TAX REFORM: ITS EFFECTS ON THE OIL AND GAS INDUSTRY

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SUMMARY

The taxation of oil and gas producers has long been the source of heated debate among economists, industry professionals, and policymakers. Recent discussions over comprehensive tax reform have again raised several issues regarding the taxation of the industry. Most important, special tax code provisions, including percentage depletion and the immediate write-off of drilling costs, have been criticized by some as unwarranted subsidies to oil and gas producers. As such, their repeal has been advocated by some proponents of comprehensive tax reform. Others see them as important incentives for domestic energy production. This study reviews the current tax treatment of oil and gas producers and discusses two proposals in depth--the Treasury Department's report on tax reform (Treasury I)1/ and the President's recent tax reform proposals to the Congress (President's proposal).2/ Some incremental changes in the current tax system are also briefly discussed.

Present tax law distinguishes among three types of capital costs incurred prior to the production of oil and gas. These are: (1) depletable costs related to determining the location of oil and gas prospects and acquiring of mineral rights, (2) costs of depreciable equipment used to drill wells and produce oil and gas, and (3) intangible costs incurred in the drilling of wells. (Intangible drilling costs are costs such as labor or materials used in the drilling of a well that have no salvage value once the well is abandoned.) Under current law, depletable costs are recovered through cost depletion or percentage depletion; depreciable costs are recovered through depreciation under the Accelerated Cost Recovery System (ACRS); and intangible drilling costs are expensed.

The provisions for percentage depletion and the expensing of intangible drilling costs are viewed as subsidies to the oil and gas industry because they allow producers more generous cost recovery than would be allowed under a capital recovery system based on economic lives. (A capital recovery system based on economic lives would allow producers to recover their investment costs only as their oil and gas properties' reserves were ex-

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1. U.S. Department of the Treasury, Tax Reform for Fairness, Simplicity and Economic Growth (November 1984).

2. The President's Tax Proposals to the Congress for Fairness, Growth and Simplicity (May 1985).

hausted.) Although not specific to the oil and gas industry, the current tax provisions for depreciable equipment--accelerated depreciation and the investment tax credit--also extend more generous treatment to assets than would be allowed under a cost recovery system based on economic lives. This study shows that the net result of these provisions under current law is an effective corporate tax rate for oil and gas producers lower than that for other industries.

The original Treasury proposal would have completely repealed the provisions for percentage depletion and the expensing of intangible drilling costs. Instead, these costs would be recovered under cost depletion, indexed for inflation. The current system of depreciation would be replaced by a new system based on economic lives, and the investment credit would be repealed. Top corporate and individual rates would be reduced to 33 percent and 35 percent, respectively. The proposal also would have repealed the Windfall Profit Tax as of January 1, 1988. If adopted, these proposals would have substantially raised the tax rate on the oil and gas extraction industry and narrowed the gap between the industry's effective tax rate and that for other industries. Indeed, one of the main goals of Treasury I was to be as neutral as possible among firms in different industry sectors. This policy could, however, result in reduced drilling and oil and gas production from domestic sources.

The President's proposals subsequently modified the Treasury proposals to allow for continued expensing of intangible drilling costs. The President's proposals would also continue percentage depletion for wells that produce less than 10 barrels of oil per day. The depreciation system is more generous than that proposed by the Treasury, but the investment tax credit would still be repealed. The plan also contains an alternative minimum tax on certain tax preferences--including percentage depletion and intangible drilling costs--that was not deemed necessary under the Treasury plan. The Windfall Profit Tax would also be continued until its scheduled repeal in 1994. The net result of these changes would be to lower somewhat the effective corporate tax rates for many industries, including the oil and gas industry. The oil and gas industry would continue to be favored under the President's plan relative to other industries. As a result, the President's plan would be unlikely to have any detrimental effect on the overall level of drilling and production in the United States.

Energy Policy Considerations

The proposed changes in tax law could have effects on domestic oil supply: changes that increase the taxation on income from marginal oil and gas investments will discourage domestic oil and gas

production. To the extent that domestic oil production would be reduced, the United States would have to import more of its oil. (In 1984, the United States imported about 30 percent of its petroleum needs; about 5 percent coming from Middle Eastern OPEC countries.)

Increased U.S. oil imports could raise concerns over oil supply vulnerability. In the short run, this concern does not seem warranted since there is significant excess production capacity in the international petroleum market. It is unlikely that any embargo by one or several foreign suppliers would have a significant effect on United States ability to fulfill its import requirements. Moreover, at current import levels, the Strategic Petroleum Reserve could fully replace imports for about 100 days.

Over the long run, some argue, the power of foreign suppliers (OPEC in particular) to affect world oil prices may become substantially greater than at present. This is because those countries have a significant percentage of proved oil reserves; at current production rates, this percentage will rise over time. In this view, it is necessary for the United States to provide tax incentives to increase domestic exploration, development, and production. The tax provisions for expensing of intangible drilling costs and percentage depletion are among those incentives. The President's proposal embraces the view that the expensing of intangible drilling costs is necessary to avert increased dependence on foreign energy that would "again make the United States vulnerable to concerted political or market action by foreign energy producers."3/

This view has been questioned by some who argue that increasing domestic production is tantamount to a policy of "draining America first." They argue that potential United States reserves should be stored (or merely not produced) and that it is cheaper to buy imports at currently depressed world market prices. Furthermore, they argue that the U.S. needs to save its reserves in case imports should become unavailable in the future, for whatever reason.

Others argue that domestic petroleum should neither be subsidized nor penalized. This implies that the oil and gas industry should be taxed at the same rate as other industries. The market, rather than the tax system, would then be the final arbiter as to how the economy's resources were allocated. Capital and labor would be directed to their most efficient uses.

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3. The President's Proposals to the Congress for Fairness Growth and Simplicity, p. 232.

Further, some argue that even if it is desirable to avoid heavy reliance on foreign oil suppliers, an oil tax or import fee is a better solution than a production subsidy. Because an oil tax or import fee would reduce oil consumption (through fuel switching or conservation) by raising its price, dependence on foreign suppliers would be reduced. Moreover, in the case of an import fee, domestic production of oil (and other fuels) would simultaneously be encouraged. As a further protection, the revenue from such a tax could be used to fund directly the Strategic Petroleum Reserve.4/

This paper is in four parts: the first part presents some general information on the structure and organization of the oil and gas industry; the second part discusses the current taxation of oil and gas producers and the changes that have been proposed; the third part examines the overall effects of these proposals on different oil investments; and the fourth part discusses the effect that each proposal might have on domestic oil and gas production in future years. Other proposals for changing the taxation of oil and gas producers are also discussed.

4. See Congressional Budget Office, Charging for Federal Services (December 1983).

CHAPTER I.

STRUCTURE AND ORGANIZATION OF THE INDUSTRY

The oil and gas extraction industry is engaged in the process of finding, developing, and producing crude petroleum and natural gas.5/ This process starts with geological surveys and seismographic testing to identify possible oil-bearing land. Once a prospect has been identified, producers negotiate (or bid for) a lease from the mineral rights holder (usually the landowner). Leases are generally characterized by one-time up-front "bonus" payments in return for the opportunity to explore for oil and gas reserves. In addition to the bonus, a lease usually contains a provision that if reserves are subsequently discovered and produced, the leaseholder will receive a percentage share of the gross revenue (or production in kind). This revenue-sharing payment is generally referred to as a royalty; the share is often in the range of one-eighth to one-sixth of gross production.6/

Once a firm has obtained the right to explore for oil and gas, further geological testing is done to establish the best sites for drilling exploratory wells. The riskiest form of exploratory well is known as the "wildcat" well. This type of well is drilled in an area that has not already proved to be productive.7/ One or several exploratory wells are drilled on a property to determine whether the land contains sufficient deposits of oil and gas to make further development and production economic. (Oil and gas reserves are considered economic if the present discounted value of sales revenue is greater than the present value of future costs of development and production.) If it is decided that insufficient reserves exist, the property is abandoned as uneconomic.

Should oil and gas reserves be found such that further development is warranted on economic grounds, the firm will drill further development wells in order to tap the reserves. Drilling

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5. For the purposes of this paper, further petroleum-related activities, such as refining and marketing, are excluded from consideration.

6. Royalties for federal offshore lands typically are one-sixth of production.

7. A wildcat well is defined as a well drilled into a geological formation that is at least two miles from an already productive property. About 15 percent to 20 percent of wildcat wells are considered successful.

an oil well involves sinking a hole of from less than 1,000 feet to more than 20,000 feet. At present, costs of drilling can range from $50,000 to more than $4 million. Drilling time also varies substantially: from less than one month to many months.

Once a well is drilled, equipment must be installed (for example, tanks, pumps) to lift the oil and gas out of the ground and send it on its way to the purchaser, usually a refinery in the case of oil. In the early stages of an oil reservoir's life, the natural pressure of the surrounding formation is usually sufficient to provide the impetus to push the oil out of the ground.8/ In the later stages of a reservoir's life, the pressure declines and some means of artificial lift (pumps) must be used.

The natural pressure of a formation influences the rate of production and the spacing of wells. In general, the faster a reservoir is depleted (through closer-spaced wells or faster flow rates), the faster the natural pressure will decline; this can reduce the ultimately recoverable reserves. The producer faces a trade-off between more rapid depletion (and higher current revenue) and slower depletion (and more future revenue). This production decision is dictated by the geophysical properties that characterize the reservoir and by economic factors, such as expected future prices and interest rates.

In general, producing wells usually exhibit a time profile that is characterized by high initial production diminishing at a relatively constant rate over time. In the later stages of a well's life, it turns into a "stripper" well--that is, a well that produces less than 10 barrels per day.9/ The well is finally capped and abandoned when the revenue from production is not sufficient to cover its continued operating costs. This point is referred to as the "economic limit" of a well.

The oil and gas extraction industry is very capital-intensive relative to other industries. The production process involves large up-front capital expenditures in the form of bonus payments, drilling costs, and depreciable equipment, but relatively small

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8. Oil and gas reserves are found in porous rock in certain types of geological formations. Contiguous formations of oil- and gas-bearing rock are referred to as reservoirs or pools.

9. Some marginal wells may even start out as stripper wells, or become stripper wells in less than one year.

current operating expenses.10/ Most of the sales price per barrel of production is required to pay investors (stockholders, bondholders or other lenders) for the use of their financial capital. Because the industry is so capital-intensive, taxes on capital income are likely to have significant effects on the relative attractiveness of investments in the oil and gas industry. Moreover, changing the tax system that now is in place could have significant effects on domestic oil and gas production in the United States.

The Participants

The oil and gas industry includes a wide variety of participants--from large multinational corporations to passive investors. A number and range 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, usually only one firm does the actual drilling and production. This partner or operator is responsible for conducting the exploration, production, and distribution operations (it may, however, contract with other firms to perform these activities).

In 1982, the top 32 oil and gas companies (mostly integrated producers)11/ produced about 76 percent of domestic oil and 59 percent of natural gas. Independents (all oil and gas companies other than the top 32 ranked by the value of production) accounted for about 24 percent of the oil and 41 percent of the natural gas produced domestically (see Table 1). The "independents" can be divided into two groups--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 400--that is, firms other than the majors or the larger independents--produced about 10 percent of the oil and 14 percent of the natural gas in the United States. Although production is dominated by the larger firms in the industry, a number of small firms compete on the fringe. According to Department of Commerce

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10. For example, according to the Annual Survey of Oil and Gas, direct operating costs (exclusive of taxes and overhead) averaged about 15 percent of production revenues in 1982. In the initial years of a property's production, operating costs are likely to be much lower, only to rise to higher levels in later years.

11. An integrated producer is one who also is engaged in refining and distribution of petroleum.

TABLE 1. OIL AND GAS INDUSTRY STATISTICS, BY CATEGORY OF COMPANY

		Percentage Distribution				
	Total United States[a]	Integrated Companies (Top 32)	Large Independents (Next 168)	Medium Independents (Next 200)	Small Independents (Others)[b]	Non-Operating Interests[c]
Gross Revenue ($ billions)	134.6	67.6	18.0	6.2	8.3	0.0
Net Revenue ($ billions)	134.6	53.8	10.4	2.1	8.6	25.2
Gross Oil Production (millions of bbls)	3,083.2	76.2	9.5	3.9	10.4	0.0
Net Oil Production (millions of bbls)	3,083.2	64.7	5.4	3.2	6.5	20.2
Gross Stripper Production[d] (millions of bbls)	372.6	48.5	11.2	9.4	30.9	0.0
Net Stripper Production[d] (millions of bbls)	372.6	39.7	4.4	6.9	21.2	27.8
Gross Natural Gas Production (trillions of cubic feet)	19.0	58.8	23.3	4.3	13.6	0.0
Net Natual Gas Production (trillions of cubic feet)	19.0	43.8	16.0	3.2	8.2	28.8
Net Production per Day per Firm (barrels per day)[e]		289,439	10,459	2,717	152	
Drilling:						
Gross expenditures ($ billions)	38.5	47.5	27.2	na	25.3[f]	0.0
Net expenditures ($ billions)	38.5	40.4	16.8	na	16.9[f]	25.9
Gross wells completed (thousands)	63.6	21.1	17.4	na	61.6[f]	0.0
Net wells completed (thousands)	63.6	16.8	13.0	na	43.0[f]	27.2
Gross well footage (millions of feet)	358.5	25.9	21.3	na	52.8[f]	0.0
Net well footage (millions of feet)	358.5	20.8	15.6	na	37.0[f]	26.7

SOURCES: U.S. Department of Commerce, Bureau of the Census, 1982 Census of Mineral Industries: Crude Petroleum and Natural Gas (February 1985) and Annual Survey of Oil and Gas, 1982 (March 1984); and CBO estimates.

a. Data exclude companies with no paid employees.
b. 8,276 firms
c. Includes limited partnership and royalty interests (including federal, state, and local governments).
d. Total U.S. stripper production (including producers not included here) has been estimated at 442 million barrels.
e. Includes natural gas computed as equivalent of 6,000 cubic feet per barrel.
f. Includes both medium independents and small independents.

statistics, 8,676 companies were engaged in oil and gas extraction in 1982.12/

As mentioned above, the producing companies generally do not receive 100 percent of the revenue derived from their operations. In 1982, the top 32 companies produced 76 percent of the oil, but had an economic interest of only 65 percent. Similarly, the top 400 firms produced 90 percent of the oil, but had an estimated net interest of 73 percent. The differences between the gross and the net interests reflect royalties and payments to landowners, including federal, state and local governments.

On average, the top 32 firms produced 289,439 barrels per firm per day (net) of oil and natural gas (on an oil-equivalent basis). In contrast, firms other than the top 400 averaged only 152 barrels per day (per firm) of oil and gas production. Stripper production (oil from wells that produce less than 10 barrels per day) was about 12 percent of oil production; the top 400 firms produced 69 percent of this amount.13/ On a net interest basis, these firms produced about 51 percent of stripper production. Of the 825,242 producing oil and gas wells in 1983, 441,501 (54 percent) were stripper wells.

In general, most oil is produced by corporations. In 1982, corporations produced 94 percent of the oil and gas on a gross basis. Sole proprietorships were responsible for about 2 percent and partnerships produced about 1 percent. These shares are gross amounts produced by the firms, regardless of who owns the actual economic interest in the production. On a net basis, the producing corporations have an economic interest of 75 percent as compared to their 94 percent share of gross oil production. Sole proprietorships and partnerships each have about a 1.5 percent net interest in oil production. Non-producers have net interests in oil of about 20 percent and in natural gas of 29 percent. These interests include parties outside the operating segment of the industry, such as individual royalty holders, limited partners, and landowners (including governments and corporations not engaged in the production of oil).

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12. Companies without paid employees are excluded.

13. These statistics only relate to operating companies (with payrolls). Taking all producers into account, stripper production is about 15 percent of total U.S. production. The top 32 firms account for about 41 percent of this amount.

Drilling and Exploration

The independents play a more important part in drilling and exploration than in production. Of the $38.5 billion spent on drilling in 1982, 53 percent was spent by firms other than the top 32 companies. Firms other than the top 200 spent 25 percent compared to their 15 percent share of gross lease revenues. While the large oil and gas corporations spend more for exploration and development wells than the smaller firms, drilling of wells is done mostly by smaller firms: firms other than the top 200 drilled 62 percent of the total wells completed during 1982. Larger firms generally drill deeper and more costly wells than the independent firms. The top 32 firms completed wells averaging about 6,900 feet in depth, at $197 per foot; firms other than the top 200 completed wells averaging about 4,800 feet and costing $51 per foot. In large part, this reflects the greater activity of the large companies in offshore areas.

CHAPTER II.

CURRENT TAX TREATMENT OF OIL AND GAS VENTURES

Present law distinguishes among three types of capital costs incurred by oil and gas producers: (1) costs incurred prior to drilling; (2) drilling costs; and (3) equipment and machinery used for the drilling of wells or the production of oil and gas. Pre-production costs include those associated with acquiring the mineral rights to search for oil and gas. These costs usually include lease bonuses that are paid to the landowner; for example, companies pay sizable amounts to the federal government for rights to search for oil in the outer continental shelf. In addition to acquisition costs (primarily lease bonuses), there are costs associated with exploration. These include seismic surveys and geological testing and mapping. Both mineral rights acquisition costs and exploration costs are referred to in the tax code (for oil and gas producers) as depletable costs; that is, they can be recovered by depletion as defined by the tax law. The second type of cost associated with an oil and gas venture is intangible drilling costs. These are costs that relate to the drilling of the well and its preparation for production; they include labor, materials, energy, and other expenditures that have no salvage value. These are generally referred to as capital costs because they occur prior to production and are associated with future revenue over the life of the property. The third type of capital cost is for equipment and machinery, such as pumps, tanks or flow-lines, that can be readily used for other wells (or other purposes). These costs are referred to as depreciable costs. Operating expenses related to actually producing the oil and/or gas, like other operating costs, are deductible as ordinary business expenses.

For 1982, the Annual Survey of Oil and Gas reports that for the oil and gas industry as a whole $14 billion was spent on depletable assets, about $31 billion on intangible drilling costs, and about $5 billion on depreciable assets.14/ Due to the wide variety of oil and gas investment projects across the country, however, large differences exist in the shares spent on each of the above categories. These large differences in the composition of capital costs make it very difficult to assess how changes in the tax structure are likely to affect specific producers.

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14. The Annual Survey of Oil and Gas presents the most detailed annual set of statistics on the oil and gas industry. The 1982 data are the latest available; the survey was discontinued after that year.

Under current law, oil and gas producers are allowed to recover depletable costs by deducting percentage depletion (I.R.C. sections 613 and 613A) or cost depletion (I.R.C. section 611); to recover intangible drilling costs through expensing (I.R.C. section 263c); and to recover depreciable costs through the Accelerated Cost Recovery System (I.R.C. section 168). Each of the provisions affect the amount of oil and gas drilling by altering the after-tax profitability of oil and gas investments.

Since 1975, federal tax law has differentiated between the integrated oil companies and the independents by exempting independents in whole or in part from oil industry tax increases. 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 excludes virtually all producers with significant downstream operations. Unless otherwise noted, this definition applies to all provisions concerning independent producers in the tax code.

A further distinction can be made between "small" independents and "large" independents. A small independent is one that fits the tax code definition of an independent producer, and whose production of oil and gas is less than 1,000 barrels per day.15/ A large independent produces over 1,000 barrels per day. The reason for this distinction is that production under 1,000 barrels per day (by independents) is eligible for percentage depletion, as well as lower rates of windfall profit tax; production over 1,000 barrels per day does not qualify for these provisions. Many of the top 400 oil and gas companies (see Table 1) are independents, but few (if any) produce less than 1,000 barrels per day.16/

DEPLETION

Firms in extractive industries, including oil and gas firms, are allowed a deduction to recover costs (as depletion) that reflect exhaustion of reserves by production. Depletion allowances are analogous to depreciation provisions for capital assets--both are intended to compensate the taxpayer for the decline in the value of assets over time.

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15. Natural gas is put on an oil equivalent basis at the rate of 6,000 cubic feet of gas per barrel of oil.

16. Average production for companies 300th to 400th in size is 1,140 barrels per day per firm, exclusive of royalties and production payments.

Until 1975, all oil and gas producers were allowed to use either cost or percentage depletion, whichever was greater, for tax purposes. 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 estimated 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 (as are intangible drilling costs) or that are not subject to depreciation (as is lease equipment). Cost depletion is limited to the original cost basis of the property, while percentage depletion is computed without regard to the basis.

Prior to 1970, the percentage depletion rate was 27.5 percent. The rate was reduced to 22 percent in 1970 and was further restricted by the Tax Reduction Act of 1975 (P.L. 94-12). The 1975 Act limited the deduction to independent producers and royalty owners (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).17/ In addition, the act scheduled a reduction in the depletion rate from 22 to 20 percent in 1981, and phased the rate down to 15 percent in 1984 and for years thereafter. In 1985, about 20 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 7 percent. The 1975 act also disallowed percentage depletion on proven properties that were sold after 1974, except in certain special circumstances. Table 2 presents the percentage depletion rates and relevant restrictions since 1926.

The Joint Committee on Taxation (JCT) estimates that the revenue loss from percentage depletion (measured relative to cost depletion) will be about $1.3 billion in 1986, and will total $6.9 billion over the 1986 to 1990 period.18/ For an independent

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17. Natural gas produced by independents is also allowed percentage depletion based on a conversion factor of 6,000 cubic feet per barrel of oil.

18. Joint Committe on Taxation, Estimates of Federal Tax Expenditures, 1986-1990 (April 12, 1985), Table 1.

TABLE 2. 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: Internal Revenue Code.

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.

producer, this tax subsidy is equivalent to an outlay subsidy of about $2 per barrel of oil.19/

Percentage depletion may allow a company to recover more than the cost basis of the property over its useful life; cost depletion does not. This does not mean, however, that percentage depletion is preferable to cost depletion in every year. In the early years of a well's life, cost depletion allowances may exceed percentage depletion. Independent producers are allowed to deduct the greater of percentage or cost depletion (computed each year), and they will commonly deduct 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. During periods of rising oil prices, percentage depletion is highly preferable because the absolute size of the allowance increases with gross sales revenue, whereas cost depletion remains linked to the historical cost of the property.

In any cost recovery system, whether it is depreciation for equipment or depletion for oil and gas properties, a major consideration in determining the benefits of certain provisions is their timing over an investment's life. Because current tax deductions are worth more than those taken in the future, the sum of deductions over time can provide a misleading measure of the tax benefit provided by a given tax provision. The present value of deductions allowed under a certain provision accounts for differences in the timing of deductions over future years.

Percentage depletion can have a present value greater than the initial cost of a property. This may happen because percentage depletion is geared to actual production revenue, not to the original cost of the property. If a company pays a low bonus bid for a property, the present value of gross revenue can far exceed the original bonus amount. This is especially the case of high-risk properties where the probability of success is low (say 5 percent) and companies are unwilling to pay large amounts up front.

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19. This would be the subsidy required on the outlay side of the budget that would hold an independent producer harmless if percentage depletion were replaced with indexed cost depletion. It should be noted that this is a gross subsidy--the net subsidy would be less because it is assumed that the gross subsidy would be counted as part of income and subject to taxation. The actual subsidy received by any given producer is likely to vary widely depending on specific circumstances. The subsidy estimate made here is based on the "cost of capital" model discussed later in the text and in the Appendix.

As the above discussion points out, percentage depletion may be more generous than expensing of depletable costs (writing off the full cost in the first year).20/ If the Congress wanted to allow the equivalent of expensing, it could allow all full-lease acquisition costs as a deduction in the first year. Because gross income varies widely by property (and age of well), no single percentage depletion rate will yield the same result as expensing for all properties. Therefore, 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, however, could cause problems for taxpayers unable to use such a large deduction in the first year of a property's life.21/

For properties that are not productive, current law allows companies to write off depletable costs when properties are abandoned. (By definition, these properties are not eligible for any form of depletion.) For example, if a company pays a lease bonus of $10,000 for a property that proves to be worthless two years from now, it can deduct the $10,000 at that time. Similarly, if a company has not recovered the full amount of its depletable costs by the time it abandons a productive property, it may deduct those costs (less accumulated depletion) at that time.

50 Percent Taxable Income Limitation. Present law limits the deduction for percentage depletion to 50 percent of the taxable income from a property. Taxable income is defined as gross income less operating expenses, overhead, selling expenses, depreciation, and intangible drilling costs that are expensed. This limitation severely limits the production incentive offered by percentage depletion because it drastically reduces (and may eliminate) the deduction for those properties that are near their economic limit. (The economic limit is reached when the gross revenue from production equals current operating costs. As long as revenue exceeds operating costs, production will be maintained. At the point that operating costs exceed revenue, the property will be abandoned as uneconomic.)

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20. Expensing provides a good comparison because it implies a zero effective marginal tax rate on the asset. Under current law, intangible drilling costs are primarily expensed; the present value of depreciation deductions and the investment tax credit on three- and five-year ACRS property is also about equivalent to expensing. Other building and structure investments are accorded less generous capital recovery than expensing, however.

21. Firms could use any excess deductions in future years by carrying them forward.

For example, suppose a property generates $100,000 in gross revenue, and has net taxable income of $10,000. The net taxable income limitation reduces the otherwise allowable percentage depletion deduction from $15,000 to $5,000 (50 percent of $10,000). As taxable income goes to zero, so does the depletion deduction. Because of the net income limitation, percentage depletion may have virtually no effect on the incentive to keep stripper wells in production. Therefore, repealing the depletion allowance is unlikely to have any effect on shortening the life (or reducing production) from existing stripper (or other marginal) wells.

INTANGIBLE DRILLING COSTS

Until the Tax Equity and Fiscal Responsibility Act of 1982 (TEFRA--P.L. 97-248), both independent and integrated oil producers were allowed to deduct their expenditures for intangible drilling costs (IDCs) when they were incurred. These are capital expenditures with no salvage value, such as amounts paid for fuel, labor, materials, and supplies used in the preparation and drilling of oil or gas wells. They exclude expenditures for lease equipment, such as storage tanks or pumping machinery, which are treated as five-year recovery property under ACRS. Although lease equipment is eligible for the investment tax credit, intangible drilling costs (IDCs) that are expensed do not qualify for the credit. Since the combination of accelerated depreciation and the investment tax credit is about equivalent to expensing at a 10 percent discount rate, lease equipment and expensed IDCs currently receive similar effective tax treatment.

In TEFRA, the Congress reduced (to 85 percent) the percentage of IDCs that integrated oil corporations could expense; the Deficit Reduction Act of 1984 (DEFRA--P.L. 98-369) reduced this to 80 percent. The remaining 20 percent of an integrated firm's IDCs are amortized on a straight-line basis over 36 months. Independent companies may still deduct 100 percent of their IDCs. In present value terms, this amortization requirement has reduced the present value of the deduction for IDCs from 100 percent of total outlays to about 97 percent (using a discount rate of 10 percent). This limitation on expensing only applies to producing wells--costs associated with dry holes continue to receive full expensing treatment.

The JCT estimates that the revenue loss from allowing companies to expense IDCs will be $2.3 billion in 1986, and $13.8 billion over the 1986 to 1990 period. (This is measured

relative to unindexed cost depletion.) The outlay equivalent subsidy to this tax provision is about $4.75 per barrel.22/

Recapture. In the event that an oil and gas property is sold, the difference between the sales price and current basis is subject to capital gains taxation.23/ Under current law, long-term capital gains for corporations are subject to a top rate of 28 percent for corporations and a top rate of 20 percent for individuals. To the extent that a producer has elected to expense IDCs incurred after 1975, these amounts must be treated as ordinary income upon the sale of a property.24/ The amount included in ordinary income is reduced by the amount of deductions that would have been allowed under cost depletion had the producer decided to capitalize its IDCs instead of expensing them. This adjusted amount cannot exceed the total gain recognized upon the sale.

DEPRECIATION

Capital assets used in oil and gas exploration and production, such as pumps, holding tanks, collecting pipeline, or construction equipment, that have a salvageable value, are depreciated under the Accelerated Cost Recovery System (ACRS). Most depreciable assets employed in the oil and gas industry may be written off over five years.25/ The present value of depreciation deductions

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22. This is the per barrel subsidy on the outlay side of the budget that would hold producers harmless if the expensing provision were replaced by indexed cost depletion.

23. The current tax basis is the historical cost of the property (including depletable, depreciable and intangible drilling expenditures), less any deductions for depletion, depreciation, or intangible drilling costs.

24. The term "recapture" is used to reflect the fact that these costs were deducted against ordinary income and are taxed upon sale as ordinary income, instead of at lower capital gains rates. Since drilling costs produce an asset that has a value long after the deduction has been taken, this recapture provision is intended to prevent taxpayers from taking deductions against ordinary income and then realizing a gain from the sale of an asset that is taxed at a much lower rate.

25. Under 5-year ACRS, firms may deduct 15 percent of the cost of the asset in the first year, 22 percent in the second year, and 21 percent in each of the three remaining years.

under ACRS (at a 10 percent discount rate) is 84 percent of an asset's cost. Five-year ACRS property is also eligible for a 10 percent investment tax credit. The credit is accompanied by a requirement that firms reduce the depreciable basis of the affected assets by 50 percent of the credit (that is, 5 percent).26/

By themselves, depreciation deductions under ACRS are not as generous as expensing, but in combination with the investment tax credit (for which intangible drilling costs and depletable assets are not eligible), the present value of tax savings exceeds the present value of savings under full expensing. The present value of depreciation and the 10 percent investment tax credit is 102 percent of the asset's cost.27/ This implies that ACRS property is treated more favorably than expensing (at a 10 percent discount rate), and more favorably than expensed intangible drilling costs. At higher discount rates (perhaps indicating higher inflation), the present value of ACRS (and the credit) declines and is worth less than expensing.

THE WINDFALL PROFIT TAX

The Crude Oil Windfall Profit Tax Act of 1980 established a federal excise tax on oil production based on an estimate of the windfall profit received by producers as a result of oil price decontrol. The tax does not apply to natural gas production. The act established three categories of oil and set different tax rates for each class. The three oil "tiers" are defined as follows:

Tier One. All oil except that oil classified as Tier Two or Tier Three.

Tier Two. Stripper oil (that is, oil produced from wells with less than 10 barrels per day of production) and oil produced from the Naval Petroleum Reserve.

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26. Effectively, this reduces the present value of ACRS deductions by 5 percent to 80 percent. Firms also have the option of reducing their credit by two percentage points, but this is generally not preferable.

27. Again, discounted at 10 percent. The credit is converted into its "deduction equivalent" at the top corporate tax rate of 46 percent. At this rate, the credit is equal to a deduction of 22 percent.

Tier Three. Newly discovered oil (production from properties developed after 1978), heavy oil, and incremental tertiary oil.

The standard tax rates specified by the law are 70 percent (of the windfall profit)28/ on tier one oil, 50 percent on tier two oil, and 30 percent on tier three oil.29/ For oil in either tier one or tier two, the act specified reduced rates for independent oil producers on their first 1,000 barrels of production per day.30/ The reduced rate on tier one oil is 50 percent and on tier two 30 percent; there is no reduced rate on tier three oil. Table 3 sets out the tax rates and production shares for 1983 in each category of oil.

Tier One. In 1983, tier one oil was approximately 66 percent of taxable domestic production.31/ Six percent of tier one oil was subject to the lower 50 percent rate for independents. Excluding Alaskan oil, this advantage was equivalent to about $1.50 per barrel of production. This benefit, however, will decline as long as oil prices decline or remain steady (or increase less than the rate of inflation). Because the windfall profit declines if oil prices rise less than the GNP deflator, the tax differential is smaller when oil prices are lower.

Stripper Exemption. Stripper oil (about 14 to 15 percent of domestic production) was subject to reduced rates (under tier two) for independent producers under the 1980 act. This advantage was

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28. The windfall profit is defined as the difference between the market wellhead price and the 1979 base price. For example, the tax on tier one oil equals 70 percent of the market price less the base price; that is, tax = 0.7 percent (market price - base price). The base price is indexed to reflect changes in the GNP deflator each year.

29. The tax rate on newly discovered oil was reduced by the Economic Recovery Tax Act of 1981 to 15 percent over a six-year period. This transition was slowed down by DEFRA. The current rate is 22.5 percent and will be 15 percent starting in 1989.

30. As defined by the Windfall Profits Tax Act of 1980, an independent's status is determined on a quarterly basis instead of on an annual basis. Thus, in any quarter an independent cannot refine more than 50,000 barrels on any day nor have retail sales in excess of $1.25 million.

31. In 1983, total oil production was about 8.7 million barrels per day. Of this amount, about 85 percent (7.4 million barrels per day) was subject to tax.

TABLE 3. SHARES OF TAXABLE PRODUCTION AND WINDFALL PROFIT TAX LIABILITY BY OIL TIER (1983) a/

Oil Tier	Percent of Taxable Oil Production	Percent of Windfall Profits Tax Liability
Tier One	65.6	84.6
Taxed at 70 percent	61.6	79.1
Taxed at 50 percent	4.0	5.5
Tier Two	8.6	8.9
Taxed at 60 percent	8.0	8.5
Taxed at 30 percent b/	0.6	0.4
Tier Three (Taxed at 30 percent)	25.8	6.6
Newly discovered c/	16.8	4.7
Incremental tertiary	4.0	1.4
Heavy oil	5.0	4.6
Total	100.0	100.0

SOURCE: U.S. Department of the Treasury, Internal Revenue Service, Statistics of Income Bulletin, vol. 2, no. 2 (Fall 1984), p. 67.

a. Taxable production excludes production that is exempt, such as state and local government interests, Indian oil, or charitable interests.

b. Production in this class is basically stripper production, which has been made exempt from tax as of January 1, 1983.

c. The tax rate on newly discovered is now 22.5 percent and will decline to 20 percent in 1988 and to 15 percent in 1989 and thereafter.

increased by a provision in the Economic Recovery Tax Act of 1981 (ERTA--P.L. 97-34) that exempted all stripper production by independent companies. (About 45 percent to 50 percent of otherwise taxable stripper production is eligible for this exemption.) In the third quarter of 1984, the average tax per barrel of tier two oil (produced by an integrated company) was about $4.20.32/ Since then, the decline in oil prices has eroded the tax to an estimated $2.00 per barrel.

The exemption for stripper oil does not count against a firm's 1,000 barrel limit on oil eligible for reduced rates in either tier one or tier two. (Independents could have some tier two production resulting from the Naval Petroleum Reserve.) A firm could, for example, exempt 700 barrels per day of stripper oil and still receive favorable tax treatment on 1,000 barrels per day of tier one and tier two oil.

The exemption of stripper oil was justified in order to prevent "premature abandonment of such properties as the costs of production rise relative to the income available from the property."33/ This exemption has the effect of extending the economic life (and increasing the ultimate total production) of oil wells that are marginally profitable. Restriction of this exemption to independent producers seems inconsistent with the stated intent of the law, however. In 1982, about 33 percent of the output from stripper leases was produced by the top 32 companies (on a net company basis). This indicates that stripper oil production is not solely a province of the independent firm. The objective of increasing oil production does not by itself support a policy of providing an incentive for independents to extend the life of wells, while not providing the same incentive for integrated firms.

Tier Three Oil. Oil production from properties that were discovered after 1978, heavy oil, and incremental tertiary production are taxed as tier three oil. This tier is taxed at a statutory rate of 30 percent, although a reduced rate of 22.5 percent (declining to 15 percent in 1989) is provided for new oil. The effective tax rate (dollars per barrel) on this tier is now very low because the estimated windfall profit on each barrel has declined substantially in recent years. This is because market oil prices have declined since 1981, and because the formula for computing the adjusted base price increases at a real rate of 2 percent per year above inflation. (This extra 2

32. U.S. Department of the Treasury, Internal Revenue Service, Statistics of Income Bulletin, vol. 5, no. 1 (Summer 1985), p. 88.

33. Joint Committee on Taxation, General Explanation of the Economic Recovery Tax Act of 1981, p. 321.

percent only applies to tier three oil.) In fact, by the end of 1985, most tier three oil production should be effectively exempt from the windfall profit tax. Since much of new domestic production will be regarded as tier three oil, the windfall tax now imposes very little (if any) disincentive to invest in new sources of oil production. The tax will, however, continue to impose a burden on new production from old properties and on stripper production owned by integrated companies. Under current law, the windfall profit tax is scheduled to expire by the end of 1994.

CHAPTER III.

TAX TREATMENT OF OIL AND GAS VENTURES UNDER THREE TAX REFORM PROPOSALS

The President's recent tax reform proposal and the original Treasury tax reform report proposed several changes in the taxation of the oil and gas industry.

The original Treasury proposal would have completely repealed the provisions for percentage depletion and expensing of intangible drilling costs. Instead, these costs would be recovered under cost depletion, indexed for inflation. The current system of depreciation would be replaced by a new system based on economic lives and indexed for inflation, and the investment tax credit would be repealed. The top corporate and individual rates would be reduced to 33 percent and 35 percent, respectively. The President's proposals subsequently modified the original Treasury proposal to continue expensing of intangible drilling costs, and retained a limited provision for percentage depletion (for stripper wells only). The depreciation system is more generous than originally proposed by the Treasury, but the investment tax credit would still be repealed. In addition, the tax rate cuts remain intact. (Table 4 compares the oil and gas tax changes under current law and these two proposals.)

An example of an oil and gas investment will be used to illustrate each of the proposals. Consider a company that acquires two leaseholds to explore for oil and/or gas properties at a cost of $5,000 per lease. On the first lease, the firm spends $20,000 on drilling costs for wells that prove worthless and are abandoned after two years. The firm spends $70,000 for drilling costs on the second lease for successful (producing) wells. The firm also spends $10,000 on the second lease to equip the well so that the output can be pumped and delivered to purchasers. The investment is summarized in the table below.

	Lease 1	Lease 2
Lease Acquisition	$ 5,000	$ 5,000
Intangible Drilling Costs	20,000	70,000
Lease Equipment Costs	0	10,000
Total Investment	$25,000	$85,000

Current Law. Under current law, the lease acquisition costs for the second (productive) lease would be capitalized and written off over time according to cost depletion (or percentage depletion if that was greater and if the firm was an independent). Since the first lease is considered to be worthless at the end of the second year, all lease acquisition costs would be deducted at that time. The drilling costs for both leases would be allowed as

TABLE 4. TAX REFORM PROVISIONS AFFECTING THE OIL AND GAS INDUSTRY

Type of Cost	Current Law	Treasury Plan	President's Proposal
Lease Acquisition Costs			
Productive Property	Unindexed Cost Depletion	Indexed Cost Depletion	Indexed Cost Depletion
Unproductive	Deducted When Property Abandoned	Deducted When Property Abandoned	Deducted When Property Abandoned
Percentage Depletion	Independents Only a/	Repealed	Independent Stripper Production Only a/
Drilling Costs			
Productive Wells	Expensed b/	Indexed Cost Depletion	Expensed b/
Unproductive Wells On Productive Properties	Expensed	Indexed Cost Depletion	Expensed
Unproductive Wells On Unproductive Properties	Expensed	Deducted When Property Abandoned	Expensed
Depreciable Property	5-year ACRS Depreciation and Investment Tax Credit	18% Declining Balance Depreciation (Indexed), No Investment Tax Credit	33% Declining Balance Depreciation (Indexed), No Investment Tax Credit

SOURCES: Internal Revenue Code; U.S. Department of the Treasury, Tax Reform for Fairness, Simplicity, and Economic Growth (November 1984); and The President's Proposals to the Congress for Fairness, Growth, and Simplicity (May 1985).

a. Independent oil companies are entitled to percentage depletion or cost depletion, whichever is greater. They are limited to percentage depletion on 1,000 barrels per day of production.

b. Integrated companies must amortize 20 percent of drilling costs associated with productive wells over 36 months.

current deductions, although the drilling costs of the second lease would be subject to the 20 percent three-year amortization requirement for integrated companies. (The costs of drilling dry holes would be deducted in full since they are not subject to the 20 percent amortization requirement.) The $10,000 of lease machinery and equipment would be eligible for the investment tax credit and would be depreciated over five years under ACRS.

The Treasury Plan. Treasury I would abolish the current tax provisions for percentage depletion and the expensing of intangible drilling costs. In lieu of these provisions, the plan would require drilling costs and depletable costs to be recovered through indexed cost depletion. This is similar to depletion under current law, except that the depletion deductions would be adjusted by the price level. In this respect (indexing), the Treasury plan is more favorable to taxpayers in the oil and gas industry than current law. Depletable and drilling costs related to properties that proved worthless could only be deducted at the time of abandonment.34/

In the example, the $10,000 in acquisition costs for both leases and the $90,000 of drilling costs would be capitalized. The $5,000 of acquisition costs and $20,000 in drilling costs associated with the unproductive lease would be deducted when that property was abandoned. (This differs from current law that allows all drilling costs to be deducted as incurred.) The $5,000 in acquisition costs and $70,000 in drilling costs for the productive lease would be recovered over time through indexed cost depletion. (Note that any drilling costs for unproductive wells on a property with productive wells would be included in the cost basis for depletion; they would not be immediately written off as under current law unless the property was entirely abandoned.)

The Treasury plan repeals ACRS and the investment tax credit. Depreciable costs would be deducted according to a system of indexed declining-balance depreciation (referred to as the Real Cost Recovery System, RCRS). The Treasury depreciation rates are intended to approximate economic depreciation--the real decline in the value of an asset. In the case of oil and gas machinery and equipment, this would allow 18 percent of the annual indexed balance to be deducted each year. In the example, $1,800 (18 percent of $10,000) would be deductible in the first year,

34. Current law allows drilling costs to be expensed immediately for dry holes. Under the Treasury plan, firms would have to capitalize all drilling costs, but could deduct them when a property (lease) was abandoned as worthless.

leaving a balance of $8,200.35/ If inflation is 5 percent, the balance at the start of the second year is $8,610 (1.05 times $8,200), and that year's depreciation deduction is $1,550 (18 percent of $8,610). This continues for 12 years at which time all the remaining balance of the equipment is written off.36/ The present value (discounted at 10 percent) of depreciation deductions for this class is 83 percent of the asset's cost under RCRS.

The plan would reduce the top statutory tax rate from 46 percent to 33 percent for corporations, and would allow companies to deduct 50 percent of their dividends paid to investors. The top statutory rate for individuals would be reduced from 50 percent to 35 percent. The Treasury plan would also repeal (beginning in 1988) the windfall profit tax, the add-on minimum tax, and the 20 percent amortization requirement for intangible drilling costs.

The President's Plan. The plan set forth in The President's Proposals to the Congress for Fairness, Growth and Simplicity differ significantly from those originally contemplated by the Treasury in its report. The President's proposals retain the current law provisions for the expensing of intangible drilling costs (including the 20 percent amortization requirement for integrated companies) and only partially eliminate the deduction for percentage depletion. In most respects, the President's proposals retain the current law distinctions between integrated and independent producers.37/

The percentage depletion deduction is eliminated, except for wells that produce stripper oil. As under current law, only independent producers would be entitled to percentage depletion. Royalty owners, however, would be denied percentage depletion altogether under the President's proposals. In lieu of percentage depletion, producers would be allowed indexed cost depletion on

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35. This assumes the equipment is used for a full 12 months; a proportionate reduction in depreciation is required if the property is held for less than a full year.

36. The Treasury plan contains seven different depreciation classes with different depreciation rates, depending on the durability of the assets in the class. Short-lived assets have a higher rate, and vice versa. Oil and gas machinery and equipment has been assigned to a class with an annual depreciation rate of 18 percent.

37. These include the 20 percent amortization requirement for intangible drilling costs (of integrated companies), the retention of percentage depletion for independent stripper production, and the reduced windfall profit tax rates for independents.

their undepleted basis in a property.38/ If the current basis in a taxpayers property is now zero, the repeal of percentage depletion would not be compensated for by any future deductions for cost depletion. The repeal of percentage depletion is phased in over a five-year period, with the deduction being reduced by 20 percent each year until 1990 when the allowance is completely eliminated.

The stated rationale for retaining percentage depletion on stripper wells is to provide an incentive for producers to maintain production from wells that would otherwise be uneconomic. This is probably an ineffective (and inefficient) incentive because once a well nears its economic limit (that is, when gross revenue exceeds production costs by only a small amount), the deduction for percentage depletion becomes very small (if not zero) because of the tax code provision that percentage depletion cannot exceed 50 percent of the taxable income of the property.39/ If the taxable income of the property declines to zero (or below), no deduction for percentage depletion is allowed and, therefore, percentage depletion provides very little (if any) incentive to extend the life of a stripper well.40/

The President's proposals would eliminate the investment tax credit and replace the current system of depreciation with a new system referred to as the Capital Cost Recovery System (CCRS). For mining and oil field machinery, this involves a recovery period of six years (instead of the current five). The basis of depreciable assets is indexed so that the deductions under CCRS retain their real value. At a 10 percent interest rate, the present value of depreciation deductions under CCRS

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38. The undepleted basis of a property is its historical cost of acquisition (and investment) reduced by all accumulated deductions for depletion (either cost or percentage) and intangible drilling costs.

39. Section 613A of the Internal Revenue Code limits the deduction for percentage depletion to 50 percent of a taxpayer's income from a property. The code defines income as gross revenue less all production costs, overhead costs, depreciation, and intangible drilling costs.

40. Percentage depletion may offer an incentive to continue production from marginal wells, if the income from those wells is grouped with the income produced by more profitable wells on the same property. The taxable income limitation is figured on a per property basis, not on a per well basis. This still means, however, that the deduction provides no production incentive for a property near its economic limit.

(for six-year property) is 91 percent of an asset's acquisition cost, compared to 84 percent under ACRS.41/ Since CCRS is indexed for inflation and ACRS is not, the comparison of the two depreciation systems is quite sensitive to the expected rate of inflation. At high rates of inflation, CCRS is relatively more generous than ACRS.

As in Treasury I, the President's plan reduces the top corporate tax rate to 33 percent and the top individual tax rate to 35 percent. The plan retains a 10 percent deduction for dividends paid, reduced from 50 percent in the original Treasury proposal. Under current law, the Windfall Profit Tax is not repealed as proposed by the Treasury.42/ The President's proposals also include a "recapture" tax on accelerated depreciation taken since 1981 as a transition provision. This is intended to recoup part of the windfall gain received by firms whose taxes were deferred under ACRS. (Firms would realize a gain on their deferred taxes because they would be repaid at the new lower rate of 33 percent instead of the old 46 percent tax rate.)

The President's plan eliminates the current corporate minimum tax and replaces it with an alternative minimum tax. The alternative tax is computed as 20 percent of a firm's alternative taxable income. Alternative taxable income is defined to include regular taxable income plus certain tax preference items whose aggregate amount exceeds $10,000. Preference items that affect the oil and gas industry are the amount of percentage depletion that exceeds the current basis of the property,43/ and 8 percent of intangible drilling costs expensed in a given year.

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41. These calculations assume an inflation rate of 5 percent and a real return of 5 percent. The ACRS calculation does not include the 50 percent basis adjustment for the investment tax credit. If the value of the investment credit is included, the present value of ACRS is 102 percent under current law.

42. The termination provisions of the windfall profit tax under current law would remain in effect. By the end of 1994, the tax would be completely phased out.

43. This is the rule for properties placed in service prior to January 1, 1986. With respect to properties placed in service after that time, the tax preference amount would be calculated as the difference between percentage depletion and indexed cost depletion.

CHAPTER IV.

COMPARATIVE ANALYSIS OF TAX REFORM PLANS

METHODOLOGY

This study uses two different approaches to analyze the effects of tax reform proposals on the oil and gas extraction industry. The first examines the effect that changes in the tax law would have on sample oil properties with different characteristics. This "micro" approach measures the overall tax burden on oil and gas production by estimating the total taxes a producer is liable to pay over the life of a given property. By discounting back to the present, the total "present value" of tax payments can be calculated. As tax provisions are modified, changes in taxes, internal rates of return, and equivalent oil price levels are calculated. This property-by-property method allows most of the tax provisions that especially affect the oil and gas industry to be taken into account over the entire life of the investment.

The second method of analysis used in this study is the "cost-of-capital" approach. This is more of a "macro" approach since it looks at the oil industry from an aggregate viewpoint and calculates overall tax effects. By making a series of assumptions as to composition of the "representative" oil and gas investment, the cost of capital to the industry and its overall effective tax rate can be calculated. Moreover, since this general methodology can be used to calculate the cost of capital and effective tax rates in other industries, the effects on the oil and gas industry can be compared with those of other industries.

Both these forms of analysis are "partial equilibrium" in the sense that they take no account of the feedback effects that tax changes in other industries might have on the oil and gas sector. These other effects might take the form of changes in interest rates or in greater competition from alternative fuels, such as coal or nuclear power. In fact, these indirect effects may be sufficiently large in the case of sweeping changes in the tax system to outweigh any effects calculated on a partial equilibrium basis.

THE MICRO INVESTMENT MODEL

The micro approach to analyzing oil and gas taxes uses a "discounted cash-flow" (DCF) model to estimate the taxes paid on the income from an oil investment over its life. The oil investor (producer) estimates the revenues and associated costs over the

life of the investment and determines the investment's present value by discounting all revenues and costs back to the present. The discounted present value of the property is the current value that an investor places on all the future net income from the oil investment. The producer will then decide to undertake the investment if it can be acquired (or developed) at a cost that is less than or equal to its present value. (For example, if the present value of an oil well's net after-tax cashflow was $1 million, but its full cost of acquisition and development was only $800,000, the producer would not hesitate to exploit the prospect.) In the DCF model used here, it is assumed that the producer is willing to pay the landowner (mineral rights holder) an amount (the lease bonus) that is exactly equal to the difference between the present value of net cashflow and the cost of development (if that is, drilling costs, machinery and equipment, and geological costs). If the lease bonus calculated in this manner is less than zero (the present value of cashflow is less than the cost of the investment), the property does not get developed because it is not worth anything to the investor.

The structure of the model assumes that there is a fixed supply of land (properties) that has oil-producing potential. If landowners have no alternative use for the properties, they should be willing to lease them to an oil company for any price above zero.44/ That is, they will accept any bonus bid above zero. Assuming that oil companies compete for prospective oil properties, the bonus will be bid up to the point where the producer expects to earn no more than a normal (risk-adjusted) rate of return (the discount rate) after payment to the landowner.

The DCF model is used to estimate the taxes under current law, the Treasury proposal, and the President's proposal for an independent company and an integrated company. Three hypothetical oil properties that differ in their investment and production characteristics are analyzed. Since no two oil properties are the same, these hypothetical prospects do not capture the full range of possible tax outcomes that might arise. They do, however, provide a representation of the possible results that might arise for prospects with differing characteristics.

The production profiles and investment costs of each of the prospects are set forth in Table 5. Their characteristics are as follows:

44. If they have an alternative use for the property, landowners will demand a minimum bonus that is equal to the value of the property in its most profitable alternative use, such as housing or farming.

TABLE 5. CHARACTERISTICS OF PROPERTIES USED IN DCF MODEL

Producer	Property No. 1	Property No. 2	Property No. 3
Required After-Tax Rate of Return	12%	12%	12%
Required After-Tax Real Return	8%	8%	8%
Probability of Success	50%	60%	20%
Investment Costs ($000)			
Dry wells	2,642.5	564.6	3,500.0
Geological	300.0	100.0	400.0
Development wells (if successful)	6,955.0	1,556.0	8,000.0
Lease equipment/well (if successful)	1,364.0	600.0	1,500.0
Annual Production Costs (Real) (000 bbls)	150.0	114.0	150.0
Royalty Rate	12.5%	12.5%	12.5%
Severance Tax Rate	11.5%	4.6%	4.6%
Field Size (if successful)(000 bbls)	1,517.7	483.0	3,149.5
Production Decline Rate	10.0%	10.0%	8.0%
Oil Tier	3	1	3
WPT Base Price (dollars)	28.00	18.40	28.00
Oil Price Inflation	CBO	CBO	CBO
GNP Price Inflation	4%	4%	4%
Development Time	1988:1	1987:1	1988:1
Time of Peak Production	1989:1	1987:2	1989:1
Peak Production Per Well Per Day	40	15	70
Time Production Starts to Decline	1991:1	1988:2	1991:1

SOURCE: Congressional Budget Office.

Property No. 1. This property is a medium-risk venture that has a probability of success of 50 percent. It has average production and investment costs (relative to the other two properties). This property has lower expected initial oil output than property no. 3, and has a faster production decline rate. Like property no. 3, this property's oil would be considered new oil for purposes of the windfall profit tax. In general, this property could be characterized as a medium-risk medium-payoff prospect, such as a prospect close to an existing oil field.

Property No. 2. This property has a relatively high chance of success--60 percent. It can be developed swiftly, and reaches peak production relatively fast. Its initial production rate (and reserves) are low compared to the other two properties. Production costs are lower in this case than the others, and the costs of dry and producing wells are relatively low. This prospect is classified as tier one (old) oil for purposes of the windfall profit tax. Overall, this prospect is considered a low-risk low-payoff opportunity, such as an extension to an existing property.

Property No. 3. This property can be characterized as a relatively high risk exploratory prospect--its probability of success is only 20 percent. Offsetting this disadvantage is the relatively high production rate per well (if successful) and a low production decline rate. Compared to the other prospects this property has high costs for dry wells--$3.5 million--and also takes a relatively long time to develop and reach peak production. If successful, the output would be considered new oil for purposes of the windfall profit tax. This property has the highest potential payoff of the properties; it also has the biggest chance of failure.

The DCF model assumes that the lease bonus and geological costs are paid up front and that other investment costs occur in future periods. This analysis assumes that these costs are borne on January 1, 1986. The dry hole costs are assumed to occur ratably over the time between when the bonus is paid and when a development decision is made. If (and when) the property proves unsuccessful, the lease bonus and geological costs are deducted at that time, and the costs of the development wells and lease equipment are not incurred. The costs of development wells and lease equipment are assumed to occur at the time development starts if the property is successful.

The discount rate applied to future cash flows is 12 percent--this reflects a real return of 8 percent and an inflation

premium of 4 percent.45/ The rate of expected inflation is assumed to remain a constant 4 percent over the life of the property. The price of oil is assumed to be $26 per barrel for 1986 and 1987; after that it is assumed to rise by 4 percent per year. These assumptions are consistent with CBO's latest economic projections.

The DCF model is structured so that the price of oil and investment costs remain fixed, but the bonus payment to the landowner varies in response to differences in taxation. The full amount of any difference in taxation is assumed to be fully capitalized into the value of the lease bonus payment. This implies that the taxation of domestic oil producers does not affect the domestic price of crude oil, but that changes in taxation are manifested in lower payments to landowners. Higher taxes mean that landowners would be paid less, and vice versa. Note that if the value of the bonus drops below zero because of a change in the tax law, the property will not be developed since it is no longer profitable to do so. This is the primary mechanism by which higher taxes can affect domestic oil production.

The assumption of a fixed oil price is based on the rationale that the price of oil in the United States is determined in world markets and that domestic producers have no control over its level. That is, if domestic producers tried to pass on a tax increase to purchasers in the form of higher prices, purchasers would stop buying from domestic producers and substitute imported oil (at the prevailing world price).

The DCF model measures the effect that changes in taxation are likely to have on prospective oil investments; it does not indicate how taxes would change on past investments. Once an investment has been made (that is, once a well has been drilled), it becomes a sunk cost; at that point, the taxes paid over its life will be a function of actual events, not of assumptions or forecasts. In other words, changing the taxation of income from existing investments does not affect their level, but does affect their realized return. Changing the taxation of oil and gas income affects future oil and gas production primarily

45. The 8 percent real return used here is higher than the average market real interest rate, reflecting a substantial risk premium associated with oil and gas ventures. In practice, the actual specific risk premium is likely to be related to the riskiness of the investment in question. For simplicity, the real rate has been held constant across the properties considered here.

through its effects on prospective investments.46/ Thus, the DCF model is primarily concerned with the way in which changes in taxation affect the returns to prospective projects rather than already existing ones.

The model assumes that the producer is a corporation that faces the top corporate tax rate of 46 percent. The model incorporates the provisions that affect the determination of corporate taxes, such as depreciation or depletion, as well as the provision for the add-on minimum tax. Although the source of finance (debt or equity) is not explicitly modelled, it is assumed that the real discount rate (8 percent) represents a weighted average of the firm's after-tax marginal cost of funds, from whatever source derived.47/ The model does not take account of taxes paid at the personal level on dividends, interest, or capital gains that might be realized from the investment.

The DCF model can also be used to calculate an equivalent change in the price of oil that would have the same effect on the project's discounted present value as the change in tax policy. This equivalent price change is calculated by replacing the initial bonus payment with the new bonus payment (under the alternative tax system), and solving for the new price of oil that would maintain the required real after-tax return of 8 percent.

The Treasury Proposal. The results from the DCF model under current tax law and the provisions proposed under the original Treasury plan are shown in Table 6. The table summarizes the taxes that would be paid on each property, the required pretax return, the effective tax rate, and the equivalent oil price.48/

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46. Changing the taxation of already existing oil properties affects future investments in those properties (through enhanced recovery techniques, for example) and, to some extent, the timing of production from existing wells. This latter effect, however, is likely to be small relative to effects on prospective investments.

47. In the case of debt, the cost of the funds would reflect the fact that interest is deductible, and the increase in potential bankruptcy costs asssociated wih issuing more debt.

48. The effective tax rate is a summary measure of the overall effect of the tax system on a particular investment. The effective tax rate is defined as the difference between the pretax return and the after-tax return divided by the pretax return. Note that because it is assumed that the after-tax return is fixed, the pretax return must adjust as taxes are changed. That is, if the tax burden is increased, the

For the first property--the medium-risk property--taxes under present law are higher for the integrated company than for the independent company. The present value of total taxes for the integrated company is $426 thousand compared to a negative $118 thousand for the independent company. (The negative taxes mean that the company actually receives a net tax refund from the investment, or is able to offset other income taxes on unrelated income.) The difference in the present value of taxes ($543 thousand) is directly reflected in differences in the amount of the lease bonus that each producer would be willing to pay for the investment.

Since these tax amounts depend on the size of the project, it is useful to compare the effective tax rates, measures of the tax burden standardized for such differences.49/ The effective tax rate for the integrated producer on the first property is 12 percent under current law; the effective tax rate on the independent firm is -4 percent. (By comparison, if the income from the oil properties was taxed in full, the effective tax rate would be the statutory tax rate of 46 percent.) The fact that the effective tax rates are so low reflects certain advantages in the tax law, such as the deduction for intangible drilling costs and the write-off of abandoned properties. The lower tax rate on the independent company is the result of the allowance of percentage depletion only for the independent and the requirement that integrated companies amortize 20 percent of their drilling costs. The present value of cost depletion for the integrated company is $188 thousand compared to $1,356 thousand in percentage depletion for the independent. This advantage is partially offset by the add-on minimum tax, which collects $126 thousand (in present value) from the independent and nothing from the integrated producer.

For both properties 2 and 3, the independent also has a lower tax rate than the integrated producer under current law. On property 2, the integrated producer's tax rate is 42 percent versus 32 percent for the independent; on the third property, the integrated producer's tax rate is 10 percent compared to -4 percent for the independent. The relatively high tax rates on the second property are the result of the high windfall profit tax rates on old oil. (In the other two cases--considered new oil for purposes of the windfall profit tax--the tax imposes no burden

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pretax return must rise in order to maintain the fixed after-tax return.

49. The effective tax rate calculation is on a per dollar of capital basis and therefore does not depend on the scale of the project, but does reflect differences in the composition of investment outlays and revenue flows.

TABLE 6. TAX EFFECTS OF THE ORIGINAL TREASURY TAX PROPOSAL

Category	Current Law	Treasury Proposal	Absolute Change	Percentage Change
Property No. 1				
Major				
Taxes (present value)($000)	425.6	1096.1	670.5	157.5
Pretax return	13.1	15.3	2.2	16.8
Effective tax rate	12.1	28.5	16.4	135.5
Equivalent price	26.00	23.05	-2.95	-11.3
Independent				
Taxes (present value)($000)	-117.5	1096.1	1213.6	*
Pretax return	11.7	15.3	3.6	30.8
Effective tax rate	-3.6	28.5	32.1	*
Equivalent price	26.00	20.89	-5.11	-19.7
Property No. 2				
Major				
Taxes (present value)($000)	659.6	373.4	-286.2	-43.4
Pretax return	18.0	15.0	-3.0	-16.7
Effective tax rate	42.3	27.0	-3.0	-16.7
Equivalent price	26.00	30.54	+4.54	+17.5
Independent				
Taxes (present value)($000)	463.8	373.4	-90.4	-19.5
Pretax return	15.9	15.0	-0.9	-5.7
Effective tax rate	32.3	27.0	-5.3	-16.4
Equivalent price	26.00	27.34	+1.34	+5.2
Property No. 2 a/				
Major				
Taxes (present value)($000)	336.6	373.4	36.8	10.9
Pretax return	14.7	15.0	0.3	2.0
Effective tax rate	24.8	27.0	2.2	8.9
Equivalent price	26.00	25.66	-0.34	-1.3
Independent				
Taxes (present value)($000)	175.6	373.4	197.8	112.6
Pretax return	13.3	15.0	1.7	12.8
Effective tax rate	14.0	27.0	13.0	92.9
Equivalent price	26.00	24.20	-1.80	-6.9
Property No. 3				
Major				
Taxes (present value)($000)	350.0	743.4	393.4	112.4
Pretax return	12.9	14.1	1.2	9.3
Effective tax rate	10.3	20.8	10.5	101.9
Equivlant price	26.00	24.07	-1.93	-7.4
Independent				
Taxes (present value)($000)	-128.0	743.4	871.4	*
Pretax return	11.7	14.1	2.4	20.5
Effective tax rate	-4.1	20.8	24.9	*
Equivalent price	26.00	22.03	-3.97	-15.3

* Not applicable.

a. Same as Property No. 2, except that it is considered newly discovered oil instead of tier one (old) oil.

because the base price is above the market price.) The effective tax rates if property 2 is considered new oil instead of tier one oil are 25 percent for the integrated producer and 14 percent for the independent.

The results of the DCF model simulations for the same three properties under the Treasury tax proposal are shown in the second column. The provisions of the Treasury's tax proposal would increase the effective tax rate on two of the properties (1 and 3), but decrease it on property 2. The effective tax rates on the three properties are 29 percent, 27 percent, and 21 percent, respectively. These rates apply to both integrated and independent companies because the tax distinctions between independent companies and integrated companies would be eliminated. The higher tax rates reflect the requirements that drilling costs for productive wells be capitalized, that drilling costs for nonproductive wells not be written off until a property is abandoned, and that no deduction be allowed for percentage depletion. All investment costs (except for depreciable assets) related to producing properties would be capitalized and recovered through cost depletion. The basis of the property would be indexed for inflation so that cost depletion deductions would automatically maintain their real value.

The lower tax on the second property for the integrated company is the result of the repeal of the windfall profit tax under the Treasury proposal. In the long run, the windfall profit tax is scheduled to expire so that the reduced taxes from this effect are only temporary. If this property is considered new oil for purposes of the windfall profit tax, the Treasury proposal raises the effective tax rate on it also.

The equivalent oil price calculations (for the integrated company) show that the Treasury proposal would have the same effect as lowering the price of oil from $26.00 per barrel to $23.05 on property one--a reduction of $2.95 per barrel.50/ There is a price increase for property 2 of $4.54 per barrel, and a price decrease of $1.93 for property 3.51/ The equivalent price reductions are larger for the independent company. They are -$5.11 per barrel on property 1 and -$3.97 per barrel on property 3. Property 2's price increase is also smaller ($1.34 versus $4.54). These changes show that Treasury I would have a more

50. This is the initial price. It is assumed that the price is decreased proportionately over all future periods.

51. The equivalent price increase on the second property reflects the proposed repeal of the windfall profit tax. If this property is considered new oil, there is an equivalent price reduction of $0.34.

severe effect on small independent companies than on larger producers.

The President's Plan. The results from simulating the President's tax plan are shown in Table 7. The effective tax rates are lower for the integrated company for all three properties than under current law, but higher for the independents. For the integrated company, the tax rate on property 1 falls from 12 percent to 9 percent; on property 2 it falls from 42 percent to 40 percent; on property 3, it falls from 10 percent to 6 percent. The high tax rate on property 2 remains because the President's plan, unlike Treasury I, would not accelerate the elimination of the windfall profit tax.52/ The lower tax rates on the integrated company are the result of the reduction in the statutory tax rate from 46 to 33 percent, and of the allowance for indexed cost depletion instead of historical cost depletion. These advantages are partially offset by the elimination of the investment tax credit.

The higher tax rates on the independent company are primarily the result of the almost complete repeal of percentage depletion. (The independent company is assumed to be eligible for percentage depletion in the later years of each property's life once production declines to stripper levels.) They are also affected by the repeal of the investment tax credit. In general, the tax rates on the independent and the integrated company would become much closer together under the President's plan, but not as close as under Treasury I. The only basic differences that would remain would be the allowance of percentage depletion for stripper oil produced by independents and retention of the 20 percent amortization requirement for intangible drilling costs for integrated companies. Also, to the extent that the two different types of companies remain subject to the windfall profit tax, independent companies will continue to enjoy the benefits of reduced rates for their production.

The President's tax plan is likely to have only a small effect on the prospective profitability of future investments in oil and gas compared to current law. For integrated companies there is likely to be a tax reduction, making some currently uneconomic ventures profitable. This should have positive effects on investment in the domestic petroleum industry. On the other hand, the limitation on the allowance for percentage depletion should reduce the attractiveness of investments undertaken by

52. If property 2 was considered new oil, the tax rate for the integrated company would fall from 25 percent to 18 percent.

TABLE 7. TAX EFFECTS OF THE PRESIDENT'S TAX PROPOSAL

Category	Current Law	President's Proposal	Absolue Change	Percent-age Change
		Property No. 1		
Major				
Taxes (present value)($000)	425.6	318.3	-107.3	-25.2
Pretax return	13.1	12.8	-0.3	-2.3
Effective tax rate	12.1	9.2	-2.9	-24.0
Equivalent price	26.00	26.47	+0.47	+1.8
Independent				
Taxes (present value)($000)	-117.5	255.5	373.0	*
Pretax return	11.7	12.7	1.0	8.5
Effective tax rate	-3.6	7.5	11.1	*
Equivalent price	26.00	24.42	-1.58	-6.1
		Property No. 2		
Major				
Taxes (present value)($000)	659.6	600.9	-58.7	-8.9
Pretax return	18.0	17.4	-0.6	-3.3
Effective tax rate	42.3	39.5	-2.8	-6.6
Equivalent price	26.00	26.92	+0.92	+3.5
Independent				
Taxes (present value)	463.8	537.2	73.4	15.8
Pretax return	15.9	16.7	0.8	5.0
Effective tax rate	32.3	36.2	3.9	12.1
Equivalent price	26.00	24.90	-1.10	-4.2
		Property No. 2 a/		
Major				
Taxes (present value)($000)	336.6	227.0	-109.6	-32.6
Pretax return	14.7	13.7	-1.0	-6.8
Effective tax rate	24.8	17.6	-7.2	-29.0
Equivalent price	26.00	26.47	+0.97	+3.7
Independent				
Taxes (present value)($000)	175.6	191.7	16.1	9.2
Pretax return	13.3	13.5	0.2	1.5
Effective tax rate	14.0	15.1	1.1	7.9
Equivalent price	26.00	25.85	-0.15	-0.6
		Property No. 3		
Major				
Taxes (present value)($000)	350.0	207.8	-142.2	-40.6
Pretax return	12.9	-12.6	-0.3	-2.3
Effective tax rate	10.3	6.3	-4.0	-38.8
Equivalent price	26.00	26.69	+0.69	+2.7
Independent				
Taxes (present value)($000)	-128.0	168.5	296.5	*
Pretax return	11.7	12.4	0.7	6.0
Effective tax rate	-4.1	5.1	9.2	*
Equivlant price	26.00	24.65	-1.35	-5.2

* Not applicable.

a. Same as Property No. 2, except that it is considered newly discovered oil instead of tier one (old) oil.

small independent companies.53/ Some properties that independents would find profitable under current law may no longer be worth the investment under the President's proposal. The overall change in output depends on the relative sizes of the positive effect on investment by integrated firms versus the negative effect on investment by independent companies.

The equivalent oil price calculations show that the President's proposal would have the same effect as raising the price of oil (for integrated companies) from $26.00 per barrel to $26.47 on property 1--an increase of $0.47 per barrel. The price increase for property 2 is $0.92 per barrel, and for property 3 $0.69. On the other hand, the equivalent oil price falls for independent companies because of the loss of percentage depletion. The equivalent price reductions for the independent company are -$1.58 for property 1, -$1.10 for property 2, and -$1.35 for property 3. Overall, these changes are relatively small and should have only a minor effect on domestic drilling and production.54/

COST OF CAPITAL MODEL

The second mode of analysis used in this study is the "cost-of-capital" approach. This approach analyzes the oil extraction industry from an aggregate viewpoint and calculates overall tax effects. The same general methodology is also used to calculate the cost of capital and effective tax rates on other industries, compared to those in the oil and gas industry. This is important because the tax reform proposals affect all industries, not just the oil and gas industry.

The full effect of a tax reform proposal should be viewed in the broad context of how it affects the industry's taxation relative to other industries. In other words, is the oil and gas industry hurt more by the proposal than other industries? The reason this is an important question is that capital markets (that is, savers and investors) are primarily concerned with the relative after-tax profitability of alternative investments. If a

53. Even though some large independents lose the benefit of percentage depletion, this may not affect their marginal investment decisions because they are ineligible for that allowance on production over their first 1,000 barrels per day.

54. These conclusions are broadly consistent with those reported in Department of Energy, Energy Information Administration, Analysis of the Impacts of the President's Tax Proposal on Major Sectors of the Energy Industry (August 1985).

tax reform proposal alters the current distribution of after-tax returns, investors will tend to shift their funds toward those sectors that are relatively favored.55/ Those industries that are relatively favored (or merely less "hurt") by a tax change will benefit because their cost of capital will be reduced as investors shift funds into these industries, thereby lowering their required after-tax returns. An industry's cost of capital may fall even if the tax on the industry itself is increased.

THE COST OF CAPITAL APPROACH

The tax system affects the demand by businesses for different kinds of assets by changing the relative user costs of forms of capital. The user cost of capital is generally defined as the cost to a firm of employing a unit of capital for one period. It is equivalent to what a firm would have to pay to lease the same unit, assuming perfectly competitive markets. Hence, the terms "user cost" and "rental cost" are often used interchangeably. In equilibrium, the user cost of an asset will also equal the marginal revenue it produces, since otherwise firms would have an incentive to shift the level or composition of their capital stock.56/ The user cost includes three factors: the amount of capital consumed (or economic depreciation), taxes, and a net after-tax return paid to investors.

In the absence of taxes, the real user cost of capital (C) equals the sum of economic depreciation (d) and the competitive

55. To the extent that savers and (in the aggregate) investors provide a lower amount of financial capital because of an increase in taxes on capital income, the overall level of new investment could shrink. At present, however, there is no consensus on how sensitive the rate of national saving is to changes in the effective tax rate on capital income. Some economists argue that saving is very sensitive to changes in capital taxation; others argue that there may be no effect at all.

56. If an asset's revenue is less than its user cost, the asset is unprofitable and will not be acquired. Conversely, if its revenue is more than its user cost, firms will buy more of the asset. An equilibrium is reached when revenue equals cost and firms have no incentive to alter their capital stock.

rate of return (r) multiplied by the asset's acquisition cost (q).57/ That is:

$C = q(r + d)$

where q = asset acquisition cost
r = real rate of return
d = rate of depreciation of output

Note that depreciation in this case is the exact amount that the firm needs to recover in order to leave its total capital intact. This equation is based on an asset whose productivity is assumed to decline at a constant rate over time. By setting the cost of the asset (q) equal to one, the user cost of capital, per unit of capital, is equal to the sum of the real return and economic depreciation. That is, $C = r + d$.

When taxes are imposed on the income from capital, the cost of capital rises to cover the taxes, as well as to cover the return to investors and depreciation.58/ Under the assumption that investors require a fixed real rate of return after tax of r^*, the user cost of capital (per unit of capital) is equal to:

$$C = (r^* + d)(1 - uz - k)/(1 - u)$$

where r^* = required real after-tax rate of return (real discount rate)
z = present value of depreciation allowances (discounted at the nominal post-tax interest rate)
k = investment tax credit rate
u = corporate tax rate

In this equation, the present value of depreciation allowances (z) refers to those allowed by the tax code. It also includes items such as tax depletion, amortization, or any other form of deduction allowed for recovery of capital expenditures. From this equation, it is apparent that the user cost of capital is lowered

57. See Jane G. Gravelle, "Effects of the 1981 Depreciation Revisions on the Taxation of Income From Business Capital," National Tax Journal (March 1982), pp. 1-20, for a derivation of the user cost of capital and effective tax rate equations.

58. If instead it is assumed that pretax returns remained fixed, and the after-tax return declines in response to the imposition of the tax, the user cost of capital remains unchanged. In this case, the suppliers of capital (savers) bear the full cost of the tax through a reduced after-tax rate of return. (This alternative assumes that the supply of capital to the industry is perfectly inelastic.)

by increases in the present value of capital recovery allowances or the investment tax credit rate (k), and rises if the tax rate (u) is increased. (For purposes of this analysis, the only tax considered is the corporate income tax. In other words, r^* reflects the return that investors require after the corporate tax, but before individual income taxes.)

Suppose the tax law allows firms to deduct actual (or economic) depreciation indexed for inflation. This allows firms to keep their real capital intact, without providing any investment subsidy. Also assume that no investment credit is allowed. In this case, the user cost per unit of capital is simply:

$$C = (r^*/(1 - u)) + d$$

The user cost is equal to the pretax rate of return plus depreciation. Note that the pretax rate of return $(r^*/(1 - u))$ equals the required after-tax rate of return (r^*) increased by the amount of income taxes.

Effective Marginal Tax Rates. In general, the effective marginal tax rate for an asset is calculated by the ratio:

$$TR = (r - r^*)/r$$

where TR = asset tax rate
r = pretax rate of return
r^* = required after-tax rate of return

It is the difference between the pretax and after-tax rates of return, divided by the pretax rate of return. The required after-tax rate of return is the return that the corporation must earn over the life of the asset in order to undertake the investment. (This assumes that the corporation has other investment opportunities from which it can earn as much as r^*.) In equilibrium, r is the pretax rate of return that yields r^* after tax. It should be stressed that the effective tax rate derived by this method is the theoretical tax rate that would result under a certain set of assumptions; these include assumptions of depreciation, inflation, and interest rates, as well as an assumption that all deductions and credits can be fully utilized on a current basis. This same general mathematical formulation has been used in several studies to estimate effective marginal corporate tax rates.59/ This model, like the DCF model, only takes account of

59. See Alan J. Auerbach, "Corporate Taxation in the United States," Brookings Papers on Economic Activity 1983: 2 (Washington, D.C.: The Brookings Institution, 1984), pp. 451-514; Jane G. Gravelle, "Effects of the 1981 Depreciation Revisions on the Taxation of Income From Business Capital,"

corporate-level taxes; personal taxes on dividends, interest, and capital gains are excluded.

The rate of return r that yields r* after tax is defined by:

$$r = \frac{(r^* + d)(1 - uz - k)}{(1 - u)} - d$$

where
r = Pretax rate of return
r* = Required after-tax rate of return
d = Economic depreciation rate
k = Investment tax credit rate
u = Statutory tax rate
z = Present value of tax depreciation deductions (discounted at the nominal after-tax interest rate)

Using this formula yields an effective tax rate equal to the statutory tax rate when economic depreciation or depletion (indexed for inflation) is allowed (and the investment credit is disallowed). As either the investment credit or the present value of depreciation allowances rises, the effective tax rate falls. This is important because the more accelerated depreciation allowances are allowed for tax purposes, the lower is the effective tax rate.

The tax rate on each industry reflects a weighted average of the tax rates on most fixed assets in its capital stock. (This includes depreciable assets and inventories, but not other assets, such as patent rights, good will, or working capital.) For the oil and gas industry it is assumed that the initial capital stock consists of 69 percent intangible drilling costs, 20 percent mineral acquisition and geological costs (depletable costs), and 11 percent lease (depreciable) equipment.60/ Of the drilling costs, 30 percent are assumed to be for dry wells, the remaining 70 percent are for producing wells. Forty percent of

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National Tax Journal (March 1982), pp. 1-20; Charles R. Hulten and James W. Robertson, Corporate Tax Policy and Economic Growth: An Analysis of the 1981 and 1982 Tax Acts, Urban Institute Discussion Paper (December 1982): and Mervyn A. King and Don Fullerton, The Taxation of Income From Capital: A Comparative Study of the United States, United Kingdom, Sweden, and West Germany (Chicago: University of Chicago Press, 1984).

60. These ratios are based on data reported in Bureau of the Census, Annual Survey of Oil and Gas, 1982 (March 1984). These cost ratios are assumed to be the same for both integrated and independent companies.

lease bonus and geological costs are assumed to be associated with properties that turn out to be worthless. Eighty percent of production is assumed to be produced by integrated and large independent companies; the remainder is produced by small independent companies. It is also assumed that the economic depreciation (depletion) rate for the oil industry is 10 percent. In calculating the user cost of capital for the oil industry, it is assumed that the initial output price remains fixed and that the bonus (mineral acquisition costs) adjusts to maintain the required after-tax return.

User Costs and Effective Tax Rates Under Alternative Tax Reform Proposals

Previous CBO reports have illustrated how effective tax rates on corporate investments differ among industries, and how effective tax rates would be altered by the President's tax reform proposals.61/ The estimates of effective tax rates for particular industry groups shown below are comparable to those in earlier reports, but are not exactly the same because of different assumptions about the real discount rate and expected inflation. In addition, earlier reports did not show the effective tax rate on the return to investments (including land acquisition costs and intangible drilling costs) in oil and gas extraction.

Current Law. Table 8 presents estimates of the user cost of capital and effective tax rates for eight broad industry classes, including oil and gas extraction, under current law. The assets included in each industry are limited to depreciable (and depletable) assets and inventories; other assets such as land, patent rights, or working capital have been excluded. These calculations reflect an assumed required real return of 8 percent, an expected inflation rate of 4 percent, and full use of credits and depreciation deductions on a current basis.62/ The effective tax

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61. See Congressional Budget Office, Revising the Corporate Income Tax, Chapter IV (May 1985), and Congressional Budget Office, Effective Tax Rates and Real Costs of Capital Under Current Law and Under the President's Proposed Tax Reform, Staff Working Paper (August 1985).

62. These tax rates are relatively insensitive to the assumed real rate of return. (The tax rates in Table 8 are replicated in the Appendix under an assumed real rate of 5 percent.) However, the effective tax rates under current law are especially sensitive to the assumption of the 4 percent expected inflation. (This assumption is consistent with CBO's latest economic forecast.) At higher expected infla-

rate refers only to the corporate-level tax and does not include any tax effects at the personal level on capital gains or dividends. Furthermore, the windfall profit tax is assumed to be zero since it is effectively zero on newly discovered oil.63/

The overall tax rate of the oil and gas industry is about 10 percent, about 19 percentage points lower than the average for industries other than oil and gas extraction.64/ The oil and gas tax rate reflects an effective tax rate on integrated companies of 14 percent and an effective rate of -10 percent on independent companies.65/ Industries that use relatively more assets eligible for the investment tax credit, such as transportation or communications, generally have relatively low tax rates. Others that rely more heavily on inventories and buildings and structures (not eligible for the investment tax credit), such as wholesale and retail trade, have higher tax rates.

The effective tax rates measured here differ significantly from average "cash-flow" tax rates based on company financial reports.66/ A cash-flow tax rate is limited to one year's taxes and income and includes the full range of a company's operations. (In the case of oil and gas, it might include refining and retailing operations.) In addition, a cash-flow rate is an average of all the company's investments--new and old alike. In any given year, a cash-flow tax rate is likely to depend on the timing of a firm's investments and other economic conditions that may be specific to that particular year (for example, whether oil prices are going up or down). By contrast, the effective marginal tax rate used in this study pertains only to potential future investments and covers their full expected life. Because of these

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tion, tax rates rise under current law, but remain virtually unchanged under Treasury I and the President's proposal because of their provisions for indexing for inflation.

63. Since the effective tax rate calculations only apply to marginal investments, this treatment is appropriate.

64. The Appendix provides sensitivity analysis results for an assumed real return of 5 percent. In this case, the differential is 17 percentage points.

65. A negative rate implies that the present value of taxes is less than zero--that is, the industry receives a net refund. It also implies that the pretax rate of return is <u>less</u> than the after-tax rate of return.

66. For example, see Joint Committee on Taxation, <u>Study of 1983 Effective Tax Rates of Selected Large U.S. Corporations</u> (November 28, 1984).

TABLE 8. EFFECTIVE TAX RATES AND REAL USER COSTS OF CAPITAL UNDER CURRENT LAW AND REFORM PROPOSALS (In percents)

Industry	Real User Cost of Capital	Required Pretax Return	Effective Tax Rate
Current Law			
Manufacturing	20.8	11.9	33
Construction	23.6	11.6	31
Transportation	17.7	9.8	18
Communications	16.8	9.3	14
Public Utilities	15.7	10.2	22
Wholesale and Retail Trade	21.8	12.8	38
Services	20.2	10.3	22
Average Rate	19.4	11.2	29
Oil and Gas Extraction	18.9	8.8	10
Treasury Proposal			
Manufacturing	20.6	11.7	32
Construction	23.7	11.7	32
Transportation	19.3	11.4	30
Communications	18.6	11.1	28
Public Utilities	17.3	11.8	32
Wholesale and Retail Trade	20.7	11.7	32
Services	21.5	11.6	31
Average Rate	19.9	11.7	32
Oil and Gas Extraction	20.7	10.7	25
President's Proposals			
Manufacturing	19.9	11.0	27
Construction	22.8	10.8	26
Transportation	17.9	10.0	20
Communications	17.1	9.7	18
Public Utilities	15.1	9.6	17
Wholesale and Retail Trade	20.2	11.2	29
Services	20.1	10.2	21
Average Rate	20.1	10.5	24
Oil and Gas Extraction	18.7	8.3	8

SOURCE: Congressional Budget Office.

NOTE: Tax rates are computed under the assumptions that financing is 100 percent equity and all deductions and credits can be taken on a current basis. The real required return is assumed to be 8 percent; expected inflation is assumed to be 4 percent. The taxpayer is a corporation with a marginal tax rate equal to the top corporate tax rate. Taxes paid by individual shareholders on dividends and on capital gains are not counted in the calculation. The tax rate is the corporate income tax rate only.

differences, the two types of effective tax rates cannot be readily compared.

The estimated user cost of capital is 18.9 percent for the oil industry. This is the real net operating profit (per dollar of capital) that an oil investment must generate in order to cover corporate taxes, economic depletion and depreciation, and provide investors with a real return of 8 percent.

Treasury I. The middle panel of Table 8 shows effective tax rates by industry under the original set of Treasury tax reform proposals. They are calculated under the same set of assumptions as used under current law. Although the real after-tax return is likely to change with the adoption of any major tax reform package, for the purposes of this analysis, it is assumed that this return stays fixed at 8 percent.

The Treasury plan would have raised all industry effective tax rates to about 32 percent. The plan is based on the premise that effective tax rates should equal the statutory rate for all industries; this would largely be achieved under this proposal.67/

The oil and gas tax rate (25 percent) would remain below the all-industry average tax rate, although its increase would be quite substantial--about 15 percentage points. The rate would remain significantly below the statutory rate of 33 percent because some forms of investment would still be written off faster than the economic decline of the oil and gas properties. For example, dry hole costs and lease bonuses would be written off when a property was abandoned, even though they are required to discover or develop properties that prove productive. Under this proposal, no distinction would be made between integrated and independent companies for tax purposes.

The user cost of capital would rise from 18.9 percent to 20.7 percent. However, since domestic producers cannot affect the real price of oil in the world market, they cannot increase prices (by reducing output) to cover this higher cost. Instead, the higher taxes would probably lower the bonuses paid for oil-bearing land while maintaining a constant output price. Assuming depletable costs (bonuses) adjust instead of prices, the new depletable cost share under the Treasury proposal would be 11.2 percent instead of 20 percent of the initial investment.

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67. The Treasury (and this study) use estimates of economic depreciation reported in Charles R. Hulten and Frank C. Wykoff, "The Measurement of Economic Depreciation," in Charles R. Hulten, ed., Depreciation, Inflation and the Taxation of Income from Capital (Washington, D.C.: Urban Institution, 1981).

This reduction is about equivalent to a 5 percent decline in the current operating profit (equal to the user cost C) per barrel of oil.

The reduced bonus amount (or equivalent price decline) would be likely to affect domestic oil supply by making marginal oil properties no longer economic.68/ A 5 percent profit decline under Treasury I would reduce drilling and domestic reserves. In the first year, drilling might be reduced by about 3 percent to 3.5 percent, and reserve additions could decline by 0.4 to 0.8 percent.69/ Production would only be slightly affected initially; after several years of reduced drilling and reserve finds, production would be more severely affected.

President's Proposal. The bottom panel of Table 8 shows the effective tax rates under the President's proposals. The tax rate on oil and gas extraction remains about the same--it falls slightly from 10 percent to 8 percent.70/ This indicates that the effect of repealing percentage depletion (which would raise the tax rate) is about offset by the reduction in the top statutory rate from 46 percent to 33 percent. As a result, the cost of capital for the oil and gas extraction business remains virtually unchanged. By contrast, the average tax rate on other industries declines from 29 to 24 percent.

This analysis suggests that the drilling and production effects of the President's proposals would likely be quite small. The equivalent price change under the President's plan is only $0.05 per barrel. Any change in drilling is likely to be less than 1 percent. The President's proposals would result in an

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68. A property would become uneconomic if its bonus bid dropped below zero.

69. Data Resources (DRI) reports results similar to those estimated here. (Data Resources, Inc., Analyzing the Effects of the Treasury Tax Reform Proposals on the Oil and Gas Industry. Monitoring Bulletin (June 1985).) In 1986, DRI estimates that a 9 percent drop in the price of oil would result in a 5 percent decline in footage drilled. The implied price elasticity of drilling is about 0.53. (In other words, a 1 percent change in the price of oil yields a 0.53 percent change in drilling activity.) In the model used here, the implied elasticity of drilling (total wells) with respect to the price of oil (evaluated in 1984) is about .61--slightly higher than estimated by DRI. A description of the model used to estimate drilling and reserves is available upon request.

70. Given the uncertainty of the assumptions used in this model, this decline is insignificant.

effective tax rate on oil and gas extraction much below the average rate for other industries. For example, the tax rates on manufacturing and on wholesale and retail trade would be 27 percent and 29 percent, respectively. This indicates that, relative to investment in other industries, new investment in oil and gas extraction would remain relatively tax-preferred.

Extending the repeal of percentage depletion to all wells--including stripper wells--in the President's tax plan would have only a negligible effect on marginal tax rates or on oil production. The effect would be virtually insignificant because the decision to invest in new oil properties is unlikely to be affected by a tax benefit that is relatively small and is only received late in a property's life. Furthermore, as noted above, the 50 percent net income limitation would lower the benefit received on stripper wells to zero as they neared their economic limit.

Partial Changes. Other less comprehensive tax changes have also been suggested for the oil and gas industry. These proposals would not completely restructure the current tax system, but would simply alter the way intangible drilling costs or percentage depletion are handled under current law.

Repealing percentage depletion and requiring all producers to use cost depletion (unindexed) would raise the average effective tax rate from 10 percent to 13 percent. The tax rate on integrated companies would remain unchanged at about 13 percent, and the rate on independent companies would rise from -10 percent to 11 percent. This change would be equivalent to lowering the real operating profit per barrel by about 1 percent. Such a change would have the effect of lowering drilling by about 0.6 percent and reserve additions by a smaller amount.

Requiring producers to amortize their drilling costs over 60 months would have a much larger effect.71/ This change would affect all oil producers and have the effect of raising the industry's effective tax rate from 10 percent to 22 percent. This new tax rate would remain slightly below the average rate that currently prevails in other industries. Such a change would be equivalent to lowering the real operating profit by about 4 percent per barrel. It would result in reduced drilling of about 2 to 2.5 percent annually, and in reduced reserve additions of about 0.3 to 0.6 percent.

These effects would be even more severe if producers were required to use cost depletion (unindexed) instead of 60 month

71. This assumes companies would only amortize drilling costs for productive wells; dry hole costs would still be expensed.

amortization for their drilling costs. In this case the effective tax rate would rise to about 34 percent. This change would be about equivalent to lowering the real operating profit by about 9 percent. The effect on drilling in this case would be a reduction of around 5.5 percent; reserve additions would decline by 0.7 percent to 1.4 percent.

REVENUE ESTIMATES

Revenue estimates from changing certain oil and gas provisions are shown in Table 9. Over the 1986 to 1990 period, repealing percentage depletion altogether would raise about $5.8 billion. In lieu of percentage depletion companies would be allowed to deduct their depletable costs according to cost depletion under current law. This estimate compares to the estimate of $4.5 billion for the repeal of all percentage depletion, except for stripper wells (as proposed by the President).

Under current law, cost depletion is less generous than economic depletion. This is because cost depletion is not indexed for inflation and the value of future deductions is severely eroded even in times of moderate inflation. One alternative to current law cost depletion that has been proposed is to allow producers depletion at a constant rate of 25 percent of the property's current tax basis.72/ (The current tax basis is the historical value of the firm's depletable costs associated with the property, less all prior deductions for depletion.) For example, if a firm originally spent $1,000 for a property, its first-year deduction would be $250. In the second year, the current tax basis would be $750 and that year's depletion deduction would be $187.5 (.25 times $750). This process would continue until the property was abandoned, at which time the remaining basis would be written off.

Adoption of the constant rate depletion proposal would accelerate depletion deductions and therefore lose revenue. Over the 1986 to 1990 period, the revenue loss from this proposal is about $2.5 billion. This assumes that percentage depletion is already repealed and that both independents and integrated companies would be required to use the constant rate system. In conjunction with repealing all percentage depletion, this would result in a net revenue gain of about $3.3 billion over the 1986 to 1990 period.

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72. This proposal is in the tax reform bill introduced by Senator Bill Bradley and Congressman Richard Gephardt (H.R. 800, S. 409).

TABLE 9. REVENUE EFFECTS FROM CHANGES IN OIL AND GAS TAX PROVISIONS

Addition to CBO Baseline	Annual Added Revenues (Billions of dollars)					Cumulative Five-Year Addition
	1986	1987	1988	1989	1990	
Repeal All Percentage Depletion (except stripper wells) a/	0.5	1.0	1.0	1.0	1.1	4.5
Repeal All Percentage Depletion a/	0.7	1.2	1.3	1.3	1.4	5.8
Accelerate Cost Depletion b/	-0.4	-0.7	-0.6	-0.5	-0.4	-2.5
Capitalize Drilling Costs (25 percent constant rate depletion) c/	2.5	4.0	3.4	2.9	2.6	15.3
Amortize Drilling Costs Over 60 Months c/	2.6	4.2	3.5	2.7	1.8	14.8

SOURCES: Joint Committee on Taxation and Congressional Budget Office.

a. Percentage depletion is replaced by current law cost depletion.

b. Current law cost depletion is replaced by constant rate depletion (25 percent annual rate).

c. This estimate assumes that all percentage depletion has been repealed.

Eliminating the provision for expensing intangible drilling costs for producing wells could raise $15.3 billion over the 1986 to 1990 period.73/ Under the proposal, firms would be required to capitalize their drilling costs and add them to their depletable basis (that is, the aggregate of all depletable costs). They would then be allowed subsequent deductions according to constant rate depletion (at a 25 percent rate).

The simultaneous repeal of both percentage depletion (in total) and the expensing of intangible drilling costs would raise about $18.6 billion over the 1986 to 1990 period. Companies would instead be allowed to deduct these costs according to constant rate cost depletion. All depletable costs would also be subject to depletion under the constant rate system.

If elimination of the expensing of IDCs was not accompanied by the repeal of percentage depletion, independent companies might be especially hard hit since they would lose the ability to expense their drilling costs, but might not be able to realize higher depletion deductions. This would happen if their current percentage depletion deductions exceeded their deductions (based on cost depletion) resulting from capitalizing their drilling expenditures. One way of allowing firms to retain percentage depletion and realize some benefit from capitalizing their drilling expenditures would be to allow all companies to amortize their drilling expenditures over five years, regardless of their deduction for percentage depletion. Such a provision would raise $14.8 billion over the 1986 to 1990 period.

Extending the Windfall Profit Tax past 1991 would raise a relatively small amount of revenue. CBO now estimates that the tax would yield net revenue on the order of about $1.1 billion per year by 1990. Even if oil prices were to stay constant in real terms, this amount would gradually decline over subsequent years. By the year 2000, the annual net revenue yield from the tax would be about $450 million.

Increasing the tax on new oil from its current level (22.5 percent now, declining to 15 percent by 1989), back up to its original level of 30 percent would have a negligible revenue effect over the 1986 to 1990 period. This is due to the fact that much of new oil is now exempt from the tax because its adjusted base price exceeds its market price, and its windfall profit is therefore zero. Changing the tax rate would have little or no impact on collections because the tax base has declined to almost nothing.

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73. This estimate assumes that percentage depletion has already been repealed.

APPENDIX

THE EFFECTS OF TAX POLICY ON THE USER COST OF CAPITAL

A simple cost of capital model was used to analyze changes in tax policy. In a world without taxes, the real operating profit per barrel must be enough to cover the real return required by the investor plus economic depreciation.73/ On the marginal investment, the real profit equals the cost of capital. (The cost of capital is the real return plus economic depreciation plus taxes.) As discussed in the text, the formal expression for the cost of capital is:

(1) $C = q(r^* + d)(1 - uz - k)/(1 - u)$

Where: C = operating profit per barrel (or user cost of capital)
q = investment amount
r^* = required after-tax return
d = economic depreciation rate (production decline rate)
u = corporate tax rate
z = present value of tax depletion and depreciation, evaluated at the nominal after-tax interest rate
k = investment tax credit rate

The pretax rate of return equals the user cost less economic depreciation ($r = C - d$), and the effective tax rate equals the difference between the pretax and after-tax rates of return divided by the pretax rate of return ($TR = (r - r^*)/r$).

Under current law, the present value of depletion and depreciation deductions consists of a number of factors that represent different components of an oil investment. In this model, it is assumed that the investment is composed of depletable costs (20 percent), drilling costs (69 percent), and depreciable costs (11 percent). Of the depletable costs, it is assumed that 60 percent are capitalized and recovered through depletion, and the remaining 40 percent are associated with properties that prove worthless; they are deducted after one year. Thirty percent of drilling costs are assumed to be for dry wells; the other 70 percent are for producing wells. Under these assumptions, the present value of deductions for the integrated company equals:

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73. The real operating profit per barrel is the selling price less all current production costs, such as labor or energy needed to extract and sell the production.

$$(2)\ z = 0.2[0.6(d/(d + r^* + p) + 0.4/(1 + r^* + p)] + 0.69\ [0.3 + 0.7(am)] + 0.11(dep)$$

Where: dep = Present value of depreciation plus the investment tax credit (on a deduction equivalent basis

am = Present value of amortized drilling costs

p = Expected rate of inflation

The first term in this expression is the present value of deductions related to depletable costs. The present value of depletion under an unindexed depletion system is equal to $d/(d + r^* + p)$, where p is the expected rate of inflation.74/ The expression ".4/(1 + r^* + p)" reflects the assumption that 40 percent of depletable costs are written off after one year due to abandonment. The second term represents the deductions for drilling costs. Since 20 percent of the costs related to productive wells must be amortized over three years, the term (am) is somewhat less than one. The last term represents the present value of depreciation and the investment tax credit. The values of these terms change as the tax treatment of each of the components is altered.

The cost of capital for an independent company is somewhat different than that for an integrated company because of the effect of percentage depletion. The expression for the independent company is:

$$(3)\ C = (r^* + d)(1 - uz)/[(1 - u) + .1875u]$$

The term ".1875u" reflects the value of percentage depletion. The percentage depletion rate is 0.15 and it is assumed that the ratio of price to operating profit (C) equals 1.25.75/ In this case, the z term excludes the present value of cost depletion. It equals:

$$(4)\ z = 0.2[0.4/(1 + r^* + p)] + 0.69[0.3 + 0.7] + 0.11(dep)$$

This expression has also been modified to reflect the fact that independent companies are not required to amortize any of their drilling expenses, but may write them all off immediately.

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74. This formulation assumes that cost depletion deductions accrue continuously over time (at the same rate production declines). The present value of deductions under indexed cost depletion would be $d/(r^* + d)$.

75. 0.1875 = (0.15)(1.25).

Under the assumptions that the decline rate equals 10 percent, expected inflation equals 4 percent, and the real return is 8 percent, the cost of capital (C) equals 19.3 percent for the integrated company. In 1984, the real (1972 dollars) operating profit was estimated at about $8 per barrel. This implies that the real investment amount (q) per barrel of reserves equals about $4.2 per barrel.76/

The industry cost of capital is equal to 18.9 percent and reflects a weighted average of integrated companies (80 percent) and independent companies (20 percent).

Changes in tax policy will affect the cost of capital by changing the present value of tax deductions. If it is assumed that the real after-tax return is fixed at 8 percent, and that the cost of capital can adjust (through price changes), a new cost of capital can be computed for each new tax regime. Alternatively, if it is assumed that the output price remains fixed, it is possible to solve for the new cost of capital by letting the scale of the investment adjust. Specifically, by altering the share of depletable costs (that is, lease bonuses), and holding the after-tax return constant, a new cost of capital can be calculated.

For example, suppose the expensing of intangible drilling costs (for productive wells) is replaced by unindexed cost depletion. In this case the new z (for the integrated company) is the same as the old, except that the present value of amortization (am) instead equals the present value of cost depletion $(d/(d + r^* + p)$. If prices are allowed to adjust (holding the after-tax return fixed at 8 percent), C would rise to 22.9 percent and the composition of the investment would remain unchanged. Alternatively, if prices remain fixed at their pre-change level, the depletable cost share (bonus) must fall from 20 percent to 5 percent. In this case, the cost of capital rises to 22.2 percent, but less capital is invested per unit of output.

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76. In this case, reserves would be 10 barrels (1/0.1) and the investment per barrel of reserves would be about $4.2 in 1972 dollars ($9.3 per barrel in 1984 dollars). For reference, it has been reported that the ratio of exploration and development expenditures per barrel of reserve additions for the domestic oil industry was $9.90 in 1981, and $11.14 in 1982. See, Energy Information Administration, Performance Profiles of Major Energy Producers, 1983 (February 1985), Table G35.

This reduction in depletable costs is equivalent to a fall in C (under current tax law) from 18.9 percent to 17.2 percent.77/

In this case, C falls by about 9 percent. Evaluated at a pre-change real operating profit of $8.13, this implies an equivalent reduction in the real profit per barrel of about $.72 ($1.58 in 1984 dollars). In this way, changes in tax policy can be translated into equivalent changes in the real profit per barrel--the variable used in the supply model to estimate the supply response from changes in oil prices or taxes.

Clearly these results depend on the assumptions used; different assumptions would result in somewhat different results. For example, if the initial calibration of q was based on a real after-tax rate of return (r*) of 5 percent, the drop in C would be $0.60 (in real terms) for the case of unindexed cost depletion compared to the $0.72 calculated under the 8 percent real return. By contrast, if the decline rate was set at 15 percent instead of 10 percent (but returning r* to 8 percent), the decline in C under unindexed cost depletion would be $0.44 instead of $0.72. Thus, the estimated change in C (and therefore the effect of tax policy changes) is quite sensitive to the set of assumptions used.

Effective tax rates for different policy regimes are also different under different assumptions. Effective tax rates by industry (comparable to those shown in Table 4 of the text) are shown in Table A-1 based on the alternative assumption of a 5 percent real return, holding all else the same. Under current law, the effective tax rate is virtually unchanged for the oil and gas extraction industry, but is higher for other industries. The oil and gas rate remains 10 percent, but the other industry rate is now 27 instead of 29. This indicates that at higher real returns, the tax preference in favor of the oil and gas industry is somewhat larger.

Under the Treasury proposal, the industry tax rates hardly change at all. This is because the Treasury proposal attempts to approximate economic depreciation rates in setting its tax depreciation rates. (If economic depreciation is allowed for tax purposes, the tax rate is invariant with respect to the discount rate.)

The tax rates under the President's plan are also very similar to those calculated at a 5 percent real return. The oil and gas rate remains 8 percent, and the other industry rate is 22

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77. 17.2 percent is computed by substituting the new lower depletable cost share into the cost of capital equation under current law and solving for the new cost of capital which equals the real profit per unit of output.

TABLE A-1. EFFECTIVE TAX RATES AND REAL USER COSTS OF CAPITAL UNDER CURRENT LAW AND REFORM PROPOSALS: 5 PERCENT REAL DISCOUNT RATE (In percents)

Industry	Real User Cost of Capital	Required Pretax Return	Effective Tax Rate
Current Law			
Manufacturing	16.2	7.3	31
Construction	19.0	7.0	29
Transportation	13.6	5.7	12
Communications	12.9	5.5	9
Public Utilities	11.6	6.1	19
Wholesale and Retail Trade	16.9	7.9	37
Services	15.9	6.1	18
Average Rate	15.9	6.8	27
Oil and Gas Extraction	15.5	5.5	10
Treasury Proposal			
Manufacturing	16.3	7.4	32
Construction	19.4	7.4	32
Transportation	15.0	7.1	30
Communications	14.3	6.9	28
Public Utilities	12.9	7.4	32
Wholesale and Retail Trade	16.3	7.3	32
Services	17.1	7.3	32
Average Rate	16.3	7.3	31
Oil and Gas Extraction	16.6	6.6	25
President's Proposals			
Manufacturing	15.7	6.8	26
Construction	18.8	6.7	25
Transportation	18.9	6.0	17
Communications	13.4	5.9	15
Public Utilities	11.4	5.9	15
Wholesale and Retail Trade	15.9	6.9	28
Services	16.2	6.3	20
Average Rate	15.6	6.4	22
Oil and Gas Extraction	15.4	5.4	8

SOURCE: Congressional Budget Office.

NOTE: Tax rates are computed under the assumptions that financing is 100 percent equity and all deductions and credits can be taken on a current basis. The real required return is assumed to be 5 percent; expected inflation is assumed to be 4 percent. The taxpayer is a corporation with a marginal tax rate of the top corporate tax rate. Taxes paid by individual shareholders on dividends and on capital gains are not counted in the calculation. The tax rate is the corporate income tax rate only.

percent (versus 24 percent). This indicates that the estimated difference in taxation between the oil industry and other industries under the President's proposal is slightly smaller if a lower real required after-tax return is assumed.