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Oil and Gas Taxation: A Study in Reform

BY SANFORD M. GUERIN*

INTRODUCTION

Although all citizens are guaranteed equality under the law, the exigencies of economic and political realities often require a certain amount of compromise in the equitable apportionment of the tax burden between respective taxpayers. Because the tax laws, in addition to their purely revenue-producing function, are often utilized to regulate and promote a wide spectrum of economic, social, and political policies, the laws frequently encourage a conflict between competing policy considerations. One by-product of this problem has been the tendency toward increased complexity of the tax laws, with a proportional increase in difficulty of interpretation and administration. Nowhere is this more evident than in the field of oil and gas taxation.

Since the inception of the federal income tax, concerned taxpayers and legislators have voiced considerable criticism of the federal tax provisions which promote preferential or special treatment for certain groups. This criticism has become undeniably stronger in recent years. Reform-minded taxpayers have been most vocal over the existence of loopholes and "tax shelter" provisions that, even when not intending to do so, allow high income taxpayers to avoid paying their "fair share" of the tax burden. Responding to this criticism, Congress has enacted amendments to existing provisions and created new and more restrictive provisions under the various tax reform acts. The principal target has been the oil and gas provisions.

While presenting a general overview in oil and gas taxation, this article will emphasize the relative merits and drawbacks of recently enacted provisions and trends in the field of oil and gas taxation. But first, a discussion of the intrinsic nature of oil and gas is necessary to aid understanding of the congressional intent underlying the oil and gas tax provisions.

Although sharing a number of the general concepts with

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other provisions of the Internal Revenue Code (hereinafter referred to as the Code), oil and gas taxation differs conceptually in certain key aspects. The reasons for the differences in concept, with corresponding differences in terminology, can be reduced to a basic trio of physical, economic, and political considerations. The fact that oil and gas deposits are nonrenewable, are found at often considerable depths beneath the surface of the earth or ocean floor, and are extractable only through various exploration, drilling, pumping, and recovery-enhancement operations constitutes a part of the unique physical factors inherent in oil and gas activities. The economic factors include those of burgeoning demand, finite supply, foreign oil, inflation, cost effectiveness of recovery techniques, and alternative energy sources. The political considerations involve dealing with the problems inherent in attempting to allocate and regulate a relatively scarce commodity among competing consumer and producer groups, both internally on the national level and externally on a global scale.

At present, there appears to be two competing schools of thought regarding the preferential tax treatment historically afforded the oil and gas industry. The one school concerned with the unfair tax advantage designed to benefit the oil and gas taxpayers contends that certain oil and gas provisions, not truly serving to promote or stimulate domestic exploration, create a "tax shelter industry" in themselves. As such, these provisions are counterproductive to the broad national policy favoring energy self-sufficiency and efficiency. The opposite school of thought is entertained by critics who charge that recently enacted provisions vitiate the national policy favoring increased incentives for domestic oil and gas exploration. Congress is presently giving with one hand and taking with the other. These critics contend, for example, that the availability of the percentage depletion allowance, a major incentive for the drilling and development of domestic oil and gas deposits, should have been expanded, not restricted, as was the case in recent legislation. The tension created by these two divergent views is no better reflected than in the tax reform provisions that modify the basic tenets of oil and gas taxation as discussed in this article.

I. Intangible Drilling Costs

A. *The Significance of Intangibles*

Because intangible drilling costs (hereinafter referred to as IDC) are a major part of the total cost of an oil and gas venture and are afforded preferential tax treatment, a thorough understanding of IDC is of great importance to those interested in the taxation of oil and gas. The IDC provisions play a vital role in the national policy favoring incentives for exploration and development of oil and gas reserves by granting the taxpayer the option of deducting IDC as an expense in the year paid or incurred rather than capitalizing and recovering these costs, like other capital expenditures, through depreciation or depletion.[1]

During the past decade, several factors presented new challenges of statutory interpretation for the courts and serious policy and administrative considerations for the Congress involving the deduction of IDC. These factors are as follows: 1) the insatiable worldwide appetite for oil and gas; 2) the increasing difficulty of locating accessible oil and gas deposits; 3) the rapidly increasing expense of drilling and developing producing wells; 4) the advancement of drilling technology; and 5) the increasing fervor over the tax-sheltering potential of an investment in an oil and gas venture. Due to the legislative, administrative, and judicial responses to these considerations, the subject of IDC has become increasingly complex and controversial.

B. *Historical Development of IDC Provisions*

The option to deduct IDC was created by an administrative ruling[2] incident to the Revenue Act of 1916. The lack of statutory authority and the clearly capital nature of intangible drilling expenditures invited attack.

The first attack occurred in 1931 in the case of *Sterling Oil and Gas Company v. Lucas.*[3] The district court found that, although IDC were classified properly as capital expenditures, the long acceptance and the unmodified reenactment of the IDC provisions gave the regulation the force and effect of law.[4]

1. Treas. Reg. § 1.612-4(b)(1),(2) (1965).
2. Treas. Reg. 45, Article 223.
3. 51 F.2d 413 (W.D. Ky.), *aff'd on other grounds*, 62 F.2d 951 (6th Cir. 1933).
4. 51 F.2d 413 (W.D. Ky.) at 416.

Two years later the circuit court reached the same conclusion.[5]

However, in the second attack in 1945 the court held the IDC regulations to be invalid in the case of *F.H.E. Oil Company v. Commissioner.*[6] The court reasoned as follows: 1) the allowance of a deduction for capital expenditures would be improper under the Code, 2) no specific authority could be inferred from the depletion provisions in the Code, and 3) the lack of specific authority could not be cured by a regulation promulgated without statutory authority and congressional acquiescence.[7] The industry fought back and obtained a resolution from the 79th Congress[8] to indicate previous congressional recognition of the IDC regulations. Unswayed, the court in *F.H.E. Oil* denied a second request for rehearing.[9]

Finally, the matter of deductibility of IDC was codified in 1954 and regulations were authorized to be prescribed.[10] Subsection 263(c) created a specific exemption for IDC from the general rule of subsection 263(a) prohibiting deduction of capital expenditures.

C. *IDC Defined*

The regulations define IDC as "expenditures made by an operator for wages, fuel, repairs, hauling, supplies, etc., incident to and necessary . . . for the production of oil and gas."[11] These expenditures must be incurred in the following three areas:

> 1) In the drilling, shooting, and cleaning of wells;
> 2) In such clearing of ground, draining, road making, surveying, and geological works as are necessary in preparation for the drilling of wells; and

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5. Ramsey v. Commissioner, 66 F.2d 316 (10th Cir.), *cert. denied*, 290 U.S. 673 (1933).

6. 147 F.2d 1002, 1005, *rehearing denied*, 149 F.2d 238, *second rehearing denied*, 150 F.2d 857 (5th Cir. 1945), *aff'g* 3 T.C. 13 (1944), *nonacq.* 1944 C.B. 37, *nonacq. withdrawn and acq.* 1960-1 C.B. 4.

7. *Id.*

8. 59 Stat. 44 (1945).

9. 150 F.2d 857 (5th Cir. 1945).

10. I.R.C. § 263(c). This subsection provides as follows:

> Notwithstanding subsection (a), regulations shall be prescribed by the Secretary under this subtitle corresponding to the regulations, which granted the option to deduct as expenses intangible drilling and development costs in the case of oil and gas wells and which were recognized and approved by the Congress in House Concurrent Resolution 50, Seventy-ninth Congress.

11. Treas. Reg. § 1.612-4(a) (1965).

> 3) In the construction of such derricks, tanks, pipelines, and other physical structures as are necessary for the drilling of wells and the preparation of wells for the production of oil and gas.[12]

The regulations further provide that only those costs incurred which have no salvage value can be classified as intangible.[13] Thus, tangible assets such as equipment, facilities, or structures which have salvage value do not qualify as IDC whether or not they are incident to the drilling of wells or in preparing the wells for production.[14] However, the classification of costs such as wages, fuel, repairs, and hauling supplies connected with tangible assets depends on whether these structures or equipment are incident to or necessary for the drilling of wells. If so, these expenditures are deemed to have no salvage value and would qualify as IDC.[15]

The focus of the regulations is upon the drilling and preparation of wells for production. Since expenditures for reconnaissance and detailed surveys, commonly known as G and G costs, represent capital expenditures not incident or necessary for the drilling of wells, they cannot be deducted as IDC; instead, they must be capitalized and added to the basis of the property.[16] Furthermore, the Internal Revenue Service (hereinafter referred to as the Service) considers the drilling and preparation of wells for production as complete when the well casing and the "christmas tree" are installed.[17] After this point, costs without salvage value are costs incident to production and are therefore treated as currently deductible operating expenses, not IDC.

D. *Who May Deduct IDC?*

IDC are capital expenditures in nature, but as stated above, they are specifically exempted from the general rule of subsection 263(a) forbidding current deduction of capital expenditures. However, there are two prerequisites to IDC deductibility. First, only an "operator" may elect to deduct,

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12. *Id.*
13. *Id.*
14. *See id.*
15. *Id.* On the other hand, costs such as wages, fuel, and repairs that are connected with equipment or facilities not incident to the drilling of wells do not qualify for the IDC option. Treas. Reg. § 1.612-4(c)(1) (1965).
16. Rev. Rul. 77-188, 1977-1 C.B. 76. *See* text accompanying note 67 *supra*.
17. *See* Treas. Reg. § 1.612(c)(2) (1965).

rather than capitalize, IDC. Second, the election must be proper.

1. Operator Defined

An "operator," as defined by the regulations, is a party holding an operating or working interest in the property.[18] The owner of a working interest assumes the burden of developing and operating the property. Consequently, the working interest must bear all costs in connection with finding oil and gas, as well as those attributable to lifting the oil and gas from the reservoir. The working interest looks to the production of the oil and gas to recoup his drilling and operating costs and make a profit. The working interest may be acquired by purchase, lease, or any other form of contractual arrangement.[19] The actual drilling of the well may be done by the operator himself, a contractor engaged on a per-foot cost basis, or on a turnkey basis.[20]

The operator with a fractionalized working interest is allowed a deduction only for the IDC attributable to his fraction of the working interest.[21] Additionally, the working interest, or fraction thereof, must be held throughout the "complete payout period" in order to qualify the interest for the IDC election.[22]

2. Method and Effect of the Election

The operator electing to deduct the IDC must do so on his return for the first taxable year in which the costs are paid or incurred.[23] A formal statement is not necessary, but a failure to deduct the costs in the first year is deemed an election to capitalize these expenditures.[24] An amended return for the first taxable year IDC are paid or incurred reflecting the election will not cure the original return's oversight of capitalizing IDC unless the amended return is filed before the due date of the original return.[25]

18. Treas. Reg. § 1.612(a) (1965).

19. *Id.*

20. *Id.*

21. *Id.*

22. *See* Rev. Rul. 71-207, 1971-1 C.B. 160; Rev. Rul. 71-206, 1971-1 C.B. 105; Rev. Rul. 70-336, 1970-1 C.B. 45; Rev. Rul. 69-332, 1969-2 C.B. 87.

23. Treas. Reg. § 1.612-4(d) (1965).

24. *Id.*

25. Commissioner v. Titus Oil and Inv. Co., 132 F.2d 969, 970 (10th Cir. 1949).

The effect of the election to either capitalize or deduct IDC is clear—the election is binding for all subsequent years.[26] Moreover, costs deducted under the election may not be included in the basis of the property for depreciation or depletion purposes.[27]

However, all is not lost where an operator failed to deduct his IDC in the first taxable year. In the case of nonproductive wells, the regulations provide the operator a second option:

> If the operator has elected to capitalize intangible drilling costs, then . . . such costs incurred in drilling a nonproductive well may be deducted by the taxpayer as an ordinary loss provided a proper election is made in the return for the first taxable year . . . in which such well is completed.[28]

E. *Areas of Uncertainty or Controversy*

1. Deepening Wells and Secondary Recovery

Although the regulations provide a broad description of items qualifying as IDC, examination of applicable revenue rulings and case law reveals certain expenditures which, though not appearing to be directly connected with drilling and development for production, can indeed qualify for the IDC election. For example, an operator may decide to deepen, perhaps with an eye towards dual completion,[29] a well already in production at a certain depth. Although the costs of operating a well are clearly not IDC, the costs for intangible items connected with the deepening of such a well qualify for IDC treatment as costs incurred in preparing for production.[30]

Secondary recovery expenditures provide another example of IDC that are not immediately obvious from a reading of Regulation section 1.612-4[31] which defines IDC. Frequently, additional wells will be drilled adjacent to production wells for the purpose of injecting water, gas, chemicals, steam, or combustible materials, into a reservoir in an effort to repressurize

26. Treas. Reg. § 1.612-4(e) (1965).

27. Ramsey v. Commissioner, 66 F.2d 316, 379 (10th Cir.), *cert. denied*, 290 U.S. 673 (1933).

28. Treas. Reg. § 1.612-4(b)(4) (1965).

29. Dual completion is a term describing a single well which penetrates two separate deposits, one atop the other, both of which are capable of producing commercial quantities of oil and gas. In practice, production may be limited to one deposit at a time, or may occur simultaneously upon both.

30. *See* Moniovia Oil Co., 28 B.T.A. 335, 347 (1933), *aff'd on other grounds*, 83 F.2d 417 (9th Cir. 1936).

31. (1965).

the wells to enable further recovery of the oil and gas in place.[32] Although these injection wells are not capable of producing oil and gas themselves, the intangible costs incurred in drilling them qualify as IDC because they are paid or incurred for the purpose of enabling the existing wells to resume or increase production.[33] Also, costs for the fracturing of rock or sand structures surrounding existing wells in production can qualify as IDC incurred in development for production.[34]

Although it is apparent that those costs incident to drilling and development of wells qualify for the IDC election, a problem arises in classifying those costs incurred in connection with the workover of wells as either IDC or operating expenses.[35] Regulation section 1.612-4(a)(1),[36] which provides that the intangible costs incurred in the cleaning of wells qualify as IDC, implies that IDC are not limited to preproduction expenses. While one case has held that pulling rods and tubing and cleaning out a well constituted operating expenses,[37] it may be reasonable to assume that a broader reading of the regulations might overturn this precedent.

What about workover costs incurred in connection with the *maintenance* of production? Although the Service has ruled that the costs incurred for wells drilled to dispose of salt water encroaching upon petroleum deposits must be capitalized as costs related to improvements for operations,[38] one authority has suggested that a salt water well drilled for the dual purpose of disposal and injection for pressurization might qualify for IDC treatment if the principal purpose was repressurizing for

32. This is one of many methods of secondary and tertiary recovery of oil and gas.

33. Rev. Rul. 69-583, 1969-2 C.B. 41; *see also* Page Oil Co., 41 B.T.A. 952, *nonacq.* 1940-2 C.B. 13.

34. Producers Chemical Co. v. Commissioner, 50 T.C. 940 (1968), *acq.* 1969-1 C.B. 21.

35. The importance of distinguishing IDC from operating expenses remains whether the operator has opted current deduction or capitalization for intangibles. Should capitalization be elected, perhaps due to circumstances favoring cost depletion being taken, the operator is concerned with maximizing his depletable basis. Should current deduction be elected, the operator must take into account the possibility of recapture (*see* text accompanying note 90 *infra*) and tax preference item treatment for (*see* text accompanying note 93 *infra*) those expenditures qualifying for IDC treatment.

36. (1965).

37. P-M-K Petroleum Co. v. Commissioner, 24 B.T.A. 360, 365 (1931), *acq. on this issue*, X1-2 C.B. 8.

38. Rev. Rul. 70-414, 1970-2 C.B. 132.

production.[39] At present, however, it seems likely that the drilling or development for production versus expenditures incident to operation concept would remain applicable for determining IDC qualification.

2. Offshore Drilling

Because of rapid technological growth and obvious adverse physical limitations, offshore drilling programs have presented numerous novel tax issues. Perplexing questions have arisen over classification of costs incident to exploratory drilling operations, platform construction and hauling, and permanent platform anchoring and erection. Satisfactory answers may only be achieved by innovative theories.

The case of *Exxon Corporation v. United States*[40] is a classic confrontation between the Service and the oil industry over a new issue emanating from offshore drilling. The primary issue before the court involved the expenditures to fabricate and construct drilling platform prior to the time the components were lifted from the transport barge at the drill site.

a. *The Position of the Service*

The Service argued that the construction on land and fabrication activities during transportation constituted acquisition costs that were not subject to the IDC election.[41] In other words, these expenditures for construction of the platform before installment of the structure at the drill site constituted tangible assets with salvage value so as to preclude current deductibility as IDC. The Service cited[42] as authority Revenue Ruling 70-596,[43] which was a response to the changing methodologies of offshore drilling. The ruling determined that expenditures relating to

> any offshore platform that, although used in connection with drilling operations, are not incident to or necessary for the drilling of wells, or any platform component necessary for the production activity, including service facilities for personnel, incorporated into the platform structure, or the installation of the production equipment . . .[44]

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39. R. Bowhay & F. Burke, Jr., Breeding & Burton Income Taxation of Oil and Gas Production, 14.14 (1978).

40. 547 F.2d 548 (Ct. Cl. 1976), 77-1 T.C. ¶ 9114.

41. *Id.* at 557, 77-1 T.C. ¶ 9114, at 86,056.

42. *Id.* at 549, 77-1 T.C. ¶ 9114, at 86.054.

43. 1970-2 C.B. 68.

44. *Id.* at 69.

must be capitalized as a depreciable investment. This ruling concluded that the costs of building platform components on land did not fall within the purview of subsection 263(c) and, therefore, represented nondeductible acquisition costs.[45]

b. *The Position of the Court of Claims*

Noting that the primary issue rested on the differing interpretations of the regulations, the court overruled Revenue Ruling 70-596.[46] The court responded to the Service's argument favoring a limited reading of the IDC provisions by disapproving of the Service's contention that only those expenditures incurred in the course of *installing* constructed property at the well site were properly deductible as IDC.[47] The court, which refused to sustain an interpretation that excluded from the option all expenditures relating to construction of physical property at a place other than the actual well site, stressed the necessity of such preconstruction on land for the later drilling and preparation of the well at sea.[48]

The court also disapproved of the Service's argument that the intangible expenditures were so linked to tangible assets as to have salvage values[49] of their own, thereby precluding applicability of subsection 263(c).[50] Under this line of reasoning, total salvage of the entire platform would occur at the moment the reservoir was reached by the string of oil casing. The court reasoned that, although only certain costs of drilling and preparation for production are enumerated in Regulation section 1.612-4,[51] the Service's conclusion regarding salvage would preclude *any* cost related to a drill platform from being deductible for having a salvage value as a production facility.[52]

Finally, in holding in favor of Exxon, the court supported its decision on national policy considerations. It stated that the Service's position was contrary to congressional intention of

45. *Id.*

46. 547 F.2d 548, 558, (Ct. Cl. 1976), 77-1 T.C. ¶ 9114, at 86,062.

47. *Id.* at 556, 77-1 T.C. ¶ 9114, at 86,060.

48. *Id.* at 553, 77-1 T.C. ¶ 9114, at 96,058.

49. Treas. Reg. § 1.167(a)-1(c) provides that salvage occurs only "upon sale or other disposition of an asset when it is no longer useful in the taxpayer's trade or business or in the production of his income and is to be retired from service by the taxpayer.

50. 547 F.2d 548, (Ct. Cl. 1976), 77-1 T.C. ¶ 9114, at 86,060.

51. (1965).

52. 547 F.2d 548, (Ct. Cl. 1976), 77-1 T.C. ¶ 9114, at 86,061.

favoring oil and gas prospecting, and, if followed, would result in the proliferation of ambiguities and categorization problems.[53]

c. *The Risk Theory of IDC Classification*

Since *Exxon* represents judicial disapproval of the Service's increasingly restrictive position regarding qualification of expenditures for IDC treatment, it is an extremely significant pro-taxpayer case in the IDC series. But the Court of Claims has created a measure of uncertainty in *Exxon*. Until new guidelines are established, the operator seeking to qualify expenditures as IDC incurred in expanding technologies may have to resort to broader theoretical considerations behind IDC provisions.

In an excellent article on IDC and offshore drilling programs,[54] one commentator has documented a growing judicial trend to examine IDC election qualification as a function of the level of risk inherent in the IDC activity and the nature of the taxpayer's interest in the oil and gas property.[55] Citing directly to that article,[56] subsequent case law[57] has preferred the "risk" test over the Service's proposed "purpose" (intent to produce) test.

The "risk" theory is an after-the-fact attempt to provide a cohesive theoretical framework within which those expenditures which merit IDC treatment may be distinguished from others. Although "risk" has never been an overt consideration in the IDC provisions, no other theory appears to be as broadly applicable and theoretically coherent to determinations involving IDC qualification. Briefly summarized, the risk test theory states that economic risk can be equated with the degree of risk per dollar spent, and comparisons between any two operations are proper only if their costs are comparable. The term "risk" is defined as composite of two probability elements: 1) the funds expended for the operation will fail to obtain an economic benefit (from ultimate production); and 2) other property or money will be lost because the original expenditure has

53. *Id.* 558, 77-1 T.C. ¶ 9114, at 86,062.

54. Linden, *Review of Offshore Drilling — What Are Intangibles?* TWENTY-SIXTH OIL AND GAS INST. 441 (1975) (hereinafter cited as Linden).

55. *Id.* at 451-52.

56. Standard Oil Co. (Ind.) v. Commissioner, 68 T.C. 325, 351 (1971).

57. *Id.*

led to an economic detriment in excess of the loss of the expenditure itself.[58]

Application of the risk test analysis for the purpose of distinguishing, for example, G and G items from IDC items, yields a logical and consistent result. Because the survey covers a very large area to yield information on potential petroleum deposits, seismic G and G surveys have a relatively low risk factor when compared to offshore exploratory drilling. As the area of investigation decreases, the probability of locating oil and gas decreases proportionately. Thus, although the same fixed amount of money might be spent for both a seismic survey and an exploratory, the latter has a much higher risk factor because of the greater chance (dollars spent per area investigated) of failure. Examples of low risk activities requiring capitalization include lease bonuses, seismic surveys, tangible equipment acquisition, and production equipment installation. In contrast, examples of high risk activities include well drilling and completing and platform hauling and erecting.

Application of the risk test analysis to property interests also yields logical and consistent results. The working interest requirement for the IDC election effectively results in potential economic benefit for the operation solely from future oil and gas production.[59] Consequently, the working interest holder bears the full cost risk of discovering oil and gas in paying quantities. No discovery results in no recoupment of IDC expenditures. In contrast, nonworking interest holders possess a noncost-bearing interest in the form of production payments or royalty rights. They share in production but not in costs or risks. Moreover, nonworking interests may not exist throughout the entire payout period[60] because they are frequently limited in term or amount.

In conclusion, the Service's position with regard to offshore drilling activities has been an attempt to limit IDC qualification to only those drilling operations in which the operator has the intent to produce oil and gas. Not only does this "intent to produce" test create difficult administrative determinations based upon an operator's intent, the test cannot adequately

58. Linden, *supra* note 54, at 454.
59. *See* text accompanying note 18 *supra*.
60. *See* text accompanying note 22 *supra*.

explain why injection wells, dry holes, and exploratory wells which were not originally intended for production but are later reentered for production purposes qualify for the IDC election.

Although the Tax Court has recognized the fact that "risk and IDC are inextricably related,"[61] it is premature to state with certainty that the risk test will be unanimously adopted. Nevertheless, application of a risk test type of analysis should prove helpful to operations seeking IDC treatment of novel expenditures.

F. *Geological and Geophysical Exploration Costs as IDC*

1. Background

The tax treatment of the costs incurred in the geological and geophysical exploration[62] for oil and gas projects is a somewhat perplexing topic in the field of oil and gas taxation. Whereas "hard minerals" enjoy a specific deduction for those expenses connected with predevelopmental prospecting and exploration,[63] oil and gas exploration costs do not. Also, although the search for petroleum deposits could perhaps be analogized to a research or experimental activity, oil and gas activities are specifically excluded from the R & E deduction provisions.[64] Finally, an examination of the IDC deduction option provisions reveals that only those geological survey exploration expenses incurred to determine the *exact* location of the drill site will qualify for deduction under the section 263(c) option.[65]

How, then, are the preliminary geological and geophysical costs incurred prior to the selection of the actual drill site to be treated for tax purposes? The general and long-established rule is that these costs, not deductible in the year incurred, are

61. Standard Oil Co. (Ind.) v. Commissioner, 68 T.C. 325, 350 (1977).

62. Geological and geophysical survey expenses represent the expenses incurred in the exploration for oil and gas deposits for the purpose of "narrowing down" the area being searched for an eventual drill site location.

A typical exploration program for previously unexplored areas involves at least two phases: 1) the reconnaissance survey(s) of the project area(s), and 2) one or more detailed surveys of areas of interest within the layer project area(s). The ultimate decision to sink a shaft or to acquire to retain the oil-and gas-bearing property is often dependent upon the results of the reconnaissance and detailed surveys. The group providing and generating the survey information may be an independent contractor rather than a group already existing in the development organization.

63. I.R.C. § 617(a).

64. I.R.C. § 174(d).

65. *See* Treas. Reg. § 1.612-4(a) (1975).

to be capitalized and recovered over the producing life of the well.[66] Obviously contrary to the interests of taxpayers concerned with maximizing current deductions in an oil and gas venture, such treatment, however, may be subject to judicial change.

2. The Proper Classification of G and G Costs

The law is not specific in its differentiation of G and G costs from IDC; a reading of only the Code and regulations would lead one to assume that these costs may be one in the same. For example, there is no Code section dealing specifically with preproduction oil and gas expenses other than section 263(c), which exempts IDC from the general rule disallowing a current deduction for capital expenditures. Further, the regulations lists as an example of IDC as expenditures for "clearing or ground, draining, road making, *surveying, and geological works* as are necessary in preparation for the drilling of wells . . . ."[67] Arguably, it would be reasonable to assume that these expenditures concerning surveying and geological works as being "necessary" for the preparation of wells, should include the entirety of the reconnaissance and detailed survey costs that are initiated to determine the location of the most advantageous drill site. Such is not the case; the Service has characterized these surveys as being capital expenditures incurred "for the purpose of obtaining and accumulating data which will serve as a basis for the acquisition or retention of property."[68] By characterizing G and G costs as capital expenditures made in connection with the acquisition or preservation of property, the Service has attempted to remove them from consideration as IDC, which, of course, are subject to the option for current deduction.

One question which arises at this point concerns the possible characterization of G and G costs as ordinary and necessary business expenses.[69] Certainly, a taxpayer in the business of producing oil and gas will find it necessary to search for that upon which his operations depend; until a successful search is

66. Rev. Rul. 77-188, 1977-1 C.B. 76.

67. Treas. Reg. § 1.612-4(a)(2) (1965) (emphasis added).

68. Rev. Rul. 77-188, 1977-1 C.B. 76.

69. Hall, *Geological and Geophysical Costs*, SIXTEENTH OIL AND GAS INST. 584 (1965). The author suggests that prior to 1938 tax-payees routinely deducted G and G costs as ordinary and necessary business expenses pursuant to Code section 162.

made, he cannot undertake production. The main reason G and G costs are capital expenditures, rather than ordinary and necessary business expenses, is because the Service has so ruled.[70]

The Service's present position on the nondeductibility of G and G costs can be found in Revenue Ruling 77-188.[71] The holdings of this ruling can be summarized briefly as follows:

1. Property acquired or retained upon the basis of information from G and G survey and exploration has its adjusted basis increased by the amount of G and G cost;
2. Oil and gas exploration programs are conducted on the basis of project areas, with separate project areas being deemed to exist if they are noncontiguous to one another. Reconnaissance surveys are typically made of each project area, and areas of interest subject to detailed surveys are revealed by the larger reconnaissance surveys. If no preliminary reconnaissance survey is made, the project area and area of interest are deemed to be coextensive. If more than one noncontiguous area of interest is found, each area of interest is independent of the other.
3. The G and G costs, generally capitalized entirely to the area of interest found, is apportioned equally, without regard to acreage of actual proportional cost, between the areas of interest if more than one exists within the project area.
4. The G and G costs are deductible as a loss under section 165 only where no area of interest is located within a project area.
5. An exception to the above rules exists where a property within, adjacent to, or nearby an area of interest is acquired; here, a portion of the reconnaissance survey attributable to the area of interest, as well as the entire cost of the detailed survey of the area of interest, is apportioned to the property acquired. If more than one property within, adjacent to, or nearby, the area of interest is acquired, the G and G costs are capitalized and apportioned between them on a per acreage basis.

This revenue ruling cites a series of cases[73] beginning in 1928 in support of the Service's position. However, close examination of these cases reveals that the Service's position, not supported by sound judicial reasoning and interpretation, re-

70. Rev. Rul. 77-188, 1977-1 C.B. 76, *at* 77.

71. *Id.*

72. *Id.*

73. *Id.* The cases cited are: Louisiana Land and Exploration Co. v. Commissioner, 7 T.C. 507 (1946), *aff'd on other issues*, 161 F.2d 842 (5th Cir. 1947); Schermerhorn Oil Corporation v. Commissioner, 46 B.T.A. 151 (1952); G.E. Cotton v. Commissioner, 25 B.T.A. 866 (1932); C.M. Nusbaum v. Commissioner, 10 B.T.A. 664 (1928); and Seletha O. Thompson v. Commissioner, 9 B.T.A. 1342 (1928).

sults by virtue of certain somewhat dubious interpretations which have, through long usage, attained the effect of law.

Notwithstanding the lack of sound judicial reasoning and interpretation, the fact that development and exploration costs for natural resources, particularly G and G costs for oil and gas, are capital expenditures cannot be denied. Although the line of cases relied upon by the Service can be questioned as to soundness and validity, it seems likely that these long standing positions by the Service and courts would be virtually impossible to overcome. Akin to leasehold improvements that are beneficial over the term of the lease, G and G costs are undeniably capital expenditures.

However, in light of the fact that Congress has made a substantial concession for IDC with section 263(c), the fact that G and G costs are properly characterized and treated as capital expenditures should not automatically preclude their current deductibility. Certainly, those IDC expenditures qualifying for the section 263(c) election are also capital expenditures since they benefit production over the term of the property interest. Isn't it possible that certain G and G costs would be recharacterized as IDC items? The answer, at present, appears to be in the affirmative, at least to certain costs of development of offshore drilling projects.

3. Exploratory Drilling

Offshore drilling projects involve large areas of the ocean floor which must be explored and prospected at considerable expense[74] to determine the possibilities of locating petroleum deposits in quantities sufficient for commercial exploration.

74. In contrast to land-based explorations, offshore explorations are subject to additional contraints which serve to "up the ante" for G and G exploration. For example, because of environmental considerations, these G and G exploration activities, (involving exploratory surveying and drilling by the use of seismic boats, jack up rigs, submersibles, drilling vessels, and ice islands), have come under increasing governmental administrative agency review and regulation. A partial list of those bodies having licensing and regulatory powers are: the Department of the Interior, United States Geological Survey, Environmental Protection Agency, Corps of Engineers (Army), Coast Guard, Council on Environmental Quality, various state coastal zone management commissions, and other state environmental regulatory agencies. Among the applicable laws and acts are: the Outer-Continental Shelf Lands Act, the National Environmental Policy Act, the Federal Water Pollution Control Act Amendments of 1972, the Clean Air Act Amendments of 1970, Research and Sanctuaries Act of 1972 (as amended), the River and Harbor Act of 1899, the Coastal Zone Management Act of 1972, and the Fish and Wildlife Coordination Act.

The accumulated data from surveys of project areas serves as a basis for abandonment or further detailed survey of any areas of interest. However, since G and G data resulting from undersea surveying is more limited than data resulting from land-based exploration, greater reliance is placed on the results of exploratory wells for the purpose of determining the location of permanent production wells and facilities. Because of the extremely high costs of undersea drilling, a common practice is to install casings and fixtures suitable for production before it is known whether petroleum deposits will be of production quality and quantity. In the event a suitable deposit is discovered, other wells must be drilled to determine the boundaries of the deposit and the placement of production wells.

Because of the uncertainties inherent in exploratory drilling, the Service has maintained that exploratory drilling costs are to be capitalized and cannot qualify for IDC treatment.[75] Appearing contrary to the regulations,[76] the Service's position was attacked in the recent Tax Court case of *Standard Oil (Indiana) v. Commissioner.*[77] In *Standard Oil,* the petitioner drilled twenty-one wells from mobile platforms between 1967 and 1979. Four of the wells were drilled in the offshore waters of Louisiana, nine wells were drilled in the United Kingdom portion of the North Sea, and eight wells were drilled off the coast of Trinidad. All of the wells drilled, except for two off the coast of Trinidad, found deposits of petroleum in producing quantities. Pursuant to subsection 263(c), Standard Oil claimed as current deductions the drilling costs of the successful exploratory wells.

The Service determined deficiencies of over $48,000,000 claiming that the drilling costs represented nondeductible G and G capital expenditures. In support of its position, the Service contended that Standard Oil had not met the burden of proof with respect to qualifying the well expenditures as IDC.[78] The Service maintained that the wells were an extension of exploratory work, and therefore, they could not be considered as incident to development for production until the decision to install a permanent drilling platform had been made.[79]

75. Rev. Rul. 70-596, 1970-2 C.B. 68.
76. Treas. Reg. § 1.612-4 (1965).
77. 68 T.C. 325 (1977).
78. *Id.* at 343.
79. *Id.* at 345.

The Tax Court made several observations before discussing the primary issue. First, under *F.H.E. Oil Company v. Commissioner,*[80] the court stated that all expenses incurred in drilling the wells were capital expenditures under subsection 263(a) and therefore, cases dealing with the question of characterization of expenses as capital expenditures were inapplicable.[81] Second, the fact that the wells provided G and G data did not preclude the deduction of drilling costs as IDC.[82] Third, and perhaps equally important, the court stated that "Congress favors a liberal interpretation of the IDC regulation." Finally, the court, holding that the mere classification of the wells as being "exploratory" did not preclude them from being a part of the "development" of the properties for production, stated "the dividing line between exploratory work which must be capitalized and development activities coming within the IDC option is the point at which the preparations for drilling begin."[84] The court, finding no express or implied limits in the regulations stating that the only wells drilled after the decision to install a permanent drilling platform could qualify for IDC treatment, held in favor of the taxpayer. It noted that the Service's theory on IDC qualification would result in the disallowance of not only all "wildcat" wells, but also those wells which were drilled from mobile drilling rigs and later reentered from a fixed platform.[85] The Service's "decision to install a permanent drilling platform"[86] test, found by the court to be akin to an "intent to produce" test, was invalidated—application of this test would disallow drilling costs clearly within the ambit of section 1.612-4 of the regulations.[87] The court concluded by holding that the proper method to restrict the IDC provisions lay in amending legislation, not judicial restriction.[88]

In conclusion, the primary importance of the *Standard Oil*

80. 147 F.2d 1002 (5th Cir. 1945).
81. Standard Oil Co. (Ind.) v. Commissioner, 68 T.C. 325, 344 (1977).
82. *Id.* at 345.
83. *Id.*
84. *Id.* at 348.
85. *Id.*
86. *Id.*
87. *Id.*
88. *Id.*

case lies in its presentation of the first coherent and well-reasoned analysis distinguishing IDC from G and G costs. Resting solely on the facts of the instant case, the decision as to deductibility of certain offshore exploratory drilling expenses will also be applicable to future situations involving neoteric systems and technologies. However, to claim that the *Standard Oil* case has effectively converted certain G and G costs into IDC would be erroneous; it merely allows more expenditures to be properly characterized by clarifying the distinctions between IDC and G and G costs.

G. *Tax Reform Reduces IDC Benefits*

While the Service has endeavored to restrict IDC treatment for expenditures through their strained interpretation of the statutes and regulations, Congress has pursued a direct approach to minimize the favorable tax effects of IDC treatment.

1. Recapture of IDC

Aimed at limiting the conversion of ordinary income into capital gain, the Tax Reform Act of 1976 added section 1254 to the Code. This provision, a progeny of section 1245 and 1250[89] recapture provisions, requires gains from the disposition of oil and gas properties, heretofore treated as capital gain, to be recaptured as ordinary income to the extent of the IDC deductions taken after December 31, 1975. This recaptured amount[90] is to be reduced by the amount that would have been deducted had the IDC been capitalized. In short, upon the disposition of an oil or gas property the operator now realizes ordinary income to the extent that his deductions for IDC ex-

89. Section 1245 prescribes recaptare of capital gain into ordinary income where the gain is attributable to depreciation deductions claimed on the tangible personal property sold. Section 1250 prescribes recapture of capital gain into ordinary income where the gain is attributable to depreciation deductions claimed in excess of straight line depreciation on the real property sold.

90. Special rules are provided for determining the amount recaptured as ordinary income where a taxpayer sells a portion of, or an individual interest in, an oil or gas property. First, in the case of a disposition of a portion of an oil or gas property other than an undivided interest, Section 1254(a)(2) provides that the entire amount of the aggregate IDC that have been deducted after December 31, 1975 is allocated to the portion of the property disposed of first. Any excess of IDC that are not recaptured in the first disposition of a portion of the property is to be subsequently allocated to the remaining portion of the property. Such a situation obviously occurs when the IDC exceed the total amount of gain realized. Second, if an "undivided interest in an oil or gas property, or a portion thereof, is disposed of, Section 1254(a)(2) provides that a proportionate part of the IDC attributable to that property is to be allocated to the undivided interest to the extent of the gain."

ceed the amount that would have been allowed had the IDC been capitalized, not deducted, and recovered over the life of the property. However, the recaptured amount cannot exceed the gain realized on the sale of the property.[91]

An example is in order to illustrate the effects and mechanics of section 1254. On July 1, 1978, an investor purchases for $30,000 the mineral estate which contains potential oil and gas deposits. The investor becomes an operator and incurs $25,000 in IDC which he deducts on his 1978 return. Without the election to deduct IDC currently, the operator would have deducted $5,000 through cost depletion. After discovering oil, the operator holds the property interest for over 12 months[92] and sells his working interest in the mineral estate for $100,000 on August 1, 1979. Before enactment of section 1254, the operator would have a capital gain computed as follows:

Sales Price	$100,000
Less Basis	30,000
Capital Gain	$ 70,000

After enactment of section 1254, the capital gain is recaptured as ordinary income to the extent IDC were deducted in excess of the amount that would have been deducted had the IDC been capitalized and recovered through cost depletion. The capital gain and ordinary income is computed as follows:

Gain Realized		$70,000
IDCs Deducted	$25,000	
Cost Depletion Deduction	5,000	
Ordinary Income		$20,000
Difference is Capital Gain		$50,000

As can be readily seen, the new provision converts $20,000 of capital gain into ordinary income.

2. IDC as a Tax Preference Item

By adding "excess" IDC to the list of tax preference items,[93] the Tax Reform Act of 1976 further watered down in-

91. I.R.C. § 1254 (a)(1)(B).

92. By holding the property over 12 months, the owner satisfies section 1222(c) which defines the holding period required before capital gain treatment is allowed.

93. Code section 57 delineates 11 items of tax preference: 1) excess itemized deductions; 2) accelerated depreciation of real property; 3) accelerated depreciation on

centives once present in the tax-deferring IDC election. Newly-enacted paragraph 57(a)(11) serves to penalize certain operators[94] by classifying a portion of IDC deducted currently as a tax preference item.

For tax years beginning after 1977, the tax preference portion of the IDC deduction is equal to the actual IDC deduction minus the amount which would have been deductible had the IDC been capitalized and recovered via straight line recovery of intangibles.[95] The phrase "straight line recovery of intangibles" is defined by subsection 57(d) as the greater of:

> 1. ratable amortization of such costs over the 120-month period beginning with the month in which production from such well begins; or
> 2. any method which would be permitted for purposes of determining cost depletion with respect to such well.

This new tax preference rule does not apply in two cases. The first case occurs where the operator elects to capitalize, rather than deduct, IDC. The second case occurs where the well is nonproductive.[96]

An example of the mechanics of this new provision is appropriate. An operator incurs $48,000 in IDC in November and December of 1978. The amount of the IDC tax preference item for 1978 will be $48,000 minus the straight line recovery of intangibles of $800 computed as follows:

$$\$48{,}000 \text{ times } \frac{2 \text{ months}}{120 \text{ months}} = \$800$$

The additional tax liability would be $7,080 computed by multiplying $47,200 (IDC net of straight line recovery intangibles) by 15% minimum tax rate.[97]

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leased personal property; 4) amortization of certified pollution control facilities; 5) amortization of railroad rolling stock; 6) stock options; 7) reserves for losses on bad debts of financial institutions; 8) depletion (*see* text accompanying note 221 *infra*); 9) capital gains; 10) amortization of on-the-job training and child care facilities; and 11) intangible drilling costs.

94. Code section 57(a)(11) excludes corporations as an operator who must treat IDC as a tax preference item.

95. I.R.C. § 57(a)(11).

96. *Id.*

97. Section 56(a) provides that the minimum tax is equal to 15% of the amount by which the sum of the tax preference items exceeds the greater of (1) $10,000 or (2) one-half of the taxpayer's regular tax. After 1978, this 15% add-on tax will no longer

II. THE AT RISK LIMITATIONS

Tax shelter investments, including those involving oil and gas, typically involve one or more of the following elements: 1) deferral of tax; 2) conversion of ordinary income into capital gain; and 3) leverage of investment power through use of borrowed funds. In the case of oil and gas, two of these common elements, deferral and conversion, have been limited by enactment of previously discussed provisions: one classifying certain IDC as tax preference items and the other creating a recapture of IDC. Leveraging, the third common element, has been restricted by the enactment of section 465, the at risk limitation provision.

A. *The Basic Problem—Tax Deductible Losses*

This provision was enacted in response to the executive and legislative branches' growing preoccupation with the politically expedient issue of tax reform, particularly in regard to tax shelter activities. In 1973 the Secretary of the Treasury, George Shulz, observed, "[T]axpayers who have large incomes and pay little or no tax do exist in limited, but significant numbers,"[98] and "[p]reoccupation with tax manipulations—particularly *tax deductible 'losses'*—too often obscures the economic realities and can have the effect of discouraging profitable and efficient enterprise."[99]

How are these tax deductible losses created? The answer is simple—leveraging. The role of leveraging in creating these tax deductible losses has been succintly described as follows:

> Without borrowing one can only defer recognition of an amount of gain not greater than his investment. But by borrowing he can make his gross investment exceed his net investment, and the amount he can defer, while limited to his gross investment, may exceed his net investment several times over. Thus it is that investors in tax shelters may not only deduct their whole investment, but actually get it back in the form of tax savings within a short period, and still go on to shelter more income. The tax

apply to the capital gains or the excess itemized deductions preference items. Instead, these two items become part of the new alternative minimum tax which becomes effective in 1979. This new alternative tax will apply only if it produces a tax that is higher than the individual's regular tax liability as increased by the add-on minimum tax. *See* section 55 of the Internal Revenue Code enacted into law by section 421 of the Revenue Act of 1978.

98. *Hearings on General Tax Reform Before the House Comm. on Ways and Means*, 93rd Cong., 1st Sess. 6877 (1973).

99. *Id.* at 6878 (emphasis added).

cost is a so-called phantom gain to be recognized some years hence.[100]

The advantages in leveraging are even more apparent when the borrowing is on a nonrecourse basis. The lack of personal liability for repayment is particularly attractive when the nonrecourse loan proceeds can be used to increase the gross investment amount, and thereby increase the sheltered activity's potential for sheltering other income.

The following oil and gas tax shelter arrangement was not atypical before the Tax Reform Act of 1976. A drilling corporation would obtain an oil and gas lease. In order to obtain financing to develop the lease, the corporation would sell limited partnership interests to investors and obtain a loan from a bank. The arrangement can be graphically shown as follows:

Partner	Percentage of Interest
Corporation — general partner	20%
A — limited partner	20%
B — limited partner	20%
C — limited partner	20%
D — limited partner	20%
	100%

If the required financing is $1,000,000 and each partner contributes $20,000, then the bank loan must equal $900,000. Each limited partner's adjusted basis for determining the extent he can deduct partnership tax shelter losses was $200,000 ($20,000 contributed plus $180,000 share of the loan). If the general partner incurs $500,000 in IDC expense in the first year, each limited partner's deductible loss would be $100,000 or one-fifth of the partnerships losses notwithstanding the fact that as limited partners, they were not personally liable on the loan. If the partner is in a 50% bracket, the $100,000 deduction represents a tax savings of $50,000; while the most the partner can lose is $20,000, his initial contribution. Understandably, the Service had long been galled by the taxpayer's ability to

100. Lee & Fogg, *Secs 465 and 704(d): Invest at Your Own Risk*, TAX ADVISOR 8:132 (1977) at 133.

include the full amount of nonrecourse liability in his depreciable basis or his adjusted partnership's basis.[101]

2. Limitation of Tax Deductible Losses

Congress reacted to the problem of nonrecourse financing and artificial tax losses by designing section 465. Enacted in the Tax Reform Act of 1976, this provision served to limit the taxpayer's allowable loss deductions[102] to the amount of the taxpayer's investment which is "at risk" at the close of the taxable year. Oil and gas exploration was one of four activities subject to the "at risk" limitation.[103] However, with the Revenue Act of 1978 Congress amended section 465 to include all activities except real property investing[104] and equipment leasing by closely-held corporations.[105]

Applying section 465 to the example of the limited partner creating a \$100,000 IDC tax loss with a \$20,000 contribution, the partner's loss is limited to the amount he has "at risk." Since he can only lose \$20,000, he can only deduct \$20,000. The \$80,000 balance may be deducted in succeeding years to the extent he has "at risk" capital.[106]

Obviously crucial to the workings of this new provision, the definition of "at risk" is not as simple as one might hope. For example, although it is clear that taxpayers are considered to be "at risk" to the extent of cash and the adjusted basis of their property contributed to the activity,[107] borrowings that are invested will not be considered "at risk" if they are nonrecourse,[108] or are protected through "stop-loss" or other liability-limiting arrangements.[109] Furthermore, amounts borrowed from a person holding an interest in the activity other than a

101. *See, e.g.*, Boger v. Commissioner, 59 T.C. 760 (1973); Mayerson v. Commissioner, 47 T.C. 340 (1966), *acq*. 1969-1 C.B. 21.

102. Section 465(d) provides that in computing the loss from an activity, loss is defined as the deductions allowable for the taxable year determined without regard to section 465, in excess of the income received or accrued by the taxpayer from the property.

103. I.R.C. § 465(c)(1)(D). The other three activities were: 1) holding, producing, or distributing motion picture films; 2) farming; and 3) leasing any section 1245 property.

104. I.R.C. § 465(c)(3)(D)(i).

105. *Id.* § 465 (c)(3)(D)(ii).

106. *Id.* § 465(d).

107. *Id.* § 465(b)(1)(A).

108. *Id.* § 465(b)(1)(B)(4).

109. *Id.*

creditor,[110] amounts borrowed from a related party as defined by section 267(b), and amounts borrowed secured by property used in the activity also will not be considered to be "at risk."[112]

Enacted in the Revenue Act of 1978, subsection 465(e) plugged a loophole generated by section 465 as enacted by the Tax Reform Act of 1976. Under section 465 as originally enacted, the taxpayer was only required to be at risk at the end of the taxable year for which losses were claimed.[113] Consequently, subsequent withdrawals of amounts originally placed at risk could be made without recapture of previously allowed losses. Therefore, subsection 465(e) requires the recapture of previously allowed losses when the amount at risk is reduced below zero.[114]

III. THE DEPLETION ALLOWANCE

In the field of oil and gas taxation, the emotionalism engendered by issues of the IDC deduction and the loss limitaton is only exceeded by the issue of the depletion allowance. The balance of this article will explore the definition and types of economic interests, the computation and theory of cost and statutory depletion, and the legislative restriction on the amount and availability of statutory depletion.

A. *Introduction To Depletion*

Oil and gas deposits constitute a form of nonrenewable wasting asset of finite supply. By diminishing the quantity that may be recovered, the removal of oil and gas from the reservoir constitutes a "physical" depletion of the deposit. Since the value of the oil and gas deposit diminishes proportionately with the physical depletion, "economic" depletion, described in terms of diminution in value, can be said to go hand-in-hand with physical depletion.

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110. *Id.* § 465(b)(3)(A).

111. *Id.* § 465(b)(3)(B).

112. *Id.* § 465(b)(2)(B).

113. *Id.* § 465(a).

114. *Id.* § 465(e)(1). The House Ways and Means Committee Report states: Mechanically, this rule works by providing that if the amount at risk is reduced below zero (by distributions to the taxpayer, by changes in the status of indebtedness from recourse to nonrecourse, by the commencement of a guarantee or other similar arrangement which affects the taxpayer's risk of loss, or otherwise), the taxpayer will recognize income to the extent that his at risk basis is reduced below zero. However, the amount recaptured is limited to the excess of the losses previously allowed in that activity over any amounts previously recaptured.

However, for tax purposes the term depletion is used to describe a somewhat different concept of diminution than is set forth above. Whereas the "physical" and "economic" depletion concepts are linked to the number (and value) of the units produced from the deposit, the tax depletion provisions[115] are based on "income derived from production" concept. This concept of income from production, which is vital to a proper understanding of the theory and application of depletion for oil and gas, produces annual depletion deductions which serve to allocate a portion of the cost of the asset to the gross income generated by the asset during the tax year.

The theory of depletion also includes a "return of capital" concept. Because a portion of the production of oil and gas represents a return of the original capital investment, deduction in the form of a depletion deduction is allowed as a recovery of the cost of the mineral deposit as the extracted mineral is sold.

Treasury regulations provide that income from production of oil and gas results from the sale of the units (barrels or cubic feet) produced.[116] Due to the connection between depletion and income as opposed to production, only those units produced which are actually sold can qualify for the depletion deduction. Thus, units consumed in the operation of the property,[117] or somehow destroyed prior to sale,[118] cannot qualify for the depletion allowance.

B. *Economic Interests*

Since only those persons possessing an "economic interest" in the mineral in place are entitled to the oil and gas depletion allowance, and because not all possessory interests in the oil and gas property qualify as "economic interest," the definition of an economic interest should be of vital concern to all oil and gas taxpayers.

1. Economic Interest Defined

Not defined specifically in the Code, the term "economic

115. I.R.C. § 611-13.

116. Treas. Reg. § 1.611-2(a).

117. Roundup Coal Mining Co. v. Commissioner, 20 T.C. 388 (1973) *acq. and nonacq. on other issues*, 1954-1 C.B. 6, 8.

118. Pioneer Cooperage Co. v. Commissioner, 53 F.2d 43 (8th Cir.), *cert. denied*, 284 U.S. 686 (1931).

interest" is a creation of case law[119] that was adopted by the Treasury in Regulation 1.611-1(b)(1).[120] This regulation provides that an economic interest is acquired when "the taxpayer has acquired by investment any interest in mineral in place . . . and secures, by any form of legal relationship, income derived from the extraction of the mineral . . . to which he must look for a return of his capital."[121] The regulation further provides that "[a] person who has no capital investment . . . does not possess an economic interest merely because through a contractual relation he possesses a mere economic or pecuniary advantage from production.[122]

This regulation and subsequent case law make it clear that economic interest exists only where there has been a capital investment in mineral in place and the right to income exists as a recovery of capital from extraction and production of the mineral. The capital investment need not, however, be a direct investment in the sense of "dollars for minerals in place"; it is possible to acquire an economic interest by making an indispensable contribution in a form other than cash.[123]

The critical distinction in determining the existence of a capital investment is the connection between the investment and the minerals in place. As long as the investment is necessary for the extraction of the mineral, the capital investment element should be satisfied. The "right to income from production" element requires that the taxpayer's right to receive income is dependent *solely* upon the extraction and production of the mineral. Again, the critical factor is the absolute relationship of the right to receive income with the mineral deposit. In *Anderson v. Helvering*,[124] the Supreme Court held that the right to receive oil payments out of both production and proceeds from the sale of land did not constitute an economic interest because the right to receive income was not solely upon production.[125]

119. Palmer v. Bender, 287 U.S. 551 (1932).

120. (1960).

121. Treas. Reg. § 1.611-1(b)(1) (1960).

122. *Id.*

123. Burton-Sutton Oil Co., Inc. v. Commissioner, 328 U.S. 25 (1946).

124. 310 U.S. 404 (1940).

125. In *Anderson*, the Oklahoma City Co. (O.C.C.) owned fee title, royalty interests, and oil payment rights in certain oil producing properties. It sold everything to Prichard for $160,000 payable $50,000 in cash, and $110,000 from 50% of the oil

In summary, the income from an economic interest may be measured by a share of the mineral extracted, the gross sales price of the mineral, or the net profits realized from the extraction of the mineral, so long as there is no obligation to pay from any source other than the production of the mineral. However, if payment is made regardless of extraction, or is in any form guaranteed, the income is not income with respect to an economic interest even though it is actually received from the production of the mineral.

2. Basic Types of Economic Interests

The four basic types of interests in oil and gas properties that qualify as economic interests are the following: working interests,[126] royalty rights,[127] net profits interest,[128] and all pre-

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produced from the land *or,* if the land was sold by Prichard, the proceeds of the sale were to be applied by Prichard to satisfy the balance remaining on the production payment. The Supreme Court held that O.C.C.'s $110,000 "production payment" did not qualify as an "economic interest" in the oil in place. The Court held that although payment might be and, in fact, was satisfied from oil production, it also could have been satisfied from the proceeds of the sale of real property. As a result of the Court's holding, Prichard was required to include in his income the 50% he paid to O.C.C., O.C.C. was not entitled to a depletion deduction on the amounts received, and O.C.C. was required to report as a capital gain any amounts received in excess of its basis in the production.

126. The term "operating interest" is defined by Regs. 1.614-2(b) as "a separate mineral interest as described in section 615(a), in respect of which the costs of production are required to be taken into account by the taxpayer . . . ." Because the person holding this interest is the one who physically operates the extraction and production process, a working interest is separate and distinct from royalty, production type interests, and net profits interests. The other three types of economic interest are "nonoperating" interests in the sense that the holders of those interest do not participate in the production process, but merely receive income from the operations. In connection with the concept of a working interest to IDC, *see* text accompanying note 19 *supra*.

127. A "royalty interest" entitles its holder to a share of the gross production of the gas and oil from a specific property. The share in production typically lasts as long as the property interest to which it applies continues to produce. However, in certain circumstances, it may be limited by local law or be payable at a variable rate or at a minimum or accelerated rate. A nonproductive royalty, a royalty which applies to a property not in production, will lapse at the end of a stated term. However, a royalty interest that is, upon creation, limited to a certain term will continue to exist beyond the stated term as long as production of the oil and gas actually continues. In this circumstance, this so called "term royalty" might be more accurately described as a form of production payment.

128. A "net profits interest" can be briefly described as the right to receive a specified share of the net profits from production. The method for computation of "net profit" is not specified statutorily (by the Code or regulation); however, the contract creating this interest will usually specify those costs and expenditures to be deducted from gross income to arrive at the net profits figure. Again, a net profits interest, considered to be a nonoperating interest, is one which lasts throughout the period of

1969 and certain post-1969 production payments.[129] Is there a reason for the conspicuous absence of the "fee interest" in the list of basic economic interests? Yes, the fact that an individual holds fee title to land does not automatically mean that he has any interest in the minerals beneath its surface. Clearly, it is possible to acquire title to land which has had its mineral rights severed and conveyed by a prior owner. In addition, it is possible to hold title to land as a form of security device. In this case, the titleholder has no economic interest in the minerals in place.[130] Finally, even in those situations where the fee interest holder does hold title to the mineral rights, he does not necessarily possess an economic interest in the minerals in place because economic interest exists upon the production of the mineral deposit. The mere holding of a mineral rights interest, without taking any other action does not qualify as an "economic interest."

B. *Production Payments*

A common method of obtaining the additional capital or equipment necessary to bring a property to the producing stage is to agree to share the mineral in place upon production. Consequently, the taxpayer may either retain an interest in production or transfer an interest in production to the party who assists in the development of the property. Such a transferred interest is commonly known as a "production payment."

Defined by Regulation 1.636-3(a)(1),[131] the term production payment is a right to receive a specified share of the production from a mineral property which is limited by any of the following: 1) dollar value, 2) amount of oil and gas produced, or 3) a specified length of time. In order to qualify as a production payment, the interest must have an economic life of shorter duration than of the mineral property to which it applies.

Production payments may be created in either of two ways. First, they may be created by one who sells the working interest in the mineral property and reserves a production payment for himself. This type is called a retained production

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production. As with the "term royalty", a "term net profits interest" might be construed as a form of a production payment.

129. *See* text accompanying note 131 *supra.*

130. Gap Anthracite Co. v. Commissioner, 31 T.C.M. (CCH) 924, 931, (1972) (CCH), *cert. denied,* 417 U.S. 931 (1973).

131. (1973).

payment. Second, they may be created by one who keeps his working interest in the mineral property and creates or "carves-out" a production payment which he sells to a third party. By virtue of section 636, a provision enacted in the Tax Reform Act of 1969, retained production payments may be treated as purchase mortgage and carved out production payments may be treated as mortgages loans. As will be shown hereinafter, the enactment of section 636 caused these preproduction payments to lose their status as "economic interests." Thus, the section substantially impairs the tax planning devices once available through the use of production payments. The most notable is the device of the ABC transaction.[132]

1. Retained Production Payment

Under law prior to the enactment of section 636, during the payout period, the holder of the retained production payment possessed an economic interest in the property. Accordingly, the income from production paid to the holder of the production payment in satisfaction of the obligation was interpreted to be depletable income in the hands of the holder of the production payment and excludable from the gross income of the operator.

For example, assume that in 1967, A, owning a producing oil property in which he had an adjusted basis of $10,000, sells his property to B for $15,000 cash plus the retention by A of a $100,000 production payment, payable from 50% of the oil produced and bearing interest at 5% per annum on the unpaid balance. Since the $100,000 production payment is not considered when computing A's gain on the sale, A will have a $5,000 taxable gain ($15,000 cash less $10,000 basis) that is subject to depletion. B will now have a basis in the property of $15,000, the amount of cash conveyed to A. In 1968 the property produces $50,000 of oil. Abiding by the contract, B pays $25,000 to A and includes in income the balance of the $50,000 of oil. The $25,000 paid to A is allocated as follows: $2,500 to interest on the production payment, and $22,500 to reduce the principal of the production payment to $77,500 (the $100,000 retained production payment less the $22,500 principal payment).

Now, assume this sale transpired in 1970 or later years.[133]

132. *See* text accompanying note 133 *supra*.

133. Treasury regulation section 1.636-4(a) provides that section 636 applies to

Section 636 prescribes that a retained production payment on the sale of the mineral property is to be treated as if it were a purchase money mortgage and, contrary to prior law, it does not qualify as an economic interest to its holder. Consequently, A realizes a gain of $105,000 (the sales price of $100,000 retained production payment and the $15,000 cash less A's $20,000 basis in the property). On the other hand, the income from production used to satisfy the obligation supported by the production payment is depletable ordinary income in the hands of the owner of the working interest. Consequently, B, as the new owner of a working interest in the mineral property purchased from A includes in gross income the total $50,000 of oil production and 100% of production income in subsequent years. The $25,000 payment to B represents merely a payment on the purchase money mortgage and has no tax effect on either A or B. B has a basis of $115,000 in the property (the $100,000 "purchase money mortgage" plus the $15,000 cash).

2. The ABC Transaction

The ABC transaction differs from the normal retained production payment in only one aspect; after selling the working interest, the initial owner of the property sells the retained production. In the ABC transaction, A, the owner of oil and gas property, sells it to B, an operator and developer. B, in turn, secures financing from C, who receives a production payment for the amount of his advance. In essence, the transaction consists of the sale of A's property to B in return for cash consideration and a retained production payment, with A simultaneously assigning the production payment to C in return for the remainder of the sale price. Before section 636, A was deemed to have sold his entire interest in which capital gain treatment was available. C had a depletable in-oil payment right analogous to a royalty right. B, who possesses a working interest subject to the in-oil payment to C, was also entitled to a depletion allowance.

The aforementioned tax result is changed by section 636(b) which treats the production payment as purchase money mortgage loan rather than an "economic interest" in the mineral property. As the purchaser of the working interest, B

production payments on or after August 7, 1969, other than production payments created on or after January 1, 1971, pursuant to a binding contract entered into before August 7, 1969.

is now required to treat as depletable income the amounts used to make the production payment. As the purchaser of the production payment, C treats the payments from B as the receipt of nontaxable return of principal plus taxable interest. As the seller, A's tax treatment remains unchanged; he realizes a taxable gain on the sale.

For example, assume that A sells his property to B for $100,000 cash plus a $300,000 retained production payment. If A sells the retained production payment to C for $300,000, A's gain on the sale is taxable as it was prior to August 7, 1969. Holding a mineral property with a $400,000 rather than a $100,000 basis if prior to 1970 basis, B has a higher cost for purposes of computing cost depletion. However, this advantage is more than offset by the fact that B may no longer exclude from gross income the amounts he pays to C in satisfaction of C's production payment. The reason for this is that C's production payment, no longer an economic interest, is deemed to be a loan. Therefore, B is now taxable on the total production of the property and is entitled to deduct only that portion to C which represents payment of interest on the indebtedness.

Obviously, after August 6, 1969, the acquisition of oil properties by developers by use of an ABC transaction, a common practice prior to enactment of section 636, has lost much of its appeal because of the loss of economic interest status for the retained production. The developer, B, is no longer able to purchase the mineral property with before-tax dollars.

3. Carved-Out Production Payment

Section 636(a) provides a general rule that a carved-out mineral production payment, once treated as an economic interest is now to be treated as a mortgage loan on the mineral property. However, section 636(a) also provides an exception to this general rule. A production payment carved out for the "exploration or development of a mineral property"[134] is not treated as a mortgage loan, and is therefore not affected by the new law, if gross income is not realized by the person creating the production payment. For example, A carves out a production payment for $100,000 at a selling price of $90,000 to X. A agrees also to use the proceeds to drill development wells on his mineral property. The exception in section 636(a) applies: X

134. I.R.C. § 636(a).

can continue to treat the $100,000 production payment as an economic interest subject to depletion while A does not include the $90,000 in his income.

The tax treatment of all carved-out production payments created prior to August 7, 1969 and the treatment of those carved-out production payments created after August 6, 1969 which do not qualify for the section 636(a) exception, is illustrated by the following examples.

Assume that on December 31, 1967, A carves out a $100,000 production payment bearing interest at 5% of the productin of his oil property. B purchases the "carve-out" from A for $95,000. For 1967, A has $95,000 of ordinary income subject to depletion and B owns a $100,000 production payment. In 1968, assume A has gross income of $50,000 from the property. He excludes $25,000 from his income, paying it to B in partial satisfaction of the production payment, and claims depletion against the $25,000 he retains. On the other hand, B is entitled to cost depletion in such an amount that the only net taxable income he would have to report over the life of the payment is the interest equivalent which was built into the production payment.

However, with the enactment of section 636, the treatment of both A and B has changed. Assume A, the owner of a producing oil property, carves out a production payment on December 31, 1970, in the principal amount of $100,000 bearing interest at the rate of 5% per year and payable from 75% of the gross production. A sells this carve-out to B for $75,000. Since under section 636(a) A is treated as having obtained a loan, this transaction creates no taxable income for A in 1970. Because B is treated as making a loan, the transaction does not create an economic interest which would allow B to claim depletion.

Assume further that in 1971, the property produces $100,000 of income from oil. A could have $100,000 of ordinary income subject to depletion. On December 31, 1971 he pays $75,000 to B in partial satisfaction of the production payment. The $75,000 is treated as follows: $5,000 as interest (deductible as an interest expense to A and includible as interest income to B); $52,500 as a nontaxable return of capital (75% of the $75,000 payment to B less $5,000 in interest); and $17,500 as capital gain to B (not subject to depletion). The principal amount of the production payment is reduced to $48,500 ($100,000 less the $52,500 return of capital).

C. *Depletion—Computation of Allowance*

Once it has been ascertained that the taxpayer and his particular property[135] qualify for the depletion allowance, the computations necessary for the depletion deduction can be made. The four major considerations inherent in the computation of the depletion allowance are as follows:

1) Depletion must be computed on a "mineral property by mineral property" basis;[136]
2) The Code provides one method for calculating depletion known as cost depletion;[137]
3) The Code provides an alternative method, subject to certain qualifications, for computing depletion known as percentage depletion;[138]
4) Both depletion methods must be computed for each property on an annual basis because the taxpayer is required to use the higher of the cost of percentage amounts to determine the allowable depletion deduction.[139]

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135. Because depletion must be computed separately for each oil and gas property owned by the taxpayer (sections 612 and 613), and because the taxpayer cannot compute his allowable depletion deduction until he has determined the number of properties he holds, (section 614(a)) the importance of the term "property" for depletion purposes, cannot be overstressed. The following example demonstrates the calculation of the allowable depletion on a per property basis:

	Operating mineral interest S	Operating mineral interest T	Aggregation of S and T
Gross Income	$1,000	$1,000	$2,000
Expenses	950	250	1,200
Taxable income (before depletion)	— 50	— 750	— 800
Depletion:			
22% of gross income	220	220	440
50% of net income	25	375	400
Cost (assumed)	50	200	250
Allowable (Greater of percentage and cost depletion)	50	230	400

136. I.R.C. §§ 612-13.
137. *Id.* §§ 611-12.
138. *Id.* §§ 611, 613, 613A.
139. *Id.* § 613(a).

1. Cost Depletion

Because the taxpayer is allowed to recover by way of deduction a proportional amount of his capital investment over the useful life of the asset, the concept of cost depletion can be likened, in theory, to the straight line method of depreciation. The main difference, however, between the two concepts rests in the definition of the asset's "useful life." In the case of depreciable tangible assets, the useful life is measured in years; whereas, the depletable asset's useful life is measured in terms of units produced (and sold) and units remaining in reserve. The discussion of cost depletion will focus on computing cost depletion, adjusted basis, and number of units remaining in the oil and gas deposit.

a. *The Calculation of Cost Depletion*

Cost depletion is the basic method of depletion. The allowable cost depletion amount is the product of the "depletion unit" times the "number of units of mineral sold within the taxable year."[140] Section 1.611-2(a)(1) of the regulations defines "depletion unit" as the basis of the mineral property, determined with reference to section 612 and the regulations thereunder, divided by the "number of units remaining as of the taxable year." The regulation defines the "number of units remaining as of the taxable year" as including those units which have not yet been recovered, those which have been recovered but not yet sold, and those which have been recovered and sold during the taxable year.[141] When the regulations are reduced to algorithmic form, the formula for computing cost depletion can be stated as follows:

$$Dc = \frac{(S)\ (B)}{(U)} \quad \text{where :}$$

Dc = Cost depletion amount

S = Number of units sold during the taxable year

B = Adjusted basis of property at end of the year

U = Number of units remaining at end of year (includes units in the reservoir, units recovered but not sold, and units sold within the taxable year).

140. Treas. Reg. § 1.611-2(a)(1) (1967).

141. Treas. Reg. § 1.611-2(a)(3) (1967).

For example, assume that the oil or gas property has an adjusted basis of $40,000 as of the end of the taxable year, that the remaining estimated recoverable units is 30,000 barrels, and that of the 5,000 barrels produced only 3,000 were sold. The allowable cost depletion deduction for the property is

$$Dc = \frac{(3{,}000)\ (40{,}000)}{30{,}000}$$

$$Dc = \$4{,}000$$

b. *Adjusted Basis*

The starting point in determining adjusted basis is the taxpayer's initial cost in the acquired property.[142] However, since the adjusted basis of the property for depletion purposes is determined at the end of the taxable year, any capital expenditures made during the year are automatically provided for in the cost depletion computation.

Although the computation of adjusted basis is relatively simple in most cases, a problem of allocating costs between depletable and nondepletable property may arise when, without any differentiation, both types are acquired in a single conveyance. Examples of such a transaction would be the acquisition, for a lump sum, of an oil and gas (depletable) leasehold interest along with equipment (depreciably) or the acquisition of a fee interest in surface land (nondepletable) and mineral deposit (depletable) without specification of cost breakdown.

In the event that allocation between depletable and nondepletable property is necessary, sections 1.611-1(d)(4)[143] and 1.167(a)(5)[144] can be cited for the proposition that the relative fair market values of the properties should be used in determining the proper allocation of cost. In this context, although the acquisition cost of an oil and gas property usually approximates the fair markets of the assets, it is noteworthy that a situation can arise wherein the cost and fair market value amounts differ radically. Such a situation was presented in the *Island Creek Coal Company*[145] case. In *Island Creek,* the peti-

142. I.R.C. §§ 1011-12.
143. (1960).
144. (1956).
145. Island Creek Coal Co. v. Commissioner, 25 T.C.M. (CCH) 540 (1966).

tioner acquired coal-bearing property including sales contracts, depreciable assets, and mineral leases. He contended that the value of the depreciable assets alone was worth more than the entire purchase price.[146] The Service, however, contended that the mineral leases represented a part of the cost of the acquired property.[147] On the issue of the valuation of the intangible nondepreciable assets (mineral leases) the Tax Court held: "We have also concluded from the evidence that the coal leases had no cost to petitioner over and above the royalties which were to be paid to the lessors if, as, and when the coal was mined and that the sales contracts and other intangible assets had no value."[148] Responding to this adverse decision with Revenue Ruling 69-539,[149] the Service stated, "Only in rare and extraordinary circumstances will a taxpayer acquire a going enterprise in which the mineral leases have no value apart from the royalty that they specify for the lessor."[150]

What happens when land is acquired with the mineral lease or estate? The old rule provided that allocation of basis to the mineral interest was only proper when the property was in a "proven" area.[151] However, the current regulations require that where surface land is acquired along with a mineral interest in a single transaction, the portion of the cost attributable to the land, which is nondepletable and nondepreciable, must be excluded when determining the basis of the mineral interest.[152]

Problems of allocating basis between mineral interests and surface land acquired in a single transaction can also arise in gain or loss computations when the property is conveyed in separate transactions. An illustrative case is *American Realty Company v. Commissioner.*[153] In this case the taxpayer acquired the surface land and mineral interest in a single transaction. In subsequent years, the taxpayer granted a mineral lease and claimed percentage depletion on the bonuses received.

146. *Id.* at 541.
147. *Id.*
148. *Id.* at 543.
149. Rev. Rul. 69-539, 1969-2 C.B. 141.
150. *Id.*
151. XIV-1 C.B. 98 (1935), *declared obsolete,* Rev. Rul. 68-661, 1968-2 C.B. 607.
152. Treas. Reg. § 1.612-1(b) (1960); *see also,* Beaver Dam Coal Co. v. United States, 370 F.2d 414 (6th Cir. 1967).
153. 47 B.T.A. 653 (1942).

Upon the sale of the entire surface land and mineral interest, the taxpayer, claiming that there was no independent mineral cost at the time of acquisition, did not reduce its basis to reflect the depletion taken. The Board of Tax Appeals required the taxpayer to reduce its basis in the property for purposes of computing gains and losses to reflect the depletion taken in prior years.[154] As a result of this decision, even though no cost allocation is ever made, a taxpayer who claims depletion deductions will have to reduce his basis in the mineral property at the time of sale.

c. *Number of Units Remaining at the End of the Taxable Year*

While the "number of units sold" during the year, determined in accordance with the oil and gas taxpayer's method of accounting,[155] presents no unusual problems of interpretation or application, the "number of units remaining at the end of the year" presents a more troublesome problem. The problem arises because the number of units remaining in the oil and gas reserves is an *estimation* of the quantity of units contained within the deposit. The problem is militated by the fact that the estimated reserves are based not only upon developed deposits, but also upon those which are "probable" or even merely "propective".[156] Due to extensions into known deposits, where there is a "high degree of probability" or "good evidence" that reserves exist,[157] such "probable" or "prospective" reserves are estimated in conjunction with the track record of the larger tract or parcel containing the oil or gas property.[158]

Since the estimated reserve figure presupposes

154. *Id.* at 657.

155. Treas. Reg. § 1.611-2(a)(2) (1960). It provides that the phrase "number of units sold within the taxable year"—

> (i) In the case of a taxpayer reporting income on the cash receipts and disbursements method, includes units for which payments were received within the taxable year although produced or sold prior to the taxable year, and excludes units sold but not paid for in the taxable year, and
>
> (ii) In the case of a taxpayer reporting income on the accrual method, shall be determined from the taxpayer's inventories kept in physical quantities and in a manner consistent with his method of inventory accounting under section 471 or 472.

156. Treas. Reg. § 1.61102(c)(1)(ii) (1960).

157. *Id.*

158. *Id.* § 1.611-2(c)(1)(ii)(a) (1960).

"recoverable reserves,"[159] the estimation of reserves also requires a calculation as to that portion of the overall estimated deposit that will be *recoverable.* The regulation on this point states, "[T]he estimate or determination must be made according to the method current in the industry and in light of the most accurate and reliable information obtainable."[160] Therefore, it appears that an estimation of recoverable reserves for oil and gas deposits may also take into account the possibility of using secondary or tertiary recovery methods.

When must the taxpayer make his estimation on the basis of such methods? In the leading case on this point,[161] the Tax Court held that the petitioner's plans for increased recovery by way of considerable capital expenditure for recovery enhancement was "impractible from a business standpoint."[162] It would appear that an estimation of recoverable reserves should be based only upon those reserves which can be recovered from a feasible economic standpoint. Obviously, the "feasibility" due to our expanding technology of recovery enhancement for recoverable reserves creates a high degree of uncertainty. For example, whereas "waterflooding" has been used for many years to stimulate production, more current methods such as gas recycling, miscible fluid injection, and even "fireloading" have been gaining favor, although some are still only experimental. Therefore, since extension of the "recoverable reserves" doctrine to the more exotic recovery enhancement techniques seems reasonable, fortunately from the taxpayer's viewpoint, experimental methods will probably not qualify for estimated recoverable reserve revision purposes.

2. Percentage Depletion

a. *Background and History*

The percentage depletion allowance, also referred to as statutory depletion, has been one of the preeminent issues in the field of oil and gas taxation. Most taxpayers have learned of the existence of the percentage depletion allowance for oil and gas and have formed a strong opinion on the subject. As a result, the percentage depletion allowance is one of the most

159. *Id.* § 1.611-2(c)(1) (1960).
160. *Id.*
161. Black Gold Petroleum Co. v. Commissioner, 3 T.C.M. (CCH) 241 (1944).
162. Revenue Act of 1916.

emotional and bitter facets of the "special treatment" tax dispute.

Statutory provision first enacting percentage depletion can be found in the Revenue Act of 1926. The first specific statutory reference to oil and gas depletion provided for a reasonable allowance for actual reduction in the "settled production" or regular flow from the well. The "reduction in flow" concept[164] gave way, in the Revenue Act of 1918, to a "discovery value depletion" allowance based upon the cost of the property, or where the fair market value was substantially disproportionate to the cost, "based upon the fair market value of the property at the date of discovery, or within thirty days thereafter . . . .[165] The Revenue Act of 1921[166] left the other discovery value provisions intact but added a clause limiting the depletion allowance to 50% of the net income from the property.[167]

Great dissatisfaction was voiced by the oil and gas industry over both the difficulties and uncertainties in establishing discovery values and the inequalities between competing taxpayers.[168] The search for a simpler and more operationally uniform basis for the depletion allowance led to the "depletion allowance based on the income" concept codified in the Revenue Act of 1926. While discarding the "discovery value" concept, this act retained the 50% of net income from the property limitation and provided for a depletion allowance based upon 27 ½% of the gross income from the property.[169] Although arbitrary, the concept of a 27 ½% depletion rate based on gross income from the property provided the necessary uniformity while retaining the discovery and development incentive fac-

164. The reduction in flow method of computing depletion was based on measuring the rate of flow at the time it became regular, or "settled", and then again at the end of the taxable year. Any reduction in the rate of flow was reduced to a ratio which was applied against, and ultimately limited to, the capital investment in the well to yield the allowable depletion deduction from income.

165. Revenue Act of 1918, §§ 214(a)(10), 234(a)(9), (Individuals and corporations respectively).

166. Revenue Act of 1921, §§ 214(a)(10), 234(a)(9), ch. 136, 42 Stat. 227. (Individuals and corporations respectively).

167. This same limitation is located at § 613(a).

168. Although the 1921 Act solved the problem of the taxpayer taking a larger depletion deduction than the net income from his property, a very broad discretion still remained in the taxpayer with a newly discovered oil and gas property.

169. Revenue Act of 1926, § 204(c)(2), ch. 27, 44 Stat. 9.

tors, and ease of administration lacking in the "discovery value" method.

The evolution of the current version of the percentage depletion allowance involved many refinements and clarifications upon the original provisions. It was recognized early that only those taxpayers qualifying for cost depletion could qualify for percentage depletion. In 1945 the court in the case of *Kirby Petroleum Company v. Commissioner* held as follows: "The allowance of percentage depletion is made only to the persons who would be entitled to claim cost depletion on account of their ownership of a depletable capital asset, the fundamental theory of the allowance not having been altered by the provisions for percentage depletion."[170] Further, although the Service tried to limit allowance of percentage depletion to only those taxpayers who have a positive basis for their economic interest, the courts consistently ruled as follows:

> The percentage depletion allowance is not conditioned upon the existence of any basis, and bears no relation thereto. Under the plain terms of the statute, it is allowable to any taxpayer who owns an economic interest in oil or gas in place and derives income therefrom during the taxable year.[171]

Also, disputes arose over the proper allocation of depletion and gross income between taxpayers because the percentage depletion allowance was linked directly to income from production. Numerous clarifications concerning proper allocation of percentage depletion between economic interest holders were made in the *Twin Bell Oil Syndicate* case.[172] The holding in *Twin Bell* was based on the following train of logic: no matter which method of computing depletion is used, the total allowable deduction must be apportioned between the lessor and lessee.[173] To allow a ¼ royalty holder and the taxpayer, both of whom receive gross income for the property, to take depletion on their gross income would result in a total allowance of 27½% of 5/4 of the total production which is inconsistent with the principal of apportionment between lessor and lessee. The Court noted further that the concept of "gross income from the property" as a basis for computing percentage depletion could not be interpreted to include all uses possible, but only the

170. 148 F.2d 80, 81 (5th Cir. 1945), *rev'd.* 326 U.S. 599 (1946).
171. Rowan Drilling Co. v. Commissioner, 130 F.2d 62, 66 (5th Cir. 1942).
172. Commissioner v. Twin Bell Oil Syndicate, 293 U.S. 312 (1934).
173. *Id.* at 320.

gross income from oil and gas.[174] By restricting the concept of allowable depletion to a single depletion allowance among economic interest holders, the royalty holder was entitled to percentage depletion on his gross income from the royalty, and the taxpayer was limited to percentage depletion calculated on the portion of his gross income from the property he had the right to retain.[175]

The importance of the percentage depletion allowance is due largely to the results of the interplay between percentage depletion and other oil and gas provisions, such as the IDC election and the mandatory capitalization of G and G costs. For example, a taxpayer claiming percentage depletion who opts to deduct intangible drilling costs, can achieve a greater total deduction than if the IDC are capitalized, even though the IDC must be included in the expenses offsetting gross income to reach the net income figure for purposes of the 50% net income limitation.[176]

The following example illustrates the computations involved in percentage depletion:[177]

Gross Income		$100,000	
IDC	$30,000		
Operating Expenses	$20,000		
Total Expense		$ 50,000	
Net Income		$ 50,000	
50% of Net Income		$ 25,000	
22% of Gross Income		$ 22,000	
Allowable Depletion		$ 22,000	
IDC Deduction		$ 30,000	
Total Deductions			$52,000

b. *Recent Legislative Enactments*

The creation of the percentage depletion allowance spawned an argument that has flourished for more than fifty years. While terming the percentage depletion provisions as "special treatment," many taxpayers and legislators have at-

174. *Id.* at 321.
175. *Id.*
176. Treas. Reg. § 1.613-5.
177. The assumptions are: 1) the taxpayer elects to deduct IDC currently under § 263(c); and 2) taxpayer has one property as defined by § 614(a).

tacked the percentage depletion allowance on the grounds that it provides unwarranted and preferential tax benefits for a single industry and group of elite taxpayers. In rebuttal, oil and gas taxpayers, citing the importance of domestic energy sufficiency, have argued that, in the face of extreme economic risk and the requisite large capital investment, the loss of percentage depletion would reduce the incentive to discover and develop new oil and gas deposits. For many years the oil and gas industry was able to maintain the upper hand in Congress. Recently, however, the industry suffered a resounding defeat. By enacting the Tax Reform Act of 1969 and the Tax Reduction Act of 1975, Congress acknowledged the political influence of reform-minded taxpayers.

While the Tax Reform Act of 1969[178] repealed the 27½% depletion rate and instituted a new flat rate of 22% of gross income from the property, the Tax Reduction Act of 1975[179] effectively repealed the section 613 percentage depletion allowance provisions for all except four limited groups of taxpayers.[180] The 22% depletion allowance is now granted only to taxpayers with income from production of the following: 1) regulated natural gas;[181] 2) natural gas sold under a fixed contract;[182] and 3) any geothermal deposit which is determined to be a gas well.[183] The fourth group of taxpayers still allowed to

178. § 501, Pub. L. No. 91-172, 83 Stat. 487 (1969).

179. § 501, Pub. L. No. 94-12, 89 Stat. 47 (1975).

180. I.R.C. § 613A(b)(1).

181. Section 613A(b)(2)(B) defines regulated natural gas as:

> domestic natural gas produced and sold by the producer, before July 1, 1976, subject to the jurisdiction of the Federal Power Commission, the price for which has not been adjusted to reflect to any extent the increase in liability of the seller for tax under this chapter by reason of the repeal of percentage depletion for gas. Price increases after February 1, 1975, shall be presumed to take increases in tax liabilities into account unless the taxpayer demonstrates the contrary by clear and convincing evidence.

182. Section 613A(b)(2)(a) defines natural gas sold under a fixed contract as the following:

> domestic natural gas sold by the producer under a contract in effect on February 1, 1975, and at all times thereafter, before such sale, under which the price for such gas cannot be adjusted to reflect to any extent the increase in liabilities of the seller for tax under this chapter by reason of the repeal of percentage depletion for gas. Price increases after February 1, 1975, shall be presumed to take increases in tax liabilities into account unless the taxpayer demonstrates to the contrary by clear and convincing evidence.

183. Geothermal deposit is not defined in section 613A. Section 1.613A-7(e), of the

take percentage depletion are those "independent producers and royalty owners" who qualify under paragraphs 613A(c)(1) through (11) as limited by paragraphs 613A(d)(1) through (4). However, these independent producers and royalty owners are further restricted in claiming percentage depletion. Not only are they subject to a new limitation based on taxable income,[184] independent producers and royalty owners are also limited to a sliding scale in future years on both the applicable percentage[185] and the quantity of production.[186] In addition, depletion is a tax preference item for minimum tax purposes.[187] The exemption afforded the independent producers and royalty owners with their correlative restrictions deserve further analysis.

i. Qualification as Independent Producers on Royalty Owners

Known also as the "small producers" exemption, the independent producers and royalty owners exemption in section 613A(c) is most easily defined by exclusion. Oil and gas taxpayers who are "retailers," "refiners," or are "related" to retailers or refiners cannot qualify under the section 613A(c) exemption.

A "retailer" is any taxpayer who sells oil or natural gas, or any product derived therefrom, directly or through a "related person", either 1) through any retail outlet operated by the taxpayer or a "related person", or 2) to any person who is: a) obligated to use a taxpayer's or a related person's trademark or service name in marketing or distributing the oil or natural gas product, or b) given authority by the taxpayer or a related person to occupy any retail outlet which is owned, leased, or otherwise controlled by the taxpayer or a related person.[188]

A "refiner" is a taxpayer or related person who refines crude oil and on any single day during the year refines more than 50,000 barrels.[189]

For purposes of both the retailer and refiner exclusions, a

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proposed regulations defines it in terms of a geothermal reservoir of heat, stored in rocks or aqueous fluid, in the form of liquid or vapor.

184. *See* text accompanying note 217 *infra*.

185. *See* note 203 *infra*.

186. *See* note 199 *infra*.

187. *See* text accompanying note 221 *infra*.

188. I.R.C. § 613A(d)(2).

189. *Id.* § 613A(d)(4).

related person exists whenever 1) the taxpayer or another person holds a significant ownership interest in the other, or 2) a third person has significant ownership interest in both the taxpayer and such other person.[190] A significant ownership interest is deemed to exist where the taxpayer, other person, or third person, owns 5% or more of either 1) the value of the outstanding stock of a corporation, 2) the profits or capital of a partnership, or 3) the beneficial interest in an estate or trust.[191]

Although the statutory provisions in the 1975 Act excluding retailers, refiners, and related persons were very comprehensive and detailed, it is clear that, in many situations ambiguities can arise over the proper interpretation of the provisions. For example, in an explanation of the Act it was stated:

> [T]he retailer exclusion could have been interpreted to deny the small producer exemption to a royalty interest holder who also holds a mere 5 percent interest in a partnership that operates a corner drugstore which sells petroleum jelly. The Congress believes that the retailer exclusion should apply only where the taxpayer has substantial retail operations and not to cases where a taxpayers retail operations are essentially *de minimus*.[192]

Assuming the taxpayer does not run afoul of the retailer and refiner exclusions, he faces two more obstacles before he may begin to compute his percentage depletion allowance. These obstacles are the advance royalty rule and the transfer rule. Because the percentage depletion allowance for small producers is allowed only where there is actual production during the year, under section 1.613A-7(f) of the proposed regulations advanced royalties and lease bonuses no longer qualify for percentage to the extent actual production during the taxable year is insufficient to earn such royalties.[193] As the second obstacle, transfer of "proven" oil and gas property to an otherwise small producer transferee precludes the transferee from qualification under the section 613A(c) exemption to take percentage depletion on income attributable to that property.[194] Also, production from that property cannot be taken into account in any computation.

190. *Id.* § 613A(d)(3).

191. *Id.*

192. JOINT COMMITTEE ON TAXATION, 94th Cong., GENERAL EXPLANATION OF THE TAX REFORM ACT OF 1976 (CCH) 625 (1976).

193. 42 Fed. Reg. 24, 279, 24,287 (1977).

194. I.R.C. § 613A(c)(9).

ii. Restriction on the Quantity Subject to Percentage Depletion

The small producer exemption allows the taxpayer to compute his percentage allowance only upon his "average daily production" of oil or natural gas[195] as limited by his "depletable oil quantity" or his "depletable natural gas quantity."[196]

The Code provides that taxpayers "average daily production" for the taxable year is determined by:

> dividing his aggregate production of domestic crude oil or natural gas, as the case may be, during the taxable year by the number of days in such taxable year, and (B) in the case of a taxpayer holding a partial interest in the production from any property (including an interest held in partnership) such taxpayer's production shall be considered to be that amount of such production determined by multiplying the total production of such property by the taxpayer's percentage depletion participation in the revenues from such property.[197]

The aggregate production used in the above computation does not take into account any production resulting from secondary or tertiary process.[198] Interestingly, the average daily production determination is made on a per-taxpayer basis rather than a per-property basis.

The taxpayer's depletable oil quantity, which limits the average daily production, is equal to the tentative "phase-out table" amount.[199] This amount is reduced, but not below zero, by the taxpayer's average daily secondary or tertiary production for the taxable year.[200]

The taxpayer's depletable natural gas quantity is an

195. *Id.* § 613A(c)(1)(A).
196. *Id.* § 613A(c)(1)(B).
197. *Id.* § 613A(c)(2).
198. *Id.* § 613A(c)(2)(B).
199. *Id.* § 613A(c)(3)(B). The table is reproduced below:

In the case of production during the calendar year:	The tentative quantity in barrels is:
1975	2,000
1976	1,800
1977	1,600
1978	1,400
1979	1,200
1980 and thereafter	1,000

200. *Id.* § 613A(c)(3)(A)(i), (ii).

amount equal to his phase-out table barrel amount multiplied by 6,000 cubic feet.[201] Thus, if he elected to apply his total tentative quantity to natural gas, a taxpayer in 1980 would have a tentative depletable natural gas quantity amount of 6,000,000 cubic feet of natural gas.

Because the section 613A(c)(3)(B) tentative depletable oil quantity is reduced by the taxpayer's average daily secondary or tertiary production for the taxable year, percentage depletion computations must be made separately for the taxpayer's primary and secondary production attributable income. On this point, section 613A(c)(6) provides that the amount of secondary or tertiary production (computed on an average daily basis for the taxable year) that does not exceed the taxpayer's tentative depletable oil quantity or depletable natural gas quantity, is entitled to the 22% rate of depletion[202] notwithstanding the sliding scale applicable percentage rates listed in subparagraph 5.[203] Section 1.613A-7(k) of the proposed regulations[204] defines secondary and tertiary production in terms of increased production of oil or gas from a domestic well following application of a secondary process. "Increased production" is that marginal increase in actual production during the year over that which would have been produced absent application of the "secondary process," and is manifested by an increase in either the rate or duration of recovery.[205] A "secondary process" is a process in which liquids or gases are injected in the

201. *Id.* § 613A(c)(4).

202. *See* note 199 *supra*.

203. I.R.C. § 613A(c)(5). The applicable percentage table is reproduced below:

In the case of production during the calendar year is:	The applicable percentage
1975	22
1976	22
1977	22
1978	22
1979	22
1980	22
1981	20
1982	19
1983	16
1984 and after	15

204. 42 Fed. Reg. 24,279, 24,287 (1977).

205. *Id.*

deposit to increase the internal pressure in order to enhance recovery.[206]

One major exception to the secondary process provisions involves any process which must be introduced early in the productive life of the property in order to be reasonably effective.[207] Cycling of gas in a gas condensate well is specifically excluded from secondary process status.[208] But injection or fire-flooding will not be so disqualified if they would still have been reasonably effective had they been introduced later in the production life of the property.[209]

It should be noted that the apparent benefit of retention of the 22% rate for secondary or tertiary production until 1981 may be disadvantageous to taxpayers whose production exceeds the quantity limitations.[210] Since secondary and tertiary processes are very expensive and such expenses are subtracted from gross income for the net income percentage limitation, the taxpayer who is required to use all his depletable oil and natural gas quantity for such secondary or tertiary production may have any benefit realized from the 22% rate retention offset by the lower allowable deduction due to the net income limitation.

Those small producer taxpayers whose average daily production exceeds the quantity limitations must look to special rules for guidance. Excess production of both oil[211] and natural gas[212] requires the taxpayer to compute his allowable depletion for each property as follows:

> 1) Divide the applicable depletable oil or natural gas quantity by the average daily production in barrels or mcf for the taxable year.
> 2) Compute the total percentage depletion allowance which would have been allowable for the property using the applicable sliding scale percentage rate for the property.
> 3) Multiply the amounts calculated in 1) and 2) to yield the allowable percentage deduction for the property.[213]

Also, depending on the taxable year, the applicable per-

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206. *Id.*
207. *Id.*
208. *Id.*
209. *Id.*
210. *See* note 203 *supra.*
211. I.R.C. § 613A(c)(8)(A).
212. *Id.* § 613A(c)(8)(B), (C).
213. *Id.* § 613A(c)(7).

centage rate to be applied against gross income may differ. The taxpayer taking depletion upon regulated natural gas, fixed contrast natural gas, or geothermal deposits, is allowed a flat 22%[214] rate until 1984.[215] On the other hand, the small producer must look to the applicable percentage table.[216]

iii. The Limitation Based on Taxable Income

Section 613A(d)(1) created a new 65% limitation based on the taxpayer's taxable income. The purpose of the limitation is to further restrict the allowable percentage depletion deduction for the small producer. The 65% limitation is applied to taxable income computed without regard to any depletion on production which is subject to the small producer exemption rules, any net operating loss carryback, any capital loss carryback, and certain distributions from a trust to its beneficiary.[217] Any amount of deduction which is disallowed for the current taxable year can be carried forward over to the next taxable year,[218] in which case such amount must be allocated back among the respective properties owned for purposes of determining the higher of cost or percentage depletion.[219]

The 65% limitation does not replace the section 613(a) 50% of taxable income limitation. The distinction between the 65% and 50% limitations is that they apply to taxable income on a per-taxpayer basis and per-property basis respectively. The result is that the small producer taxpayer must apply both limitations in his computations of allowable percentage depletion deduction. Because of the per-taxpayer and per-property difference, the provision for carry-over of the amount of percentage depletion disallowed by virtue of the 65% limitation, creates horrendous problems of computational complexity when combined with the 50% limitation and higher-of-cost or percentage provisions.[220]

iv. Depletion as a Tax Preference Item

The small producer faces yet another computation which

214. *Id.* § 613A(c)(6)(A)(ii).
215. *Id.* § 613A(c)(6)(C).
216. *See* note 203 *supra.*
217. I.R.C. § 613A(d)(1).
218. *Id.*
219. For a detailed discussion of this problem, see Burke, Jr., *Tax Reform Act of 1975 — Two Years Later,* TWENTY-EIGHTH OIL AND GAS INST., 611, 611-14, 622-23, (1977).
220. *See* text accompanying note 139 *supra.*

will impose additional tax liability. Enacted in 1969, section 57(a)(8) lists depletion deducted which is in excess of the adjusted basis of the property at the end of the taxable year as a tax preference item subject to the minimum tax provisions.[221]

V. A COMPREHENSIVE EXAMPLE

The following example illustrates several computations required when a small producer endeavors to claim depletion.

Assume that in the taxable year 1981 a taxpayer, W, owns one property which has both primary and secondary production oil income of 255,500 and 109,500 barrels for the year respectively. Gross income of $1,500,000 and expenses of $1,000,000 are incurred from the producing property. The taxpayers taxable income is $400,000. Assuming his allowable cost depletion is $240,000, what is the taxpayer's allowable percentage depletion?

Computation of Depletable Oil Quantity

Average daily primary production $225,500 ÷ 365	700 bbl
Average daily secondary production $109,500 ÷ 365	300 bbl
Aggregate average daily production	1,000 bbl
Less number of barrels from secondary production	300 bbl
Depletable oil quantity	700 bbl

Apportionment of Gross and Taxable Income to Primary and Secondary Production

Gross Income

Primary	700 bbl × $1,500,000 = $1,050,000
Secondary	300 bbl × $1,500,000 = $ 450,000

Taxable Income

Primary	700 bbl × $400,000 = $350,000
Secondary	300 bbl × $500,000 = $150,000

Computation of Tentative Percentage Depletion

	Primary	Secondary
Gross Income	$1,050,000	$450,000
Taxable Income	350,000	150,000

221. The 20% is applied against primary production while 22% is applied against secondary production. *See* note 203 *supra*.

20/22% of Gross Income	210,000	99,000
50% of Taxable Income Limitation	175,000	75,000
Amount Allowable	175,000	75,000

Computation of Total Percentage Depletion Allowable

Combined primary and secondary depletion	$250,000
The 65% limitation: 65% × 400,000	$260,000
Lesser of the two	$250,000

Since the percentage depletion is higher than cost depletion on the property, the taxpayer will deduct $250,000 as percentage depletion.

VI. CONCLUSION

As witnessed by the favorable percentage depletion and intangible drilling cost provisions in the Internal Revenue Code, there has been, and at present there still is, a national policy favoring the exploration for and exploitation of domestic oil and gas reserves. However, juxtaposed to the longstanding preferential Code provisions reflecting this policy favoring oil and gas exploration and exploitation are the newly enacted provisions, added in recent years in response to taxpayer criticism and "tax reform" demands.

It has been readily apparent that the aforementioned "reform" legislations have served to greatly reduce the incentives and preferential tax treatment previously afforded the oil and gas industry. Although these "reforms" have not been exclusively restrictive, as this article has pointed out, the bulk of the new provisions limit potential benefits, while the remainder are rather neutral in effect.