generally conveys but a small fraction of his working interest. The consideration received by the lessor appears more nearly severed from his $\frac{1}{6}$ or $\frac{1}{8}$ retained interest than the consideration received by the producer is severed from his own larger fraction. To reduce the issue to its logical extremes, we may imagine a lessor receiving a \$100,000 cash payment plus a $\frac{1}{1,000}$ royalty worth a negligible sum, and the producer selling a \$100 oil payment out of a fraction of his $\frac{999}{1,000}$ interest. Is the \$100,000 received by the lessor "income from the property", while the \$100 received by the producer is "selling price"? Perhaps the answer is that in so extreme a case the lessor's income, too, would be "selling price". Or perhaps the long-unquestioned rule of *Burnet v. Harmel*,⁷⁹ *Palmer v. Bender*,⁸⁰ and *Herring v. Commissioner*⁸¹ is

118 F. (2d) 459 (C. C. A. 5th, 1941), cited note 59 *supra*. In the *Ortiz* case it was held also that amounts contributed to the producer by co-owners of the property in excess of their proportionate shares of the drilling costs were fully taxable to the producer.

79. 287 U. S. 103 (1932).

80. 287 U. S. 551 (1933).

81. 293 U. S. 321 (1934).

proven untenable. Or perhaps the two lines of cases will be permitted to wend their divergent ways with but one arbitrary signpost to inform the puzzled taxpayer.⁸²

X. THE INVESTOR AND PRODUCTION RIGHTS

The taxation of the investor in production rights follows the same pattern as that of other owners of "economic interests in the oil and gas in place." If the interest acquired is a "participating interest" or an oil payment right, his share of the production proceeds is taxable as income from the property, whether or not there has been a formal assignment of a property interest.⁸³ It is ordinary income, subject to depletion, and is not taxable as capital gain.⁸⁴ Even when the investment is in the form of a "loan" to be repaid out of oil produced, the taxpayer may not recoup his investment out of the first payments: the "loan" is merely the basis for cost depletion.⁸⁵ In our example, therefore, The Oil Finance Co. obtains a \$50,000 investment in the oil and gas in place. The production income which it receives is fully taxable as income from the property, except as such income is reduced either by percentage depletion, or by depletion based upon its \$50,000 cost.

If the owner of royalty, oil payment or other production rights sells his interest, the effect is that of any other sale of property: the difference between the selling price and the undepleted cost (or other basis) is taxable as gain or loss. If the taxpayer exchanges his interest for other production rights, the computation of a gain or loss must overcome the difficulty of evaluating the interest acquired. In two cases before the Board, gain was twice recognized on the receipt of a working interest, and once denied on the receipt of an oil payment right.⁸⁶ It is certainly questionable whether this factual difference

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82. Inevitably, however, the borderline cases will arise. In *Berry Oil Co. v. United States*, 25 F. Supp. 97 (Ct. Cl., 1939), the taxpayer lessee assigned the drilling rights beyond a specified depth, the consideration consisting of a lump-sum payment, a contingent lump-sum payment if the well was developed, and a right to one-half of the production after deducting taxes, drilling expenses, etc. The taxpayer was denied depletion against the initial lump-sum payment, on the ground that the payment represented "selling price" of a one-half interest. Here, the taxpayer was more nearly in the position of a lessor or assignor than of a producer, yet the *Harmel*, *Palmer*, and *Herring* cases were held inapplicable. Perhaps the same result could have been reached on firmer ground: since the taxpayer was not a producer with respect to the depth of producing ground subject to the assignment, his reservation of a share of net profits was not an "economic interest" under the rule of *Helvering v. Elbe Oil Land Development Co.* 303 U. S. 372 (1938), cited note 40 *supra*.

83. *T. W. Lee*, 42 B. T. A. 1217 (1940).

84. *Charles Pettit*, 41 B. T. A. 264 (1940), *aff'd*, 118 F. (2d) 816 (C. C. A. 5th, 1941), *cert. denied*, 62 Sup. Ct. 68 (1941).

85. *Roland L. Taylor*, 44 B. T. A. 370 (1941), *appeal pending*, Ct. App. D. C.

86. *Midfield Oil Co.*, 39 B. T. A. 1154 (1939); *Kay Kimbell*, 41 B. T. A. 940 (1940). In the latter case, it was held that the exchange of a working interest for an oil payment was a "taxable" exchange, but that no gain was realized until the tax-

justifies the difference in result. It is possible, of course, that either type of interest may, in a given case, be so clearly realizable as to justify an immediate tax upon its receipt in an exchange. In the usual case, however, it would seem not undue lenience to postpone the tax until the income is realized by actual production.

XI. THE DRILLING CONTRACTOR AND PRODUCTION RIGHTS

When a drilling contractor is engaged for a fixed amount of cash, the excess of that amount over his cost is ordinary business income.⁸⁷ If, however, part or all of his compensation consists of a right to share in gross production, he joins the circle of "economic interests" and is privileged to partake of its tax complications.

To the extent that the consideration received by the contractor is an interest in the property, his drilling costs represent a capital investment, rather than a current expense. This is true whether or not his interest was created by a formal assignment,⁸⁸ and whether the drilling expenses were incurred before or after his acquisition of the interest.⁸⁹ The present fair market value of the interest is not income at the time the interest is acquired,⁹⁰ but neither may the entire drilling cost be recouped from the first production payments.⁹¹ In other words, the contractor's "economic interest" is the same as that of a lessor or of

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payer's basis of the working interest was recovered out of production. The Board seemed to imply that the income derived after such recovery would be taxable as capital gain—a taxpayer's windfall, indeed. In *E. C. Laster*, 43 B. T. A. 159 (1940), *appeal pending*, C. C. A. 5th, the taxpayer had received oil payment rights in a corporate liquidation, and the then value of the oil payments had presumably been taken into account in computing the taxpayer's gain or loss on liquidation. Income subsequently realized on the oil payments was held ordinary income, subject to depletion, but not subject to the recoupment of cost from the first payments received. Since gain or loss on liquidation is the same as gain or loss on an exchange of property (see *Robert J. Boudreau*, 45 B. T. A. No. 70 (1941) cited note 34 *supra*) the distinction between the *Kimbell* and *Laster* cases as to the nature of the income would seem to stand solely on whether or not gain or loss was recognized on the exchange. The rule, it is submitted, should be the same in both cases. Since the oil payment in both cases represents an "economic interest", the amounts subsequently realized from production should be ordinary income subject to depletion. If the oil payment right had no fair market value, at the time of the exchange, its basis for depletion should be the same as that of the interest transferred in exchange. This should follow whether or not the exchange qualified under the "like kind exchange" provisions of INT. REV. CODE, § 112 (b) (1). See *E. C. Laster*, *supra*.

87. *Rowan Drilling Co.*, 44 B. T. A. 189 (1941).

88. *T. W. Lee*, 42 B. T. A. 1217 (1940). The Board expressly overruled the distinction which had previously been expressed in *Cook Drilling Co.*, 38 B. T. A. 291 (1938), and *F. H. E. Oil Co.*, 41 B. T. A. 130 (1940).

89. *F. F. Hardesty*, 43 B. T. A. 245 (1941), *appeal pending*, C. C. A. 5th; *Hodges Drilling Co.*, 43 B. T. A. 1045 (1941); *G. C. M.* 22224, 1940-2 CUM. BULL. 216.

90. *Com'r v. Edwards Drilling Co.*, 95 F. (2d) 719 (C. C. A. 5th, 1938), *aff'd* 35 B. T. A. 341 (1937).

91. *Dearing v. Com'r*, 102 F. (2d) 91 (C. C. A. 5th, 1939); *Fleming v. Com'r*, 121 F. (2d) 7 (C. C. A. 5th, 1941); *T. W. Lee*, 42 B. T. A. 1217 (1940). In *Rowan Drilling Co.*, 44 B. T. A. 189 (1941), the taxpayer was allowed percentage depletion against oil payments realized in the taxable year, though it had deducted its drilling costs as expenses in a prior year.

an investor: his share of production income is taxable as ordinary income, subject to depletion. For the purpose of cost depletion, of course, his basis is the drilling costs for which the interest was obtained.

If the driller receives a fixed cash payment in addition to the interest in the property, the drilling cost must be apportioned in the ratio which the cash bears to the present value of the interest. In our example The Deep Drilling Co. spent \$20,000 to drill the well, and received \$10,000 in cash plus a \$50,000 oil payment. If the oil payment is assumed to be worth \$30,000, then $\frac{1}{4}$ of the \$20,000 cost is allocable to the \$10,000 cash, and the \$5,000 net amount is taxable as ordinary business income. The remainder of the cost is available for cost depletion against the income to be realized on the oil payment.

One further point may be noted. Had the drilling company received a participating interest in addition to the cash and the oil payment, an allocation of cost among the three classes of consideration would be required. The portion allocable to the participating interest would be further apportioned between depletable and depreciable property. The importance of the latter step is that a percentage depletion deduction may be taken against the production income without the sacrifice of the depreciation deduction based on cost.⁹²

CONCLUSION

On the whole, the courts have woven the multiplicity of oil and gas interests into a reasonably consistent pattern. The attempt has been made to tax all production income, but to avoid the duplication of such tax upon the various interests in the chain of title. The one serious criticism of the pattern is that the Supreme Court too narrowly limited the test for "economic interest", with the result that a lessor or assignor may obtain an unwarranted advantage at the expense of the producer. Payments by one interest to another in anticipation of production have been treated with somewhat less consistency. Perhaps the Supreme Court's early analogy between a lessor's bonus and advance royalties warrants re-examination; certainly the different rules applied in the oil payment and bonus case, and in the producer-investor case rest upon tenuous distinctions.

Athwart any possible tax pattern, however, is the barrier of percentage depletion. If cost depletion were the only offset against production income, the problem would be to measure each taxpayer's income in relation to his investment. From that point of view, it would

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92. G. C. M. 22332, 1941-1 CUM. BULL. 228.

not be too difficult to synthesize the various interests involved in an oil and gas property, and to allocate the tax burden. Since cost is not a factor in determining the arbitrary deduction for percentage depletion, such an allocation ceases to be a matter of logic and tax principle. The distinction between income from property and gain or loss on the disposition of property is important throughout the tax law. It determines not only the rate of tax applicable to the transaction, but whether any, or part, or all, of the taxpayer's cost is to be offset against such income. But where this distinction determines whether or not 100% or 72½% of the taxpayer's income is subject to tax, regardless of cost, the refinements of property interests have a slight flavor of fantasy. The inevitable result has been an artificiality of reasoning which frequently defies analysis.