ANALYSIS OF SPECIAL TAX PROVISIONS AFFECTING INDEPENDENT OIL AND GAS PRODUCERS

Special Study

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PART I. DESCRIPTION OF THE INDEPENDENTS

A broad spectrum of firms are engaged in petroleum exploration and production in the United States. The companies range in size from Exxon ($62.9 billion in assets) to Patton Oil ($6.2 million in assets) to the lone stripper operator in Oklahoma. From the standpoint of the actors in the petroleum business, there are two types of firms in the industry--the large integrated producers (the majors) and the independents (all the rest). Whereas the integrated companies are involved in exploration, production, refining, and marketing, the independent firm frequently restricts its operations to the exploration and production phases of the business. In general, the independents are active in onshore areas and leave the high-cost offshore fields to the majors.

Two definitions of "independent" are used in this paper. One is that used by the petroleum industry, which considers all but the the very largest oil and gas corporations--about 25 firms--to be independent producers. Another definition is that of the tax code, which usually defines an independent as a producer with no significant retail or refining operations, thus excluding refiners, gas distribution companies, service station operators, and fuel oil (residential) distributors. For statistical reasons, the standard industry definition will be used in Part I, which provides an overview of independent operators. In Part II (tax provisions), the tax code definition will be used.

The oil and gas industry includes a wide variety of actors--from large multinational corporations to passive investors. A number of parties usually have an economic interest in any given oil property. Partnerships and joint ventures are common, used both to raise capital and to share risks among producers. Although there may be a number of separate economic interests in a given property, there is usually only one firm that does the actual work. This partner or operator is the actor responsible for actually conducting the exploration, production, and distribution operations (though it may also contract with other firms to perform these activities). The distinction between gross and economic (net) interests is important for both statistical and tax reasons. In general, production statistics on a "gross" basis reflect the activities of a firm or subset of firms regardless of ownership interest (that is, gross production is the amount that a company actually produces). On a gross operator basis, a firm will report data for all properties operated, regardless of ownership; this includes working interests, royalty interests, and production payments to the owners. Statistics derived on a "net" basis reflect the economic interests of a firm

or firms. Thus, net company statistics reflect the net ownership of a firm's interests in oil and gas leases. For example, a firm may produce 100 barrels--its gross production--and have an economic (net) interest of only 70 barrels. In addition, firms are generally taxed only on their economic or net interests and not on their gross production.

Structure of the Industry

In 1981, the independents (all oil and gas companies other than the top 24, ranked by value of production) accounted for 25 percent of the oil and 40 percent of the natural gas produced domestically (see Table 1).[1] The "independents" can basically be divided into two groups--the large and medium-sized corporations that are similar to the majors, and a large number of smaller corporations, proprietorships, and partnerships. Firms other than the top 200--that is, firms other than the majors or the large independents--produced about 10 percent of the oil and 11 percent of the natural gas in the United States. Although production is dominated by the larger firms in the industry, there are a number of small firms competing on the fringe. According to 1977 statistics, approximately 6,230 companies were engaged in oil and gas extraction (and another 7,637 were involved in oil and gas field services).[2]

The producing companies generally do not receive 100 percent of the revenue derived from their operations. In 1981, the top 24 companies produced 75 percent of the oil, but had an economic interest of only 62 percent. Similarly, the top 200 firms produced 90 percent of the oil, but had a net interest of 72 percent. The differences between the gross and the net interests reflect the royalty payments to landowners and interests of limited partners and other investors.

On average, firms other than the top 200 produced about 101 barrels per day (net) of oil and 612 MCF (thousand cubic feet) per day of natural gas.[3] In contrast, firms in the top 200 averaged 30,418 barrels per day of oil and 179,862 MCF per day of natural gas production. Stripper production

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1 For statistical reasons, the independents are defined as firms other than the top 24, instead of the top 25.

2 Companies without paid employees are excluded.

3 Clearly, this assumes that the universe of companies has remained the same as in 1977. If more firms have entered the market, which

TABLE 1. OIL AND GAS INDUSTRY STATISTICS, BY CATEGORY OF COMPANIES RANKED ACCORDING TO VALUE OF PRODUCTION, 1981

	Total United States		Top 24 Firms (percent)	Next 176 Firms (percent)	Other Firms (percent)
Gross lease revenues	141,222.1	mil. dol.	69	21	10
Net lease revenues	141,222.1	mil. dol.	56	14	7
Gross oil production	3,111.8	mil. bbl.	75	15	10
Net oil production	3,111.8	mil. bbl.	62	10	7
Net stripper production	438.9	mil.bbl.	40	10	21
Gross natural gas production	20,251.6	BCF	60	29	11
Net natural gas production	20,251.6	BCF	47	18	7
Gross exploration expenditures	16,899.2	mil. dol.	40	32	28
Gross development expenditures	19,001.7	mil. dol.	38	33	29
Gross number of wells drilled	68,622	wells	20	20	60
Employment	215.4	thousand	45	25	30
Gross book asset (net interest, end-of-year)	196,570.0	mil. dol.	67	25	8
Number of firms[a]	6,230		24	176	6,030
Average net oil production (barrels per day per firm)	1,074	bbl/day	219,543	4,028	101
Average net gas production (MCF per day per firm)	6,367	MCF/day	1,078,664	57,298	612

NOTE: BCF is billion cubic feet and MCF is thousand cubic feet.

SOURCE: U.S. Department of Commerce, Bureau of the Census, Annual Survey of Oil and Gas, 1981, Tables 1, 2, 6A, and 6B; and General Report on Industrial Organization: 1977 Enterprise Statistics, Table 16.

a. Number of firms is as reported in 1977 Enterprise Statistics. This excludes companies without a payroll.

(oil from wells that produce less than 10 barrels per day) was about 14 percent of total oil production; the top 200 firms produced 50 percent of this amount. Of the 755,848 producing oil and gas wells in 1981, 409,539 (54 percent) were stripper wells.

In general, most oil is produced by firms organized on a corporate basis. In 1981, corporations produced 95 percent of the oil and gas on a gross operator basis. Sole proprietorships were responsible for about 3 percent and partnerships produced about 2 percent. These shares represent gross amounts produced by the firms, even though they may not be entitled to the full economic interest in the production. On a net basis, the producing corporations have an interest of 75 percent as compared to their 95 percent share of gross oil production. Sole proprietorships and partnerships each have a 1.5 percent net interest in oil production. Nonproducers have net interests in oil of about 22 percent and in natural gas of 29 percent. These interests include parties outside the industry, such as individual royalty holders, limited partners, and landowners (for example, governments and non-oil corporations).

Drilling and Exploration

The independents play a more important part in drilling and exploration than in production. Of the $35.9 billion spent on drilling and equipping exploratory and development wells, 61 percent was spent by firms other than the top 24 companies. Firms other than the top 200 spent 29 percent ($10.3 billion) compared to their 10 percent share of gross lease revenues. Corporations were responsible for 92 percent of drilling expenditures; partnerships and sole proprietorships accounted for a total of 7 percent of expenditures. Corporations also drilled 76 percent of the exploratory and 87 percent of the development wells.

While the large oil and gas corporations spend more for exploration and development wells than the smaller firms, in terms of the number of wells the situation is reversed--firms other than the top 200 drilled 60 percent of the total wells completed during 1981. This indicates that the larger firms drill deeper and more costly wells than the independent firms. The top 200 firms completed wells averaging about 6,700 feet in depth, at $138 per foot; the other firms completed wells averaging about 4,600 feet and costing $54 per foot. In part, this reflects the greater activity of the large companies in offshore areas.

Footnote Continued

is believed to be the case, the average production figures would be lower.

Finance

Oil and gas companies are financed in a variety of ways. The larger companies are often publicly held corporations that can raise cash in the security markets. This is also true of the larger independents, such as Superior Oil or Mesa Petroleum. Larger firms also rely heavily on internally generated funds. It is also common for companies to engage in joint ventures, allowing them to spread the risk (and any consequent rewards). To the extent that these joint ventures are between major corporations, they are financed by the sponsoring firms.

Smaller oil and gas companies are generally privately held corporations, partnerships, or sole proprietorships. These firms rely less on public capital markets and more on private investors and banks as sources of finance. As with the large firms, they are also dependent upon their own internally generated cash for a large part of their capital spending.

In general, the established oil and gas firms (whether or not they are independent) have a history of profitability and are thereby able to utilize the full range of tax deductions common to the industry: write-offs for intangible drilling costs, percentage depletion or cost depletion, abandonment losses, accelerated depreciation, and investment credits. Smaller and less profitable firms may be less able to take full and immediate advantage of these tax provisions, since savings are limited by the amount of their tax liability. The current tax rules require firms to defer the recognition of losses for tax purposes, thereby reducing the value of deductions. In order for tax deductions or credits to be useful, firms must generate sufficient income and tax liability to absorb them. Thus, it is common for sole proprietors and partnerships (operating) to rely on outside investors with substantial taxable income who can make use of the "extra" write-offs. Those interested in a small oil and gas firm might include other members of the industry--corporations or individuals with positive taxable income--or "passive" investors--such as high-income individuals or non-affiliated corporations that can make use of the write-offs.

Limited Partnerships. Where outside investors are involved in the oil and gas industry, it is commonly involved on a "limited partnership" basis with a general partner (the actual operator). The general partner can be either a corporation or an unincorporated oil and gas firm. The limited partnership arrangement is attractive to outside investors because their liability is limited to their capital contribution, whereas the general partner is liable for the partnership's liabilities in full. The limited partners also generally have little say in how the partnership allocates its drilling and development funds. In this sense, the limited partnership is similar to a corporation--the stockholders have limited liability and do not usually direct the firm's ongoing operations. Unlike a regular corporation,

however, the limited partnership arrangement allows the firm to pass through to the partners their full share of deductions and tax losses.[4]

The tax rules generally allow limited partners to take a proportionately greater share of the start-up deductions in exchange for a lower percentage of the revenues. For example, the limited partners may be allocated 90 to 100 percent of the intangible drilling cost deduction of the operation.[5] One of the advantages of this arrangement is that the limited partners will be able to use the high front-end deductions involved in oil and gas drilling.

The limited partnership financing arrangement has significant advantages over a bank loan. If the operating company borrowed the amount necessary to drill an oil field, it would not be entitled to write off its intangible drilling costs right away unless it had taxable income from other sources. (To the extent that a limited partnership takes out a loan, the partners are restricted from taking a tax loss in excess of the amount they personally are at risk.) Thus, the limited partnership arrangement allows small oil firms to generate capital from outside investors who can use tax deductions that might not otherwise be utilized. In addition, it allows individuals the opportunity to invest in a high-risk operation without becoming active participants in the venture, while the operator is free of the definite repayment obligations associated with a loan.

Limited partnerships provide a significant source of finance for the industry, amounting to several billion dollars over the last few years. In 1980, public partnership "drilling funds" registered with the Securities and Exchange Commission (SEC) raised $1.3 billion.[6] These funds represented about 6 percent of all drilling expenditures in 1980 and 20.6 percent of

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4 Under the Subchapter S revisions of 1982, limited partnerships are now very similar to Subchapter S corporations.

5 "Public Oil and Gas Program Investment Declines in 1982," Investor's Tax Shelter Report, vol. 2, no. 1 (January/February 1983), p. 4.

6 The Tax Reform Act limited special allocations to those circumstances where they have a "substantial economic effect," that is, where the allocation actually affects the dollar amount of the partners' share of the total partnership income or loss, independent of tax consequences.

drilling expenditures by firms other than the top 200. In 1981, capital provided through public drilling funds rose to a record $2.0 billion (6 percent of total drilling expenditures), but fell by 50 percent to $1.1 billion in 1982. Drilling capital is also raised through private placements of limited partnerships that are not registered with the SEC. Although there are no available statistics on the amount supplied through these funds, it has been estimated that the amount provided through privately placed funds may be twice that of SEC-registered funds.

A Limited Partnership In Action. A limited partnership in the oil industry often takes the form of a general partner offering "shares" to investors in the partnership. The sponsoring firm may set up many such partnerships, each as a separate entity. The general partner directs all oil exploration and development operations; the limited partners have no control over the operating methods of the general partner.

The most common form of limited drilling partnership in oil and gas is referred to as a "functional allocation" program. In this type of structure, the sharing of costs turns on their tax treatment. Investors pay all "expensed" costs (those that are written off right away), while the sponsor pays all capital costs. Revenues are shared from the start of production. Although this arrangement maximizes the first-year deductions of the investors, it also maximizes their exposure to risk, since they are fully responsible for the costs of dry holes. Moreover, the sponsor's share of capital costs, although not fully deductible in the first year, benefits from depreciation under the Accelerated Cost Recovery System (ACRS) plus the investment tax credit and percentage depletion. Thus, the sponsor loses little (if anything) by sharing costs in this way, and gains significant insulation against the vagaries of the industry. This is in addition to a revenue-sharing arrangement that disproportionately favors the sponsoring firm.

A typical sharing of the costs and revenues of a functional allocation program is shown below:

	General Partner (percent)	Limited Partner (percent)
Management Fee	0	100
Sales Commissions	100	0
Capital Costs		
Lease bonuses	100	0
Equipment	100	0
Non-capital Costs		
Intangible drilling	0	100
Lifting Costs	50	50
Administrative Overhead	50	50
Revenues	50	50

In this arrangement, the general partner receives 50 percent of the net operating revenue (gross revenue less lifting costs and overhead) in exchange for providing the capital costs, such as lease bonuses and depreciable equipment. As a percentage of the total investment in a producing well, capital costs might be 25 percent. Basically this type of operation calls for the operator to become financially involved when a well is completed and the lease equipment installed. If a lease is abandoned, the limited partners are responsible for the costs involved in nonproducing acreage; the operator is only engaged in acreage that is productive.

Upon formation of a partnership, the proceeds from the sale of "shares" are applied to the development of oil and gas properties. In this case, it is assumed that the limited partners' investment is applied as follows:

	Percent
Management fee	6
Administrative overhead	4
Drilling and equipping wells (Intangible drilling costs)	90

Assume, for example, that the investors put up \$555,556, of which 90 percent (\$500,000) goes toward drilling an oil well. The 10 percent

($55,556) that goes for overhead and management fees may be amortized over 60 months as reimbursement of the costs of organizing a partnership. (Overhead determined to be in excess of reasonable compensation, or determined to be reimbursement of syndication costs, including sales commissions, would not be deductible.)

The operator leases the rights to 500 acres of land that is unproven. The landowner receives an up-front bonus of $50,000 plus a one-eighth royalty. In the first year, the venture drills and completes its well, expending the full $500,000 in intangible costs. If the well turns out to be dry, the investors are allowed to write off their full investment of $555,556. Assuming they are in the 50 percent tax bracket, their real loss is half of their original investment ($277,778).

If the well strikes oil, the tax implications are much more complex. The limited partners are allowed to write off their full share of intangible drilling costs and overhead in the first year. The management fee is considered a partnership organization cost and is amortized over five years. The income and expense profile of the limited partners is shown in Table 2. The well is assumed to remain productive for nine years, after which time the operating costs exceed revenues. The investors are entitled to 50 percent of the revenues and can deduct 50 percent of the costs. The investors are assumed to be eligible for percentage depletion at a rate of 15 percent. For simplicity, it is assumed that the investors are not subject to the alternative minimum tax, in regard either to intangible drilling costs or to percentage depletion.

In 1984, the gross receipts of the partnership are $400,000 and are reduced by the 12.5 percent royalty to arrive at gross income of $350,000. Both the limited partners and the operator share this amount evenly. The limited partners' share of operating costs is $21,875, yielding a net pretax cash flow of $153,125. This amount is then adjusted to reflect the provisions in the tax code for deriving taxable income. The limited partners are allowed percentage depletion of $26,250 and a deduction of 20 percent of their management fee ($6,667). After these adjustments, taxable income is calculated at $120,208, yielding a tax liability of $60,104. This is subtracted from the investors' pretax cash flow to arrive at their post-tax cash flow of $93,021. This is the amount in which the investor is critically interested when evaluating various investment opportunities.

The general partner's income statement is shown in Table 3. It is assumed that the general partner is a sole proprietor and is subject to a marginal tax rate of 50 percent. The general partner's income share is the same as the limited partners', except that the operator also receives the 6 percent management fee. The general partner invests $75,000 in depreci-

TABLE 2. OIL EXPLORATION PARTNERSHIP - INVESTORS' ACCOUNTS

		1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
A	Gross Receipts	0	400,000	500,000	450,000	350,000	275,000	200,000	150,000	100,000	50,000
	Less royalty	0	50,000	62,500	56,250	43,750	34,375	25,000	18,750	12,500	6,250
	Gross income	0	350,000	437,500	393,750	306,250	240,625	175,000	131,250	87,500	43,750
B	Income Allocated to Partners (50 percent)	0	175,000	218,750	196,875	153,125	120,313	87,500	65,625	43,750	21,875
C	Expenses Allocated to Partners										
	Intangible drilling costs (100 percent)	500,000	0	0	0	0	0	0	0	0	0
	Administrative and lifting costs (50 percent)	22,222	21,875	21,875	21,875	21,875	21,875	21,875	21,875	21,875	21,875
	Management fee (100 percent)	33,334	0	0	0	0	0	0	0	0	0
D (B-C)	Pre-Tax Cash Flow	-555,556	153,125	196,875	175,000	131,250	98,438	65,625	43,750	21,875	0
E	Tax Adjustments										
	Deduct percentage depletion	0	26,250	32,813	29,531	22,969	18,047	13,125	9,844	6,563	0
	Amortize management fee	-26,667[a]	6,667	6,667	6,667	6,667	0	0	0	0	0
F (D-E)	Taxable Income or Loss (-)	-528,889	120,208	157,395	138,802	101,614	80,391	52,500	33,906	15,312	0
G	Regular Income Tax (50 percent)	-264,445	60,104	78,698	69,401	50,807	40,196	26,250	16,953	7,656	0
H (D-G)	Investor Cash Flow	-291,111	93,021	118,177	105,599	80,443	58,242	39,375	26,797	14,219	0

a. The management fee ($33,334) is not allowed as a deduction; this reduces the tax loss by $33,334. However, the investors are allowed to amortize 20 percent of the fee ($6,667) in the first year. Thus, the net effect is to reduce the tax loss by $26,667 ($33,334 - 6,667).

TABLE 3. OIL EXPLORATION PARTNERSHIP - OPERATOR'S ACCOUNT

		1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
A	Gross Receipts	0	400,000	500,000	450,000	350,000	275,000	200,000	150,000	100,000	50,000
	Less royalty	0	50,000	62,500	56,250	43,750	34,375	25,000	18,750	12,500	6,250
	Gross income	0	350,000	437,500	393,750	306,250	240,625	175,000	131,250	87,500	43,750
B	Income Allocated to Operator (50 percent)	0	175,000	218,750	196,875	153,125	120,313	87,500	65,625	43,750	21,875
C	Other Income and Expenses Allocated to Operator										
	Plus management fee (100 percent)	33,334	0	0	0	0	0	0	0	0	0
	Less administration and lifting costs (50 percent)	22,222	21,875	21,875	21,875	21,875	21,875	21,875	21,875	21,875	21,875
	Less cost of depreciable assets	75,000	0	0	0	0	0	0	0	0	0
	Less lease bonus	50,000	0	0	0	0	0	0	0	0	0
D (B-C)	Pre-Tax Cash Flow	-113,888	153,125	196,875	175,000	131,250	98,438	65,625	43,750	21,875	0
E	Tax Adjustments										
	Deduct percentage depletion	0	26,250	32,813	29,531	22,969	18,047	13,125	9,844	6,563	0
	Depreciation	-64,313[a]	15,675	14,963	14,963	14,963	0	0	0	0	0
	Bonus not deductible	-50,000	0	0	0	0	0	0	0	0	0
F (D-E)	Taxable Income	425	111,200	149,099	130,506	93,318	80,391	52,500	33,906	15,312	0
G	Regular Income Tax (50 percent)	213	55,600	74,550	65,253	46,659	40,196	26,250	16,953	7,656	0
H	Investment Tax Credit (10 percent)	-7,500	0	0	0	0	0	0	0	0	0
J (D-G-H)	Operator Net Cash Flow	-106,601	97,525	122,326	109,747	84,591	58,242	39,375	26,797	14,219	0

a. The cost of depreciable assets ($75,000) is not deductible in the first year; this reduces the tax loss by $75,000. However, the operator is allowed first year depreciation of $10,687, so that the net effect is $64,313 ($75,000 - 10,687).

able assets and $50,000 in the lease bonus in the first year. The bonus is not allowed as a tax deduction--percentage depletion, however, is allowed. The tangible assets are subject to ACRS and the 10 percent investment tax credit. It is assumed that the depreciable property is in the five-year recovery class and is placed in service in the first year.

This type of limited partnership generally favors the sponsoring firm. The general partner has only put up $125,000 to get a 50 percent share of the revenues, while the limited partners have invested $555,556 for the same opportunity. In addition, $75,000 of the operator's investment (depreciable equipment) will be contributed only after the property is known to be productive. The general partner, however, is liable for all debts and obligations that the partnership might generate in excess of the capital contributions of the limited partners.

Although this is only an illustration, it is interesting to note that the internal rate of return for the limited partners (after-tax) is 22.3 percent. In contrast, the internal rate of return on a pretax basis is 16.2 percent. The rate of return is 6.1 percentage points higher after tax than before. This implies that the effective tax rate on the investment is a negative 38 percent. On the general partner's side of the ledger, the post-tax internal rate of return is 94 percent, while the pretax return is 138 percent, yielding a positive tax rate of 32 percent. The reason that these returns are so high is that this is a highly speculative investment that has just happened to pay off. The divergence in returns between the general and limited partners reflects the relative mismatch in revenues and investment between the two parties. Exploratory drilling funds often use the "functional allocation" structure in order to minimize the operator's risk in the venture.

Some limited partnerships engage in a significant amount of borrowing that allows them to leverage their investment. With the adoption of the "at risk" rules in 1976, leveraging can no longer be used to generate a tax loss in excess of the amount for which an investor is personally liable. At present, leveraging a limited partnership increases the amount that the venture stands to lose while simultaneously increasing the potential rate of return on equity. In order for a leveraged investment to pay off, the pretax rate of return must exceed the rate of interest on the loan, otherwise leveraging will lower the rate of return. Because the oil business is risky to begin with, increasing the leverage of the investment magnifies the riskiness of the venture.

For example, suppose the investors in the partnership borrowed 50 percent of their capital contribution. Because they are in the 50 percent tax bracket, the investors are essentially paid back their full capital contribution in the first year. In subsequent years, they would have the

same cash flow as before except that they would be able to deduct interest payments and would have to pay back the loan. Clearly, if the program returns more than the interest rate, the investors are well ahead of the game; conversely, if the project does not succeed, the investors have to pay back the loan out of their other income or assets.

The functional allocation structure is one of four basic partnership arrangements used by oil and gas drilling funds. Briefly, the others are structured as follows:

Promoted Interest. In this structure, the general partner pays 10 percent or more of the exploration and drilling costs. The sponsor shares disproportionately in the revenues (for example, 25 percent). There is a strong identity of interest between the investor and the sponsor because the general partner has a significant stake in the success or failure of the program right from the start.

Carried Interest. The investors pay 99 percent of all costs. Revenues are shared disproportionately (usually 85 percent to limited partners); thus, the investors' "carry" the operator's share of the costs. This type of structure minimizes the risk to the general partner as the investors bear almost all of the downside risk should the project fail.

Reversionary Interest. This is similar to the carried interest structure in that the investors pay for most of the costs. In this case, however, the investors may receive 99 percent of the revenues until "payout" (as defined by the partnership agreement). Once a project is "paid-out," the sponsor's share reverts to a substantial interest, such as 25 percent.

In addition to differing in their structure, drilling partnerships also differ in their drilling philosophy in regard to exploratory versus developmental wells. Exploratory wells are riskier and the rewards potentially greater; developmental wells are generally less uncertain. In 1982, about 58 percent of the funds in drilling partnerships went toward programs that emphasized exploratory wells; 26 percent to programs that emphasized development wells; and the remainder to basically balanced programs.[7]

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7 Arthur King, "Simple Factors Make a Big Difference," Tax Shelter Digest, March 1983, pp. 7-11.

A 1982 study of drilling funds indicates the risks and rewards to the investor of such ventures.[8] The average post-tax expected internal rate of return was 9.9 percent, and 21.2 percent of the funds were expected to return in excess of 20 percent. In contrast, about 25 percent were not expected to break even on an after-tax basis.

Drilling funds are the most speculative in the oil and gas area. Other partnerships, called "income" funds, buy proven reserves in the ground, and thereby eliminate the largest risk in the oil industry. The big uncertainty with these programs is future oil and gas prices and not whether a well will be a "duster." In general, these partnerships purchase working interests in producing properties, with the limited partners bearing the costs of exploiting those interests. An income fund is basically an investment in the future price of oil, with a more stable return than an exploratory drilling program. In 1982, income funds registered with the SEC attracted $1.3 billion in capital.[9]

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8 Ibid.

9 "Public Oil and Gas Program Investment Declines in 1982," p. 5.

PART II. SPECIAL TAX PROVISIONS AFFECTING INDEPENDENT OIL AND GAS PRODUCERS

Federal tax law sometimes differentiates between the integrated oil companies and the independents. This part examines several tax code items that impose differing burdens on particular groups of producers in the oil industry. All of the distinctions that have been made between independent and integrated companies have been enacted since 1975 and exempt independents in whole or in part from oil industry tax increases. Although differences in tax treatment existed before 1975 for corporations, partnerships, and sole proprietorships, only recently have oil producers been distinguished by the type of operations they perform. For tax purposes, an "independent" producer is classified as one engaged almost exclusively in the exploration and extraction phases of the oil business. An independent cannot refine more than 50,000 barrels in any single day during the year nor have annual retail sales in excess of $5 million. This basically excludes all producers with significant downstream operations. Unless otherwise noted, this definition applies to all provisions concerning independent producers in the tax code.

DEPLETION

Oil and gas firms, as well as firms in other extractive industries, are allowed a deduction to reflect the exhaustion of reserves as they are produced. Depletion allowances are analogous to depreciation provisions for capital assets--both are intended to compensate the taxpayer for the decline in value of assets over time.

Basically, two forms of depletion are available to taxpayers for computing annual depletion allowances--percentage depletion and cost depletion. Percentage depletion allows a firm to deduct a fixed percentage of the gross income from the property, regardless of its actual initial cost or current basis. In contrast, cost depletion allows the firm to deduct a percentage of the historical cost equal to the percentage of recoverable reserves produced in a given year. The cost basis of a property is its historical acquisition cost, which includes lease bonus payments, exploratory costs, and any capital expenditures that are not expensed (such as intangible drilling costs) or that are not subject to depreciation (such as lease equipment). Cost depletion is limited to the original cost basis of the property, while percentage depletion is computed without regard to the basis.

Until 1975, all oil and gas producers were allowed to use either cost or percentage depletion, whichever was greater, for tax purposes. The percentage of gross income allowed as a deduction was 22 percent, although before 1970 it had been 27.5 percent. The 1975 Tax Reduction Act severely restricted the allowance for percentage depletion. It limited the deduction to independent producers (excluding integrated companies) and allowed percentage depletion on only the first 2,000 barrels per day of production (phasing down to 1,000 barrels per day by 1980).[1] In addition, it lowered the depletion rate from 22 to 20 percent in 1981, and phased the rate down to 15 percent in 1984 and thereafter. For the purposes of the act, royalty holders and holders of nonoperating interests were also allowed percentage depletion under the same restrictions as independent producers. In 1983, about 29 percent of the value of oil and gas is estimated to be subject to percentage depletion--independent producers accounting for about 13 percent and royalty holders for 16 percent. The act also disallowed percentage depletion on proven properties that were sold after 1974, except in certain special circumstances. Table 4 presents the percentage depletion rates and relevant restrictions since 1926.

Although percentage depletion allows a company to recover more than the cost basis of the property over its useful life, this does not mean that it is preferable to cost depletion in every year. In any cost recovery system, whether it is depreciation for equipment or depletion for oil and gas properties, the primary element in determining the benefits of certain tax provisions is their timing over an investment's life. In the early years of a well's life cost depletion allowances often exceed percentage depletion. Because independent producers have the choice between percentage and cost depletion, they will commonly choose to use cost depletion in the early years of a well and switch over to percentage depletion in later years when the cost basis has declined sufficiently.

Percentage depletion has an advantage over cost depletion in the out-years of a property because by then the cost basis has been reduced. Moreover, during periods of oil price increases, percentage depletion is highly preferable because the size of the allowance increases with inflation, whereas cost depletion is linked to the historical cost of the property.

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1 Natural gas produced by independents is also allowed percentage depletion based on a conversion factor of 6,000 cubic feet per barrel of oil. Gas producers are allowed to deduct percentage depletion (22 percent) if it is sold under a fixed contract, in effect on February 1, 1975, that prevents price increases from reflecting the increased income taxes resulting from the repeal of percentage depletion.

TABLE 4. PERCENTAGE DEPLETION RATES ALLOWED FOR INDEPENDENT PRODUCERS

Year	Percentage of Gross Income (percent)	Quantity Limitation (bbl/day[a])
1926 - 1969[b]	27.5	None
1970 - 1974	22.0	None
1975	22.0	2,000
1976	22.0	1,800
1977	22.0	1,600
1978	22.0	1,400
1979	22.0	1,200
1980	22.0	1,000
1981	20.0	1,000
1982	18.0	1,000
1983	16.0	1,000
1984	15.0	1,000
1985+	15.0	1,000

SOURCE: Walter J. Mead, Dennis D. Muraoka, and Philip Sorensen, "The Effect of Taxes on the Profitability of U.S. Oil and Gas Production: A Case Study of the OCS Record," National Tax Journal, vol. 35, no. 1 (March 1982), p. 23.

a. The quantity limitation imposes a limit on the amount of percentage depletion that can be claimed by each eligible company (or taxpayer). Alternatively, percentage depletion can be taken on a limited amount of natural gas production. The depletable gas quantity in cubic feet is the depletable oil quantity multiplied by 6,000.

b. Integrated companies were also allowed percentage depletion before 1975. An integrated company is defined as one that has more than $5 million in retail sales (on an annual basis) or refines more than 50,000 barrels on any day during the tax year.

Since independents are allowed their choice of depletion methods, they obviously have an advantage over the integrated firms.

Percentage depletion may be more or less generous than expensing (writing off the full cost in the first year).[2] In order to mimic expensing, either the full lease acquisition costs would have to be allowed as a deduction in the first year or firms would have to be allowed an annual depletion deduction equal to the net income related to the depletable assets.[3] Because the ratio of net to gross income varies by property (and age of well), no single percentage depletion rate will yield the same result as expensing for all properties. (The ratio of depletable to total assets involved in production also varies considerably by property.) If the policy goal is to provide expensing, it would be easier and more accurate to allow firms to write off all of their oil and gas investments in the first year rather than to allow percentage depletion. This approach would cause problems only for taxpayers unable to use the full deduction in the first year.

Minimum Tax Considerations. Percentage depletion that exceeds the adjusted cost basis of a property is subject to the add-on minimum tax for corporations and the alternative minimum tax for individuals. The current minimum tax rates are 15 percent for corporations and 20 percent for individuals. Cost depletion is not subject to the minimum tax.

When the adjusted cost basis of a property goes to zero, the full percentage depletion deduction is subject to the alternative minimum tax for individuals (assuming the taxpayer's other tax preferences exceed the exemption amount for the minimum tax). The alternative minimum tax is truly an alternative tax because taxpayers pay the greater of their regular tax or their minimum tax. For a taxpayer subject to the alternative

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2 Expensing provides a good comparison because it implies a zero effective marginal tax rate on the asset. In addition, intangible drilling costs, as well as ACRS three- and five-year property, are essentially subject to expensing. Other building and structure investments are accorded less generous capital recovery than expensing, however.

3 For example, if 50 percent of an investment in an oil property was capitalized (that is, subject to depletion), a firm would be allowed to deduct 50 percent of the net income from the property (for present purposes, "net income" refers to gross income less production costs and excise taxes, but not depletion). Thus, if net income was 75 percent of gross income, the appropriate percentage depletion rate would be 37.5 percent (50 percent of 75 percent) of gross income.