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Report to the Chairman, Subcommittee on Energy and Power, Committee on Energy and Commerce, House of Representatives

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TAX POLICY

Additional Petroleum Production Tax Incentives Are of Questionable Merit

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General Government Division

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The Honorable Philip R. Sharp
Chairman, Subcommittee on Energy and Power
Committee on Energy and Commerce
House of Representatives

Dear Mr. Chairman:

This report is in response to your request for information on the effects of additional tax incentives for the petroleum production industry. It considers the effects of additional incentives on petroleum production and federal revenues, the federal tax burden on new domestic petroleum production investments under current law, and the comparative tax treatment of petroleum production investments in the United States and other nations.

As arranged with the Subcommittee, we are sending copies of the report to the Secretary of Energy, the Secretary of the Treasury, and appropriate congressional committees and other interested parties. We will send copies to others upon request.

Major contributors to this report are listed in appendix V. Please contact me at 275-6407 if you or your staff have any questions concerning this report.

Sincerely yours,

Jennie S. Stathis

Jennie S. Stathis
Director, Tax Policy and
Administration Issues

Executive Summary

Purpose

Since 1985 domestic oil production has declined, and oil imports have increased. While these trends may be largely explained by the decline in the world price of oil and the relatively high cost of new U.S. production, they may have unfavorable implications for U.S. energy security. To assist in the evaluation of additional petroleum tax incentives, the Chairman of the Subcommittee on Energy and Power of the House Committee on Energy and Commerce asked GAO to examine (1) the effects of a range of possible tax incentives upon U.S. petroleum production and federal revenues, (2) the effective federal corporate tax rates on investments in petroleum production and other industries, and (3) the comparative tax treatment of petroleum investments in the United States and other nations.

Background

Proposed tax incentives for petroleum production include a range of provisions—such as tax credits and faster and larger deductions of costs for tax purposes—that would increase the after-tax profitability of eligible investments. Some of the proposed tax incentives would increase allowances for depletable costs, which include initial payments to landowners for exploration and development rights as well as geological and geophysical costs (costs of survey, seismic, and related activities for locating and acquiring petroleum properties). Proposals have also been made for more favorable tax treatment of other exploration and development costs, including intangible drilling costs, which are the costs of labor, services, fuel, and other site preparation and drilling expenditures that are nonsalvageable. Tax incentives have also been proposed for certain investments in enhanced oil recovery, which entails use of injectants and advanced techniques to increase oil production. Finally, tax incentives have been proposed for certain investments in stripper wells, which produce 10 barrels or less of output per day.

The provisions considered in this report include those proposed by the Bush administration in the 1991 budget submission; those examined by the Department of Energy (DOE) in the 1987 report, Energy Security; and those considered by the Joint Committee on Taxation in 1987. GAO did not independently estimate the production and revenue effects of these incentives, but instead reviewed existing information on the impacts of such proposals.

Results in Brief

Additional federal tax incentives for petroleum investments would probably increase U.S. petroleum production to a limited extent. For example, the two incentives proposed in the administration's 1991 budget for which DOE production estimates are available would increase U.S. petroleum production by a total of 0.2 to 0.3 percent. This increased production, however, would come at the expense of substantial per barrel federal revenue losses. GAO estimates that federal revenue losses could be $3 to $14 for each barrel of additional production resulting from these two proposals. Other policies, such as filling the Strategic Petroleum Reserve (U.S. oil reserves available for use in an energy emergency), may be more effective approaches to increasing U.S. energy security.

GAO analysis and other recent studies of effective tax rates for new investments show that additional incentives would further contribute to a federal tax system that already favors petroleum production investments over those in most other industries. Some proposed incentives would also further favor certain types of petroleum production investments and categories of producers over others. The favorable tax treatments received by the industry as a whole and by certain activities within the industry both provide incentives for relatively inefficient investments within the industry.

Finally, U.S. producers are making petroleum production investments abroad, rather than in the United States, largely because of factors other than taxes. Petroleum investments abroad have become relatively more attractive than those in the United States largely because of the decline in the price of oil and generally more favorable foreign geologic characteristics, including lower finding and development costs. Some foreign governments have eased their tax and royalty treatment of petroleum production in response to lower petroleum prices, however, which could provide additional incentives for investing abroad.

GAO's Analysis

Production and Tax Revenue Estimates Raise Cost-Effectiveness Concerns

Although there is uncertainty surrounding the production, tax revenue, and cost-effectiveness estimates for the proposals, GAO's review indicates that the proposals it considered are expected to have small to modest effects relative to total U.S. petroleum production and consumption. The administration's estimate for the average annual revenue loss for all of the petroleum tax incentives proposed in the 1991 budget combined is $400 to $500 million.

While production estimates are not available for all of these incentives, DOE did release production estimates for two provisions in October 1989. For these proposals—repeal of the transfer rule (a rule governing depletion allowances) and eased tax treatment of certain intangible drilling costs—DOE estimates that future U.S. petroleum production (including both oil and natural gas) would increase by a total of about 25,000 to 40,000 barrels per day. These figures imply a 0.2 to 0.3 percent increase in future U.S. production of oil. On the basis of the 1989 administration figures, GAO estimates that the proposal for eased treatment of certain intangible drilling costs could cause federal revenue losses of $3 to $6 for each barrel of additional production resulting from the incentive. Repeal of the transfer rule could cause revenue losses of $11 to $14 for each barrel of additional production resulting from the incentive. (See pp. 32-34.)

DOE considered some tax provisions that it expected to have somewhat larger production impacts (i.e., increases of about 3 percent of future U.S. production) in Energy Security. However, GAO found a series of concerns with the Energy Security modeling, including possible tendencies to overestimate production effects, that it brought to DOE's attention beginning in early 1989. DOE's October 1989 production estimates for repeal of the transfer rule are one-eleventh of the estimates for this provision in Energy Security. (See pp. 34-36.)

In general, tax provisions targeted to exploration and other new production are more cost effective than provisions applying to all existing production, such as some increases in depletion allowances. GAO's analysis shows that provisions applying to all existing production could lead to revenue losses per barrel of additional production that exceed the price of oil, which in 1989 averaged about $16 per barrel at the wellhead (i.e., before transportation costs). Even provisions aimed at new production will generally benefit some investments that would occur without new incentives, in addition to encouraging some genuinely incremental production—that is, production that would only occur with the incentives. (See pp. 36-37.)

In contrast to tax incentives, other policies are available that may better increase U.S. energy security, in terms of reducing U.S. vulnerability to an oil supply disruption. In recent work GAO has suggested several options, including developing alternative fuels, increasing fuel efficiency in transportation, and continuing development of the Strategic Petroleum Reserve as quickly as is fiscally responsible. (See pp. 71-73.) If, for example, the estimated revenue cost of the administration's proposals were instead invested in filling the Strategic Petroleum Reserve, then approximately 80 to 100 million barrels of oil (assuming a delivered cost of $20 per barrel) could be added over the next 4 years. In addition, in the event that the stored oil is sold during a crisis, the budgetary receipts would very likely more than offset the cost of the initial purchases. (See pp. 39-40.)

GAO recognizes that oil tax incentives could provide other benefits in addition to petroleum production. Incentives would increase petroleum industry employment and exploration and development capacity, for example. The incentives would also be an economic stimulus to certain portions of the economy. Proponents of additional tax incentives also suggest other arguments for them, including the risk associated with exploration and the favorable tax treatment of certain investments (such as research) in other industries. (See pp. 41-49.)

GAO is concerned, however, with the effectiveness of the provisions in terms of increasing long-term energy security. Reduced taxes for the petroleum industry would require higher taxes on other activities, increased federal debt, or reduced federal spending. In addition, the increased exploitation of U.S. reserves during a period of relatively low oil prices that could be encouraged by incentives may be a security disadvantage. (See pp. 71-73.)

Marginal Effective Tax Rates on U.S. Petroleum Investments Are Already Relatively Low

All of the proposed incentives would reduce effective tax rates on petroleum production. However, analyses by GAO, the Congressional Research Service, and others estimate that the marginal effective federal corporate tax rates—i.e., the tax rates on genuinely incremental investments—for domestic petroleum production are already among the lowest for a major industry, due to the effects of existing tax incentives. (See pp. 51-59.) These analyses estimate marginal effective rates on petroleum production investments to be about half of the statutory rate of 34 percent for integrated producers (i.e., producers with significant refining or retail activity). Marginal effective rates can be near zero for independent (i.e., nonintegrated) producers eligible for percentage depletion, a favorable tax treatment for depletable costs. These relatively low marginal rates already provide incentives to make petroleum production investments that have pretax returns below those of investments in other industries—i.e., relatively inefficient investments. Some petroleum production investments face negative marginal effective rates. This means that such investments are actually more profitable after taxes than before taxes because they help reduce taxes on other income.

The low marginal effective tax rates on petroleum investments arise largely due to the tax treatment of intangible drilling costs. This treatment can allow most drilling costs to be deducted from taxable income immediately, rather than being depreciated over time as are most other business investments. Independent producers face lower effective tax rates than integrated producers because they can be eligible for more favorable treatment of both intangible drilling costs and depletion allowances. (See pp. 21-27 and 54-59.)

Some of the proposed tax incentives would add to the existing favorable treatment of certain types of related petroleum production investments (e.g., drilling over geological and geophysical work) or certain categories of producers (e.g., independent over integrated firms). However, other proposals, such as ones affecting geological and geophysical work or depreciable equipment used in enhanced oil recovery, could provide more even treatment of activities within the industry. (See pp. 59-60.) Proposals providing more even treatment may result both in more cost-effective uses of federal revenue and in more efficient private investment than proposals aimed at activities already subject to low effective tax rates.

Investment Abroad Driven Largely by Factors Other Than Taxes

Petroleum producers are making investments abroad, rather than in the United States, largely because the decline in the price of oil combined with generally favorable foreign geologic characteristics, including lower finding and development costs, has made foreign petroleum production investment relatively more attractive than U.S. investment. The proposed tax incentives are not likely to spur substantial new production in the United States that would otherwise be undertaken in foreign countries.

Petroleum producers select regions and countries for exploration and development on the basis of overall after-tax financial returns, which reflect finding and production costs as well as taxation. In general, U.S. petroleum producers face higher average effective income taxes on their foreign production earnings than on their domestic production earnings. (See pp. 62-68.) Some foreign countries, though, have eased their tax or royalty treatment of petroleum production in response to lower petroleum prices. These changes could lead to low marginal effective tax rates on new investments in some countries, and hence provide additional incentives for investing abroad. (See pp. 68-69 and 94-97.)

Matters for Congressional Consideration

Before approving additional tax incentives for petroleum investments, Congress should weigh carefully their costs and benefits. Given the expected federal revenue losses, GAO believes that providing additional tax incentives is not the most effective method of providing significant increases in U.S. energy security. In addition, where the incentives benefit types of activities and classes of producers that are already relatively favored by the tax code, they will tend to encourage relatively inefficient investments.

Agency Comments

DOE and the Department of the Treasury provided comments on a draft of this report. These comments and GAO's detailed evaluation of them are included in appendixes III and IV and are considered in the report where appropriate.

DOE stated that it disagreed with major findings of the report and with GAO's overall conclusion that additional tax incentives are of questionable merit. DOE does not believe that extractive industries should face the same type of capital recovery for tax purposes as other industries or that the petroleum industry currently receives favorable tax treatment. DOE also does not accept the marginal effective tax rate analyses presented. In addition, DOE believes that the U.S. tax system has been an important factor encouraging petroleum production investments abroad. Finally, DOE had criticisms of the report's discussions of specific tax incentives and the Strategic Petroleum Reserve.

GAO disagrees with DOE and believes that all of the report's findings and conclusions are well supported. GAO's reasons for disagreeing with DOE are discussed in detail in appendix III and in appropriate chapters of the report.

Treasury stated that tax incentives for the domestic petroleum industry are an essential part of the administration's energy security policy. Treasury also believes that an approach that includes filling the Strategic Petroleum Reserve, encouraging the development of alternative energy technologies, promoting energy conservation, and increasing tax incentives for the petroleum industry is the best means of increasing energy security.

Treasury's comments largely restate the administration's proposals for additional tax incentives and its view that these proposals are warranted.

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Abbreviations

AMT	Alternative minimum tax
API	American Petroleum Institute
CBO	Congressional Budget Office
COE	Crude oil equivalents
CRS	Congressional Research Service
DOE	Department of Energy
EIA	Energy Information Administration
EOR	Enhanced oil recovery
G&G	Geological and geophysical
IDC	Intangible drilling cost
IRS	Internal Revenue Service
JCT	Joint Committee on Taxation
OPEC	Organization of Petroleum Exporting Countries
R&D	Research and development
SPR	Strategic Petroleum Reserve

Introduction

Declining domestic petroleum production and increasing petroleum imports have led to administration, congressional, petroleum industry, and other proposals for the adoption of a range of tax incentives for petroleum exploration, development, and production. To assist in the evaluation of these incentives, we were asked to examine the impacts of these proposals on (1) domestic petroleum production and federal revenues, (2) the federal taxation of petroleum extraction relative to other industries, and (3) the comparative U.S. and foreign tax treatment and economic attractiveness of petroleum investments.

The U.S. Petroleum Production Industry

Over the period 1970 to 1988, U.S. domestic oil and natural gas production and reserves declined despite an overall rise in oil and gas prices. Although drilling activity historically has been clearly responsive to price changes, production appears to be much less responsive. For example, by 1981 oil and natural gas prices were more than three times their 1970 level, yet domestic oil and gas production and reserves both declined.[1] If oil and natural gas production in the future reflects this general pattern of limited responsiveness to prices, then sizeable tax incentives would be required to significantly offset or reverse the trend of declining production.

Figures 1.1 through 1.6 provide an overview of petroleum industry trends over the period 1970 to 1988. Figures 1.1, 1.2, and 1.3 show that production and reserves of oil and natural gas have generally declined. Oil production in the lower 48 states declined almost every year over this period. However, it was offset in the latter half of the period by increases in Alaskan oil production. Production from stripper wells—wells that produce no more than 10 barrels per day—remained essentially constant from 1970 through 1988.[2] Prices increased rapidly in the late 1970s and early 1980s—even after adjustment for inflation and the estimated windfall profit taxes due on oil production—but have since declined (see fig. 1.4).[3] Inflation-adjusted 1989 wellhead oil prices were about 66 percent greater than deflated 1970 prices, however. Figure 1.5

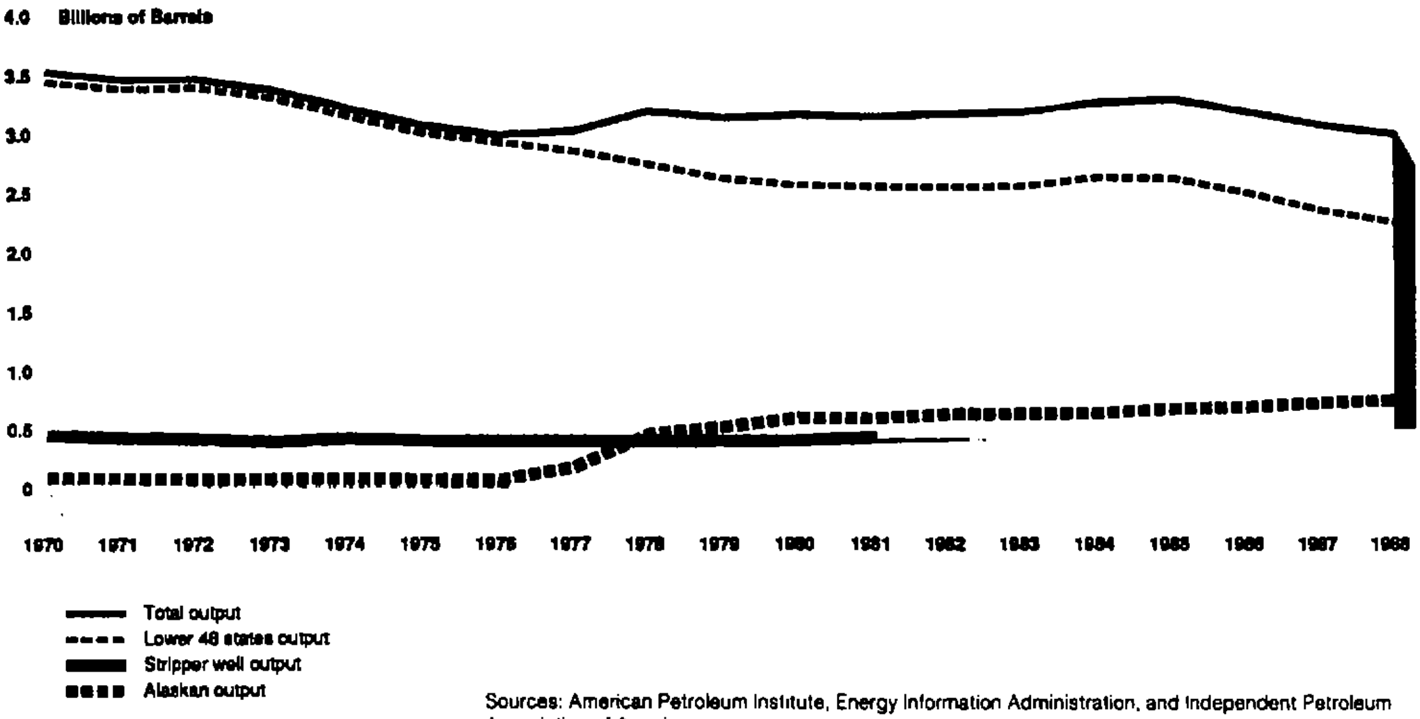
[1]This price increase is net of adjustments for inflation and the crude oil windfall profit tax—an important federal tax upon petroleum production in the early 1980s that was repealed in 1988. Without these adjustments the price increase would be substantially larger.

[2]Reported stripper well output is entirely in the lower 48 states, and is also included in the output levels for this region in figure 1.1.

[3]The oil prices in figure 1.4 reflect average U.S. wellhead prices (i.e., prices before transportation costs) in constant (1988) dollars, as deflated by the GNP deflator. We estimated average prices net of windfall profit taxes using Internal Revenue Service data in order to reflect that a portion of the price increase was captured by this tax.

shows that the patterns of total oil and gas wells drilled and geophysical crew activity were similar to the patterns of prices over the period 1970 to 1988.[4] A comparison with figures 1.1 through 1.3 suggests, however, that these activities did not lead to corresponding increases in levels of production or reserves.[5] Finally, figure 1.6 shows the increase in imports that has occurred since 1985. Currently, imports represent about half of U.S. consumption.

Figure 1.1: U.S. Oil Production, 1970-1988

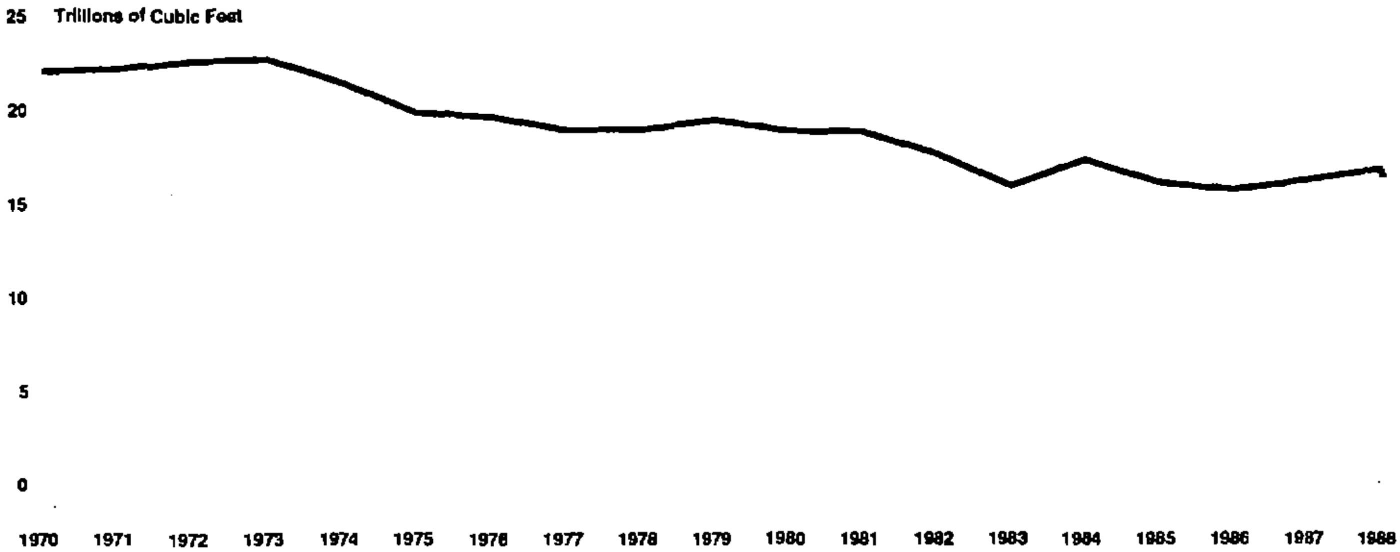


Sources: American Petroleum Institute, Energy Information Administration, and Independent Petroleum Association of America.

[4]Geophysical crew activity involves survey, seismic, and related work for the location of petroleum properties.

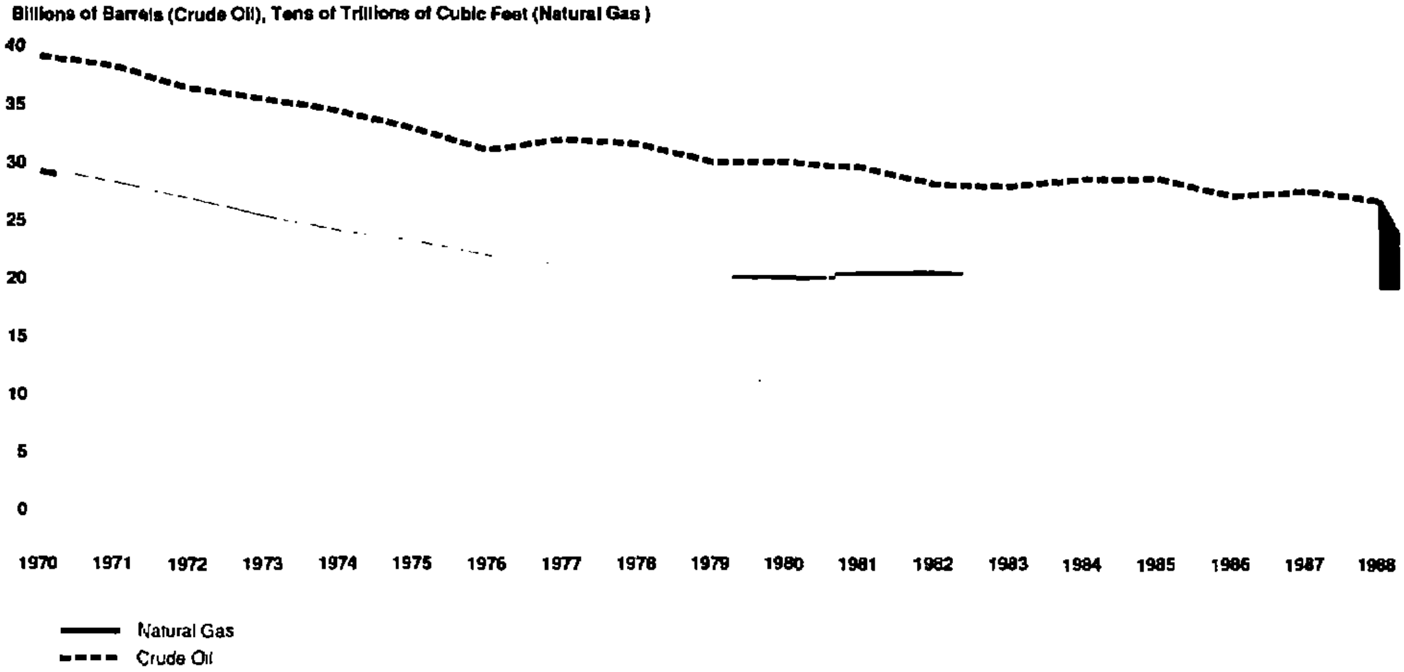
[5]Additions to crude oil reserves—as measured by revisions, extensions, and discoveries—can vary significantly from year to year. A 3-year moving average (or similar measure) of these additions, however, does indicate a general increase from the mid 1970s through the latter 1980s.

Figure 1.2: U.S. Natural Gas Production, 1970-1988



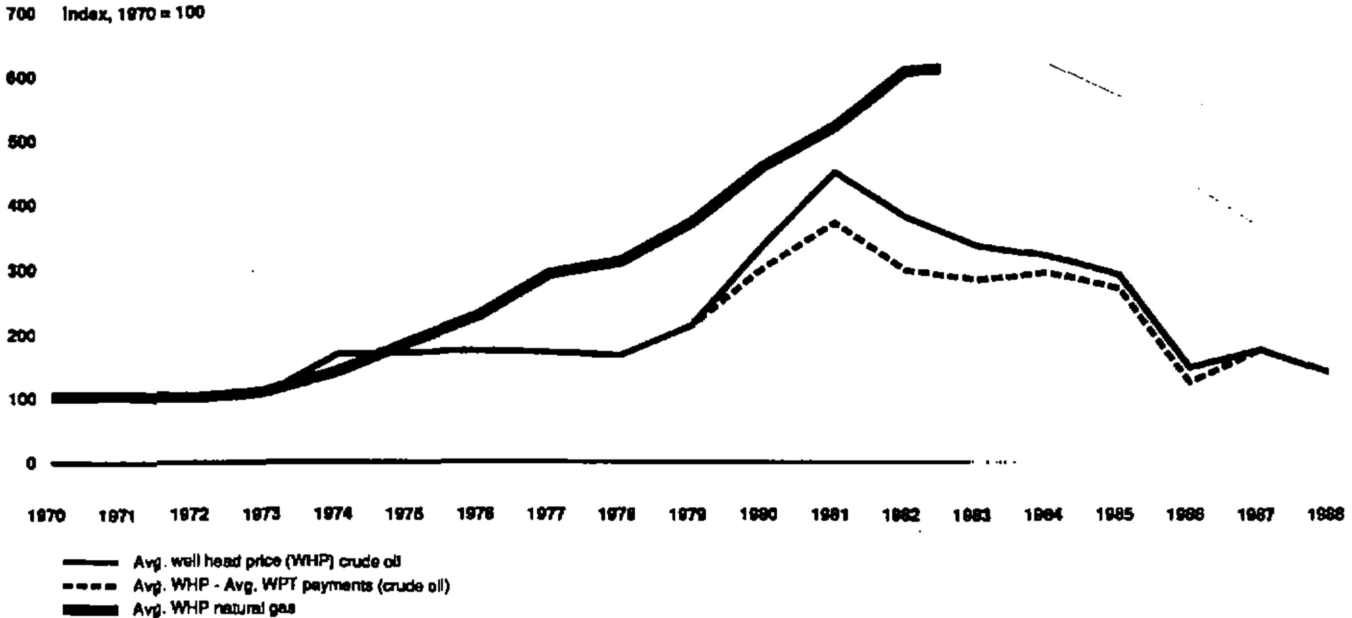
Source: American Petroleum Institute.

Figure 1.3: U.S. Reserves of Crude Oil and Natural Gas, 1970-1988



Source: American Petroleum Institute.

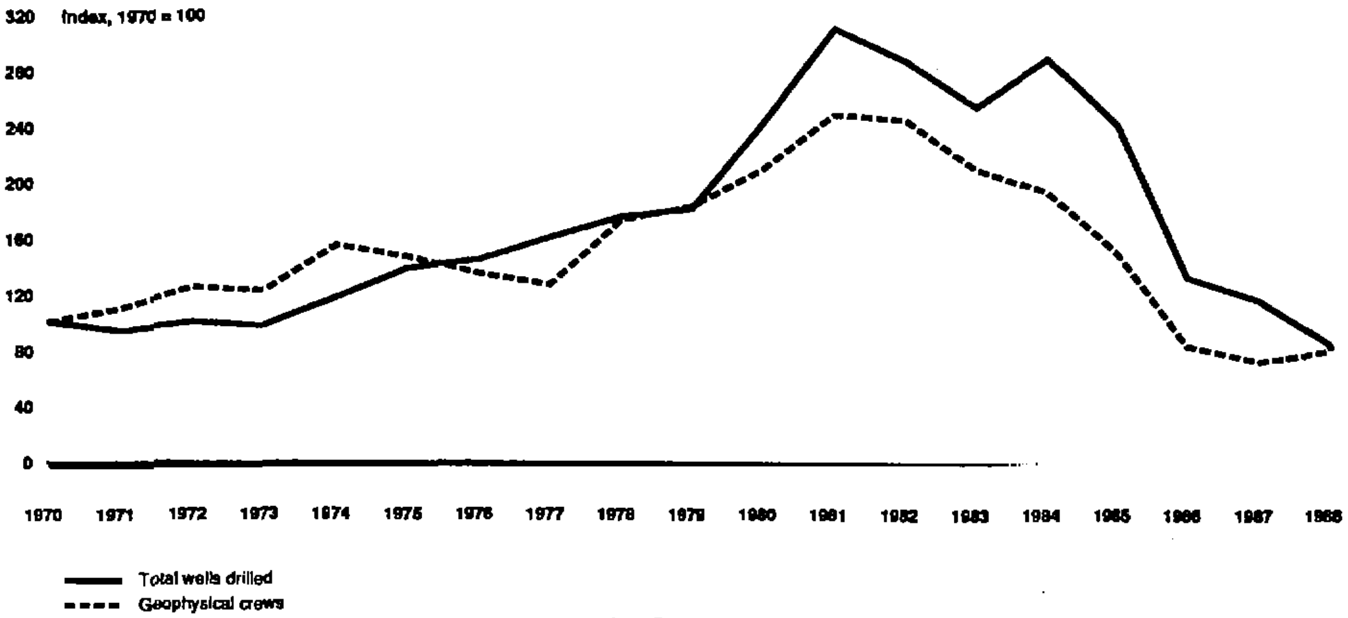
Figure 1.4: U.S. Oil and Natural Gas Prices, 1970-1988



Note: All prices deflated to constant dollars before indexing.

Sources: American Petroleum Institute, Congressional Research Service, DRI/McGraw-Hill, and GAO calculations.

Figure 1.5: U.S. Drilling and Geophysical Crew Activity, 1970-1988



Sources: American Petroleum Institute, Society of Exploration Geologists, and GAO calculations.

Figure 1.6: U.S. Petroleum Consumption, Production, and Imports, 1970-1988

Note: Consumption is demand for refined products. Production includes natural gas liquids. Imports include refined products.
Source: American Petroleum Institute

The relationships among oil and natural gas production, prices, and activities illustrated graphically here are also supported by econometric studies of the industry. Generally, these studies show that oil supply is not very responsive to the price of oil but that drilling activity is. The implication of these studies is that the increased activity accompanying higher prices has diminishing returns.

Industry statistics also show differences between the exploration and development activities of integrated firms, which have substantial refining or retail activity, and independent firms, which do not. Based on data reported by the Petroleum Industry Research Foundation, Inc., the group of firms currently represented by the 16 largest integrated oil companies accounted for 55 percent of oil production and 45 percent of natural gas production from 1980 through 1987.[6] Over this period these

[6]The actual number of firms represented by this group has varied over this time period due to mergers and acquisitions.

firms also accounted for 51 percent of additions to domestic oil reserves and 23 percent of additions to natural gas reserves.[7] These firms drilled about 13 percent of the new exploratory and developmental wells from 1980 through 1987. Correspondingly, independent firms historically have drilled about 85 percent of all U.S. wells.[8] On average the large firms' wells yielded more than 3 times the oil and gas reserves as the industry average.[9] Larger companies had higher costs per well, however. Expenditures for geological and geophysical work and for drilling and equipping wells made up 16 percent and 21 percent, respectively, of the exploration costs of the 19 largest firms in 1988, according to the American Petroleum Institute. These expenditure categories accounted for 9 percent and 45 percent of the exploration costs of the rest of the industry. Expenditures on improved recovery of oil accounted for 12 percent of the large firm development costs, as compared to 2 percent for the rest of the industry.

Objectives, Scope, and Methodology

In response to a request from Congressman Philip R. Sharp, Chairman of the Subcommittee on Energy and Power of the House Committee on Energy and Commerce, we examined a series of issues related to the use of tax incentives for petroleum production. Our objectives were to examine (1) the impacts of a range of proposed petroleum tax incentives on petroleum exploration, development, and production and on federal revenues; (2) the relative federal corporate tax burden on investments in petroleum ventures and in other U.S. industries; and (3) the comparative petroleum tax policies of the United States and other nations to determine whether favorable tax treatment was a major cause of increasing investment abroad and declining U.S. production.[10]

[7]These figures reflect additions through exploration, revisions, and improved recovery and are net of substantial downward revisions in Alaskan gas reserve figures that were made from 1985 through 1987 by three of the large firms. These downward revisions were made because of the recognition that these reserves have no economically accessible market at present. According to the Petroleum Industry Research Foundation, if the downward revisions in Alaskan reserves attributable to one of these firms are excluded, the 16 large firms accounted for 57 percent of net additions to combined oil and gas reserves in 1987.

[8]According to the Independent Petroleum Association of America there are currently about 12,000 independent producers of oil and natural gas. These producers range from one-person operations to large corporations.

[9]About 45 percent of large firms' exploratory wells were productive, as compared to about 25 percent for the rest of the industry over the period 1980 through 1987. The large firms experienced a 92 percent success rate for developmental wells as compared to a 77-percent rate for the rest of the industry.

[10]Because oil production is dominated by corporate producers, our work focused on corporate tax policy.

The tax incentives considered in this report include modifications to depletion rules, major increases in depletion allowances, more favorable treatment of various exploration and development expenses, and tax credits for enhanced oil recovery (which involves the use of certain injectants and advanced techniques to increase oil production) and stripper well costs (see Glossary).[11] The provisions considered include those proposed by the Bush administration in the 1991 budget submission; those examined by the Department of Energy (DOE) in the 1987 report, Energy Security; and those considered by the Joint Committee on Taxation (JCT) in 1987.[12] While additional provisions have been advanced in various legislative proposals, this set of provisions spans a wide variety of alternatives and therefore enables coverage of representative features of various other provisions. The report focuses only on the production component of the petroleum industry, as opposed to the transportation, refining, and marketing components of the industry.

To accomplish the first objective we reviewed production and revenue estimates presented by DOE in Energy Security.[13] The DOE estimates were the most prominent estimates of production effects of alternative tax incentives at the time of our review. To evaluate these estimates we interviewed present and former DOE staff who participated in this work. We also reviewed work documents that DOE made available. We did not, however, examine the revenue-estimating methodology of the Department of the Treasury, which contributed to DOE's report. In addition, we present revenue estimates for the incentives proposed by the Bush administration for 1991 and estimates for a series of proposals examined by the JCT in May 1987, which was the latest publicly available set of JCT analyses at the time of our review. We also report DOE production estimates released in October 1989 for two of the Bush administration proposals. We did not examine the methodology underlying these estimates. Finally, to develop further insights into the cost per barrel of alternative petroleum tax incentives, we developed a relatively simple economic model of the responsiveness of petroleum supply to tax changes.

[11] These modifications are termed tax incentives in this report because they would increase the incentive for various petroleum activities. In other studies these provisions are also termed tax preferences or tax expenditures, which highlights the fact that the modifications would also imply relatively favorable tax treatment and expected tax revenue losses.

[12] Our analysis initially focused on the administration's 1990 budget proposals. The 1991 proposals are the same, however. The JCT analysis is reprinted in the June 4, 1987, Daily Report for Executives.

[13] Selected references are listed in the Bibliography.

To accomplish the second objective we reviewed government, interest group, industry, and academic studies of both average and marginal effective tax rates. As part of this work we asked the Congressional Research Service (CRS) to provide us with a series of estimates of marginal effective tax rates. While we provided some of the assumptions to be used for these calculations, we did not examine the database or computer program used in the calculations.

We analyzed international tax incentives on the basis of discussions with experts and a review of the literature on taxation in approximately 12 countries with potential petroleum exploration interest to U.S. investors. We selected the countries based on their relevance to the petroleum industry and discussions with congressional staff. The countries include Argentina, Australia, Brazil, Colombia, Canada, Denmark, Ecuador, Indonesia, the Netherlands, Norway, the United Kingdom, and the United States.

In addition to involving efficiency issues such as the cost-effectiveness of alternative policies and the tax burdens on alternative investments, decisions on petroleum tax incentives involve considerations of the national security, distributional, and environmental effects of these incentives versus alternative energy policies. However, these last three issues have been only partly addressed because a full treatment was beyond our scope.

We discussed aspects of all of the above areas with experts from leading accounting and consulting firms, including Arthur Andersen, ICF Resources Inc., Price Waterhouse, and The WEFA Group; firms and industry groups, including the American Gas Association, the American Petroleum Institute (API), Amoco Inc., the Independent Petroleum Association of America, and the Petroleum Industry Research Foundation, Inc.; a public interest group, Citizens for Tax Justice; research organizations, including the Institute for International Economics, Resources for the Future, and Tax Analysts; and universities, including Carnegie-Mellon University, Stanford University, the University of Maryland, the University of Pennsylvania, the University of Texas, and the University of Virginia. We also discussed these issues with experts at the Congressional Budget Office (CBO), CRS, DOE, including the Energy Information Administration (EIA), and Treasury, including the Internal Revenue Service (IRS). In addition, a draft of this report was reviewed by experts at CBO and CRS and their comments were incorporated where appropriate. Finally, we also briefed industry representatives on the contents of a draft of this report.

This review was done from July 1988 through October 1989 in Washington, DC, according to generally accepted government auditing standards.

Agency Comments

DOE and Treasury provided written comments on a draft of this report. Relevant portions of their comments are discussed at the ends of chapters 2 through 6, and changes have been incorporated into the report where appropriate. Appendixes III and IV present the DOE and Treasury comments in their entirety along with our detailed analyses of them.

Current and Proposed Tax Treatment

Federal corporate income taxation of petroleum investments is complex, with special provisions in the tax code affecting the different types of costs associated with these investments. The administration and recent legislative initiatives have proposed a range of additional tax incentives—including tax credits and faster and larger deductions of certain costs for tax purposes—that would modify these provisions.

Under federal income tax law, deductions are generally allowed for the depreciation of investment costs over the period that the investment produces income—i.e., the economic life of the investment. Some investment costs, however, receive favorable tax treatment under depreciation rules that allow faster write-off (i.e., deductions) than the actual rate of economic depreciation. The fastest possible write-off, called expensing, allows a taxpayer to deduct the costs in the taxable year incurred. Most of the current and proposed petroleum tax provisions involve the write-off treatment allowed for particular types of investments by certain categories of producers.

Current Federal Corporate Taxation of Petroleum Investments

Current and proposed petroleum tax provisions distinguish among the following types of costs:

- depletable costs, which reflect the cost of the petroleum deposit, including both the up-front payments paid to landowners for the right to explore for and produce petroleum (bonuses) and the costs of geological and geophysical work;
- intangible drilling costs, which are the labor, energy, road-building, and other costs of site preparation and drilling, except for the cost of equipment and structures owned by the producer;
- depreciable costs, which reflect the use of equipment and structures owned by the producer to find and produce petroleum; and
- operating costs, including pumping expenses, royalties (payments to landowners that are determined by production levels or value), and state severance taxes (taxes assessed by states, based on production value or volume).

In addition, a number of the alternative minimum tax provisions of the federal corporate income tax can affect petroleum investment.

Table 2.1 summarizes the basic tax treatment of these costs under current law. This treatment and a variety of proposed modifications to it are explained in detail in the remainder of this chapter.

Table 2.1: Summary of Tax Treatment of Petroleum Exploration, Development, and Production Costs

		Tax treatment	
Type of cost	**Examples**	**Independent firms**	**Integrated firms**
Depletable	Cost of property, including bonus (payments to landowners) and geological and geophysical work	Percentage depletion (15 percent of gross income) allowed on first 1,000 barrels of average daily production, subject to limitations (transfer rule, 50 percent net income limit, 65 percent overall taxable income limit, alternative minimum tax (AMT) recovery of deductions in excess of original basis) Same treatment as integrated firms on remainder of production.	Cost depletion (deduction of share of depletable costs equal to fraction of remaining reserves pumped and sold in the year). Any remaining depletable costs can be fully deducted upon abandonment
Intangible drilling costs (IDCs)	Labor, site preparation, and drilling services involved in drilling exploratory and developmental wells	Can be expensed (subject to AMT recapture of excess IDCs on successful wells)	Unsuccessful wells can be expensed. Successful wells can be 70-percent expensed, with remaining 30 percent deducted straight-line over 5 years (subject to AMT recapture of excess IDCs on successful wells).
Depreciable	Equipment and structures used to find, pump, or store petroleum	Depreciated according to schedules	Depreciated according to schedules
Operating	Royalties; labor, electricity, or fuel used to pump, state severance taxes.	Expensed	Expensed.

Note: See text and glossary for additional details

Depletable Costs

Costs of the petroleum property, including bonus and geological and geophysical (G&G) expenses, are considered depletable costs. Producers are allowed to recover these costs over a period of time to reflect the depletion of their economic interests in petroleum reserves.

There are two forms of depletion allowances. The first, percentage depletion, may be elected only by independent producers—producers without significant retail or refining activity—on the first 1,000 barrels of average daily production. Integrated firms—firms that have retail sales of more than $5 million on an annual basis or refine more than 50,000 barrels on any given day during the tax year—must use the second form of depletion, cost depletion.[1]

Percentage depletion is based on a percentage of the value of a property's output. Currently, independent producers are entitled to a deduction of 15 percent of the gross income from a property for up to 1,000

[1]This report considers only the tax treatment of petroleum producers, as opposed to that of recipients of bonus and royalty payments (i.e., royalty owners). Royalty owners may also be eligible for depletion allowances on certain income.

barrels of average daily production. Percentage depletion deductions do not directly reflect the property's cost or remaining basis (that is, the portion of the original investment not already recovered through depletion deductions). Total percentage depletion deductions may, for example, exceed the original cost of the property. Percentage depletion is subject to certain limitations, however, as discussed in the sections on the alternative minimum tax (AMT) and on the proposed modifications to depletion rules.[2] The current depletion rate of 15 percent has been in effect since 1984 and represents the culmination of a series of reductions from the rate of 27.5 percent that was in effect from 1926 through 1969. Before 1975, both independent and integrated firms could claim percentage depletion on an unlimited amount of production.

Under the second depletion method, cost depletion, taxpayers deduct the share of their remaining cost basis that corresponds to the share of reserves depleted during the tax year. Thus, if producers pay lease bonus and G&G costs totaling $100,000, and 10 percent of reserves were pumped and sold in the first year, then the producer could claim cost depletion of $10,000. The following year, the remaining basis would be $90,000 ($100,000-$10,000); if 10 percent of remaining reserves were also pumped in this year, the allowance would be $9,000. Total cost depletion allowances cannot exceed the cost of the property and G&G work.[3]

Although independent producers often use percentage depletion, they also at times use cost depletion. For example, only cost depletion can be used on production over the 1,000 barrel per day limit for percentage depletion. In addition, the law requires use of the depletion method that results in the greater allowance. In the early years of production, for example, cost depletion deductions may exceed allowable percentage depletion deductions. Firms may, therefore, use cost depletion initially and then switch to percentage depletion in later years. Finally, when unproductive or unprofitable properties are abandoned, firms may deduct the remaining basis in the property.[4]

[2]For example, allowable percentage depletion is limited to the lesser of 65 percent of overall taxable income before the depletion allowance and certain other deductions or 50 percent of taxable income from the property.

[3]Where it is ascertained that the remaining recoverable reserves are materially greater or less than the prior estimate, the estimate must be revised.

[4]The remaining basis is defined as the initial costs minus the accumulated depletion, if any.

While some of the tax proposals discussed in this report would increase the ability of taxpayers to claim percentage depletion, repeal of the percentage depletion allowance is a revenue-raising option that would eliminate a tax preference. CBO reported in February 1990 that eliminating percentage depletion allowances for oil and gas as well as hard minerals would increase federal revenues by $3.8 billion over the period 1991 through 1995. DOE, in its comments on this report, estimates that the oil and gas component of this total would be about $1.9 billion or less.

Intangible Drilling Costs

Intangible drilling costs (IDCs) are the expenditures for labor, fuel, services, and nonsalvageable materials associated with preparing sites and drilling wells. All of these expenditures can be deducted from income for tax purposes by independent producers in the year they are incurred, i.e., expensed. Integrated firms may expense all IDCs incurred on unproductive wells and 70 percent of IDCs incurred on productive wells; the remaining 30 percent can be deducted using straight-line depreciation over 5 years.[5]

Although outlays on IDCs themselves have no direct salvage value (in contrast to drilling equipment that can be used elsewhere), if they lead to finding or development of petroleum reserves, they have contributed to an investment with value. Thus, they are analogous to the expenses for labor, energy, and other nonsalvageable items that are used in constructing a building that then has value that depreciates over time.[6] Although the percentage of costs represented by IDCs varies with the type of oil investment, DOE reports that IDCs usually represent 75 to 85 percent of total drilling expenditures.

The ability to expense IDCs (or deduct them from income over a shorter period than the investment's productive life) raises the after-tax present value of investments in IDCs over alternative investments that are allowed only more gradual depreciation deductions.[7] IDCs contribute to an asset with long-term value—productive oil wells. The fact that they are largely allowed to be expensed is widely viewed as a tax preference when contrasted with the treatment of most business investments, which are depreciated for tax purposes more in line with their actual

[5]Under straight-line depreciation, an equal portion of costs is deducted in each year.

[6]For tax purposes, for example, buildings and other assets that are constructed by their owners—like those assets that are purchased—are depreciated.

[7]For example, an investor would generally prefer to have a deduction equal to $100 of income today rather than a deduction of $10 per year in each of the next 10 years.

economic depreciation. The expensing of IDCs incurred on successful wells, for example, is one of the tax expenditures reflected in the administration's budget and in the Joint Committee on Taxation (JCT) report on tax expenditures.[8]

A number of tax experts have also noted that expensing of IDCs on unsuccessful wells is also a form of tax preference and that, in principle, these costs should also be depreciated over time. This view holds that the expenses for unsuccessful wells and properties can be viewed as part of the cost of developing successful properties that have value that depreciates gradually.[9]

Oil industry representatives, in contrast, said that they believe the expensing of IDCs associated with both successful and unsuccessful wells is appropriate, as the inputs (e.g., labor and services) are not long-lived. Some other types of intangible investments—such as advertising and research and experimentation—are also expensed or eligible for relatively favorable tax treatment, even though they also may have value that depreciates gradually.

While some of the proposals discussed in this report would make the treatment of IDCs more generous—for example, by also allowing a tax credit for a portion of them—restricting IDC tax treatment to more gradual deductions based on actual depletion of a property's reserves would reduce or eliminate a tax preference while also raising revenue. CBO has estimated that repealing the expensing of IDCs for successful wells as well as comparable development costs for hard mineral producers would raise about $5.5 billion over the period 1991 through 1995.[10] To a large extent the federal revenue gain from repealing the expensing of IDCs would result from an acceleration of tax payments.

Depreciable Costs

Investments in equipment used in petroleum production, such as pumps, tanks, and pipelines, are depreciated according to schedules, just as are most investments in other industries. Under current law, most of this

[8]Tax expenditures are defined as deviations from a tax system that generally treats all income sources alike.

[9]The analyses of marginal effective tax rates discussed in chapter 4, for example, in effect view the actual depreciation rate for IDCs for unsuccessful wells as being the same as for successful wells.

[10]DOE, in its comments on this report, estimates a lower figure of $3 billion for oil and gas IDCs alone. However, we do not believe its methodology for making this estimate is generally appropriate, as discussed in appendix III.

type of equipment is depreciated under the Modified Accelerated Cost Recovery System based on an accounting procedure termed the 7-year double declining balance method. This method depreciates the equipment over 7 years, with the deductions being relatively greater in the early years. This schedule is approximately consistent with economic rates of depreciation for the equipment, given reasonable economic assumptions.[11]

Operating Costs

Operating costs include the costs of energy to operate pumps, royalties paid to landowners, and severance (and other) taxes paid to state and local governments. All of these costs are deductible from income for tax purposes in the year they arise. This approach is consistent with the treatment of business expenses and taxes in other industries. In general, proposed tax incentives would not modify this treatment.

Alternative Minimum Tax Provisions

In addition to being liable for income taxes computed on a regular basis, taxpayers may also be liable for an additional amount that reflects the alternative minimum tax (AMT). The AMT is calculated by first applying a reduced tax rate—20 and 21 percent for corporate and noncorporate taxpayers, respectively—to a larger tax base than the regular tax.[12] This process results in determination of the tentative minimum tax. If the tentative minimum tax is greater than the regular income tax, then the difference between these two values is the AMT.

The tax preference items that are added back into the tax base for purposes of calculating the AMT include some specifically related to petroleum production. First, percentage depletion amounts that exceed the adjusted basis for the property in that year are a tax preference item.[13] Second, excess IDCs—a measure of the difference between allowable IDC deductions for tax purposes and a slower method of recovery—are taxable to the extent that they exceed 65 percent of net oil and gas income. Third, depreciation deductions for equipment and structures that exceed

[11]These assumptions involve rates of inflation and investors' required rates of return, which are used to calculate the present value of depreciation deductions for tax purposes.

[12]This base reflects regular taxable income (1) increased by certain tax preference items that are not subject to the regular tax and (2) with some items adjusted in computing the AMT so that favorable regular tax treatment is reduced.

[13]Thus, for example, if total depletion deductions to date exceed the cost of a property and G&G work, then any additional percentage depletion deductions are added back to taxable income for purposes of the AMT.

depreciation based on a slower recovery schedule are also a tax preference under the AMT. Finally, to address the concern that firms reporting substantial earnings pay little or no income tax, another provision adds to the AMT tax base a portion of the difference between a measure of earnings reported for financial statement purposes and alternative minimum taxable income.[14]

The first of these items, the percentage depletion preference, is, by definition, only relevant for independent petroleum producers. The second item, the excess IDC preference, is relevant both for integrated and independent petroleum producers. The depreciation preference and the earnings adjustments affect all types of industries. Finally, while AMT payments raise tax payments for some taxpayers, they generally can be used as credits in future years against regular taxes.[15]

Alternative Tax Incentive Proposals

The tax incentives considered in this report include modifications to depletion rules, major increases in depletion allowances, more favorable treatment of various exploration and development expenses, and tax credits for enhanced oil recovery and stripper well costs. The provisions considered include those proposed by the Bush administration in the 1991 budget submission; those examined by DOE in the 1987 report, Energy Security; and those considered by the JCT in 1987. While additional provisions have been advanced in various legislative proposals, this set of provisions spans a wide variety of alternatives and, therefore, enables coverage of representative features of various other provisions. This section provides a description of the basic features of these provisions. Additional properties of these incentives, including their estimated effects on production and federal revenue, are discussed in chapter 3.

Modifications to Depletion Rules

The Bush administration has proposed two modifications to rules that limit the ability of producers to claim percentage depletion allowances on some properties. As discussed earlier, only independent producers are eligible to claim percentage depletion, and even these producers may not claim it on more than 1,000 barrels of average daily production.

[14]For years beginning after 1989, alternative minimum taxable income is increased by 75 percent of the amount by which an adjusted measure of current earnings exceeds it.

[15]One exception, however, is that for individual taxpayers AMT payments due to depletion preferences may not be used to offset future regular income tax payments.

One proposed modification is repeal of the transfer rule, which generally prohibits use of percentage depletion on acquired properties with proven petroleum potential. Thus, on such properties independents must use cost depletion and do not have the ability to use percentage depletion, which can be more generous. Repeal of the transfer rule would allow independents to claim percentage depletion on production from these transferred properties, just as they claim such depletion on production from properties they acquire that are of unproven potential.

The second proposed modification would modify the "net income limit," which under current law limits the amount of percentage depletion that can be claimed to 50 percent of the net income from a property. The administration has proposed raising this limit to 100 percent of the property's net income. Thus, if in a year a property produces $100 worth of oil and has $60 worth of costs, the net income would be $40. Under current law, an independent producer could claim a $15 depletion deduction on this property, based on the full 15 percent depletion rate. On the other hand, if revenues were $100 but costs were $80, the net income would be only $20. In this case the producer could not claim the full $15 of depletion but would be constrained by the net income limit to claim only $10 of percentage depletion (50 percent of net income). The 50 percent net income limit ensures that at least half of the net income from a property is subject to taxation. Raising the limit to 100 percent of net income would allow all of a property's net income to be offset by percentage depletion allowances. Eliminating the limit completely would allow percentage depletion deductions from a petroleum investment to partially offset other income.[16]

Major Increases in Depletion Allowances

DOE investigated two proposals that would significantly expand the percentage depletion allowance. One of these would raise the depletion rate for independent producers from the current 15-percent level to 27.5 percent of the value of production. The second proposal would allow all producers to claim percentage depletion at a 27.5-percent rate on all new production. Neither of these proposals has been made by the Bush administration, though they have appeared in various forms in congressional proposals.

[16]Under current law allowable percentage depletion deductions are also limited to 65 percent of overall taxable income. A proposal considered by the JCT in 1987 would repeal this provision, too.

More Favorable Treatment of Exploration and Development Expenses

A number of potential incentives would lead to more favorable treatment of various exploration and development expenses. The Bush administration has proposed two incentives that would lead to more favorable treatment of IDCs incurred in exploratory drilling. The first proposal applies to the regular tax for all producers, while the second applies to the AMT for independent producers alone. Provisions examined by DOE in Energy Security and by the JCT include tax credits for exploration and development investments and more favorable treatment of G&G expenses.[17]

The first Bush administration proposal would provide a tax credit for IDCs incurred for exploratory drilling. The credit proposed by the administration would be 10 percent of the first $10 million of investments and 5 percent for additional investments; phase-out of the proposed credit would begin if average domestic wellhead oil prices are at least $21 per barrel for a year. A proposal considered by DOE would provide a 5 percent investment tax credit for exploration and development costs, including G&G costs, IDCs, and lease equipment and structures costs.[18] Finally, the JCT examined a provision with a much larger credit (50 percent) for wildcat IDCs. Wildcat IDCs appear to be similar to the administration's notion of exploratory IDCs.[19]

An exploration and development credit shares some similarities with the investment tax credit that existed for qualifying investments in all sectors before its repeal by the Tax Reform Act of 1986. Although the Tax Reform Act eliminated the investment tax credit for all sectors and investment classes, a portion of research and experimentation expenses can be eligible for a credit. In addition, the investment tax credit was not generally applicable to IDCs or G&G expenses.

[17] We consider proposed modifications to G&G cost treatment here because they relate to a form of exploration. Because G&G expenses are currently depletable costs, however, these modifications could be viewed as changes in depletion rules.

[18] Cash bonuses paid to landowners for the right to explore and develop petroleum are also costs related to exploration and development, although they might be excluded from receipt of a tax credit. If they are not excluded, market forces may lead the tax credit to be largely passed through to landowners in the form of higher bonus payments. As discussed in chapter 3, other incentives may also be, at least in part, passed through to landowners.

[19] Wildcat IDCs in the provision considered by the JCT are defined as IDCs associated with exploratory wells at least 2 miles from any producing oil or gas well and not within a proven petroleum field. The administration proposal addressing exploratory well IDCs may not be as restrictive.

The second Bush administration proposal would relax the AMT provision that currently recaptures favorable treatment of IDCs incurred in exploratory drilling activities. Currently, the expensing of IDCs is treated as a tax preference for purposes of the AMT.[20]

The final set of proposals would lower the effective tax rate on G&G investments. Under current law G&G expenses are recovered by cost or percentage depletion, depending on whether the producer is an integrated or eligible independent firm.[21] Provisions considered by DOE in Energy Security and by the JCT in 1987 would allow expensing of G&G costs in the same manner as IDCs. DOE also examined a possible tax credit for G&G costs. These proposals have not been made by the Bush administration, however.

Enhanced Oil Recovery and Stripper Well Provisions

Incentives have also been suggested that would encourage enhanced oil recovery (EOR) or that would benefit stripper wells.[22] The Bush administration has proposed a 10 percent tax credit for capital expenditures on new tertiary EOR projects. Tertiary EOR involves use of chemicals, gases, or heat to extract oil. The administration proposal would start phasing out the credit if the average U.S. wellhead price of oil is at least $21 per barrel for a year. The JCT in 1987 considered a 10 percent tax credit for qualified research and experimentation in EOR and a 10-percent credit for certain investments used in stripper well production. A tax credit would lower the after-tax cost of qualifying investments in these activities. The EOR credit considered by the JCT would not subsidize methods used in commercial application, however.

[20]Specifically, to the extent that "excess IDCs" exceed 65 percent of net oil and gas income, they become income subject to the AMT, if the producer is subject to this tax in addition to the regular corporate tax. Excess IDCs are defined as the difference between the amount expensed (plus the amount of IDCs incurred in the tax year which are amortized over 5 years in the case of integrated firms) and the amount that could be deducted based on straight-line recovery over 10 years or another acceptable cost-depletion method. (IDCs incurred on unsuccessful wells are not subject to this AMT provision, however.) The Bush administration budget proposal would eliminate 80 percent of the excess IDCs due to exploratory drilling by independent producers as a tax preference item for the AMT.

[21]When an entire area of a survey is abandoned, G&G costs can be deducted as an ordinary business expense

[22]Stripper wells are defined as wells producing on average no more than 10 barrels a day of oil during any 12-month period.

Agency Comments and Our Evaluation

DOE believes that tax treatment of investments in exhaustible resources should be fundamentally different from that of other industries. DOE also disagreed with the view that the expensing of IDCs on both successful and unsuccessful wells represents a tax preference. DOE believes that because outlays on IDCs have no direct salvage value they should not be compared to outlays on other assets in terms of their tax treatment. Finally, DOE also suggested that the estimated revenue gains we reported for repealing the tax preferences for expensing IDCs incurred on successful wells and for percentage depletion were too high.

We disagree with DOE's view about the proper tax treatment of investments in exhaustible resources. Our view—that percentage depletion allowances and expensing of successful investments to produce petroleum are tax preferences—is widely accepted. Both of these tax preferences are reflected in the tax expenditure analyses of the President's budget and the Joint Committee on Taxation, for example. The view that expensing of unsuccessful wells is, in principle, a tax preference is recognized by some, but not all, experts in taxation. Our report does not take the position that the tax treatment of IDCs should be revised to require capitalization of dry holes. However, we believe the treatment of these costs is relevant to an analysis of potential additional tax incentives for these investments. Lastly, we have clarified that CBO's estimated revenue effects of repealing the percentage depletion allowance (p. 24) and expensing of IDCs incurred on successful wells (p. 25) that we report include the effects of repealing comparable provisions for hard mineral producers. We also have included the revenue estimates reported in DOE's comments.

Treasury's comments largely restated the administration's proposals. In general, Treasury had no significant critical comments on our analysis of basic tax treatment issues.

Production and Tax Revenue Estimates Raise Cost-Effectiveness Concerns

The proposed tax incentives vary significantly in terms of their estimated impacts on petroleum production and federal revenue and in terms of their cost-effectiveness. Although we found that there is uncertainty about the magnitudes of the production, revenue, and cost-effectiveness figures, some generalizations can be made.

DOE analysis suggests that the proposals it examined are expected to have small to modest impacts on domestic petroleum production relative to total U.S. production and consumption. In addition, the cost-effectiveness of petroleum tax incentives is sensitive to the extent to which the provisions affect all production, only new production, or only genuinely incremental production. Other policies, however, such as filling the Strategic Petroleum Reserve (SPR), may be more effective means of increasing energy security.

While the provisions could lead to increases in petroleum industry employment and wages, basic economic principles suggest that in the long run much of the benefit of the provisions is expected to accrue to owners of petroleum reserves. Finally, all of the proposed incentives would decrease the taxation of petroleum investments relative to investments in other industries. Most of the proposals would also maintain or increase relatively favorable treatment for certain types of petroleum investments or producers.

Revenue, Production, and Cost-Effectiveness Estimates

Although there is uncertainty about the magnitudes of production, tax revenue, and cost-effectiveness figures for the proposals, our review suggests that the proposals are unlikely to be a cost-effective approach for significantly increasing U.S. energy security. Current DOE production estimates are available for only two parts of the administration proposal: repeal of the transfer rule and eased AMT treatment of certain IDCs. These estimates imply that future domestic oil production would increase by a total of only about 0.2 to 0.3 percent.[1] On the basis of administration figures, we estimate that these proposed tax incentives could result in federal revenue losses of $3 to $14 for each barrel of additional production stimulated by the incentives.

Table 3.1 reports revenue estimates for the four incentives proposed by the Bush administration. The administration estimates that provisions

[1] Because U.S. oil consumption in the early 1990s is expected to be roughly double domestic production, the estimated effects of tax incentives would be roughly half the magnitudes reported here, if viewed as a percentage of future U.S. consumption instead of production.

modifying depletion rules and treatment of investments in enhanced oil recovery would lead to relatively small revenue losses; provisions affecting exploration and development were expected to lead to larger revenue losses.

Table 3.1: Tax Incentives Proposed in Administration's 1991 Budget

Provisions	Bush administration estimates of average annual revenue loss (million dollars/year)[a]	Oil and natural gas production increase (thousand barrels COE/day)[b]	Oil production increase as percentage of U.S. production in 1993[c]	Estimated revenue loss per barrel of additional output ($/barrel COE)[d]
Modifications to depletion rules				
Eliminate the transfer rule and increase the net income allowance to 100 percent for independent producers and royalty owners	$50 or less	5[e]	0.04[e]	11–14[f]
Exploration and development provisions				
5 and 10 percent tax credits for exploratory intangible drilling costs	300	NA	NA	NA
Eliminate 80 percent of exploratory IDC tax preferences from AMT for independent producers	100	20–35	0.2–0.3	3–6
Enhanced oil recovery provision				
10 percent tax credit for capital expenditures on new tertiary enhanced oil recovery projects	50 or less	NA	NA	NA

[a]Source. Department of the Treasury, February 1989. The 1991 Budget revenue loss estimates for these provisions for their first year are $49 million, $190 million, $79 million, and $17 million, respectively

[b]DOE estimates, October 26, 1989 Crude oil equivalents (COE); not available (NA).

[c]GAO calculations, based on Energy Information Administration (EIA) estimate of 6 59 million barrels per day in 1993 for crude oil (calculation excludes natural gas)

[d]GAO estimates based on administration production and revenue estimates. The estimates of revenue loss per barrel reflect the fact that provisions aimed at new production will have a continuing effect in years after the initial tax break

[e]Production estimate was available only for the transfer rule repeal.

[f]Based on estimated revenue losses for transfer rule repeal alone

DOE estimates of the production impacts for two of the proposals are also reported in table 3.1. DOE estimates that repeal of the transfer rule would lead to an eventual production increase of 5,000 barrels per day of petroleum (including both oil and natural gas), or about 0.04 percent of projected 1993 U.S. oil production.[2] DOE estimates imply that modifying the AMT treatment of excess IDCs for independent firms would lead to an eventual increase in petroleum production of 20,000 to 35,000 barrels per day, or about 0.2 to 0.3 percent of estimated 1993 production.

Table 3.1 also reports our estimates of federal revenue losses per barrel of additional production stimulated by these two provisions based on the reported production and revenue estimates.[3] We estimate that repeal of the transfer rule would cause tax revenue losses of $11 to $14 for each additional barrel of petroleum production stimulated. We estimate that modification of the AMT treatment of excess IDCs would lead to tax revenue losses of $3 to $6 for each additional barrel stimulated, depending on whether output increases are at the high or low end of DOE production estimates.

Table 3.2 presents production, tax revenue, and cost-effectiveness estimates for provisions considered by DOE in Energy Security and the Joint Committee on Taxation (JCT) in 1987.[4] DOE's analysis implies that the provisions with the least impact that it considered—repealing the transfer rule and raising the net income limit—would each increase domestic oil output by about 0.5 percent. DOE estimated that the most significant provisions—involving major increases in depletion allowances or substantial tax credits—would increase oil production by about 3 percent of forecasted output.[5] DOE reported estimated federal revenue losses of less than $50 million per year for the less significant provisions. The more significant provisions have average revenue losses of several hundred million dollars per year. DOE reported that revenue losses from increased depletion for all new production are estimated to grow over time to almost $2 billion per year by 1995.

[2]The production increase would be a smaller fraction of current output. Percentage calculations are for oil production alone and exclude the portion of DOE's estimated production increases accounted for by natural gas.

[3]Cost-effectiveness estimates could not be made for other provisions because production estimates are unavailable.

[4]Although the JCT has considered other proposals more recently, these figures represent the most recent publicly available set as of June 1989.

[5]DOE staff believe that there is some overlap in the analysis of provisions that is not explicitly reported in Energy Security. For example, DOE staff believe that the estimates for increasing the depletion allowance for independents also assume that the transfer rule would be repealed.

Table 3.2: Tax Incentives Examined in 1987 by DOE or the Joint Committee on Taxation

Provision	Average annual tax revenue loss (million dollars/year)	Oil and natural gas production increase by 1992 (thousand barrels COE/day)[d]	Oil production increase as percentage of U.S. production in 1992[d]	Estimated revenue loss per barrel of additional output ($/barrel COE)[h]
Modifications to depletion rules				
Repeal transfer rule	23.4[a]	55	0.4	1
Raise net income limit from 50 percent to 100 percent	47.2[a]	58[e]	0 5	2
Repeal 50-and 65-percent limits for percentage depletion deduction applying to individual property and overall taxable income	40[b]	NA	NA	NA
Major increases in depletion allowances				
Raise depletion rate from 15 percent to 27 5 percent for independents	680[a]	280	2.2	5–7
Allow 27 5 percent depletion rate for new production by all producers	460[a,c]	370	2.9	3–8[i]
Exploration and development provisions				
Expense geological and geophysical costs like IDCs	260[a]–220[b]	200[f]	1 6[f]	1–5
Geological and geophysical 5 percent tax credit	65[a]	80	0 6	1–3
Exploration and development 5 percent tax credit	740[a]	325	2 6	3–9
50 percent tax credit for wildcat IDCs	1,300[b]	NA	NA	NA
Enhanced oil recovery and stripper well provisions				
Additional 10 percent research and experimentation credit for enhanced recovery method	40[b]	NA	NA	NA
10 percent tax credit for investment in certain assets used in stripper well production	40[b]	NA	NA	NA

[a]DOE, Energy Security, average for fiscal years 1987-1991

[b]Joint Committee on Taxation, average for fiscal years 1988-92

[c]DOE estimated that because the share of new production increases over time, this provision would have a revenue loss of almost $2 billion by 1995

[d]DOE, Energy Security. Crude oil equivalents (COE) 55 are percent crude oil and 45 percent natural gas, one barrel of oil is assumed to equal 6,000 cubic feet of natural gas NA denotes not available

[e]DOE reports this estimate for 1990

[f]DOE also estimates that this provision would increase oil and natural gas reserves by 700 million barrels COE Thus, a 1 4-percent increase in crude oil reserves is implied

Notes continued next page.

[g]GAO calculations, based on Energy Information Administration (EIA) estimate of 6.87 million barrels per day in 1992 for crude oil (calculation excludes natural gas).

[h]GAO estimates based on reported production increases and average revenue losses in DOE, Energy Security. The estimates of revenue loss per barrel reflect the fact that provisions aimed at new production will have a continuing effect in years after the initial tax break.

[i]Applying the 1992 estimated production increase to the $2 billion revenue loss estimated by 1995 yields a cost per additional barrel of about $15.

On the basis of the revenue and production figures reported by DOE in Energy Security, we estimate that these proposals would lead to federal revenue losses of from $1 to $15 dollars per barrel. Such cost-effectiveness estimates, however, have limitations. Most importantly, we found methodological shortcomings in the Energy Security production estimates, which may cause them to overestimate future output effects.

Specifically, in the course of our review we found that DOE lacks documentation for how the production estimates were generated, and their attempts to replicate them for us were unsuccessful. We discussed our initial concerns with DOE in January and February 1989, and DOE staff said they agreed with the need to keep documentation of their estimates in future work. Our discussions with DOE also prompted DOE's review of its earlier production estimates. DOE's October 1989 estimates suggest that the incentives are less cost-effective than was suggested by the earlier estimates. For example, the current production effect estimated for repeal of the transfer rule is one-eleventh of the earlier estimate, despite similar expected revenue losses. Because the latest DOE estimates were released as we were finalizing our report, we did not examine the assumptions or methodology underlying them.[6]

Provisions targeted to exploration and other new production tend to cause lower revenue loss per barrel of additional production than provisions applying to all existing production. Our analysis—based upon a relatively simple model of the responsiveness of petroleum supply to tax changes and upon published studies of the responsiveness of petroleum supply to price changes—suggests that provisions applying to all production, such as a general increase in depletion allowances, can result in tax revenue losses per barrel of additional production that exceed the price of oil.[7]

[6]In addition, it is also difficult to calculate revenue loss per barrel with the Energy Security estimates because of timing differences in the reported figures; that is, the production estimates are for the year 1992, and the revenue loss estimates are averages for the years 1987 through 1991. The estimates of revenue loss per barrel in tables 3.1 and 3.2 reflect the fact that provisions aimed at new production will have a continuing impact in years after the initial tax break.

[7]Average U.S. wellhead prices for 1989 were about $16 per barrel.

Even provisions aimed at new production will generally benefit some investments that would occur without new incentives, in addition to encouraging some genuinely incremental production—that is, production that would only occur with the incentives. Targeting provisions strictly to genuinely incremental production may be difficult administratively, however, because by definition it would require restricting the provisions to investments that would be unprofitable in the absence of the new incentives. Another method of targeting would be to limit tax incentives such as percentage depletion to recovery of the initial costs; this approach has been termed "incentive to payback." This approach could help limit the benefits received by very profitable investments. Finally, it also may be more cost-effective to target tax incentives at activities that do not already receive substantial tax breaks than at types of investments and producers that already are eligible for favorable treatment.

In December 1989 we learned of and received estimates of the economic effects of the Archer-Andrews-Boren bill ("The Domestic Energy Security Act of 1989," H.R. 664) produced for the Independent Petroleum Association of America by The WEFA Group in November 1989. WEFA estimates that by 1995 this bill could increase U.S. oil production by almost 590,000 barrels per day over its level in the absence of the bill; by the year 2000 the bill could increase oil production by 940,000 barrels per day. These increases correspond to 8.9 and 17.2 percent increases, respectively, over the base case oil production levels projected by WEFA for these years. WEFA also projects that the bill would increase annual natural gas production by 920 billion cubic feet in 1995 and by 1,790 billion cubic feet in 2000. The annual federal tax revenue losses reported by WEFA (based on the procedures used by the Joint Committee on Taxation) are $5.66 billion in 1995 and $7.46 billion in the year 2000. On the basis of the WEFA production and federal tax revenue estimates, we estimate that increased petroleum production (including both oil and equivalent natural gas) through the year 1995 will be associated with federal revenue losses of over $24 per barrel; production through the year 2000 will be associated with federal revenue losses of over $16 per barrel. These estimates of federal revenue losses per barrel do not reflect production beyond the years 1995 and 2000, respectively. If the federal tax losses were to end in the year 2000 and incremental production existing at that time was to continue for 30 more years (declining at 10 percent per year), then, based on the WEFA estimates, we estimate the federal revenue loss per barrel over the lifespan of the provisions to be about $7 per barrel.[a]

The WEFA analysis also explicitly estimates the effects on reserves. By the year 2000 WEFA estimates that oil reserves would be 400 million barrels above their estimated level in the absence of the bill. However, the production rate is estimated to be 2.34 billion barrels per year, which is 340 million barrels above the level estimated in the absence of the bill. These reserve and production estimates imply that there would be little, if any, lasting positive effect of the bill on oil reserves. WEFA estimates that natural gas reserves with the bill in the year 2000 would be 13.3 trillion cubic feet above their estimated level in the absence of the bill. WEFA estimates that natural gas production in the year 2000 with the bill would be 17.5 trillion cubic feet, which is 1.79 trillion cubic feet above the level estimated without the bill. Thus, the bill is estimated to have a more significant positive effect on natural gas reserves.

The WEFA analysis considers the production, tax revenue, employment, and other economic impacts of different provisions within the bill, as well as the effects of the bill as a whole. WEFA estimates, for example, that the tax incentives could eventually lead to revenue gains for governments (state, local, and federal) as a whole. These estimated gains result from a multiplier effect that would accompany most federal tax cuts (or spending increases) as well as higher state and local revenues in producing regions. This portion of the WEFA analysis is not comparable with the revenue-estimating methods used by the JCT or Treasury, however, because it includes multiplier effects. Because this study was received as we were finalizing our report, we did not attempt to evaluate the estimates beyond this limited level.

[a]These estimates are not discounted to reflect that the federal revenue losses for the provisions generally occur before the corresponding production gains.

Filling the Strategic Petroleum Reserve Appears More Effective Than Tax Incentives

Better perspective on the revenue loss figures can be gained through comparisons with alternative policies. For example, we estimate that incremental operation and construction costs for filling the SPR, given current planned capacity, are about $1 per barrel.[9] Although oil purchases would also require budget outlays, this oil would remain an asset of the government and would be available for use in an energy emergency.[10] While there is a cost to purchasing this inventory, the oil may also be sold for a higher price in future years. A capital budget of the type we recommend would recognize the lasting nature of investments in SPR oil by showing the expenditures on oil as leading to federal assets of comparable value.[11]

Proposed tax incentives, in contrast, would have the advantage of increasing productive capacity, such as available equipment and personnel. The tax incentives would also stimulate certain portions of the economy and would have different multiplier and trade effects than oil additions to the SPR that are imported. However, the tax incentives would also stimulate production even if there is no crisis. Such production would tend to advance the depletion of U.S. reserves, which may decrease long-term energy security by increasing U.S. vulnerability to an oil supply disruption at some point in the future.

If the $400 to $500 million average annual cost of all the administration's proposals were instead invested in filling the SPR, approximately 80 to 100 million barrels of oil could be added to the SPR over the next 4 years, assuming a cost of $20 per barrel. Alternatively, if only the expected revenue losses due to repeal of the transfer rule and eased AMT treatment of certain IDCs were invested in filling the SPR, approximately 24 million barrels could be added over the next 4 years at current prices. This volume could sustain a drawdown rate equivalent to 25,000 to 40,000 barrels per day—the expected combined impact of these two tax

[9] Oil Reserves: An Analysis of Costs—Past, Present, and Future (GAO/RCED-87-204FS, Sept. 29, 1987), p. 14. This figure includes the cost of additional construction to reach the 750 million barrel storage level, the electricity needed to pump the oil into the reserve, and the incremental cost of equipment maintenance caused by the additional oil through 1997.

[10] Thus, the price of oil is one measure of the cost of purchase. Alternatively, the cost of oil purchases can be measured by the interest that the government is forgoing by investing in oil reserves instead of, for example, reducing federal debt. However, if the cost of oil purchases is compared directly with the revenue losses due to tax incentives, as we do here, it is not necessary to consider foregone interest because we do not consider the interest costs resulting from the tax cuts and resultant higher federal debt. Foregone interest would have to be considered in an analysis of the net economic benefits of storing oil, however.

[11] Budget Issues: Restructuring the Federal Budget—The Capital Component (GAO/AFMD-89-52, Aug. 24, 1989), p. 19.

incentives on domestic output—for roughly 1.6 to 2.6 years.[12] Moreover, as the market value of this oil would—in the event of an energy emergency—likely substantially exceed the initial purchase price, the initial investment in oil for the SPR would likely be more than completely offset by budget receipts if the oil is sold. If the oil is used for defense or other governmental purposes during a crisis, it would also lead to future budgetary savings.[13] In addition, if the tax and SPR policies are compared over a longer period than the next 4 years, the amounts of additional oil that could be stored in the SPR for a cost equivalent to the tax incentives would be even greater than that considered here.

Tax Incidence: Who Benefits From Tax Incentives?

Although the tax incentives considered here are aimed at petroleum producers, basic economic principles suggest that much of the benefit of these provisions ultimately would accrue to the owners of lands with actual or potential petroleum reserves. In the short run—that is, where properties have bonus and royalty agreements in place and where supplies of equipment and labor are fixed—the incentives will benefit the producing firms and raise petroleum-sector wages and equipment prices. In the long run—over which new properties are explored and firms and workers enter or leave the industry in response to relative prices and wages—much of the benefit from the incentives is expected to be realized by the landowners, as market forces cause bonuses and royalties to rise to reflect the reduced after-tax cost of finding or extracting petroleum reserves. In some cases these landowners would be private entities, while in other cases they would be federal, state, or local governments or other public entities. Recognition of the distinction between the expected short-run and long-run effects of the provisions and between their statutory and economic incidence is useful in understanding their overall effects.

Overall, the incentives would be expected to have little effect on consumers' prices for oil. Because oil prices are determined internationally,

[12]Alternatively, the oil could be distributed at a more rapid rate over a shorter time period. For example, storage of 24 million barrels of oil would enable distribution of the equivalent of 5 percent of future U.S. production for 70 days. Storage of 100 million barrels would enable distribution of this amount for more than 9 months. Finally, according to DOE current U.S. policy is to draw down the SPR at its maximum rate in the event of a large disruption. In this case the extra oil might extend this maximum drawdown period without affecting the drawdown rate.

[13]Even in the absence of a crisis, the economics of exhaustible resources suggests that the value of stored oil will generally rise over time, with the price rise at least partially offsetting the interest foregone by investing in the inventory.

they would be relatively unaffected by the increases in production projected to occur due to changing U.S. tax treatment of petroleum investments. This is particularly likely because the estimated output changes would generally be a few percent or less of U.S. production and even smaller percentages of U.S. consumption or world production. The tax incentives could have somewhat more effect on natural gas prices in the United States, due to the smaller role of foreign supplies in affecting gas prices.

If capital moves to the petroleum sector from other sectors within the U.S. economy, there could be reductions in employment, wages, or both in the other sectors. Finally, to the extent that tax revenues decrease, other taxpayers would be required to pay additional taxes, federal spending would fall, federal debt would increase, or some combination of these effects would occur.

Arguments For and Against Tax Incentives

There are important arguments both for and against the proposed incentives. Some of these arguments apply to all the proposals, while others are most important for certain types of proposals.

The arguments that have been advanced in favor of incentives include the following. First, the incentives would tend to increase production, exploration and development capacity, and, to varying degrees, reserves. These increases could improve U.S. energy security. Second, petroleum exploration may share some similarities with research and development activities in other industries, both in terms of its risks and its potential benefits (i.e., "spillovers") to parties that do not directly fund the specific investments. Currently, qualified research and experimentation expenditures are eligible for relatively favorable treatment under the federal corporate income tax. Third, increased petroleum activity would raise the incomes of some workers, firms, and regions.

Arguments against the incentives include the following. First, at least in some cases, they may not be cost-effective measures for increasing energy security. To the extent that they reduce reserves that would be accessible in an energy emergency, they could even reduce U.S. energy security. Second, the risks of petroleum exploration can be reduced through diversification. Moreover, taxation can actually increase investors' willingness to take risks, under some conditions. In addition, while exploration activities by one firm may generate information spillovers—that is, benefits to other firms in the form of increased knowledge about the likelihood of finding and producing petroleum—

exploration may be sufficiently encouraged by substantial existing tax preferences and available contracting arrangements. Also, as discussed in chapter 4, the petroleum industry faces relatively low effective tax rates on new, marginal, investments even when favorable treatment of research and development expenditures in other industries is considered. Additional tax incentives could increase the existing favorable tax treatment of certain types of petroleum investments and producers, which could encourage activities with relatively low pretax returns—that is, relatively inefficient investments. Finally, the income gains to some parties would likely be largely offset by losses in terms of increased taxes (or reduced government services) and reduced earnings in other sectors of the economy.

Modifications to Depletion Rules

The proposed modifications to percentage depletion rules would most directly benefit independent producers, as only these producers are eligible to use this approach. Repeal of the transfer rule would also provide some benefit to integrated firms, however, by increasing the value of their properties if sold to independents. Both repeal of the transfer rule and raising the net income limit are estimated to have relatively small output and tax revenue impacts.

Advocates of repealing the transfer rule sometimes argue that independent producers may be more efficient than integrated firms, due to lower costs, and therefore may be able to keep marginal properties in production that would not be attractive to integrated firms. In addition, preservation of production from marginal proven properties may at times be more cost-effective than encouraging development of new properties that would be eligible for percentage depletion allowances and for favorable treatment of IDCs. Also, because it can be uneconomical—except at extremely high prices—to resume production from marginal properties with permanently closed wells, the argument that tax incentives will diminish U.S. energy security by depleting U.S. reserves may not apply to this proposal, since the production of the reserves under these wells may not occur if the wells are closed.

Overall, however, we believe that repeal of the transfer rule is of questionable cost efficiency, as estimated revenue losses of $11 to $14 per additional barrel of production are close to the wellhead price of oil. In addition, if it is true that independent firms are more efficient operators of the wells in question, then the independents should not require favorable tax treatment to maintain the production, as would be allowed if the transfer rule is repealed.[14]

An argument that has been made for raising the net income limit is that this limit reduces favorable depletion rates more on marginal wells (which would have relatively low net incomes) than on very profitable ones. The net income rule is particularly likely to affect properties in the event of a fall in petroleum prices. In addition, the AMT can provide some recapture of favorable percentage depletion treatment under the regular income tax, by treating deductions in excess of the property's basis as a tax preference.

An argument against repeal of the net income limit is that it ensures that at least a portion of the property's income will be subject to federal taxation. Also, the limit does not constrain cost depletion allowances, which are more comparable with depreciation rates on most other business investments.

Major Increases in Depletion Allowances

Proposals for increasing the depletion allowances for independents on all production or for allowing all producers to claim percentage depletion at a 27.5 percent rate on all new production had among the largest estimated output and revenue impacts of all the provisions considered by DOE in 1987 in Energy Security.[15]

On the basis of these production and revenue estimates we estimate that these provisions would result in revenue losses of $3 to $5 per barrel or more. Over time the revenue costs of the provisions may grow, so that revenue losses per barrel could be close to or even greater than the price of oil. Thus, on cost-effectiveness grounds these provisions seem to be unattractive methods of increasing energy security, as they could be as or more expensive than direct federal purchases of oil. In contrast to a petroleum reserve, which consists of a lasting federal asset—except in

[14]Allowing percentage depletion allowances to be claimed only on proven properties transferred between independents would reduce, but not eliminate, the potential for transfers motivated only by tax preferences. For example, some independents may be unable to fully use percentage depletion deductions due to constraints imposed by average daily production levels or the AMT. Properties owned by these firms may be more valuable to other independents that are able to fully use percentage depletion allowances.

[15]DOE reported in 1987 that the depletion provision applying to new production could increase oil industry employment by up to 50,000, thereby providing a boost to oil region economies. DOE also reported that the provision could lead to a doubling in the number of geophysical crews and significant increases in drilling activity.

the event of a crisis—the oil production subsidized by increased depletion allowances would be consumed as it is produced and would not be held for use in a crisis.

Raising the depletion rate for independent firms but not integrated firms would increase the already relatively favorable treatment of independents under existing tax law. Use of cost depletion is more consistent with tax treatment of investments in other sectors. Raising depletion allowances also most directly encourages production, as opposed to retention of reserves, so that the long-run energy security benefit may be ambiguous. Production, as opposed to retention, might be particularly encouraged if the higher depletion rates are expected to be temporary.

Exploration and Development Provisions

One economic efficiency argument for subsidizing oil exploration is that like certain research activities it can lead to information benefits that "spill over" to other parties that do not pay for their costs. Some research (e.g., Peterson, 1975 and Stiglitz, 1975) suggests that these spillovers could lead to underinvestment in exploration, because the value of the exploration to society might exceed the value of the exploration to the party doing the exploration. In contrast, research also suggests that competitive behavior may lead firms to overinvest in exploration (e.g., Peterson, 1975 and Isaac, 1987). Although both of these arguments have been made, we did not find estimates of whether their net impact calls for larger subsidies than the petroleum industry is currently provided by the tax system.[16]

Some researchers and advocates of petroleum tax incentives have also suggested subsidizing certain activities, including petroleum exploration, because they are risky. This view is based on the principle that investors who are risk averse will choose more certain outcomes with payoffs that are lower on average in preference to uncertain outcomes with higher average payoffs, and that tax subsidies may be necessary to encourage risk-taking. Importantly, however, this view applies to risks that cannot be eliminated through diversification. While the risks associated with a given potential oil venture may be high, a geographically diversified set of ventures could have significantly less risk. In addition, investors can also diversify financially to reduce risks from exploration

[16] Existing contracting methods, for example, already enable one petroleum producer to compensate another for the cost of exploratory drilling. These compensation agreements, however, are a very small fraction of firms' exploration and development costs. According to API data, these arrangements—termed "test hole contributions"—accounted for only $7 million of the roughly $24 billion of exploration and development expenditures for the industry in the U.S. in 1988.

and from changes in the price of oil. Finally, the effect of taxation on risk taking is ambiguous. Economic theory suggests that particularly where losses are fully deductible, taxation can actually encourage risk-taking. We did not find estimates that indicate whether or not existing incentives are adequate to compensate for these risks given actual diversification options and tax treatment, however.

The exploration incentives proposed by the Bush administration are targeted toward IDCs incurred on exploratory wells. Arguments for these types of proposals are that (1) they are targeted to some extent at incremental production, (2) they could lead to information spillovers benefiting other parties, and (3) they encourage risk-taking. The provision relating to AMT treatment would essentially provide producers subject to the AMT much the same tax treatment of IDCs as producers subject only to the regular tax.

One argument against the proposals that is discussed in detail in the next chapter is that they are targeted toward an asset type that already faces a marginal effective tax rate that is relatively low. Under the regular income tax, for example, independent producers expense all IDCs, so that these investments face a marginal effective tax rate of zero.[17] Integrated producers face a slightly higher effective tax rate because they cannot expense 30 percent of IDCs on successful wells; rather they must recover these over 5 years. By providing a tax credit for these investments, the administration proposal would further reduce their marginal effective taxes rates, making them negative for more producers. Relaxing the AMT treatment of these expenses would also help allow them to offset other income. A related argument against these proposals is that they would reduce the cost of only one type of exploration investment and, therefore, would be biased in favor of drilling over geological and geophysical exploration. Finally, the 10-percent portion of the proposed credit would be a net stimulus only for producers that spend less than the $10 million level of investments eligible for the 10-percent credit under the administration proposal. For firms that would undertake greater levels of investment even without this proposal, it would be, in effect, a $1 million reduction in taxes.

[17]The marginal effective tax rates are below the statutory tax rate of 34 percent because expensing generates tax deductions in the taxable year the costs are incurred that offset the present value of taxes paid on a marginal investment. Marginal effective tax rates can even be negative for independents eligible for percentage depletion allowances. Negative marginal effective tax rates mean that such investments are more profitable after taxes than before because they offset taxes due on other income.

While the administration exploration proposals focus on IDCS, other proposals considered by DOE and the JCT in 1987 focus on G&G costs. An argument for these provisions is that they would help put the tax treatment of G&G costs on a comparable basis with IDCS. Currently, integrated firms recover G&G costs, from areas that they have not abandoned, using cost depletion. This can be substantially slower than the treatment of IDCS. Yet, both activities represent exploration investments, which to some extent are substitutes. DOE's 1987 figures imply that the provisions it considered that are targeted at G&G investments are more cost-effective than the general exploration and development tax credit, much of which would be expected to apply to IDCS.[18] Allowing independent firms to expense G&G costs that they would otherwise recover via percentage depletion could particularly encourage them to invest more in this activity.

The main argument against more favorable treatment of G&G expenses is that they may already receive somewhat favorable treatment relative to economic rates of depreciation, which are approximated by current tax treatment of most business investments in other sectors. Favorable treatment may arise because G&G expenses can be deducted when an area is abandoned, rather than being depreciated in value over time even for unsuccessful areas. This view holds that all petroleum exploration activities of a firm should be regarded as one activity, rather than being considered on an area-by-area basis (see, for example, Stiglitz, 1986). Finally, if percentage depletion allowances are not adjusted to reflect immediate recovery of G&G costs, independent firms could have the advantage of both simultaneous expensing of a cost and implicit recovery through percentage depletion.

Enhanced Oil Recovery and Stripper Well Provisions

An argument that has been advanced for an enhanced oil recovery (EOR) tax credit is that EOR involves innovative techniques that should be encouraged to promote long-run energy security. The administration proposal would apply only to capital investments. Thus, it would have a lower revenue cost than a more general credit. The proposal considered by the JCT in 1987 would apply only to qualified research and experimentation on EOR and not to commercial applications. Such research could provide improved methods of reserve recovery both in the United States and abroad, thereby increasing energy security.

[18]DOE could not duplicate for us its 1987 estimation of the output effects that we used to calculate these cost-effectiveness estimates, however.

Studies of EOR potential suggest significant reserve additions may be possible given higher oil prices, technological advances, tax incentives, or combinations of these. According to DOE's Bartlesville Project Office roughly 230 billion barrels—or 47 percent of the oil ever discovered in the United States—is held immobile in reservoir rock by viscous and capillary forces. This oil is the target of various EOR processes.

Recent studies by Brashear and colleagues supported by DOE, the Interstate Oil Compact Commission, and the states of New Mexico and Oklahoma examined EOR potential for these two states and the Nation as a whole.[19] This work also examined tax incentives that could be implemented at the state or federal levels. At the state level Brashear et al. considered eliminating state corporate income, severance, and other production taxes either (1) until all costs of the project had been recovered or (2) for the life of the project. At the federal level they considered raising the percentage depletion allowance to 27.5 percent, expanding the depletion allowance to all EOR projects (including those of integrated firms), and eliminating the transfer rule and net income limit. Their analysis also assumes that AMT provisions recapturing percentage depletion allowances and IDC deductions would not apply.

Brashear et al. estimated that EOR could recover 4.2 billion barrels of reserves at an oil price of $20 per barrel under the current tax system. The study also estimated that 10 billion barrels could be recovered under current law if prices rise to $28 per barrel. With tax incentives, price increases to $28 per barrel, and technological advances, the study estimated that 20.8 billion barrels could be recovered.

The analysis by Brashear et al. suggests that state tax incentives can actually lead to increased state and local tax revenues as petroleum activity in the states increases. In both New Mexico and Oklahoma revenues would initially fall, but they would then increase in later years. Brashear et al. also find that limiting the incentive to recovery of the actual costs (i.e., limiting to "payback") would be more cost-effective than allowing the incentive for the life of the project. The former approach encourages most of the reserve additions gained under the latter approach, but with less loss of revenues.

[19]See, e.g., J.P. Brashear, A. Becker, K. Biglarbigi, and R. M. Ray, "Incentives, Technology, and EOR: Potential for Increased Oil Recovery at Lower Oil Prices," Journal of Petroleum Technology, February 1989.

At the federal level tax incentives are also estimated by Brashear et al. to show significant overall economic benefits to federal, state, and local governments. The revenue-estimating analysis of Brashear et al., however, is not consistent with the methodologies used by the JCT or the Treasury. For example, Brashear et al. assume that capital and labor are not drawn from other taxed activities, though they do consider the revenue loss attributable to tax breaks for EOR projects that would have occurred without additional incentives. In contrast, JCT and Treasury assume that capital and labor are drawn into tax-favored uses from other taxed activities, which would imply higher revenue losses than the Brashear et al. assumption.

An argument against the administration proposal, the provision considered by the JCT, and the incentives considered by Brashear et al. is that qualified research and experimentation is already eligible for favorable tax treatment. According to one expert, an additional concern with the administration proposal is whether Alaskan North Slope activities would qualify for this tax break. This region is expected to begin using EOR soon, so the administration provision could be quite costly and would subsidize some investments that would likely be made without it. Special tax incentives for EOR may also promote use of this method instead of other recovery methods that could be more efficient in the absence of this special tax break. Finally, EOR investments that are oriented toward production (as opposed to research) may not provide spillover information benefits of the type provided by exploration.

Regarding stripper wells, an argument that has been advanced for additional tax incentives is that these wells may be only marginally profitable and hence may be shut down when oil prices fall. State regulations generally require cementing-in nonproducing wells after a period of time to prevent environmental damages, such as contamination of groundwater. Thus, it can be uneconomical to resume production from affected areas (since new wells would have to be drilled) if oil prices eventually rise. In addition, as discussed in DOE's comments on this report, stripper wells may be potential sites for EOR activity. There is also a historical precedent for treating stripper wells relatively favorably. In particular, these wells received relatively favorable treatment under the windfall profit tax. Finally, one expert suggested implementing incentives for research and development on new technologies that would allow nonproducing stripper wells to remain open while still meeting environmental standards.

An argument against proposals targeted at stripper well production is that if stripper well revenues do not cover operating costs, then continued operation is not a productive use of resources, unless one expects oil prices to rise or the price of domestic oil is below the true social value of the oil.[20] In addition, one industry expert with whom we spoke noted that stripper wells have limited capacity for increased output and a limited role for providing increased energy security. Economic studies also generally find that the supply of oil from existing fields is of low responsiveness to price. This result also implies that large price increases would likely be needed to substantially increase the output from stripper wells.

Agency Comments and Our Evaluation

DOE disagreed with our discussion of the SPR and stated that the costs of additions to the SPR are higher than we indicated. DOE also believes that given the time value of money and the estimated low probability of a disruption, additions to the SPR are unlikely to provide net economic benefits. In addition, DOE disagreed with our position that expensing of IDCs represents a tax preference, as we have also discussed in chapter 2. DOE also disagreed with our observation that stripper wells have a limited role in increasing energy security. DOE notes that there are many stripper wells and that they represent potential sites for enhanced oil recovery. Finally, DOE believes that the Section 29 tax credit for producing fuel from a nonconventional source, which we did not examine, is an incentive that has proved to be effective and efficient.[21]

We believe, in contrast to DOE, that our discussion of the SPR is accurate. Our analysis explicitly focuses on filling the SPR to reach its 750 million barrel target faster. It shows that 80 to 100 million barrels of oil could be added to the SPR over the next 4 years for a cost equivalent to the administration's proposed tax incentives, assuming a cost of additions of $20 per barrel. This cost is above the level assumed by a February 1990

[20] Some studies have suggested that there may be a difference between the price of oil and its true social value. For example, a 1980 DOE study suggested that it might be reasonable to pay a premium of $4 to $10 for each barrel of imported oil due to the energy security costs imposed by imports. Imposition of an import fee would raise the price of domestic oil above the current level. While domestic oil production would also be encouraged by tax incentives, a difference between the policies of import fees and domestic production tax incentives is that import fees would discourage consumption, while production tax incentives would not. If consumption of foreign oil imposes social costs, however, then on economic efficiency grounds its consumption should be discouraged, because this would promote not just domestic oil production, but also adoption of other fuel-saving practices.

[21] Section 29 currently allows a tax credit equal to about $4.80 multiplied by the barrel-of-oil equivalent of qualified fuels that are produced by the taxpayer and sold to an unrelated person during the taxable year.

DOE study for oil purchases through fiscal year 1992. We agree with DOE that interest costs and probabilities of disruption must be considered in assessing the net economic benefits of the SPR. Although DOE raises questions about the value of expanding the SPR beyond the current target of 750 million barrels, DOE does not demonstrate that additional tax incentives would be a more effective policy for increasing energy security than faster attainment of the SPR target of 750 million barrels.

While there are many stripper wells, these wells produce only about 15 percent of U.S. output. As noted in the report, however, stripper wells have limited surge capacity, which is why we believe they have a limited role in providing increased energy security. We agree with DOE, however, that these wells may be potential sites for EOR and have now noted this explicitly (p. 48). Finally, because we focused on proposed incentives and not existing ones, we did not initially examine the Section 29 tax credit, which was in effect at the time of our study. In response to DOE's comments, however, we asked DOE to provide production and tax revenue estimates to support its position that the Section 29 credit has been efficient and effective. DOE did not provide us any such estimates. Our preliminary analysis suggests that the current Section 29 credit can be fairly costly per unit of natural gas or oil produced (see comment 25 in app. III).

Treasury's comments largely explained the rationale for the administration's proposals. Treasury noted that the proposed incentives could provide incentives for increased exploratory activity that it believes could ultimately increase reserves. The incentives would also provide continuing opportunities for skilled personnel and strengthen small independent producers, who have been recognized leaders in exploratory drilling. Treasury also noted that it is difficult to quantify these and other benefits from the incentives. In addition, Treasury noted that the administration is adding to the SPR as part of its strategy for increasing U.S. energy security.

We agree with Treasury that the proposed incentives may provide some benefits beyond those quantified here. We have increased our discussion of the reserve additions that are possible through EOR activities (pp. 46-48). We believe, however, that the incentives have not been demonstrated to have superior energy security benefits to alternative policies, such as filling the SPR more rapidly.

Petroleum Investments Face Relatively Low Marginal Effective Federal Corporate Tax Rates

The effective federal corporate tax rate faced by new, marginal, petroleum production investments is one of the lowest found for a major industry due to the effects of existing petroleum tax incentives. Recent studies have estimated these rates to be about half of the statutory rate of 34 percent for integrated firms and near zero for independent firms eligible for percentage depletion. We estimated similar values, depending largely on the mix of assets used.

Relatively low marginal effective tax rates encourage petroleum production investments to be made that have pretax returns below those of investments in other industries. Negative marginal rates arise because some petroleum investments are more profitable after taxes than before taxes, as they help reduce taxes on other investments.

The low marginal effective tax rates on petroleum production investments arise largely due to the ability of producers to expense most or all intangible drilling costs (IDCs), which can represent 75 to 85 percent of total drilling expenditures. Thus, much of the cost of an oil investment can be deducted from income in the year that the investment is made, rather than being depreciated over time as are most other business investments. Independent producers face lower effective tax rates than integrated producers because they are eligible both for total expensing of IDCs and because they can claim percentage depletion allowances on the first 1,000 barrels of average daily production.

Some of the proposed tax incentives would contribute to the existing favorable treatment of certain investments (such as drilling over geological and geophysical work) or certain types of producers (e.g., independent over integrated firms). Other proposals would reduce these types of favorable treatment or are neutral. By definition, however, all of the incentives would tend to reduce effective tax rates on the petroleum industry relative to other sectors.

Marginal Effective Tax Rates Measure the Tax on New Investment

Marginal effective tax rates measure the tax rate on new, economically marginal, investments. The measure considers the estimated economic rate of depreciation of each investment as well as the tax treatment of the investment in order to compare the after-tax return on the investment with the before-tax return.

Because of the numerous complexities of the tax code, effective taxes on income can differ substantially from statutory rates. There are two main types of effective tax rates: average and marginal. The average effective tax rate is the ratio of taxes reported for a year divided by pretax income in that year. For corporations these rates are calculated by consulting annual reports, tax returns, or other documents. In contrast, marginal effective tax rates reflect the tax borne by a new, marginal investment and are estimated by considering the present value of depreciation, expensing, depletion, and tax credit provisions that can affect the return on an investment over its useful life.[1]

Marginal and average effective rates can vary in the case of petroleum production because marginal investments can differ from average ones in their basic function, timing, and mix of inputs. In the petroleum case, for example, investments in exploration and development face significantly different tax provisions (and hence lower marginal effective rates) than investments in refining and marketing. This feature is likely to be especially relevant for integrated firms, which undertake a variety of petroleum (and nonpetroleum) activities. Timing effects can also be relevant because a firm that is growing or has a relatively new capital stock will have greater depreciation deductions than a firm with a capital stock that has already been largely depreciated for tax purposes. A new investment by either firm, however, might face exactly the same marginal tax burden.[2] Finally, different petroleum ventures involve different mixes of costs, such as bonuses, IDCs, and equipment. In particular, marginal new properties are expected to have lower bonus shares

[1]As an example, suppose investors require a 10 percent posttax return. Assume the statutory tax rate is 34 percent and that IDCs can be expensed, while equipment is deductible from taxes on the basis of its economic depreciation rate. To keep this example simple, assume that the economic depreciation rate of both investments is zero. (The marginal effective tax rate calculations cited elsewhere in this report do not assume zero depreciation, however. The mathematics of this more general case is considered by Gravelle (1982).) We will show that, in this example, because IDCs can be expensed, investors would be willing to invest in IDCs with only 10 percent pretax returns, while equipment investments would require over 15 percent pretax returns. In other words, the IDC investment would face a marginal effective tax rate of zero, while the equipment would face a marginal effective tax rate of 34 percent.

In this case investing $100 in IDCs yields a $100 immediate tax deduction, which saves $34 in tax on other income. Thus, the real cost to the investor is $66. If the IDC investment yields $10 per year—a 10 percent pretax return—then after taxes the investor will net $6.60 per year, which likewise represents a 10-percent return on the after-tax investment of $66. Pretax yields below $10 per year would not meet the investor's required pretax return; thus, the 10 percent pretax return is the necessary return on a marginal investment. The marginal effective tax rate is defined as: (pretax return - posttax return)/pretax return, or for the IDC case, (.10 - .10)/.10 = 0. In contrast, $100 invested in equipment yields no initial tax deduction. Therefore, the equipment must yield $15.15 per year before taxes in order to yield the investor a 10 percent posttax return: (1 - .34) 15.15 = 10. The marginal effective tax rate on the equipment is (.1515 - .10)/.1515 = .34.

[2]Average rates may also change when product prices change unexpectedly. Marginal effective tax rates would again not necessarily change in this case, though the amounts producers are willing to pay for bonuses and which venture is marginal would generally change.

and higher IDC shares than average properties.[3] Thus, marginal properties will tend to have lower marginal effective tax rates because IDCs receive more favorable tax treatment than other costs.

Marginal effective tax rate estimates can be sensitive to assumptions that include the rates of inflation, depreciation, and required returns to investors, as well as the amounts of different types of assets used in an activity. Marginal effective tax rate estimates also generally assume that all deductions and credits can be used as incurred, which may not be the case when firms are experiencing losses.[4] For these reasons average effective rates over a period of time can provide further perspective on the estimated marginal rates. Average effective rates on petroleum and other industries are reported in appendix I.

While the objective of tax neutrality (or a "level playing field")—i.e., a situation under which investment decisions are not determined by tax considerations—implies that marginal investments should not be distorted by the tax code, other objectives may also be relevant to policymakers. The administration, industry representatives, and others have argued that an objective of energy security is an appropriate reason for encouraging petroleum investments through the tax code. This approach causes petroleum investments to be made that have pretax returns below the required return for investments elsewhere in the economy. The appropriate tax rates for risky investments are also a matter of controversy. Some researchers have argued that relatively risky investments should face relatively lower effective tax rates.[5] Theoretical

[3]To examine how taxes affect the extent of petroleum exploration and development it is most useful to define the marginal investment as one that is undertaken or not undertaken due to changes in the tax law. These investments will be ones where the value of the petroleum extracted will just cover the drilling, extraction, and other nonbonus costs; the bonuses paid for these properties will be relatively low or zero. Eased tax provisions will make currently unprofitable areas worth exploring, while tightened tax provisions will make slightly profitable areas unprofitable. In contrast, for properties that are expected to be profitable with or without tax law changes, the changed law is assumed not to affect the exploration and development decisions, but rather to lead primarily to higher or lower bonuses. Thus, under this framework, marginal properties tend to have low bonus shares when compared to average properties.

[4]In addition, according to Furchtgott-Roth (1989), problems can arise in aggregating marginal tax rates across investments with different riskiness within a firm or across different firms within an industry.

[5]While there may be considerable risk in an individual oil property, however, a set of geographically diversified ventures would generally have less risk. Investors can also diversify their portfolios financially by investing across different firms and industries. Finally, taxation may actually encourage risky investment in some cases

taxation research also suggests that because some activities (e.g., leisure) cannot be taxed, and the supply and demand of different commodities and activities have different degrees of responsiveness to price changes, policymakers may wish to tax these items differently in order to maximize social welfare. This research can suggest, for example, somewhat greater taxation of commodities with supply or demand that is relatively unresponsive to price changes, because such taxes will change real output less. Finally, other nonneutralities in the tax system—such as treatment of housing versus nonhousing investments and consumption versus savings—may outweigh the importance of neutrality among business investments. Thus, while the objective of tax neutrality suggests a goal of equal marginal tax rates, other distributional and efficiency goals could result in more complicated objectives.

Marginal Effective Tax Rates for Petroleum Production Are Below Those for Most Other Industries

Marginal effective federal corporate tax rates on petroleum investments are lower than those in most other industries. Estimated marginal effective tax rates for both integrated and independent producers are generally well below the statutory rate of 34 percent. In contrast, most other industries face estimated marginal effective rates near the statutory rate. Both integrated and independent producers face relatively low marginal tax rates due to the favorable treatment of IDCs. Eligible independent producers can also benefit from the ability to use percentage depletion deductions instead of cost depletion.

The analysis here focuses on the effective rate of federal corporate income taxation because this is the main federal tax currently affecting petroleum investments. There is also some consideration, however, of the effects of the windfall profit tax, which was repealed in 1988. The analysis does not consider state severance, income, or property taxes, or federal and state sales or excise taxes on gasoline or other items.

Table 4.1 presents marginal effective tax rate estimates published by Lucke and Toder in 1987, based on an approach developed and discussed by CBO in 1985. The Lucke and Toder figures reflect federal corporate income and windfall profit tax rates.[6]

[6]The oil production tax rates are based on a detailed analysis of three petroleum properties with hypothetical exploration and development costs, success rates, production declines, and oil price scenarios. The analysis considers the tax rates for marginal properties as opposed to properties with large bonus payments. Lucke and Toder also model the different tax treatment of independent and integrated firms. The former are assumed to be eligible for percentage depletion on their marginal production. This assumption would not generally be valid for larger independents, however, due to the 1,000 barrel average daily production limit on percentage depletion allowances. Thus, larger independents would tend to face tax rates between those estimated by Lucke and Toder for integrated and independent firms. The effects of the alternative minimum tax are also considered. For the nonpetroleum industries, effective tax rates are estimated based on the Hall and Jorgenson (1967) model of before and after tax returns to capital. This theoretical model uses data on different asset mixes in these industries and economic assumptions about rates of return, depreciation, and inflation to estimate marginal effective tax rates. The model has been widely used by government and academic researchers. The Lucke and Toder analysis assumes that new investments are financed by equity, all deductions and credits can be used as incurred, the real discount rate is 8 percent, expected inflation is 4 percent, and that the statutory corporate tax rate faced is 34 percent.

Table 4.1: Lucke and Toder Estimates of Marginal Effective Federal Corporate Tax Rates

Industry	Marginal effective tax rate (percent)
Manufacturing	32
Food and kindred products	32
Tobacco manufacturers	32
Textiles	30
Apparel	33
Lumber and wood product	31
Furniture and fixtures	33
Paper and allied products	30
Printing and publishing	31
Chemicals and allied products	31
Petroleum refining	32
Rubber and plastic products	31
Leather and leather products	32
Stone, clay and glass products	33
Primary metal products	31
Fabricated metal products	33
Machinery, other than electrical	33
Electrical machinery	32
Motor vehicles	27
Other transportation equipment	33
Instruments and electronics	32
Construction	32
Transportation	29
Communications	24
Public utilities	27
Wholesale and retail trade	33
Services	31
All industries	31
Crude Oil Production (Range)	
Integrated Companies	7 to 24
Independent Companies	−8 to 9

Notes Figures for crude oil production include the effects of a scenario considering the windfall profit tax on crude oil production This tax has since been repealed If this scenario is not considered, Lucke and Toder calculate marginal effective tax rates for integrated firms to be 7 to 14 percent, and rates for independent firms to be −8 to 2 percent Effects of the corporate minimum tax are not shown See text for additional details

Source Adapted from Lucke, R and E Toder, "Assessing the U S. Federal Tax Burden on Oil and Gas Extraction," Energy Journal, V 8 No 4, 1987, p 61

The Lucke and Toder analysis suggests that petroleum production bears marginal effective tax rates below almost all other sectors. Marginal rates for integrated firms were estimated to range from 7 to 24 percent, while independent firms were estimated to face marginal effective rates of -8 to 9 percent. This range of effective tax rates moves somewhat lower if the scenario that assumes the 1988 world price of oil reaches $30 per barrel and that the windfall profit tax becomes a factor is excluded. This tax has been repealed but was still in effect when Lucke and Toder published their work. When this scenario is excluded, independent firms' marginal effective tax rates are estimated to range from −8 to 2 percent under the regular tax law and from 5 to 14 percent under the AMT.[7] When the windfall profit tax scenario is excluded for integrated firms, marginal effective rates are estimated to range from 7 to 14 percent under the regular tax and from 6 to 15 percent under the AMT. In contrast, most other industries were estimated to be near the 34 percent statutory rate under the regular tax.[8]

Because marginal effective tax rate estimates can be sensitive to modeling assumptions, we asked Dr. Jane G. Gravelle of the Congressional Research Service (CRS) to produce some additional estimates of these rates using a data set and computer program used in several previous CRS studies. One goal of this work was to address a limitation of the Lucke and Toder work, which was that it considered intangible drilling costs a form of capital for petroleum producers but did not consider intangible investments in other industries. To address this concern we provided Dr. Gravelle with estimates by Fullerton and Lyon (1988) of intangible capital investments in research and development (R&D) and advertising as percentages of the total capital stocks of major industries. Although they do not represent tangible assets like equipment and

[7]Lucke and Toder's AMT analysis does not reflect the adjusted current earnings provision of the AMT. Thus, it could understate the marginal effective tax rate of firms subject to the AMT. The adjusted current earnings provision of the AMT, however, may also allow more rapid write-off of IDCs than the excess IDC preference. Finally, the Lucke and Toder AMT analysis also assumes that a firm stays subject to this tax regime for the life of its investment. When firms move between AMT and regular tax coverage over the life of an investment, the effective tax rates could be either higher or lower than the rates estimated when the tax regime stays constant.

[8]Lucke and Toder's analysis suggests that while tax treatment of petroleum production costs was made somewhat less favorable under the regular corporate income tax of the 1986 Tax Reform Act, these changes were offset by lower statutory tax rates. The net effect of these changes is an estimated very small reduction in the industry's marginal effective tax rate under the regular tax. AMT provisions would tend to raise effective tax rates, however, particularly for independent producers. (Restrictions on tax shelter investments and the reduction in statutory tax rates under the personal income tax could also affect incentives to invest in independent firms' activities.) Lucke and Toder also estimate that on average other industries' marginal effective tax rates under the regular corporate income tax rose slightly with the new law. In this case less favorable depreciation provisions and elimination of the investment tax credit are not fully offset by the lower statutory tax rate.

structures, R&D and advertising can be viewed as forms of capital investment because they have value that can extend beyond the year in which they are made.

Table 4.2 shows the marginal effective corporate tax rates for oil and gas extraction and 15 other industries as calculated by Dr. Gravelle using the CRS capital stock model supplemented by the intangible capital stock estimates we provided. The rates in the first column of figures reflect inclusion of the R&D and advertising intangible capital stock estimates. The rates in the second column of figures are based on tangible capital (i.e., equipment, structures, and inventories) for all industries plus IDCs for the oil and gas extraction industry. The analysis here assumes that the oil and gas firms are integrated producers. Independent producers, which can expense all IDCs and may be eligible for percentage depletion deductions, would have lower effective rates.

Table 4.2: Effects of Intangible Capital on Estimated Marginal Effective Corporate Tax Rates

	Nonpetroleum intangible capital	
Industry	**Included**	**Excluded**
Agriculture	33	33
Mining	28	28
Crude Oil & Gas (Integrated Firms)	17	17
Construction	31	32
Food & tobacco	28	33
Textiles, apparel & leather	32	33
Paper & printing	30	32
Petroleum refining	33	35
Chemicals & rubber	26	34
Lumber, furniture, stone, clay & glass	31	34
Metals & machinery	27	34
Transportation equipment	13	35
Motor vehicles	22	33
Transportation & utilities	28	29
Trade	33	35
Services	30	32

Source: Congressional Research Service with some assumptions supplied by GAO.

Table 4.2 shows that when R&D and advertising intangible capital is included in the firms' asset bases, the oil and gas extraction sector faces the second lowest of the marginal rates of the 16 sectors considered.[9] Including intangible capital slightly lowers the marginal effective tax rate for most sectors. The estimated marginal effective rate faced by the transportation equipment sector (which includes aerospace firms), however, is less than half of its rate without this adjustment; the rate for the motor vehicles sector is two-thirds of its unadjusted rate. When nonpetroleum intangible capital is not considered, all of the sectors except oil and gas face estimated marginal rates close to the statutory rate of 34 percent.

Our analysis of hypothetical petroleum properties suggests a wider range of effective tax rates than do the Lucke and Toder and CRS studies but is consistent overall with these studies.[10] Our analysis suggests that marginal effective rates are fairly sensitive to, among other things, the asset mixes assumed. For some types of properties, for example, we estimated slightly higher effective tax rates than the other studies. These properties had lower percentages of IDCs and higher fractions of depletable and depreciable costs than either the Lucke and Toder or CRS investments. For other properties we estimated lower (including more negative) effective rates. All of the studies suggest, however, that complete or predominant expensing of IDCs, as well as the percentage depletion allowance, confer significant tax advantages to marginal petroleum production investments over most other business investments.

Marginal Effective Tax Rates and Proposed Incentives

The proposed tax incentives would all lower effective tax rates on petroleum development. In addition, the administration proposals would tend to contribute to increasing existing favorable treatment for certain types of petroleum investments and producers. However, with few exceptions, we found a consensus among experts that petroleum exploration, development, and production should face tax policies that encourage the most efficient investments and firms. Marginal investments in activities that do not currently receive tax incentives generally yield higher pretax returns than marginal investments that already receive tax incentives.

[9] The CRS analysis assumes that intangible R&D investments would all qualify for the 20 percent tax credit. This assumption produces an upper-bound estimate of the amount actually eligible for a credit. Thus, this assumption tends to produce a lower bound for the marginal effective tax rates of sectors with significant amounts of R&D spending.

[10] This work was based on the Hall and Jorgenson (1967) model, as was the CRS work. We considered alternative petroleum investments, ranging from ones based on the Lucke and Toder assumptions (which were fairly similar to CRS assumptions) to ones with higher fractions of depletable and depreciable costs. We did not verify the computer programs and input data used to produce the Lucke and Toder and CRS estimates. We did discuss and analyze the methodologies and key assumptions used by these studies, however.

Therefore, it may be not only more efficient in terms of private investment allocation but also more cost-effective in terms of federal revenue losses per barrel of additional production stimulated by an incentive to target incentives at such high-return activities.

For example, proposed modifications to depletion rules reduce the effective tax rates faced by independent firms, which are already below those of integrated firms. The modifications for IDCs affect investments that face marginal effective rates under the regular corporate tax that can be a few percent for integrated firms or zero for independent firms.

The tax credit for EOR capital investments would tend to lower the tax rate on some capital investments that are depreciable as well as others (such as IDCs and injectants) that are largely or completely expensed. Currently, the depreciable investments face marginal effective tax rates near the statutory rate for firms that are not eligible for percentage depletion.[11] Lowering the tax rate on depreciable investments would make their tax treatment more comparable to that of investments in drilling activities, though favored with respect to treatment of most investments in other industries.[12] Reducing the tax rates on investments that are largely expensed, however, would increase their overall favorable treatment.

G&G costs currently face marginal effective rates comparable to other (nonpetroleum) investments in cases where the G&G investments have relatively high probabilities of success and lower tax rates in cases with relatively low probabilities of success.[13] However, G&G costs face higher tax rates than IDCs, which are in some sense a substitutable or related activity. Thus, tax incentives for G&G expenses could tend to equate treatment among related petroleum investments, though increase relatively favorable treatment compared to other sectors.

[11]For firms eligible for percentage depletion the tax rates can be much lower.

[12]Credits for depreciable investments made in stripper wells could have similar effective rate characteristics. However, a higher fraction of stripper well investments may be eligible for percentage depletion (and hence face lower effective tax rates) than EOR investments because small independent producers are relatively more likely to own stripper wells than EOR investments.

[13]This situation arises because, for example, when probabilities of success are low, G&G costs are deducted relatively early (as areas are abandoned)

Agency Comments and Our Evaluation

DOE does not believe that extractive industries should face the same type of capital recovery for tax purposes as other industries. Thus, DOE does not believe that the petroleum industry currently receives favorable tax treatment. DOE also does not accept the marginal effective tax rate analyses presented in this chapter. Instead DOE cites other studies—including average effective tax rate studies by API and EIA, an analysis by DOE, and other research studies—that it believes indicate different results.

We do not agree with DOE's view about proper tax treatment for extractive industries. Our view is that expensing and percentage depletion provisions available to petroleum producers constitute favorable treatment because the cost of most other business investments is deductible for tax purposes over a time period that more closely corresponds to the investments' productive lives. Both of these tax preferences are reflected in the tax expenditure analyses of the President's budget and the Joint Committee on Taxation.

As we discuss in the text, average effective tax rate studies—such as those cited by DOE and those presented in appendix I—do not indicate the marginal effective tax rates currently faced by new marginal production investments. Although we asked DOE for a copy of its marginal tax rate analysis, DOE did not provide it. Thus, we are unable to comment on its methodology or assumptions. The other research studies cited by DOE that consider marginal effective tax rates are not appropriate for consideration here because they did not attempt to provide a detailed analysis of the special tax treatment of the oil and gas production industry.

Petroleum Investment Abroad Explained Largely by Factors Other Than Taxes

While domestic petroleum production and investment have fallen since the oil price decline of 1986, exploration and production activities by U.S. firms have increased in many areas abroad. Our analysis suggests that taxes are not the major reason for the relative attractiveness of foreign petroleum investments. Petroleum production investments by U.S. firms abroad have become relatively more attractive than those in the U.S. largely because of the decline in the price of oil and favorable foreign geologic characteristics, including lower finding and development costs. In general, U.S. petroleum companies face higher average effective taxes on their foreign production earnings than on their domestic production earnings. Foreign development decisions appear to be driven more by cost and geologic considerations than by tax incentives. However, many petroleum producing countries have recently tried to encourage additional petroleum exploration and production by lowering their tax rates or royalties or otherwise moderating their treatment of petroleum investment. These changes may lead to relatively low marginal tax rates on new exploration and development activities in some foreign countries and hence provide additional incentives for investing abroad by U.S. firms.

Factors Other Than Taxes Appear to Explain Foreign Petroleum Investment

Exploration and development expenditures by U.S. firms both domestically and abroad were lower in the second half of the 1980s than in the first half. Foreign petroleum investments, however, rebounded earlier after the significant fall in oil prices in 1986 than have domestic investments. In this period of relatively low oil prices, the relative attractiveness of foreign investment is largely explained by more attractive geology and lower petroleum finding and development costs abroad.

To understand the relative decrease in new petroleum investment in the United States and the increase abroad, the factors that influence investment location must be considered. According to the experts we interviewed and literature we reviewed, investors choose among projects based on differences in their expected overall financial returns—net of costs and taxes—and select projects with higher returns. Factors that affect the financial returns from petroleum projects include the expected future price of oil; expected finding, development, and production costs; taxes and regulations; and the political riskiness of the investment.[1] With the exception of the world oil price, which affects

[1] Finding and development costs include the geological and geophysical costs of locating the oil plus the costs of drilling wells for exploration and development. Production costs are the costs of pumping the oil.

petroleum investments worldwide, these factors can vary significantly by location.

Countries are endowed with different degrees of geologic promise, that is, with different expected costs of finding a given amount of reserves and producing them. In addition, there is great diversity among countries in the taxes and regulations imposed on petroleum investors. Host governments generally try to set petroleum taxes and other charges with the goal of generating revenue while also encouraging investors to develop their resources. The political risks of unilateral revisions in contract terms, expropriation, and civil disorder also vary across countries.

Evaluating a petroleum production project involves taking several factors—geologic promise, taxes, royalties, regulations, and political riskiness—into account in calculating an expected return. According to one group of experts, oil companies compare worldwide investment opportunities as follows. First, they consider the underlying geology of a proposed investment, including the probabilities of discoveries of varying sizes and the costs of production. Then they evaluate the profitability of the project under the tax and contract terms offered. Finally, they weigh the likelihood of any adverse changes in the price of oil, taxes and regulatory terms, and political stability during the life of the investment.

Petroleum taxes and regulations do not appear to be the most important factors in determining the location of petroleum investments. While foreign tax policies and other inducements can be contributing factors, favorable geologic characteristics, including lower petroleum finding and development costs abroad, appear to be the main factor behind the preference of U.S. companies to explore and develop foreign petroleum resources. A number of the experts we interviewed said that taxes were neither generally the most important influence on the location of petroleum investments, nor were taxes responsible for the decline in U.S. domestic drilling activity. DOE, however, as indicated in their comments on this report, does believe that the U.S. system of income and production taxes and royalties is an important factor in this decline.

Because so much of the United States already has been subject to extensive petroleum drilling and production, little oil remains that is cheap to find and produce. From 1980 through 1988, oil companies spent an average of $5.24 to find and develop a barrel of oil outside the United States—33 percent less than the $7.83 it cost to find and develop a barrel in the United States. Oil finding costs have declined considerably since the early 1980s; however, it has generally been more expensive to find oil in the United States than in most other oil-producing countries. Some petroleum experts suggest that finding costs in the United States are the highest of all major oil-producing countries. Table 5.1 provides estimates reported by the American Petroleum Institute (API) of petroleum finding and development cost data for the United States and foreign oil-producing areas for the past 11 years.

Table 5.1: U.S. and Foreign Petroleum Finding and Development Costs, 1978-1988

	Average costs in dollars per barrel	
Year	**U.S.**	**Foreign**
1978	6.64	4 15
1979	11 74	6.66
1980	10 57	6.17
1981	11 68	5.59
1982	9 86	8.66
1983	9.08	5.25
1984	6.80	3.94
1985	8.17	6.38
1986	7 11	7 41
1987	4 72	3.27
1988	5.09	4 73

Source API

Both petroleum costs and expected future prices affect the level of U.S. domestic petroleum investment. Lower oil prices since 1985 and the relatively high cost of U.S. supplies have encouraged U.S. oil companies to move their exploration and development activities to lower cost areas abroad. However, if oil prices rise due to changes in foreign production or consumption, we would expect U.S. production to comprise a greater share of United States consumption because the United States does have additional oil that is profitable to produce when prices are higher.

Foreign Tax Treatment Is Complex and Varies Greatly

Taxes and other rules governing the sharing of production and profits from petroleum extraction are complex and vary greatly across countries. Typically, petroleum producing countries require investors to pay a corporate income tax on profits earned in their country. Host governments often charge a royalty for any petroleum produced in their country.[2] In the United States royalties are paid either to a private landowner or to a government entity. In foreign countries, government entities generally own the petroleum resources and thus receive the royalties.

Many countries where significant reserves have been found have levied additional special taxes on petroleum profits. Governments often charge investors fees or bonuses for the right to undertake petroleum exploration, development, and production. Some countries rely mainly on production sharing with the company producing the oil to obtain their share of revenues. Occasionally, countries require that their national oil company, or a local company, be made a partner in any investment. Some countries provide investors with "petroleum allowances"—specified volumes of production that are not taxed. In addition to the taxes and charges they levy on domestic production, some governments levy income taxes on the foreign earnings of their citizens and corporations, including their foreign earnings from petroleum production.

When taxing profits, countries allow companies to use a variety of rules for expensing intangible costs—particularly drilling costs—depreciating tangible capital assets, and depleting reserves. Such rules may have a considerable impact upon the actual taxes payable. The specification of what are allowable costs, when cost recovery can begin, and how rapidly recovery proceeds can be as important to the overall burden of an income or other profits tax as the rate of taxation. For example, it is the policy of some countries to allow recovery of substantially all petroleum investment costs before any taxes are owed. Some of the complexity and variation in petroleum taxes, charges, and rules for cost recovery is illustrated in appendix II.

Because systems of petroleum tax and investment contract provisions are complex and varied, many factors must be considered to get a picture of the overall fiscal attractiveness of a country for petroleum investment. In particular, statutory tax rates must be accompanied by extensive additional information on tax code and investment contract provisions. This information includes which costs may be expensed, how rapidly capital investments may be depreciated, whether some production is untaxed, whether costs incurred in one petroleum investment can be used to offset profits earned in another, and the extent, if any, of production sharing. When this information is incorporated into an estimate of the tax on a representative investment, the effective rate of

[2]Royalties are payments to the resource owner for the right to exploit the resource.

income taxation may be less than the nominal rate. As noted in chapter 4, various provisions of the U.S. tax code permit U.S. petroleum investments to enjoy a marginal effective rate of federal corporate income tax well below the statutory tax rate of 34 percent. Some other countries' petroleum tax systems have similar provisions with similar implications.

Studies by Tax Analysts, the Joint Committee on Taxation (JCT), and the Energy Information Administration (EIA) show that average effective rates of foreign income taxes on the foreign earnings of petroleum firms have consistently exceeded U.S. income taxes on the U.S. earnings of these firms. Tax Analysts considered at least two different classes of petroleum firms (i.e., firms classified as primarily extractive and one or two classes of integrated refining firms) from 1980 through 1987 and found, with only one exception, that foreign taxes on foreign income exceeded U.S. taxes on U.S. income in each case.[3] The JCT study, which considered large integrated producers, found that foreign tax rates on foreign petroleum income exceeded U.S. income tax rates on U.S. petroleum income in each year between 1980 and 1983. Finally, U.S. Energy Information Administration (EIA) data for companies in their Financial Reporting System indicate the same pattern over the years 1981 to 1988.

We cite average, rather than marginal, effective tax rate studies here because we could not find marginal effective tax rate estimates for petroleum production investments outside the U.S. Furthermore, because some petroleum-producing countries rely mainly on non-tax instruments to obtain their share of the returns to domestic petroleum production, even if marginal effective tax rates were available for these countries, they would provide only a partial picture of the comparative fiscal attractiveness for investment. For example, whether a government requires that its national oil company or a domestically owned oil company participate in every foreign investment, requires an investor to meet domestic petroleum needs at below market prices, or requires production sharing can be important. Some of this information, along with data on statutory marginal tax rates and royalties, is provided in appendix II.

Finally, specialists in the U.S. tax treatment of foreign earnings whom we interviewed said that it is not currently possible for U.S. companies

[3]The one exception is caused by a very small sample of five extractive firms in 1985, where the average U.S. tax rate is skewed by one firm. When this firm is deleted from the sample, the general result again is obtained

engaged in petroleum production to improve their U.S. income tax position by investing abroad. U.S. companies paying income taxes to foreign governments currently receive credits against their U.S. income tax liabilities for foreign income taxes paid, but not for their payments of royalties or other non-income taxes. Instead, royalty payments to resource owners are deductible from gross income. Treasury Department and other experts said that it is not possible for these companies to disguise royalties paid to foreign governments as income taxes and, thus, receive U.S. income tax credit for royalties paid abroad. Therefore, they do not believe that U.S. petroleum producers are attracted abroad by an opportunity to reduce their U.S. income tax liabilities.

U.S. tax treatment of petroleum production investments abroad is less generous than U.S. tax treatment of domestic petroleum production investments. Specifically, the U.S. corporate tax treatment of IDCs incurred abroad is stricter than that for IDCs incurred in the United States. IDCs incurred abroad on productive wells are recovered over 10 years using straight-line amortization, or if the taxpayer prefers, using cost depletion.[4] In addition, equipment used abroad is depreciated more slowly for U.S. tax purposes than is equipment used in the United States. Finally, foreign production is ineligible for percentage depletion. Thus, U.S. firms that actually pay U.S. taxes on their foreign income will generally face higher marginal effective tax rates on their new foreign investments than they face on their new domestic investments. In general, however, U.S. petroleum firms tend to pay foreign taxes but not U.S. taxes on their foreign earnings, in part because foreign average effective tax rates are generally above U.S. rates.

Although foreign average effective tax rates are generally higher than U.S. rates, and U.S. marginal tax rates on domestic petroleum investments are relatively low compared to those on most U.S. industries, it is possible that some firms could face foreign marginal effective tax rates that are below those on some U.S. petroleum investments. Currently, some petroleum-producing countries allow expensing or similar favorable recovery of costs incurred in petroleum exploration and development. For example, in Canada all exploration costs, including G&G costs, are expensed. Thus, exploration costs face a marginal effective tax rate of zero.[5] The United Kingdom has levied a special surtax on

[4]IDCs incurred abroad on nonproductive wells are deductible when the well is completed, as in the United States.

[5]Developmental drilling costs are recovered at the slower rate of 30 percent of unrecovered costs per year, however, so they would face a higher marginal effective tax rate.

petroleum profits, the Petroleum Revenue Tax, in addition to its corporate income tax. Although the Petroleum Revenue Tax provides the bulk of the country's revenues from petroleum, 135 percent of a field's finding and development costs can be written off before any of this tax is owed. This feature and the ability to deduct costs incurred in investments in new fields against income earned from earlier investments in other fields provide a strong incentive for the ongoing investor to undertake new exploration and development projects. Although the combined statutory marginal rate of the income and petroleum revenue taxes is 83.75 percent, because of these capital recovery provisions the U.K. government is effectively bearing most of the cost of new investment. Thus, despite relatively high statutory tax rates, marginal effective tax rates may be low.

Many Governments Have Recently Improved Their Terms for Petroleum Investment

Following the oil price declines of 1985 to 1986, petroleum-producing countries seeking to maintain petroleum investments in their countries at existing levels sought to improve their incentives for petroleum investment. These measures reduced their governments' total "take"[6] from petroleum production in an effort to shore up domestic petroleum investment in the face of falling profits. As owners of their countries' petroleum resources, many of these governments used measures in addition to income tax policy to lower their total take from petroleum production.

Table II.2 in appendix II indicates which of the countries we studied changed their tax and royalty levies on petroleum production and the instruments they used. As indicated in the table, some countries, such as the United Kingdom and Canada, have made numerous adjustments to their petroleum production tax systems.

Since 1985, for example, the Canadian federal and provincial governments have adopted petroleum royalty credits and holidays, exploration and development grants and loan guarantees, cash rebates on exploration and development expenditures, and a sliding scale royalty system for marginal wells. Because royalties are generally the most important part of the total take in Canada, countercyclical royalty holidays can provide a strong incentive for prospective petroleum investors. Some incentives implemented by Canada's federal and provincial governments

[6] "Total "take" refers to income tax plus royalty, severance tax, and other revenue-based payments by petroleum producers to landowners and governments.

have recently expired or have been reduced, however, reportedly due to concern about their revenue losses.

Agency Comments and Our Evaluation

DOE states that while geology and finding costs are important to understanding the shift of exploration activity abroad, the U.S. tax system is also important. DOE bases this conclusion on several pieces of evidence, including its own analysis of total take, which includes royalties as well as taxes.

We agree, and this report states, that taxes are one factor that can affect profitability and hence firms' willingness to invest. However, finding and development costs abroad have generally been below those in the United States. Average tax rates faced by firms abroad have also generally been higher. Because of the variability and complexity of foreign tax systems, we did not calculate marginal effective tax rates precisely for firms exploring abroad. However, we did examine selected foreign tax systems qualitatively. Because some countries allow some activities to be expensed or allow cost recovery over a few years, it is possible that marginal effective tax rates on these activities could be zero or near zero in these countries. In such cases, U.S. firms may have incentives to make investments abroad because of somewhat lower taxes than would be faced on those activities in the U.S.

DOE's discussion of take, however, blurs the distinction between taxes and payments to landowners for the right to explore for and extract oil. Although we asked for a copy of DOE's take analysis, DOE did not give it to us. Therefore, we are unable to comment on DOE's methodology or assumptions. However, DOE's discussion suggests that royalties and severance taxes respond in a limited way to changes in profitability. DOE's discussion does not recognize, though, that it is precisely the income tax portion of the U.S. system that does respond to changes in profitability. At present, royalties, state severance taxes, and other state taxes imposed on oil production are deductible for federal income tax purposes. Thus, for taxpayers subject to the regular income tax, the federal government bears 34 percent of the costs of these payments through the tax system. Overall, we do not find convincing the argument that the federal government should further lower income taxes—which are responsive to profits—for one industry because some landowners and states are reluctant to lower their royalties and taxes. DOE's criticisms may suggest some benefits from expanding reliance on profit-based take systems, if the goal of the government is to encourage exploration and development when prices are low. Although increasing access to reserves would have some positive effects on energy security in the short to medium term, it would also hasten the depletion of U.S. reserves, which could have negative longer run implications for U.S. energy security.

Policy Considerations, Conclusions, and Matters for Consideration

Additional tax incentives for the petroleum industry would increase oil and natural gas exploration, development, and production above their levels in the absence of these provisions. These features could increase U.S. energy security and assist the economies of regions with petroleum activity. We are concerned, however, about the cost-effectiveness of these incentives as a means of providing long-term energy security. We are also concerned with the effect on investment allocation of increasing relatively favorable treatment for the petroleum industry as a whole and for certain types of investments and categories of producers within the industry.

Energy Security and Tax Incentives

A key argument in favor of petroleum tax incentives is the potential gain for U.S. energy security—i.e., the reduction in the vulnerability of the United States to an oil supply disruption—that can occur through the increases in production, reserves, and exploration and development capacity that are encouraged to varying degrees by the types of proposals considered here. It is not certain, however, that additional tax incentives for the petroleum industry would significantly increase U.S. energy security. They may have a relatively small and short-term impact on output, and they may also be less cost-effective than other alternatives. As an overall approach to energy security, our previous work has called for attention to alternative fuels, conservation, oil storage, international coordination, and a stable economic and regulatory environment.

Oil tax incentives can contribute to energy security by strengthening the domestic petroleum industry. Increased U.S. production may also discourage oil disruptions by foreign producers. Increased reserves would provide long-term security, although because of the time needed to start production they not be immediately available in the event of a crisis. In addition, the ability to draw upon productive capacity, such as trained personnel and specialized equipment, would also facilitate increased domestic production in the event of a crisis.

Our 1988 report and recent testimony on the world oil market found that while the United States and other major oil-consuming countries were less vulnerable to an oil crisis than they were a decade ago, the problems caused by oil disruptions warrant continued vigilance.[1] That report and testimony, as well as other studies, found that energy

[1] Energy Security: An Overview of Changes in the World Oil Market (GAO/RCED-88-170, Aug. 31, 1988); and Energy Security and the World Oil Market (GAO/T-RCED-90-12, Nov. 8, 1989).

security had increased over the previous decade due to favorable changes in the world oil market.[2] These changes include more abundant oil supplies, an increased number of petroleum exporting countries, increased reliance of these exporters on petroleum revenues, and an increase in alternative transportation routes. These studies and others, however, emphasize the seriousness of continued high reliance on foreign production.[3]

Our 1988 report recommended reducing dependency on oil and vulnerability to an oil crisis by focusing on the following:

- developing alternative fuels and emphasizing increased fuel efficiency in the transportation sector;
- continuing to build strategic oil stocks, such as the Strategic Petroleum Reserve (SPR), as quickly as is fiscally responsible and resolving related disputes with the International Energy Agency;
- adopting other standby measures, such as demand restraints, providing they can be shown to be effective; and
- maintaining a stable economic and regulatory environment that encourages investments in oil and alternative energy sources.

That report neither specifically identified nor ruled out tax incentives as an appropriate policy direction. Our recent testimony has reiterated these suggestions.[4]

As Congress weighs the energy security benefits of oil tax incentives it will be useful to compare their cost-effectiveness and other properties with the properties of alternative policies —including conservation, alternative fuels, relaxed environmental controls, and petroleum storage—that also could increase energy security. For example, we have estimated operation and construction costs for filling the SPR, within current planned capacity, to average about $1 per barrel over the period 1988 to 1997.[5] In addition, oil storage requires outlays for the purchase of the oil; however, this oil is a capital asset that would remain available

[2]See also U.S. Department of Commerce, The Effect of Crude Oil and Refined Petroleum Product Imports on the National Security, 1989

[3]See, for example, American Petroleum Institute, Energy Security White Paper: U.S. Decisions and Global Trends, November 1988

[4]The Strategic Petroleum Reserve Amendments of 1989 (GAO/T-RCED-89-38, May 4, 1989); and Energy Security and the World Oil Market (GAO/T-RCED-90-12, Nov. 8, 1989).

[5]Oil Reserves: An Analysis of Costs—Past, Present, and Future (GAO/RCED-87-204FS, Sept. 29, 1987), p. 14.

until needed. If the estimated revenue cost of the administration's proposals were instead invested in filling the SPR, then approximately 80 to 100 million barrels of oil (at a cost of $20 per barrel) could be added over the next 4 years. In addition, in the event that the stored oil is sold during a crisis, the budgetary receipts would very likely more than offset the cost of the initial purchases.[6] While current budget treatment would show the entire cost of the oil purchase at once, a capital budget of the type we recommend would recognize the lasting nature of investments in SPR oil.[7]

Besides cost, there is another way that holding petroleum reserves compares favorably with providing tax incentives for increased production. Since cheaply exploitable petroleum resources are limited in the United States, incentives for greater production today—when there is no crisis—may not enhance long-term U.S. energy security. Tax incentives for current domestic production advance the timetable of use of nonrenewable U.S. oil resources and could increase our future dependence on foreign suppliers. Furthermore, the small to modest percentage increases in production anticipated from the tax incentives discussed in this report may not significantly alter our vulnerability to disruptions. Many of the energy experts we interviewed said that the proposed tax incentives would have little or no significant impact on energy security. In contrast, several experts with whom we spoke emphasized the value of a large SPR for reducing our vulnerability to energy shocks.

Given current technologies and costs of production, alternative fuels can provide only very limited protection from domestic energy supply disruptions. Because two-thirds of U.S. oil use is for transportation, however, development of cost-effective alternative fuels and increases in efficient use could have a significant impact on energy security. Such developments also may have positive environmental implications.

Conclusions

Marginal petroleum ventures are currently taxed less than investments in almost all other industries. The zero tax rate faced by some petroleum investments, for example, encourages some activities with pretax returns one-third less than those of investments that face effective tax

[6]To determine whether oil storage in the SPR leads to net economic benefits, one would also need to consider the interest expenses incurred by investments in SPR oil. Because we do not consider the interest expenses caused by revenue losses arising from tax incentives, however, we do not include the interest expenses incurred on SPR oil purchases here.

[7]Budget Issues: Restructuring the Federal Budget—The Capital Component (GAO/AFMD-89-52, Aug. 24, 1989), pp. 18-19

rates near 34 percent. Thus, it appears that some relatively inefficient investments are being encouraged by existing petroleum tax incentives.

We also found that certain types of exploration and development activities, such as drilling, are less heavily taxed than other types, such as G&G work or investments in depreciable equipment. In addition, we found that independent firms are at times less heavily taxed on the same activities than integrated firms.

The proposed incentives that we reviewed appear costly for the relatively small to modest estimated additions to production. On the basis of DOE's October 1989 production estimates for modification of the AMT treatment of certain IDCs and repeal of the transfer rule, we estimate revenue losses of about $3 to $14 per barrel of additional production. DOE's 1987 estimates imply that provisions targeted to G&G work appear to be more cost effective than more general exploration and development subsidies. This result is consistent with the higher effective tax rate faced by G&G investments in comparison to rates faced by IDCs, which are a major share of exploration and development costs. However, because of the difficulty of estimating output, revenue, and cost-effectiveness figures, and the limitations of DOE's 1987 analysis, this cost-effectiveness analysis should be interpreted cautiously.

We also found that foreign ventures are largely encouraged by favorable geologic characteristics, including relatively low finding and development costs abroad. Petroleum production in the United States faces lower average effective tax rates than petroleum production abroad. However, many foreign governments have eased their tax and royalty treatment of petroleum production. These changes could lead to low marginal effective tax rates in some countries and further encourage U.S. firms to invest abroad.

The U.S. government could use federal tax policy to cushion its domestic petroleum industry from oil price shocks. However, the United States today is a high cost petroleum producer. If the U.S. government were to adopt countercyclical federal income tax measures specifically for the petroleum industry, it would be encouraging investments with relatively low rates of return. Furthermore, the tax reductions for petroleum production would have to be substantial, not marginal, in order to increase U.S. production by more than a small amount.

This report focuses on the cost-efficiency in terms of federal revenue losses and the relative tax burden implications of additional tax incentives. It was not within our scope to evaluate all of the issues that could affect decisions on petroleum tax policy. We did not evaluate, for example, the distributional impacts of the incentives on different regions and income groups or the environmental implications of these incentives versus alternative energy policies. We also did not determine whether the current level of petroleum tax incentives is appropriate to compensate for factors such as risk or information spillovers. In principle, these considerations could suggest taxing the industry more or less than it is currently taxed.

Some proposed incentives benefit all production, while others, such as those related to exploration and new investments, tend to benefit new production. However, even provisions aimed at new activity—whether it involves drilling or enhanced oil recovery—are likely to benefit some activities that would occur without these incentives. Limiting tax incentives to genuinely incremental production would, by definition, restrict the benefits only to projects that would be unprofitable given current prices, costs, and taxes. This would appear to be a challenge administratively, though it might be possible to target certain types of ventures. Provisions affecting types of petroleum investments not already favored by the tax code—and hence that tend to yield higher pretax returns—may also be more efficient in terms of both budgetary and private investment impacts than additional incentives for activities that already receive substantial tax preferences.

We believe, however, that it is difficult to justify the proposed provisions on the basis of energy security. The energy security gains may not be long lived or cost effective. Additions to the SPR or other policies may be more cost effective and lasting in their security impacts. We also believe that there is not a strong basis for incentives in favor of certain types of petroleum exploration activities, such as drilling, versus other types, such as G&G work. In addition, we agree with the general consensus of the experts we spoke to that there is not a good economic justification for differential treatment of investments by independent and integrated firms. With few exceptions, we found a consensus among experts that petroleum exploration, development, and production should be subject to tax policies that encourage the most efficient investments and firms.

Matters for Congressional Consideration

Before approving additional tax incentives for petroleum investments, Congress should weigh carefully their costs and benefits. Given the expected federal revenue losses, we believe that providing additional tax incentives is not the most effective method of providing significant increases in U.S. energy security. In addition, where the incentives benefit types of activities and classes of producers that are already relatively favored by the tax code, they will tend to encourage relatively inefficient investments.

Agency Comments and Our Evaluation

DOE stated that it disagreed with major findings of the report and with our overall conclusion that additional tax incentives are of questionable merit. DOE, for example, does not believe that extractive industries should face the same type of capital recovery for tax purposes as other industries. Thus, DOE does not believe that the petroleum industry currently receives favorable tax treatment. DOE also does not accept the marginal effective tax rate analyses presented. In addition, DOE believes that the U.S. tax and royalty system has been an important factor encouraging petroleum production investments abroad. Finally, DOE had criticisms of the report's discussions of specific tax incentives and the SPR.

DOE's comments reflect several areas of disagreement with the report. However, in general we believe that the issues raised in DOE's comments do not affect the report's major findings or conclusions. DOE's views on appropriate tax treatment are not consistent with leading analyses of tax preferences, including, for example, the tax expenditure studies of the President's budget and the JCT. As discussed in chapter 4 (p. 61), we also believe that DOE's criticisms of the marginal effective tax rate analyses are not valid. While we agree that taxes and royalties could contribute to some investment abroad, we also believe—as discussed in chapter 5—that these investments are largely encouraged by favorable foreign geologic characteristics, including relatively low finding and development costs. As discussed in chapter 3, available data suggests that additional tax incentives such as those proposed by the administration would not significantly increase U.S. oil production. In addition, we are not convinced that the U.S. government should modify its income tax law—which does respond to profits and already favors petroleum producers over most other industries—if take problems arise due to royalties and severance taxes that are not profit based. We also believe that our discussion of specific incentives is accurate. Finally, while DOE's discussion of the SPR raises questions about the merits of expanding the SPR beyond its planned 750 million barrel level, it does not explain why additional tax incentives are a better approach to energy security than faster additions to reach the 750 million barrel level or alternative energy policies.

Treasury stated that tax incentives for the domestic petroleum industry are an essential part of the administration's energy security policy. Treasury also believes that an approach that includes filling the SPR, encouraging the development of alternative energy technologies, promoting energy conservation, and increasing tax incentives for the petroleum industry is the best means of increasing energy security.

Treasury's comments largely restated the administration's proposals for additional tax incentives and its view that these proposals are warranted. Treasury did not indicate significant technical disagreements with the report.

Average Effective Tax Rates

Average effective rates of federal corporate income tax for oil and gas firms vary depending on the study, type of firm, and time frame considered. It is particularly difficult to compare average and marginal effective tax rate data in the case of the petroleum industry because the large petroleum firms engage in significant refining, marketing, and nonpetroleum activities that receive different tax treatment than their petroleum production investments. The studies we found on independent firms either considered very small samples or did not consider the firms' foreign tax payments or their windfall profit tax payments when this tax was in effect. Depending upon the studies and years considered, average effective rates for the petroleum industry were variously estimated to be below, near, or above those of all industries combined. In general, the petroleum industry and most other industries faced average effective tax rates below the prevailing statutory rates over the years considered.

On the basis of data for 1988 compiled by the Citizens for Tax Justice, we calculated that the 13 firms they considered in the oil, gas, coal, and mining sector had an average effective tax rate in 1988 of 25.8 percent. This compares with their study's average tax rate for 250 firms in all industries of 26.5 percent. The Citizens for Tax Justice data reflect current federal income taxes and are based on a study of financial statements of major corporations. The data do not distinguish between the tax rate on the petroleum production and other activities of the companies considered.

On the basis of these data we also calculated average effective tax rates for the 13 companies in this sector for the years 1981 to 1985, 1986, and 1987. For the period 1981 to 1985 the sector had an average effective tax rate of 18.2 percent, which is above the all-firm average of 14.3 percent. In 1987 and 1986 our calculations show that this sector had average effective rates of 13.7 and 3.4 percent, which are below the study's averages for all firms of 21.2 and 14 percent.

In a recent study, we estimated average effective tax rates for 1986 and 1987 using financial statement data based on a methodology and a sample of firms developed in a series of reports by the JCT.[1] This study considered taxes paid by 18 petroleum firms, of which most are large, integrated refiners. For 1987 these firms had a very high average effective tax rate. However, this rate was substantially affected by the very

[1] Tax Policy: A Comparison of Corporate and Industry Effective Tax Rates (GAO/GGD-90-69, May 10, 1990).

large book loss reported by one firm, Texaco, which was primarily related to its settlement of litigation surrounding the acquisition of Getty Oil. If this firm is excluded from the sample of petroleum firms for 1987, the industry had an average effective rate of 23.9 percent. This rate is below the average effective rate of 27.8 percent for all 220 firms in 29 industries in the sample. For 1986 the 18 petroleum firms had an average effective tax rate of -76.2 percent, as they had negative current U.S. corporate taxes and positive book income. The average for all firms for that year was 18.6 percent.

We also considered studies of average effective tax rates by Tax Analysts, the publisher of Tax Notes. The Tax Analysts estimates are based on financial statement data. Both the oil and gas extraction and petroleum refining sectors are estimated to have average effective tax rates close to the average for all industries in 1987, the most recent year available. Oil and gas extraction is reported by Tax Analysts to have higher than average effective corporate income tax rates for each year during the period 1980 to 1986. For this sector, however, the average rates reported by Tax Analysts may not be representative because they are the average for four or five companies, and the tax rates for their sample companies vary substantially.[2] Oil refiners are estimated by Tax Analysts to have average effective federal income tax rates below the U.S. average for each year over the period 1981 to 1986. The largest refiners and the refining industry as a whole slightly exceeded the average rate for U.S. firms in 1980 and 1987, respectively.

Starcher (1988) calculated average effective tax rates on the basis of IRS data on actual tax returns. For the period 1980 to 1984, oil and gas extraction firms had an average effective federal corporate income tax rate of 13.1 percent. The petroleum refining industry, which includes the largest oil producers, had an effective rate of 13.9 percent. These rates represented the fourth and fifth lowest rates of the 49 industries considered. The average overall tax rate was about 20.0 percent over this period. For the year 1985 the petroleum extraction and refining industries had average effective federal income tax rates of 6.8 percent and 7.0 percent, respectively, which were the lowest of the 49 industries considered. The all-industry average rate in 1985 was 19.1 percent. The Starcher analysis may show relatively low tax rates for petroleum firms—which in many cases have substantial foreign operations—

[2]Tax Analysts explicitly note that the 1985 data should not be viewed as representative because of its small sample. In this case, tax rates vary from a few percent for two of the five companies, to a few thousand percent for another. Other years' samples have even fewer companies. Tax Analysts also include a large integrated oil refiner within the oil and gas extraction group.

because of the manner in which it treats foreign tax credits, however. Because it considers only the U.S. income taxes paid net of foreign tax credits, the Starcher analysis does not reflect the foreign taxes paid on some of the income of these firms.

The average effective corporate income tax rates for petroleum producers during the years 1980 to 1986 are also likely to be reduced by the windfall profit tax payments of the firms. This tax was another source of payments by the petroleum producers, and if it had not been in effect their income tax obligations would have been higher.

Table I.1 presents API estimates of average effective tax rates that address this issue. Three types of comparisons are made to illustrate the combined average effective tax rate due to federal corporate income and windfall profit taxes during the period 1980-1988. The analysis compares a group consisting of leading oil companies with a group of 100 large industrial firms not primarily engaged in petroleum activities.[3] The API analysis does not distinguish between the tax rates on production and on refining, marketing, and nonpetroleum activities of the large oil firms considered.

Table I.1: API Estimates of Average Effective Rate of Federal Corporate Income and Windfall Profit Tax, 1980-1988

	Average effective tax rates	
Taxes compared	**1980-1988**	**1988**
Corporate income plus windfall profit taxes		
Oil firms	38 7	30 0
Non-oil firms	22 7	29 8
Corporate income tax alone		
Oil firms	20 6	30 0
Non-oil firms	22 7	29 8
Estimated corporate income tax if windfall profit tax had not been in effect		
Oil firms	26 4	30.0
Non-oil firms	22 7	29.8

Note Although some of the firms in the non-oil group had petroleum activities, as a whole this group paid little windfall profit tax thus, the estimated effective tax rates for the non-oil group are the same in all three cases Similarly, because oil firms paid negligible windfall profit taxes in 1988, their estimated tax rates are the same in all three cases for 1988

Source API

[3] API's analysis considered 19 to 20 oil companies over the period 1980 to 1988. For 1987 it excluded one firm (Texaco) because this firm reported high pretax losses that considerably raised the tax rate of the sample.

According to the API analysis, over the period 1980 to 1988 the large oil firms had a combined average effective rate of federal corporate income and windfall profit tax of 38.7 percent of net U.S. income before taxes. In contrast, non-oil firms had an average effective rate of 22.7 percent. This rate reflects essentially only corporate income taxes, since the non-oil firms paid only a small amount of windfall profit taxes. In 1988 windfall profit tax payments were negligible for oil firms, because the price of oil generally was below the price that triggered windfall profit tax payments. In this year the average combined effective rates of corporate and windfall profit tax for the oil and non-oil firms were 30.0 and 29.8 percent, respectively.

If one considers federal corporate income taxes alone, oil firms had an average rate of 20.6 percent over the period 1980 to 1988 versus a rate of 22.7 percent for the non-oil firms. However, if there had been no windfall profit tax, then oil firm profits subject to the corporate income tax would have been greater over the period 1980 to 1988. The final comparison in table I.1 shows that in this case the average effective corporate tax rate for the sample of large oil firms would have been 26.4 percent over this period.

Summary of Petroleum Tax Treatment in the United States and Selected Foreign Countries

Some of the complexity and variation in petroleum taxes and contract terms is illustrated in table II.1. The table describes taxes and regulations facing petroleum producers operating in the United States, Canada, the North Sea oil-producing countries, and some far eastern and South American oil-producing countries. The table also provides some insight into the comparative petroleum fiscal positions of 12 countries with petroleum production potential that may interest U.S. investors.[1] Table II.2 lists some of the changes these countries have made since 1985 in their tax policies and contract terms for petroleum investment.

[1] We concentrated our analysis on countries that are not members of the Organization of Petroleum Exporting Countries (OPEC) because their petroleum production is more likely to respond freely to market incentives than is OPEC production, which is influenced by quotas. Of the countries considered here, only Ecuador and Indonesia belong to OPEC.

Table II.1: Summary of Petroleum Tax Provisions for the United States and 11 Other Petroleum Producing Countries

Country	National oil company	Petroleum contract	Special petroleum tax	Top corporate income tax rate	Deductions from corporate tax
USA	None	Leases awarded by cash bonus bidding and other methods	Windfall profit tax abolished in 1988	Federal tax rate is 34 percent of profits; alternative minimum tax rate of 20 percent for corporations adds back to taxable income tax preference items arising from accelerated depreciation, percentage depletion, and the expensing of intangible drilling costs (IDCs); state average tax rate is 7 percent of profits	State income and severance taxes, royalties, most IDCs; other capital costs must be recovered under cost or percentage depletion; independents may use percentage depletion for lease bonus and geological and geophysical (G&G) costs but net income limits, production limits, and the transfer rule curb their use, integrated firms must use cost depletion.
Canada	Petro-Canada	Exploration agreements include cash bonuses and work programs; production licenses for some areas require 50-percent Canadian ownership; government loan guarantees for some new projects	Petroleum and Gas Revenue Tax was phased out as of 1989	Federal tax rate of 28 percent, plus federal income surtax of 3 percent of federal rate, plus province of Alberta tax rate of 15 percent, is 43 8 percent of profits.	G&G costs and exploration drilling costs deductible, royalties deductible for provincial tax only, provincial income taxes not deductible; 10 percent of lease acquisition costs net of previous depreciation recovered annually, 30 percent of developmental drilling costs net of previous depreciation recovered annually, 25 percent of capital equipment costs net of previous depreciation recovered annually, resource allowance of 25 percent of corporate net income is deductible for federal tax.

Cost recovery of exploration expenditures	Cost recovery of development expenditures	Statutory marginal tax rate	Royalties and production taxes
Lease bonus and G&G costs must be recovered under cost or percentage depletion, independents may expense all exploratory IDCs, integrated firms may expense 70 percent and depreciate the remainder over 5 years, all dry hole costs may be expensed	Independents may expense all development IDCs, integrated firms may expense 70 percent and depreciate the remainder over 5 years, tangible development costs must be capitalized and depreciated, cost recovery begins with the start of production	Federal corporate income plus state corporate income tax rate is 39 percent	Royalties vary by location, ownership, and production rate of field, minimum rate usually is 12.5 percent; average state government severance tax rate for petroleum is 5 percent.
All exploration costs, including G&G, recovered immediately, some cash rebates available for exploration expenditures.	30 percent of developmental drilling costs net of previous depreciation recovered annually.	Federal plus provincial corporate income tax rate, plus federal surtax, is 43.8 percent.	Federal and provincial royalty holidays and rebates for new and enhanced oil recovery projects: royalty rate 1-28 percent before rebates, depending on well production rate and price of oil.

(continued)

Country	National oil company	Petroleum contract	Special petroleum tax	Top corporate income tax rate	Deductions from corporate tax
United Kingdom	None	Discretionary allocation of leases with cash bonus bids	Petroleum Revenue Tax of 75 percent of profits on a field basis, deductible costs include exploration, development and operating costs and royalties; in addition, 35 percent of all costs incurred before field is profitable are deductible ("uplift"), volume allowances exempt some production from this tax, safe-guards limit taxes on less profitable fields, some cross-field exploration costs deductible	35 percent of profits	Petroleum Revenue Tax, royalties, interest, exploration and operating costs deductible, 25 percent of capital costs net of previous depreciation recovered annually, cost recovery begins in year of expenditure, nonpetroleum deductions and losses do not offset petroleum profits
Norway	Statoil	Discretionary leases, Norwegian operators get preferred status in lease awards, 51-85 percent state plus Statoil participation, depending on production rate, with some costs reimbursed for licenses issued after 1986	Special Tax of 30 percent of profits, exploration and operating costs and interest deductible, dividends and losses from non-oil and oil refining and marketing activities not deductible, capital costs depreciated over 6 years from time expenditure incurred, an oil allowance exempts 15 percent of the gross value of production from Special Tax	State tax rate is 27.8 percent and municipal tax rate is 23 percent of profits. There is also a tax on corporate net worth	Exploration costs, license fees, royalties, interest, dividends (from national tax only), 50 percent of losses incurred elsewhere can offset income from continental shelf petroleum production, capital depreciated over 6 years from time expenditure incurred, non-petroleum deductions and losses do not offset petroleum profits; Special Tax not deductible
Denmark	DOPAS	Discretionary allocation of leases with cash bonus bids, state oil company participation of 10-40 percent required depending on production rates, state oil company's share of exploration costs is borne by investor unless a state owned company is the field operator	Hydrocarbon Tax of 70 percent of profits on a field basis, deductions include corporate tax royalties, exploration, operating and interest costs, depreciation of equipment, plus an allowance for 25 percent of initial exploration and equipment costs for 10 years	40 percent of profits	Exploration costs before production begins, operating costs, royalties, interest, 30 percent of capital costs for development and production net of previous depreciation recovered annually, nonpetroleum deductions and losses do not offset petroleum profits

Cost recovery of exploration expenditures	Cost recovery of development expenditures	Statutory marginal tax rate	Royalties and production taxes
All exploration costs including G&G deductible	Intangible development costs deductible, tangible development costs capitalized	National corporate income tax plus Petroleum Revenue Tax rate is 83 75 percent	Royalties abolished on most offshore fields developed after 4/1/82. 12 5 percent on old fields
Either expensed or deferred until profits are earned	Depreciated over 6 years from time expenditure incurred	State corporate income tax rate of 27 8 percent plus Special Tax rate of 30 percent is 57.8 percent; municipal corporate tax rate is 23 percent, minimum tax rate on distributions is 10 percent	Royalties abolished on fields developed after 1986, 8-16 percent on old fields depending on production rate.
Exploration costs before production begins can offset other income, be carried forward as losses, or be capitalized and amortized over 5 year once production begins.	30 percent of capital costs for development and production net of previous depreciation recovered annually	National corporate income tax plus Hydrocarbon Tax rate is 82 percent	Royalties abolished for new fields, 2-16 percent on old fields depending on production rate

(continued)

Country	National oil company	Petroleum contract	Special petroleum tax	Top corporate income tax rate	Deductions from corporate tax
The Netherlands	DSM	Negotiated prospecting, exploration, and production licenses; state participation in licenses, at a rate of 50 percent, is optional	State Profit Share of 70 percent of profits, deductibles include royalties, exploration and operating costs and depreciation; in addition, 20 percent of annual operating costs ("uplift"), excluding royalties, and 70 percent of the depreciation charge on fixed assets may be deducted, subject to certain limits, corporate income tax paid is credited against Special Profit Share.	35 percent of profits	Exploration and operating costs, royalties, Special Profit Share deductible; losses elsewhere may be used to offset petroleum profits; depreciation is either straight-line or unit of production; an investment premium of 12.5 percent of field capital investment is deductible
Australia	None	Cash bonus bidding or by exploration work commitments	Resource Rent Tax of 40 percent of profits on a project basis replaces excise and royalties on some offshore fields developed after 6/84, production is untaxed until a profitability threshold is reached, exploration and development costs are deductible; Crude Oil Excise Tax on fields developed before 7/84 at 75 percent in 1990 on large fields and less on smaller fields, rate rises with the price of oil, for some new fields first 30 million barrels exempt, liquefied petroleum gas is excise-free.	39 percent of profits.	Lease acquisition costs, Resource Rent Tax, exploration costs, royalties, Crude Oil Excise Tax, capital costs depreciated over 10 to 20 years.

Cost recovery of exploration expenditures	Cost recovery of development expenditures	Statutory marginal tax rate	Royalties and production taxes
May be deducted as incurred.	Development costs recovered on a unit of production or 14 year straight line basis	National corporate income tax plus Special Profit Share is 70 percent	Royalty rate on a sliding scale of 0-15 percent depending on field production rate; production costs, including depreciation, are deductible.
Exploration costs may be deducted or carried forward.	Accelerated deductions are available for capital expenditures.	National corporate income tax plus Resource Rent Tax rate is 63 4 percent.	Royalty rate of 10-12.5 percent on fields developed before 7/84, none on some new fields, negotiable on some marginal fields.

(continued)

Country	National oil company	Petroleum contract	Special petroleum tax	Top corporate income tax rate	Deductions from corporate tax
Indonesia	Pertamina	Production sharing Pertamina gets first 14 percent of production before cost recovery, after cost recovery, oil is shared between company and Pertamina in 15 to 85 ratio, company's share rises to 20 and 25 percent for production from marginal fields and frontier areas respectively, optional 10-percent participation by a domestic company with foreign company's expenses reimbursed; domestic sales requirement of 8 5 percent of gross annual production at full market price for first 5 years, also some joint operating agreements with Petamina		Oil and Gas Contractor's corporate income tax is 35 percent of profits, plus a dividend tax of 20 percent of after-tax profits, for an effective tax rate of 48 percent of profits, tax base depends on official General Selling Price for oil, which is higher than market price	Intangible drilling costs, interest, capital operating costs recovered over 2 to 10 years, investment tax credit of 17 to 20 percent, Tax Incentive (a deduction against income tax) is based on investor's production costs and his share of profit oil.
Argentina	YPF	Risk contracts, all petroleum produced is the property of YPF, company is reimbursed for petroleum at not less than 70 percent of world market price, the balance is paid to the national and state governments and to YPF, some joint operating agreements with YPF, state can demand 15-50 percent share in a field that an oil company has developed, state reimburses most exploration and development costs on its share		45 percent of profits; there is also a tax on corporate net worth.	Percentage depletion available for petroleum, all other taxes are deductible, depreciation over useful life of asset

Cost recovery of exploration expenditures	Cost recovery of development expenditures	Statutory marginal tax rate	Royalties and production taxes
Exploration costs are recovered out of company's share of production	Same as for exploration expenditures.	National corporate income tax rate is 48 percent	Production sharing.
When state participates it pays most of the exploration costs on its share		National corporate income tax rate of 45 percent	Not collected since 1978.

Country	National oil company	Petroleum contract	Special petroleum tax	Top corporate income tax rate	Deductions from corporate tax
Brazil	Petrobras	All new risk contracting discontinued in 1988, today foreign investors can be operating contractors only; under existing risk contracts government owns all production, reimburses contractor for production costs when government deems discovery to be commercial.		30 percent of profits, plus a 10-percent surcharge on very high income; state income tax of up to 5 percent of federal tax liability.	Depletion allowance, depreciation on a useful life basis.
Colombia	Ecopetrol	Companies bid on exploration contracts and, if oil is found, on association contracts; company retains 40 percent of any production, Ecopetrol gets 40 percent; Ecopetrol has right to purchase up to 25 percent of any oil company produces.		30 percent of profits	No depletion allowance, royalties not deductible; capital expenditures depreciated over 5 years
Ecuador	CEPE	Risk contracts. If oil is discovered, companies can recover costs from the government and can become field operators receiving service fees		Oil and Gas corporate income tax is at 40 percent of profits	Depreciation over useful life of assets, percentage depletion not allowed, employee profit participation deductible.

Cost recovery of exploration expenditures	Cost recovery of development expenditures	Statutory marginal tax rate	Royalties and production taxes
		National plus state corporate income tax rate is 31.5 percent.	None.
Company pays most exploration costs; exploration costs amortized over 5 years.	Ecopetrol pays 50 percent of development costs; recovery, same as for exploration costs.	National corporate income tax rate is 30 percent; tax rate on dividends distributed abroad is 30 percent.	Ecopetrol's share, 40 percent of production, plus a royalty of 20 percent of production.
If discoveries are made, companies recover exploration costs from government over a 5-year period through payments in oil or cash at prices set by the government.	Companies recover development and production capital investments over a 10-year period.	National corporate income tax rate is 40 percent	Royalty is at 18.5 percent, Production Sharing Tax is on a sliding scale depending on production, with highest rate 30 percent; Employee Sharing Tax, on net income less the Production Sharing Tax, is at 15 percent.

Table II.2: Some Recent Tax and Regulatory Changes Affecting Investment in Petroleum Production for Selected Countries

United States	- lowered corporate income tax rate from 46 to 34 percent (but retained the alternative minimum tax) beginning in 1987
	- repealed the Windfall Profit Tax in 1988
	- Texas halved state severance tax rate to 2 3 percent on new production using enhanced oil recovery techniques in 1989
	- Alaska raised severance taxes in 1989
Canada	- the province of Alberta granted 1 to 5 year royalty holidays for oil and gas plus a 75 percent royalty tax credit against provincial income taxes for up to $3 million (Canadian) per taxpayer beginning in 1985-86
	- repealed the Incremental Oil Revenue Tax and began a 4-year phase-out of the Petroleum and Gas Revenue Tax in 1986
	- the Canadian Exploration and Development Incentive Program provided cash refunds for one-sixth of a company's 1989 exploratory and developmental intangible drilling costs up to a limit of $1 67 million per year, enacted in 1987 and ended in 1989
	- adopted in 1988 the Canadian Exploratory Incentive Program providing refunds for up to 30 percent of exploratory intangible drilling costs up to a limit of $3 million per applicant per year
	- opened up promising new exploration acreage to U.S firms in 1989
	- terminated federal drilling incentives ahead of schedule in May 1989
	- scaled back provincial royalty tax credits in 1989
	- *continued to postpone adoption of promised federal and* provincial project assistance for the development of frontier oil reserves in 1989
United Kingdom	- lowered corporate income tax rate from 50 percent to 35 percent between 1984 and 1986 (but also eliminated the first-year capital allowance of 100 percent and replaced it with a rule whereby 25 percent of capital costs net of previous depreciation may be recovered annually)
	- allowed G&G research costs and some development costs for one field to offset profits from other fields in 1987
	- in 1987 abolished the Advance Petroleum Revenue Tax and the requirement that the Petroleum Revenue Tax be paid in advance
	- doubled the cumulative oil allowance for Petroleum Revenue Tax for some new fields in 1987
	- abolished royalties on new production for onshore fields and some gas fields in 1987 and 1988
	- lowered the cumulative oil allowance for the Petroleum Revenue Tax for onshore fields and for some gas fields by 60 percent in 1988

(continued)

	· freed oil field sublessees from capital gains tax and made some cross-field operating costs deductible for the Petroleum Revenue Tax in 1988
Norway	· relieved foreign investors from the requirement to pay the state's and the state oil company's shares of exploration costs for joint ventures in 1987
	· in 1987 abolished royalties on production from fields developed after 1986
	· lowered the Special Petroleum Tax from 35 to 30 percent in 1987
	· granted depreciation from the start of spending rather than the start of production, provided a production credit for the Special Petroleum Tax (but withdrew the investment allowance or "uplift") in 1986
Denmark	· in 1989 abolished royalties on new production and decreased the minimum license share reserved for the state oil company from 20 to 10 percent for areas lacking commercial discoveries
	· adopted less favorable terms for investors choosing not to use a partly state-owned operator for exploiting petroleum finds
The Netherlands	· lowered the maximum corporate income tax rate from 42 to 35 percent in 1989
Australia	· in 1987 exempted from Crude Oil Excise Tax the first 30 million barrels produced from some new developments
	· in 1987 replaced Excise and royalties with a Resource Rent Tax for projects in high-risk areas (Resource Rent payments are postponed until a threshold profitability is reached)
	· reduced maximum Excise Tax on oil discovered before October 1975 from 87 percent in 1985 to 75 percent in 1987
	· in 1987 exempted companies from some of the exploratory work obligations in their petroleum contracts
	· lowered corporate income tax rate from 49 to 39 percent in 1988
	· removed a foreign investment restriction requiring that all development projects of more than $10 million (Australian) involve a minimum of 50 percent Australian ownership and control in 1988
	· abolished forced domestic allocations of crude oil and freed oil sales from price controls in 1988
Indonesia	· increased the foreign investor's share under production sharing for new oil in 1989
	· paid a higher price for oil sold to the government under compulsory allocation rules in 1989
	· revised formula for calculating income tax liability to the government by using a tax reference price for oil that was more favorable to the foreign investor, in 1986 and again in 1989

(continued)

	- in 1989 began opening up virgin acreage previously reserved for the national oil company to exploration by foreign firms
	- in 1989 adopted a new mechanism for production sharing that guarantees the government a minimum level of revenues from new contracts but offset this with easier terms for defining when a field is commercial
	- repealed the value-added tax for oil companies in 1989
	- lowered the top corporate oil and gas net income tax rate from 56 to 48 percent (but decreased the company's pre-tax share of oil profits) in 1985-6
Argentina	- began allowing the investor to control the field production level in 1987
	- began paying its share of exploration and development costs under production sharing in 1987
	- began paying for oil sold under domestic sales requirement with hard currency in 1987
	- in 1987 increased the price paid for natural gas from 14 to 25 *percent of a world crude oil reference price*
	- in 1987 increased the price paid for oil from 64.5 to 80 percent of a world oil reference price (when the price of oil is $19 per barrel or less) for fields with relatively high exploitation costs
	- increased the price paid for oil under the domestic sales requirement in 1988
	- opened more attractive fields to foreign exploration and production in 1989
Brazil	- in 1988 made it unconstitutional for foreign oil companies to make new, direct petroleum investments
Colombia	- extended the tax on private company remittances to include petroleum, and tightened depreciation rules, in 1986
	- assumed control of pipelines, terminals and oil field production volumes in 1986
	- increased the private sector's liabilities with regard to depreciation and depletion in 1986
	- decreed that Ecopetrol has first option to purchase up to 25 percent of all oil produced by multinationals operating in Colombia (but also provided for payment of a penalty by Ecopetrol to the country's national bank if it purchased less than 25 percent), in 1986
	- liberalized some contract provisions in 1987
	- promised current incentives would be maintained or improved in 1988
	- in 1989 announced there would be no further nationalization of the petroleum industry
Ecuador	- announced decision to remove Texaco as operator of country's biggest oil field in 1988
	- discontinued further new risk contracting with foreign firms in 1988

(continued)

	· reassured foreign contractors that their existing risk contracts would be honored in 1988
	· in 1989 reopened the door to foreign exploration contracts and considers joint ventures in areas previously reserved for state oil company exploration

Comments From the Department of Energy

Note: GAO comments supplementing those in the report text appear at the end of this appendix

The Deputy Secretary of Energy
Washington, DC 20585

April 23, 1990

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The Department of Energy (DOE) appreciates the opportunity to review and comment on the General Accounting Office (GAO) draft report entitled "Additional Petroleum Industry Tax Incentives are of Questionable Merit."

DOE does not agree with the report's overall conclusion that additional tax incentives for the petroleum industry are of questionable merit, nor does DOE concur in the report's basic findings on the following major issues: whether the capital recovery rules for the oil industry are overly generous, whether oil producers receive overly favorable tax preferences and pay lower effective marginal tax rates compared to other industries, and whether or not the U.S. tax system is a significant factor affecting the recent shift toward more U.S. investment in oil exploration overseas.

See comment 1.

In DOE's judgement, the report's overall conclusion and major findings are not adequately supported by the data and other factual information presented in the report. Moreover, as explained below, the report relies on a flawed analysis of the petroleum industry's marginal tax rates, and the unfounded assumption that the current system of capital recovery for oil and gas depletion and drilling expenditures does not reflect the true economic value of those assets. Furthermore, by considering only the effect of income taxes and not total "take" from Federal and State income taxes, severance taxes, and royalties, the report reaches unjustified conclusions about the tax treatment of domestic oil and gas producers.

Capital Recovery and Tax Preference Issues

The report asserts the view that the petroleum industry and other producers of exhaustible resources should receive the same form of capital recovery as industry in general. DOE rejects this view. Oil and gas reservoirs are fundamentally different from the plant and equipment that constitutes capital for other industries. Capital recovery of plant and equipment has traditionally been based on original cost, because that type of capital can be expected to be replaced at approximately original cost (except for inflation). Exhaustible resources such as oil and gas deposits, however, can be expected to be replaced only at a higher cost as more and more deposits are produced and recoverable reserves are depleted. Discovery of new reservoirs becomes increasingly more difficult and expensive as time passes. This is evident from the fact that in the United States, the total amount of oil and gas reserves added per well, although highly variable, has significantly declined during the last 20 years.

See comment 2

Another difference between exhaustible resources and plant and equipment is the degree of investment risk. Replacement of oil and gas reservoirs is an extremely high risk activity. New field wildcat wells resulted in dry holes 86 percent of the time during 1986-88. Replacement of plant and equipment, on the other hand, can be accomplished without any significant risk.

See comment 3.

Because of these two important distinctions, Congress has allowed faster capital recovery for exhaustible resources, including allowing recovery in excess of basis in some cases. It has recognized, as does DOE, that the oil and gas capital recovery system cannot be directly equated to that of other industries for tax purposes.

See comment 4

DOE also disagrees with the GAO's view that the current regular tax and alternative minimum tax (AMT) treatment of intangible drilling costs (IDCs) constitutes an overly generous tax preference for the oil industry. Because outlays for IDCs have no direct salvage value, it is not appropriate to compare them to other fixed assets. Furthermore, any advantage gained by the IDC deduction for regular tax purposes is essentially removed due to the addback provisions of the AMT. Failure to fully consider the strong effect of the provisions of the AMT on both percentage depletion and IDCs is a major flaw in this report, because most independent producers pay the AMT.

See comment 5.

According to unpublished Department of the Treasury estimates, about three-fourths of all independent producers were AMT taxpayers in 1987, the most recent year for which data is available. Further, other producers were in a net operating loss (NOL) position. Less than one-fifth of producers were able to reap the full benefit of the more favorable recovery allowed for regular taxpayers. According to data gathered by EIA, about one-third of the 22 largest oil companies were also subject to the AMT in 1988.

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DOE also believes that the GAO has adopted an extreme position by asserting that the expensing of IDCs on unsuccessful wells is a form of tax preference. It is DOE's view that there is little economic rationale for capitalization of dry hole IDCs, and thus expensing is appropriate. What useful life should be used to capitalize an expense that has produced a dry hole with no current economic utility and no salvage value? In fact, because dry holes must be plugged and abandoned, they can be seen as having a negative salvage value.

See comment 6

The GAO report discusses the tax savings that would occur if percentage depletion and the expensing of IDCs were eliminated. DOE believes that the estimates for the tax savings, as developed by the Congressional Budget Office (CBO) and used in the GAO report, are much too high. The estimated savings from repeal of percentage depletion is $3.8 billion during 1991-95. This total is not supported by recent Treasury Department data which show, for 1989-91, a corporate tax expenditure of $240 million and an individual tax expenditure of $965 million, or $1.2 billion total for three years of percentage depletion[1]. Since the total volume of oil and gas production is expected to decline during 1991-95, a reasonable 1991-95 estimate would be about $1.9 billion or less. The CBO's estimated savings from repeal of expensing of IDCs is $5.5 billion. However, the only savings to the government consists of a one-time postponement of IDC deductions. Extrapolating from Treasury estimates of $1.8 billion over 1989-91 gives a considerably lower estimate of $3 billion for this provision.

See comment 7

Marginal Effective Tax Rate Analysis

The GAO report asserts that the oil industry in general pays much lower effective marginal tax rates than other industries. The report states that the oil industry faces extremely low or negative marginal tax rates, but the data presented shows average tax rates of 30 to 40 percent. A combination of very high average tax rates and negative marginal rates is extremely unlikely.

See comment 8.

In response to the GAO report, DOE used its own oil and gas spreadsheet tax model to derive effective tax rates on marginal IDC expenditures. In general, the DOE model produced effective rates that are higher than those presented in the report. For

[1]The Department of the Treasury's 1991 Budget Special Analysis G, Table C-12.

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marginal properties with low bonuses and relatively high IDC expenditures, similar to those used in the GAO analysis, the marginal tax rate on additional IDC expenditures varied from 12 percent to 25 percent. As pointed out in the GAO report, the choice of discount and inflation rates, oil prices, taxpaying status (regular, AMT, or NOL), and other factors significantly affect this marginal rate.

See comment 9.

The GAO should examine the effective tax rates presented in the Energy Information Administration's (EIA's) Performance Profiles of Major Energy Producers 1988. According to this publication, the average effective corporate income tax rates on the worldwide operations of U.S. energy companies have continually exceeded those for the Standard & Poor's 400 (S&P 400) companies since 1974, except in 1988 when they were about equal. This publication also reports that the average effective income tax rate of the domestic production sector of the petroleum industry was 39 percent in 1988. This rate includes both State and Federal income taxes. Without the State taxes the rate is close to the statutory 34 percent.

See comment 10

An update of an American Petroleum Institute study cited in the GAO report also shows higher average tax rates for the oil industry than for other industries. The report examines average effective tax rates during 1980-88 and notes that oil companies paid a much larger percentage of income as tax, a 38.7 percent effective rate versus only 22.7 percent for non-oil companies.[2] The API report does not consider the effective tax rates of independent oil and gas producers. The conclusion that can be reached from examining both the EIA and API data is that in most cases, average effective tax rates of the petroleum industry and its domestic production segment equal or exceed those of other industries.

See comment 11

The GAO uses data from Lucke and Toder (1987) indicating the strong possibility that independent producers have negative marginal effective tax rates. The problem with this analysis is that the assumptions used for the "economic" rate of depreciation for IDCs and for resource depletion are basically flawed, as described above. One can obtain very low marginal effective tax rates by choosing an extended recovery schedule as the true economic recovery period.

See comment 12

[2]American Petroleum Institute, "Federal Tax Burden of Leading Oil and Non-Oil Companies 1980-88." Background Paper, Washington, DC.

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See comment 13.

The GAO report states on page 66 that "independent producers expense all IDCs so that these investments face a marginal effective tax rate of zero." It is true that expensing produces a lower after-tax economic cost of investment than does capitalization over a period of years. However, this difference does not imply a zero marginal rate for IDC investments. Other studies of marginal rates have concluded that the petroleum industry faces rates that are sometimes higher and sometimes lower than that of other industries.[1]

See comment 14.

Although not noted in the GAO study, independent oil producers may have had lower effective tax rates in recent years because many are AMT taxpayers facing a statutory rate of 20 percent instead of 34 percent. If independent oil and gas producers' marginal effective rate is near 20 percent due to the AMT, while other more profitable industries pay regular tax and thus have higher marginal effective rates, a comparison of the two industries would be erroneous because the definition of income for each industry would be quite different. Paying 20 percent of a broad definition of income does not indicate preferential treatment compared to 34 percent of a more narrowly defined income.

International Comparison

See comment 15.

The GAO report concludes that producers have shifted a significant portion of their exploration activities overseas almost exclusively due to non-taxation factors such as finding costs and favorable geology. DOE disagrees with this conclusion. First, we note that the report lists dozens of changes in foreign countries' tax and fiscal systems favorable to the oil industry, but the report then concludes that tax considerations have very little to do with the choice of location for new investment.

DOE believes that while geology and finding costs have played an important role, the regressive nature of the U.S. tax system compared to those of other producing nations is also an important factor. When oil prices decline, the U.S. system adds to the

[1]Allen D. Manvel, "Measuring Business Tax Rates," Tax Notes (January 28, 1985): pp.378-80; Don Fullerton and Andrew B. Lyon, "Does the Tax System Favor Investment in High-Tech or Smokestack Industries?" Economic Inquiry (July 1986): pp. 410-411; Alan J. Auerbach, The Fair Tax Act and Corporate Investment, Vol. C (Washington, D.C., March 1985): p 12.

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economic burden of U.S. companies by taking an increasing share of oil and gas income. This results from two factors: the relatively greater reliance in the U.S. on a revenue-based taxation and royalty system, and the effect of the AMT.

In the U.S., severance taxes (and royalties) are based on revenues, not net income. Thus, two wells producing at equal rates, but with vastly different costs and incomes, pay the same amount of severance tax and royalty. The AMT is regressive because a company becomes subject to it when its level of drilling activity generates deductions that are greater than 65 percent of its income. When oil prices fall, companies end up with lower income, resulting in greater AMT preferences, and thus greater AMT, unless they reduce drilling. This provision helps to make the oil exploration industry more cyclical and thus less efficient. For this reason, the President has proposed eliminating 80 percent of the IDC preference for the AMT.

See comment 16

Another provision of the tax code that is regressive is the 50 percent net income limitation on percentage depletion for independent producers. This provision limits the benefits of percentage depletion when they are most needed: when income is low due to increasing costs, falling production, or lower oil prices. This provision encourages early abandonment of marginal wells that by definition have low income compared to production. Further, the stated purpose of these income-based restrictions--to limit tax shelter limited partnerships--is already largely accomplished by the passive activity loss rules and lower tax rates enacted as part of the Tax Reform Act of 1986.

See comment 17

The Department of Energy is in the process of comparing not just effective income tax rates of the U.S. and various foreign countries, but also the total "take" including all tax and royalty payments. This method allows valid comparisons to be made because it considers all the economic factors that influence exploration and production. Often, royalty payments and severance taxes take a larger share of cash flow than do income taxes. In order for its report to be complete, the GAO also should have analyzed the issue of total tax and royalty payments.

See comment 18

The GAO report points out that effective income tax rates for petroleum activities are higher abroad, but fails to note that the difference between average tax rates in the U.S. and abroad has narrowed considerably. EIA data show that since 1985, the difference has shrunk from 25 percent to 13.6 percent. However, these comparisons do not reveal the relatively larger non-income based payments made in the U.S. nor the tendency of foreign

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governments, through their tax systems, to share more of the risk of exploration. DOE is attempting to take all of these financial criteria into account when comparing the U.S. and foreign systems. Our preliminary analysis reveals that the U.S. system compares relatively unfavorably to other countries' systems.

See comment 19

The best evidence that the U.S. system of oil and gas total "take" is uncompetitive with that of other nations has been the experience of the last several years. When prices collapsed in 1986, U.S. exploration activity declined far more sharply and remained lower than exploration in other countries. Since the relative difference in geology has not changed appreciably in such a short period, and relative finding costs have declined in the U.S. (see Attachment 1, and Table 5.1 in the GAO report), it is reasonable to assume that the take system has played a role in the decline in U.S. exploration.

See comment 20

Further evidence that regressive taxes in the U.S. may have played a part in the U.S. decline in exploration comes from comparing the domestic and international rig counts during the past 14 years. As can be seen from the graph in Attachment 2, the U.S. rig count is far more sensitive to prices than the international rig count. The current system of "take" tends to magnify the effect of oil prices by imposing greater effective rates of take on low income producers than on high income producers.

Many countries have responded to the drop in oil prices by reducing their total take to maintain a competitive oil and gas industry. Unlike the U.S., Canadian provinces offer progressive royalty rates that vary with price, production volume, or production costs. Other countries, such as Denmark and Norway, have eliminated royalties completely. The U.K. allows no income taxes to be collected until all investment costs are repaid, thereby substantially decreasing investment risk. The U.S. has taken little action in response to the decline in oil prices, other than repeal of the windfall profit tax. That action had very little effect, because lower oil prices had eliminated assessment of the tax at the time of repeal.

See comment 21

Tax Incentives

In chapter 3, the report states that exploration risk can be significantly lessened through geographical diversity of prospects. Basically this is saying, "Don't put all your eggs in one basket." The problem with this theory is that in all geographic regions, exploratory drilling is extremely risky, so

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diversification has very limited value in reducing investment risk. Also, the report asserts that because IDCs are expensed, they have a marginal effective tax rate of zero. This statement is based, once again, on the incorrect assumption that IDCs have some generally accepted economic life, which makes immediate deduction a preference.

See comment 22.

In describing credits for stripper wells, the report states that stripper wells have a limited role in providing energy security and that continued operation of sub-marginal wells is not a productive use of resources unless oil prices are expected to rise. DOE disputes these statements. Over three-fourths of U.S. oil wells are stripper wells. These wells make an important contribution to this nation's energy security. Also, since the vast majority of abandoned production in the U.S. was formerly stripper production, it can be argued that a proposal benefitting stripper wells is a good way to target tax incentives. Furthermore, DOE does expect oil prices to rise in the mid 1990's as OPEC regains some control of the world oil market. If the U.S. can offer incentives to save some of the 18,000 stripper wells abandoned each year, many of these wells will survive until prices rise and the wells become economic again. Currently, significant stripper oil reserves are being abandoned. This is a critical problem, because once a well is abandoned, the remaining reserves in the ground become virtually impossible to recover.

See comment 23.

Another reason that stripper wells are important for energy security is that they are potential sites for enhanced oil recovery (EOR). For the U.S. to maximize recovery of its remaining oil, we must increasingly rely on EOR techniques. In order for EOR to be feasible, the use of existing wells is often necessary to avoid the costs of drilling injection or production wells. Every well plugged and abandoned is one less site for future advanced recovery. DOE estimates that after the use of conventional production methods, two-thirds of the original oil in place will remain. Of the oil remaining in place, DOE estimates that some 76 billion barrels is potentially technically and economically recoverable. If recovered, that amount would meet the nation's energy needs for over a decade.

See comment 24

One energy tax incentive that has proved to be both effective and efficient, but was not considered in the GAO report, is the Section 29 tax credit for nonconventional fuels production. This credit, enacted in 1980, benefits a range of marginal oil and gas production including oil produced from shale or tar sands, and natural gas produced from tight sands, coal seams, Devonian

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shale, geopressured brines or biomass. Unconventional gas production has responded to the credit and now constitutes over 10 percent of all natural gas production.

The efficiency of this credit is derived from the fact that it rewards only the successful production of a resource that would not otherwise be produced in significant quantities. The credit is not paid to those who drill dry holes. It also is not paid to conventional production which would have been produced regardless of the effect of the credit. The Department of Energy is examining the Section 29 credit in the context of its development of the National Energy Strategy. For environmental reasons, natural gas is expected to play an increasingly important role in meeting our Nation's future energy needs.

See comment 25.

In the section on the beneficiaries of tax incentives, the GAO report argues that since in the long run much of the value of incentives will accrue to landowners, tax incentives do not significantly benefit petroleum producers. DOE believes that this argument, while theoretically sound, breaks down because of resistance to change in the bonus and royalty markets. Royalty payments in the U.S. are paid to private landowners who have traditionally received a minimum of a one-eighth royalty. Usually, when third party interests are involved, the total royalty is greater. Royalties do not respond well to market forces because of these traditional payment arrangements. Economic theory dictates that when prices fell in 1986, landowners, knowing that production would be less attractive for companies, would have accepted lower royalties and bonuses. There is no evidence that this occurred. Because landowners do not have information on the potential profitability of their land, they would see no incentive to ask for a lower royalty rate.

Bonuses have varied more with economic conditions than royalties, but here too, it is difficult to argue that all of the benefit of tax incentives would be gained by owners of reserves. Landowners negotiating for bonuses suffer from the same lack of information.

See comment 26

<u>The Strategic Petroleum Reserve as an Alternative to Tax Incentives</u>

The GAO report argues that tax receipts foregone due to domestic production incentives could better be spent on oil for the SPR. In doing so, the GAO attempts to portray the SPR as an investment in oil, rather than a mechanism to ease the economic damage caused by an oil supply disruption.

See comment 27

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Specifically, the GAO states that the real cost of SPR oil is about $1.00 per barrel--the cost of facilities development and operational costs. Outlays for oil are ignored because, the GAO concludes, sale of the oil in a disruption would bring more than the cost of the oil. Even if a disruption does not occur, it is noted, the Federal Government would retain an asset (the oil) that is growing in value.

See comment 28

One important factor the report overlooked is the time value of money. Oil prices are predicted to rise through the 1990s, but few, if any, analysts predict increases that exceed what would be an appropriate discount rate for the government's SPR oil investment. The Office of Management and Budget specifies that a 10 percent real discount rate be used in evaluating Federal programs (or about 14-15 percent in nominal terms). A more moderate real discount rate of 3 to 4 percent (8-9 percent nominal) was proposed for SPR analyses by the Congressional Budget Office in Senate testimony on the Administration's recently released SPR studies. The range of these discount rates implies that oil must appreciate at least 8 percent per year in nominal terms, and possibly as much as 15 percent, for the oil in the SPR to simply "break even" as an investment. Even if that took place, the value of the oil would not be realized unless it were sold.

See comment 29

These observations suggest that the SPR is only a good investment if a disruption takes place. While the GAO study seems to imply that there is a high degree of certainty in the occurrence of such an event, in fact, it is quite unlikely. A recent DOE-led SPR study noted that a disruption would have to exceed 10 million barrels per day (worldwide) and last for more than 6 months to exhaust the current 580 million barrel SPR. The intelligence community participants in the study assessed the likelihood of such an event to be less than 1 percent per year, or about 5 percent by the mid-1990s. Thus, to produce an expected return (in nominal dollars) by 1995 equal to its cost, the price of oil would have to rise by a factor of 20 in such a low-probability disruption (e.g., to $400 per barrel).

See comment 30

It follows that buying additional SPR oil in hopes of receiving high returns through its sale at a later date would be a poor investment. The oil would be unlikely to appreciate fast enough to retain its real value when the time value of money is taken into account. Even if it did, its sale would be unlikely. Finally, the probability of a disruption large enough to require

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See comment 31.

additional oil is not large enough to justify its purchase as an investment.

Apparent factual errors in the GAO report include estimates of SPR non-oil costs and assumptions about drawdown rates. Storage and operational costs for SPR oil substantially exceed the $1 per barrel estimated by the GAO. The add-on for using U.S. flag vessels alone is $1.25-$1.50 per barrel. In addition, development costs for salt dome storage (excluding maintenance costs) are in the $3.50-$7.50 per barrel range, as noted in an April 1989 DOE study requested by the Congress to evaluate expansion of the SPR to 1 billion barrels. If above-ground tanks are used, the costs may run as high as $15 per barrel for construction alone. Moreover, the addition of oil above the Administration's current plan would not increase the SPR drawdown rate unless facilities are expanded beyond those associated with a 750 million barrel SPR. It is U.S. policy to draw down the SPR at a maximum rate in the event of a large disruption. This drawdown rate is determined by the facilities that are now included in the current SPR plan.

See comment 32

In addition, when comparing the relative merits of further expansion of the SPR versus tax incentives for increased oil and gas production, the report fails to take into account the important differences that these two options have on the domestic economy. Additional purchases of SPR oil will result in increased oil imports and will worsen the Nation's balance of trade deficit. On the other hand, tax incentives that increase domestic production will have a positive effect on the trade deficit by displacing imports and will have a multiplier effect on the domestic economy through job creation and increased equipment purchases.

See comment 33.

For all of the above reasons, DOE has determined that the information and analysis in the report do not adequately support its key findings. Therefore, DOE does not concur in the report's conclusion that additional petroleum tax incentives are of questionable merit.

See comment 34

Sincerely,

W. Henson Moore

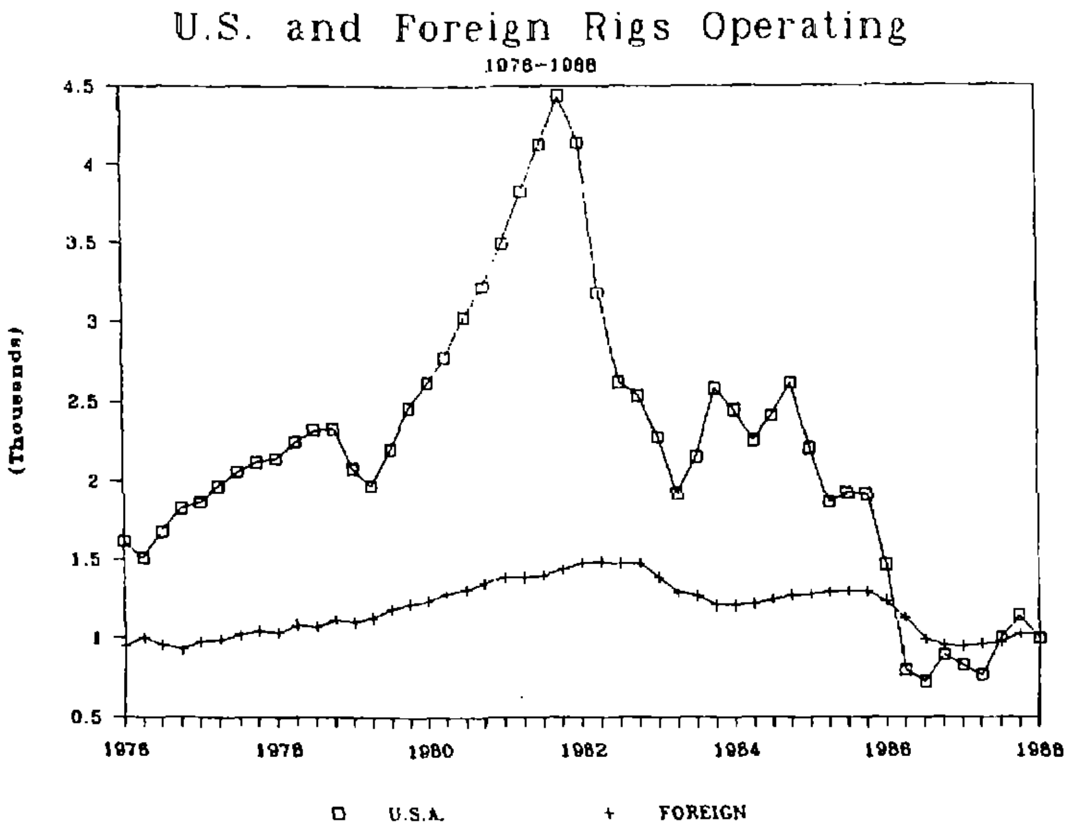
Attachments

11

Table 56. FRS Companies' Finding Costs By Geographic Area, 1984-1988
(Dollars Per Barrel of Oil Equivalent)

Geographic Area	1984	1985	1986	1987	1988
United States	8.57	8.02	7.13	6.76	5.73
Canada	4.85	3.41	3.79	2.93	3.02
Europe	3.64	3.60	4.41	3.61	3.63
Africa	7.22	9.49	10.08	10.29	8.89
Middle East	4.27	7.31	4.49	4.74	3.83
Other Eastern Hemisphere	11.95	9.13	6.87	5.77	5.39
Other Western Hemisphere	5.63	2.99	2.56	3.12	3.56

Note: 3-Year Moving Average.
Source: Energy Information Administration, Form EIA-28.


U.S. and Foreign Rigs Operating
1976–1988
(Thousands)
4.5
4
3.5
3
2.5
2
1.5
1
0.5
1976
1978
1980
1982
1984
1986
1988
U.S.A.
FOREIGN

The following are GAO's comments on the Department of Energy's letter dated April 23, 1990.

GAO Comments on DOE's Letter

1. We believe our conclusions and major findings are not affected by the issues raised by DOE, as we discuss in detail in conjunction with DOE's specific comments. The analysis of marginal tax rates we present is sound and consistent with widely accepted economic analysis. The view that the industry faces favorable capital recovery provisions is well accepted by leading experts. These provisions are included, for example, in the tax expenditure analyses of the President's budget and the JCT. Finally, while nonfederal taxes and royalties are one factor considered by firms—as noted in our report—U.S. firms' decisions to produce petroleum abroad appear to be largely driven by costs other than taxes.

2. The basic goal of capital recovery provisions is to match producers' deductions of investment costs with producers' realization of income from the investments. We agree that replacement costs of reserves may tend to rise over time as reserves are depleted. However, this increasing cost of reserves also implies an increasing value of reserves that are owned. This increasing value is a real return to the investment in reserves; it is analogous to the real return earned from alternative (non-oil) investments. If this increase in value were to be exempted from taxation—as is suggested by DOE's view—it would imply exempting real returns from oil investments from taxation. Such treatment is clearly more generous than is available for most other business activities. Thus, DOE's view would result in petroleum investments paying less federal income tax than other investments.

3. Although oil investments are risky, we would expect the market returns on successful wells—even without tax preferences–to compensate investors for unprofitable dry holes. As noted in the report (see p. 45), the effects of corporate taxes on risk-taking are ambiguous. In some cases—such as where losses can be fully offset against income—taxation may actually encourage investments in risky activities. We did not find proof that the U.S. tax system discourages risky activities and therefore requires special preferences for them. Also, the dry hole rates for the industry as a whole are lower than for the wildcat wells cited by DOE (see p. 17).

4. Congress and past administrations have, for a variety of reasons, allowed tax preferences for domestic petroleum production. Policymakers have also, however, instituted the AMT and other provisions to

prevent petroleum producers and other taxpayers from paying little or no tax in years in which they have substantial income.[1] In practice, tax laws have changed over time in response, in part, to changed perceptions of the national interest.

5. As noted above, we and leading tax experts (as reflected, for example, in studies by CBO, CRS, JCT, and Treasury) believe that IDCs contribute to producing wells that have lasting value and hence receive substantial tax preferences under current law. The view that the AMT removes any advantages provided to IDC investments under the regular tax is not generally true. As discussed in the report, the AMT only applies under certain conditions; and when it does apply it is at a rate, 20 percent (for firms), substantially below the regular statutory rate of 34 percent. Under the AMT, IDCs incurred on dry holes can still be fully expensed. IDCs on successful wells are only treated as a specific AMT preference (the excess IDC preference) if they exceed 65 percent of net oil and gas income for the taxable year. In this case they are recoverable over 10 years, which is the same treatment allowed to IDCs incurred abroad under the regular tax. The adjusted current earnings provision of the AMT may also reduce the tax preference for some IDCs; however, it can allow more rapid write-off of IDCs than the excess IDC preference.

Finally, AMT payments in 1 year can offset regular tax payments in future years. The report also notes that marginal effective tax rates of firms can vary if firms move between the AMT and the regular income tax over time. For example, many of the producers now subject to the AMT—at 20 percent tax rates—had the advantage of deducting IDCs and other outlays under the 46 percent statutory rates that preceded the Tax Reform Act of 1986. Some of the investments made would also have qualified for the investment tax credit. On the other hand, some firms may undertake new investments while subject to the AMT and realize the income when subject only to the regular income tax.

6. Our report does not take the position that the tax treatment of IDCs should be revised to require capitalization of dry holes. We do, however, accept the view that these costs are an integral aspect of oil production investments and that expensing of these costs reduces marginal effective tax rates on these investments. Thus, we believe the treatment of these costs is relevant to an analysis of potential additional tax incentives for these investments.

[1] See, e.g., Joint Committee on Taxation, General Explanation of the Tax Reform Act of 1986, May 4, 1987, pp. 432-436.

The view that in principle unsuccessful wells should be capitalized has been recognized at least since the 1950s in the work of Arnold Harberger, a prominent University of Chicago public finance economist.[2] It is also the basis for one method of financial accounting for petroleum ventures.

The economic argument for capitalizing unsuccessful wells is that both these wells and successful wells represent capital investments made to obtain oil. Providing an immediate write-off for unsuccessful wells yields a lower effective tax rate on petroleum production activities than on alternative investments. For example, suppose a piece of equipment yields a 10-percent return before taxes and depreciates at a constant rate over 10 years. In contrast, suppose a successful oil well yields a 20-percent return and also depreciates at a constant rate over 10 years, but that only half the wells drilled are successful. Both the equipment and drilling venture yield equal expected before-tax returns—in this case 10 percent. However, with expensing of dry holes, the drilling venture receives favorable tax treatment, as half of the investment is written off immediately. This favorable treatment will encourage investments in drilling activities that have expected returns below the rate of 10 percent over the alternative investment in equipment.

One approach to the useful life question could be to recover dry hole costs on a property-by-property basis, using cost depletion. Finally, the costs of plugging the dry wells are not a particular complication to this example, as these costs are simply part of the cost of the venture.

7. We have clarified our discussion in chapter 2 to reflect that the CBO revenue estimates refer to repeal of percentage depletion allowances and expensing of intangible drilling and development costs for all extractive industries and not just petroleum production. We also report DOE's revenue estimate for repealing these preferences for the petroleum industry alone.

Percentage depletion allowances, however, respond not only to production volumes but also to market prices. Thus, if prices over the period 1991 to 1995 are above those during 1989 to 1991, this could cause future tax revenue losses to rise above current tax revenue losses, despite lower production.

[2] A. C. Harberger, "The Taxation of Mineral Industries," (originally in Federal Tax Policy for Economic Growth and Stability, Joint Committee on the Economic Report, Washington, DC,) reprinted in Taxation and Welfare, A. C. Harberger, ed., University of Chicago Press, 1978. See also Stiglitz (1986, pp. 518-519)

In addition, for IDCs it is not appropriate to compare the tax expenditure estimates with revenue estimates. For IDCs the tax expenditure estimates assume that the law was changed to affect IDCs incurred in prior years, and not just the IDCs incurred in the years 1989 to 1991. Thus, the tax expenditure estimates would understate the revenue gain from repealing IDC expensing because the tax expenditure estimates offset the revenue gain on new investments with a loss of tax revenue from previous investments. In contrast, the revenue estimates assume only new IDCs would be covered. We have modified our discussion of the revenue gains from changing the tax treatment of IDCs, however, to explain that the revenue gain to the government is largely due to a speed up of collections.

8. The API data that show average tax rates near 40 percent for large integrated firms include windfall profit tax payments and also years when the statutory corporate tax rate was 46 percent. The other average effective tax rate studies cited in appendix I tend to show somewhat lower rates.

Low marginal effective tax rates arise for petroleum production investments because favorable tax treatment allows a large fraction of these investments to be expensed or recovered via percentage depletion, thereby reducing current-year taxes that would otherwise be paid. Taxes that are ultimately paid on the new investment in the future then have a relatively low present value.

There are many reasons that average rates for a firm can differ from marginal rates on a particular activity of the firm—such as petroleum production—as discussed in the report. These reasons include the relative importance of production and other activities of the firms, the extent of new investment, the timing of deductions and income, and the effects of unexpected price changes. For instance, in the example in footnote 1 in chapter 4, the firm pays zero tax in present value terms with expensing, though in most years it may have an average effective rate close to the statutory rate.

9. Although in response to DOE's comments we asked for a copy of DOE's spreadsheet analysis, DOE did not provide us with one. Thus, we were unable to evaluate the assumptions and methodology used by DOE.

10. The view that petroleum firms pay high worldwide rates of tax is consistent with our findings. Worldwide rates of tax are increased by high foreign taxes. Both the worldwide and domestic rates cited by DOE

from the EIA report include both current and deferred taxes. Some of the deferred taxes will not be paid for years, due to favorable write-off provisions for petroleum activities.

11. Appendix I of our report has been updated to reflect the new API study. The API tax rates cited by DOE include payments on the windfall profit tax, which is no longer in effect. They also reflect federal income tax payments prior to 1986 tax reforms, which rolled back accelerated depreciation provisions for most industries. The API study does not specifically address the production segment of domestic operations, and the EIA study reports deferred taxes as well as current taxes. Neither study focuses on independent producers or new investments. Thus, they do not indicate the current marginal effective tax rates on new domestic production investments.

12. Lucke and Toder's analysis assumes a 10 percent annual production decline. We discussed this assumption with DOE and industry experts, who agreed that it is reasonable. We used the same assumption in evaluating the costs per barrel of the proposed incentives in chapter 3. If production declines are faster, and production periods are shorter, the tax incentives examined in chapter 3 would generally lead to greater tax revenue losses per barrel than we reported.

13. The complete sentence quoted includes the words "under the regular income tax" (p. 45). A standard mathematical result in the economics of taxation is that expensing usually generates a zero marginal tax rate.[3] A footnote to the sentence quoted also explains that firms eligible for percentage depletion may actually have a negative marginal tax rate. The treatment of IDCs—and slightly higher marginal effective tax rates—for integrated firms is explained in the sentence following the one quoted, and the effects of the AMT are noted repeatedly in the report.

The three studies cited by DOE in the footnote all rely on the same basic approach and data set. These studies provided broad coverage of many industries without substantial detail on any one industry. Thus, according to the researchers principally responsible for them, the models used in these studies did not reflect the specific tax provisions—such as expensing of IDCs or percentage depletion allowances—that can apply to petroleum production investments. In addition, these studies were conducted before enactment of the current tax law and hence do

[3]For a general proof see, for example, Gravelle (1982, p. 5); for an example, see footnote 1 in chapter 4 of this report.

not consider it. For these reasons these studies were not discussed in our report.

14. DOE's comment assumes that for the analyses cited in the report the definition of income varies depending on whether firms are subject to the AMT or only the regular tax. This is not the case. The studies used in our report are based on economic income (for the marginal tax rate studies) and financial statement income (for the average tax rate studies). These definitions of income do not change at all based on whether or not the taxpayer is subject to the AMT.

15. The report states that U.S. producers appear to be making petroleum production investments abroad, rather than in the United States, largely because of factors other than taxes. This conclusion is supported by the facts that (1) finding and development costs have generally been lower abroad than in the United States, (2) foreign taxes paid by U.S. petroleum producers on earnings abroad are consistently much higher than their taxes on domestic production earnings, and (3) the U.S. corporate tax—which may be paid by some U.S. firms on their foreign operations—has higher marginal effective rates on investments abroad than on domestic investments. Our finding is also consistent with the views of a number of the experts with whom we spoke. The report does note that recently many foreign governments have made their tax and royalty provisions more favorable in response to lower world oil prices and that these could provide additional incentives for investments abroad.

16. Royalties (which are paid to private and public landowners) and severance taxes (which are paid to states) do not vary directly with changes in net income. Thus these assessments—although proportional to their respective bases (typically, revenues)—may represent larger shares of net income at low oil prices than at high prices. However, DOE's discussion, which treats royalties as leading to a "regressive" system, blurs the distinction between royalties—a payment to landowners for an input—and taxes. Other industries also continue to pay for inputs when product prices fall. Moreover, because royalty payments respond directly to product prices, they may be more responsive to product prices than are the input prices paid by most other industries. While we agree that fixed royalty rates may lead to larger cyclical swings in exploration activity than profit sharing agreements, it is precisely the income tax component of the U.S. "take" system that is based on profits.

We also agree that the AMT may become the operative tax system for some firms when profits are low. It is possible that firms would thus face higher marginal effective tax rates when profits are low than when profits are high, which could contribute to cyclical behavior. However, the effective tax rate faced in this case is still generally less than that faced by other industries.

The AMT offsets certain tax preferences received by petroleum producers, other firms, and individuals. However, the tax treatment it imposes on IDCs only applies to successful wells; thus, there is no capitalization of dry hole IDCs. Under the AMT the IDCs incurred on successful wells are treated more or less comparably with investments in other industries under the regular income tax, i.e., they are deducted roughly comparably to economic depreciation. Whereas most other investments would face such depreciation while subject to 34 percent regular tax rates, IDC investments face this treatment when subject to lower (20 percent) AMT rates.

17. The fact that the net income limit reduces percentage depletion allowances on marginal wells and when prices fall is recognized in the report, as is the argument that the AMT also recaptures some of the favorable percentage depletion treatment under the regular income tax. However, the net income limit does not constrain cost depletion allowances, which are more comparable to the depreciation provisions available to investments outside of petroleum production. We agree that the Tax Reform Act of 1986 has discouraged tax shelter activities. Whether production from marginal wells should be prolonged is difficult to judge without cost-effectiveness estimates. As noted in the report (p. 34), DOE has not released production estimates for modifying the net income limit, so we did not estimate the cost-effectiveness of this proposal.

18. We agree that royalty payments and nonfederal taxes could affect petroleum investment decisions. Our analysis focused on federal taxation and determined that these taxes were not the principal cause for investment being relatively more attractive abroad.

19. In 1985 foreign production faced average effective tax rates of 68.9 percent while domestic production faced taxes of 44.4 percent, according to EIA. This is an absolute difference of 24.5 percent and a relative percentage difference of more than 55 percent. By 1988 the comparable figures were foreign taxes of 49 percent and U.S. taxes of 35.4 percent—an absolute difference of 13.6 percent and a relative percentage difference of 38 percent. Because of the effects of various capital recovery provisions for petroleum production, we believe that these

rates do not generally indicate the marginal effective tax rate on new petroleum investments. Nevertheless, they do not make the case that petroleum investments are being attracted abroad because of favorable tax treatment. Moreover, according to the EIA report that is the source of these data, half of the fall in average effective tax rates abroad was due to "a decrease in the relative importance of the high-tax-rate petroleum production segment."[4] Thus, only a portion of the decline in the average effective foreign tax rates is due to changes in foreign tax policy.

In response to DOE's comments we asked for a copy of the analysis referred to by DOE. Because DOE did not provide us with a copy, however, we were unable to evaluate their analysis.

20. The sharp decline in U.S. exploration activity when oil prices fell can be explained by the relatively high cost of finding and developing oil in the United States. Tax and royalty systems may further contribute to the decline. However, because the United States is a high-cost supplier one would, in fact, expect that it experiences reduced activity when prices fall. Exploration also declined abroad when prices fell, as DOE recognizes. The EIA report from which DOE's attachment 1 is taken provides further detail on factors affecting their reported finding costs.

21. Before its repeal, the windfall profit tax itself responded to oil prices because of the manner in which it relied upon base prices. According to EIA, the windfall profit tax payment per barrel for the large firms in its sample fell from $4.56 per barrel in 1981 to about $0 per barrel by 1986, when oil prices fell. State production taxes for these firms fell from $1.19 per barrel in 1981 to $0.57 in 1988, due largely to the fall in oil prices.

Also, the discussion of "take" blurs the distinction between bonuses and royalties—which are payments to landowners for the right to explore for and produce oil and natural gas—and taxes. A concern that "total take" may be high and less than optimally responsive to price changes does not necessarily mean that income taxes are too high. Rather, it is specifically income taxes that do respond to profitability. Thus, DOE's concerns with take may suggest that certain landowners (including the federal government) could increase their earnings and social welfare by moving to profit-sharing agreements rather than royalty agreements. In effect, foreign governments may do this through their tax systems, since

[4]Energy Information Administration EIA, Performance Profiles of Major Energy Producers: 1988, DOE/EIA-0206(88), p. 28

these governments—rather than private individuals—generally own the rights to oil and natural gas produced in their countries. Likewise, DOE's concerns suggest that certain states in the United States might encourage production by moving to income taxes rather than severance taxes, which respond more directly to prices than profitability. Movements to profit-sharing agreements raise other implementation challenges, however, such as guaranteeing that petroleum producers use their most efficient production methods and accurately report their costs, so that profits subject to sharing are not reduced.

Profit-sharing systems may encourage more exploration and development activity than fixed royalty rate systems when oil prices are low. Such activity could have both energy security advantages and disadvantages. Potential advantages would be that skilled personnel are kept in the industry and reserves are found and production initiated. The potential disadvantage is that reserves would be exploited during periods of relatively low prices, instead of being conserved for a time where they had greater value.

Finally, the federal income tax allows deductibility of royalties and state severance, corporate income, and property taxes. Thus, the federal government already bears 34 percent of the burden of these taxes for a taxpayer subject to the regular income tax. Overall, we do not find convincing the argument that the federal government should further lower income taxes—which are responsive to profits—for one industry because some landowners and states are reluctant to lower their royalty and tax rates.

22. We disagree with the view that diversification has limited value in reducing investment risk. The mathematical fact that diversification does reduce risk where investments are to some degree independent of each other is a standard element of economic or financial analysis. Also, as discussed above (see comment 5), the view that IDC expensing is a tax preference is widely accepted.

23. While a large number of wells are stripper wells, these wells produced only 15 percent of U.S. production in 1988. We were told by an industry expert that these wells have limited surge capacity and a limited role in increasing energy security. Past economic studies also suggest that because the supply of oil from existing fields is of low responsiveness to price, large price increases would be required to substantially increase the amount of output from stripper wells. The report noted the high cost of resuming production from abandoned wells. The

report now also notes the suggestion of one expert for incentives for research and development on new technologies that would allow non-producing stripper wells to remain open while still meeting environmental standards.

24. We have modified the report to reflect DOE's observation that stripper wells may be sites for future EOR activities. However, we believe that decisions to maintain production should consider cost-effectiveness.

We have also increased our discussion of potential recovery from EOR technology and tax incentives (pp. 46-48). DOE's estimate of 76 billion barrels of recoverable reserves assumes both price increases (to $32 per barrel) and technological advances. The estimated reserve increases from the EOR studies considered in chapter 3—for prices of up to $28 per barrel with tax incentives worth about as much to producers as a $4 per barrel price increase—are much smaller.

25. Our report focused on additional tax incentives, not ones currently in place. Thus, we did not consider the section 29 provision in our analysis.

DOE states that the section 29 tax credit is "both effective and efficient." In response to DOE's comments, we requested any available production and revenue estimates to support this view. DOE did not provide us with any such estimates, however.

According to industry experts the section 29 credit currently benefits little, if any, oil production and primarily benefits natural gas producers. The gas that is eligible for this credit currently can receive tax credits of up to about $0.80 per 1,000 cubic feet. This is a large credit relative to the price of gas. Gas from most producing regions sold for below $1.50 per thousand cubic feet in April 1990 on the spot market; for 1989—including long-term contracts—gas prices averaged about $1.70 per 1,000 cubic feet. As producers generally must pay royalties, taxes, and production costs from these market prices, the $0.80 tax credit represents a substantial addition to after-tax profitability.

In addition, some of the gas eligible for this credit would likely be produced even without a credit. We did not find precise estimates of the amounts of gas that are produced only because of the credit. However, if only a portion of the eligible gas requires the credit in order to be produced, then the cost of the credit per unit of genuinely incremental gas produced is higher than $0.80. For example, if only two-thirds to three-quarters of the eligible gas actually requires the credit in order to be produced—a range that industry experts believe is reasonable—then the federal tax revenue loss would be about $1.20 to 1.07 per 1,000 cubic feet of genuinely incremental gas.[5] This range is comparable to the price of direct purchases of gas from some U.S. regions in the spot market in April 1990.

26. We believe that landowners will generally respond to market signals, although we agree with DOE that there may be time lags and rigidities in contractual agreements. Finding and development costs have fallen in the United States and abroad, which suggests responsiveness to market forces.

Bonus values can change substantially as oil prices and other factors affecting profitability change. For example, according to EIA, lease bonuses on federal outercontinental shelf acreage for all U.S. firms averaged about $2,930 per acre in 1981. In 1983, when the Department of the Interior increased the supply of acreage offered through areawide leasing, the average outercontinental shelf bonus fell to $873 per acre. By 1988 the average bonus had fallen to $149. According to EIA, lower oil prices, increased amounts of acreage, and declining acreage quality all contributed to this decline in bonuses. This trend of falling bonuses may raise the importance of royalties, however.

27. We considered the SPR as one alternative to the proposed tax incentives because we believe it unambiguously increases U.S. energy security and has costs that compare favorably with the proposed incentives. The report does not say that SPR additions would be a good investment for the government on financial grounds, though such additions appear to be a better investment than the proposed tax incentives.

28. The report does not state that the real cost of SPR oil is about $1.00 per barrel. Rather, it states that these are the estimated incremental operation and construction costs for filling the SPR. Moreover, the calculation that 80 to 100 million barrels of oil could be added to the SPR for the cost of the Administration's proposed tax incentives assumed a cost of approximately $20 per barrel.

29. The report does not ignore the time value of money, and in fact notes its relevance when discussing the SPR in chapters 3 and 6. The report explicitly states that foregone interest would have to be considered in an

[5] These figures are calculated by dividing $0.80 by two-thirds and three-quarters, respectively.

analysis of the net economic benefits of the SPR. As noted in the report, but not by DOE's comments, if one imputes interest on this investment in order to calculate net benefits, then one would also need to impute interest costs to the foregone tax revenue due to the proposed tax incentives. In addition, DOE states that "few, if any, analysts predict [oil price] increases that would exceed what would be an appropriate discount rate for the government's SPR oil investment." However, DOE's February 1990 analysis of alternative financing methods for the SPR assumes that oil acquisitions for the SPR will grow in cost by an annual rate of 8.9 percent from 1990 through 2000.[a] This rate exceeds the Treasury borrowing rate of 8 percent assumed by DOE's study.

30. The recent DOE study is sensitive to assumptions about the probability of an oil supply disruption. For example, DOE's recent study assumed a much lower probability of an oil supply disruption than did a November 1988 study prepared for DOE by Oak Ridge National Laboratory. The Oak Ridge study considered 50 disruption scenarios. In 44 of them they assumed about a 4-percent chance of a severe 3-month disruption; in the remaining 6 scenarios they considered about a 22-percent chance of a 4-month disruption. The Oak Ridge study found that in most cases a 1 billion barrel SPR is preferable to a 750 million barrel SPR. DOE's more recent study assumes an annual probability of about 1 percent for a disruption that is comparable in magnitude, but which lasts for a longer, 6-month, period than the Oak Ridge disruptions. According to March 1990 testimony by CBO, if DOE's probability was raised to 2 or 3 percent, then DOE's criterion for accepting the 750 million barrel SPR would also suggest expanding the SPR to 1 billion barrels.

DOE's assertion that the price of oil would need to reach $400 per barrel for the SPR oil to be a good investment is not correct. The expected return on the SPR oil is the sum of (1) the return in the event of a disruption times the probability of a disruption plus (2) the return in the event of no disruption times the probability of no disruption. DOE's assertion apparently ignores the value of the oil in the event that there is no disruption. As indicated in comment 29 above, under the base case scenario of DOE's February 1990 analysis, the value of the stored oil is expected to grow at a rate above the Treasury borrowing rate.

[a]This rate includes the additional cost for transportation on U.S. flag vessels, termed the "SPR Add-On," and is for DOE's base case. Oil prices net of this cost are assumed by DOE to rise somewhat faster (i.e. at 9.3 percent)

31. DOE's view that filling the SPR beyond its 750 million barrel target may not be a good investment on financial grounds may or may not be correct. DOE's conclusion is sensitive to assumptions about disruption probabilities, availability of oil during a crisis, and discount rates. However, as discussed in the report, filling the SPR to its 750 million barrel target more rapidly appears preferable to the proposed tax incentives. If a disruption is quite unlikely this would clearly diminish the value of the proposed tax incentives as well. In addition, if the tax incentives continue beyond the 4 years considered in this report, their costs would enable SPR oil purchases of more than the estimated 80 to 100 million barrels. Finally, the report does not say that a disruption will occur with a high degree of uncertainty. Rather, it refers to the SPR as being available in an energy emergency and being a lasting asset of the federal government, in contrast to the incentives.

32. Moving funds from the tax incentives to filling the SPR could enable the SPR to reach its target of 750 million barrels more quickly. This extra oil could maintain our drawdown rate for a longer period of time. We have modified the report to note explicitly that the drawdown rate may not increase—but that the period of available drawdown would increase—if the United States were to follow the policy of drawing down the SPR at the maximum rate. However, because SPR oil is stored at multiple sites, the addition of oil to the newer facility (Big Hill) would tend to enable the drawdown rate to stay at its peak level for a longer period of time; that is, it could tend to increase the effective drawdown rate.

In addition, our report explicitly considers the case of increasing the fill rate to reach the 750 million barrel target; it does not present cost estimates for expanding the SPR to 1 billion barrels. DOE's February 1990 study of alternative financing methods confirms the reasonableness of our estimates. Facilities and management outlays rise by only $1 million in 1991 and 1992—and fall by larger amounts in 1996 through 1999—if the fill rate is raised to 100,000 barrels per day (36.5 million barrels per year) from a level of 50,000 barrels per day (18.25 million barrels per year). These figures imply very low incremental operations and management costs per barrel of additions up to the 750 million barrel target. The add-on transportation costs cited by DOE are subsumed in our assumption that the oil additions would cost about $20 per barrel. This cost is above the level assumed by DOE's February 1990 study for oil purchases (including the add-on) through fiscal year 1992.

33. We agree with DOE that the SPR additions have different economic effects from the tax incentives, as we reflect in our report. We also revised the report to mention the multiplier and trade effects explicitly. Note, though, that if the tax incentives were offset by increased taxes on other activities or reduced federal spending, the multiplier effect would tend to be negated. In addition, it is not generally to the advantage of the U.S. economy to subsidize via the tax system production that could be obtained at lower cost from abroad.

34. As discussed above, although we have made minor revisions to address some of the issues raised by DOE, in general the issues raised by DOE do not alter our major findings or conclusions.

Comments From the Department of the Treasury

Note. GAO comments supplementing those in the report text appear at the end of this appendix.

DEPARTMENT OF THE TREASURY
WASHINGTON

April 19, 1990

Mr. Richard L. Fogel
Assistant Comptroller General
United States
General Accounting Office
Washington, D.C. 20548

Re: GAO Report -- Additional Petroleum Industry Tax Incentives Are of Questionable Merit

Dear Mr. Fogel:

Thank you for the opportunity to provide comments on the report of the United States General Accounting Office ("GAO") "Additional Petroleum Industry Tax Incentives Are of Questionable Merit."

The report examines several tax incentives for the petroleum industry, including incentives included in the Administration's FY 91 budget. The report recognizes that such incentives would, to a certain degree, increase oil and gas exploration, development, and production and thereby improve U.S. energy security. However, the report questions whether additional tax incentives for the petroleum industry are as cost effective as other measures, including continuing to build strategic oil stocks, such as the Strategic Petroleum Reserve, encouraging conservation, and developing alternative fuels.

The Nation's Energy Goals

The GAO undertook this report at a time of serious concern voiced by the Congress, the Administration, and the business community over whether the nation has adequate energy security. The GAO report recognizes the widely held view that increased dependence on foreign oil leaves the nation vulnerable to potential foreign supply disruptions. The Administration believes that a balanced approach represents the best means of achieving increased energy security. The Administration's FY91 budget energy proposals, many of which are consistent with recommendations made by the GAO report, seek to increase energy security through a combination of non-tax measures and tax incentives. The tax incentives are an important element of these proposals. Thus, we disagree with the conclusion of the GAO study that it would be inappropriate at this time to enact any tax incentives for the domestic oil and gas industry.

See comment 1.

The Administration's Proposed Tax Incentives

The Administration's FY91 budget proposed four tax incentives to encourage exploration for new oil and gas fields and the reclamation of old fields: (1) A temporary 10 percent tax

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credit for the first $10 million of expenditures (per year, per company) on exploratory intangible drilling costs and a 5 percent credit on the balance of exploratory drilling costs; (2) A temporary 10 percent tax credit for all capital expenditures on new tertiary enhanced recovery projects (i.e., projects that represent the initial application of tertiary enhanced recovery to a property); (3) Repeal of the "transfer rule," which prohibits percentage depletion for properties acquired by, or transferred to, an independent producer after the property is shown to have oil or gas reserves, and an increase in the percentage depletion deduction limit for independent producers to 100 percent of the net income of each property; and (4) Elimination of 80 percent of current AMT preference items generated by exploratory intangible drilling costs incurred by independent producers. The two tax credits would be phased out if the average daily U.S. wellhead price of oil is at or above $21 per barrel for an entire calendar year. The estimated revenue cost of these four incentives is $400 million to $500 million per year.

Exploratory Drilling. The Administration recognizes the importance of raising the level of domestic exploratory drilling. The level of proven domestic reserves is closely related to the level of domestic exploratory drilling, which has fallen by 70 percent from recent levels, largely due to uncertainty concerning low world oil prices. In addition, over the same time period, development drilling has increased 20 percent, resulting in a substantial decline in existing domestic oil and gas reserves. Special tax incentives are appropriate to encourage higher levels of exploratory drilling, that will ultimately lead to increased domestic reserves. Higher levels of exploratory drilling activity also would provide continuing opportunities for skilled geologists and drilling contractors. The GAO report does not address the fact that the proposal would help preserve the resource base and the human capital required for the nation to maintain a reasonable degree of energy independence. In addition, the report does not evaluate the additional reserves that may arise from the credit for exploratory drilling and the credit for tertiary enhanced oil recovery. By focusing solely on increased production, the report ignores the enhancement to our national energy security resulting from the addition of reserves from increased exploratory drilling.

See comment 2.

Enhanced Oil Recovery. A temporary tax credit for new tertiary enhanced recovery projects would encourage the recovery of known energy deposits that are currently too costly to produce. The proposal would encourage the development of better enhanced oil recovery ("EOR") methods. Although the GAO report asserts that the research and experimentation credit already provides sufficient incentives to discover new EOR technology, the Administration believes that a temporary tax credit would serve both to further encourage the discovery of new technology and to stimulate hands-on projects and actual production. The goal of developing EOR technology will become more important to our nation's energy security as more of our production derives from mature oil fields.

See comment 3.

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Marginal Properties. An important goal of the Administration's proposals is the preservation of production from marginal properties. The transfer rule discourages the transfer of producing wells that are uneconomic in the hands of their current owners (and thus likely to be abandoned) to those who may be more efficient, more willing to bear current losses, or better able to use the percentage depletion benefits (and thus able to continue operation of the property). Current law also provides that percentage depletion may not exceed 50 percent of the net income of a property calculated before depletion. The 50 percent net income limitation may significantly reduce the benefits of percentage depletion for production from properties generating a small amount of net income. Raising the net income limit to 100 percent would allow some oil producers to claim greater depletion deductions, thus encouraging them to continue to operate marginal properties.

See comment 4

The GAO report recognizes that incentives of the type proposed by the Administration are likely to enhance the viability of marginal properties. The report also recognizes that once a marginal property is shut in, the production is lost because it will probably never be economic to redrill the property. The Administration believes that preserving production from marginal properties justifies the revenue costs of the tax incentive.

Conclusion

See comment 5.

The Administration believes that the proposed tax incentives would encourage exploration for new oil and gas fields and the reclamation of old fields. Although the GAO report alleges that the proposed incentives are not cost effective, many of the benefits that result from the proposals are difficult to measure precisely, and thus to reflect adequately in such comparisons. For example, the proposed incentives would strengthen the financial health of smaller independent producers, that have long been recognized as leaders in exploratory drilling. It is not clear how such a benefit could be quantified.

See comment 6

In addition to the proposed tax incentives, the Administration's FY91 budget includes non-tax measures that would improve the Nation's energy security. For example, the Administration proposes to fill the Strategic Petroleum Reserve in 1991 at a daily average rate of 59,000 barrels per day. This program seeks to decrease the vulnerability of the United States to disruptions in world petroleum markets by maintaining a crude oil stockpile to be used in the event such disruptions occur. The budget also includes a request for $1 billion for 1991 for new research and development initiatives for renewable and fossil energy, energy conservation initiatives, clean coal technology, and oil and gas geoscience.

The Administration's budget proposals represent a balanced approach to our nation's energy needs. The budget proposes to

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See comment 7

expend resources to fill the Strategic Petroleum Reserve, to hasten the development of alternative energy technologies, to encourage energy conservation, and to stimulate the nation's domestic oil and gas industry. The proposals to provide additional tax incentives for the domestic oil and gas industry serve important purposes and are an essential component of the balanced approach to improving U.S. energy security.

Yours sincerely,

Robert R. Wootton
Tax Legislative Counsel

The following are GAO's comments on the Department of the Treasury's letter dated April 19, 1990.

GAO Comments on Treasury's Letter

1. Treasury states that it disagrees with our conclusion that "it would be inappropriate at this time to enact any tax incentives for the domestic oil and gas industry." Treasury's wording is not the language of our report. The report notes that in principle there could be valid reasons for additional incentives as well as valid reasons for reducing current incentives. The report concludes that overall the incentives proposed to date are of questionable merit and are not likely to be the most effective method for providing significant increases in U.S. energy security.

2. The report notes that the incentives would increase petroleum industry employment (p. 5). The Administration has not demonstrated, however, that there would be inappropriate levels of trained personnel in the absence of additional incentives.

The report also discusses the effects on reserves where estimates are available. We have increased the discussion of additional reserves possible from EOR activities (pp. 46-48). In addition, in evaluating the cost-effectiveness of proposals relating principally to exploration and development, the initial costs of the incentives are compared to production that is assumed to continue for 30 years. Thus, the analysis reflects the additional reserves from these incentives.

In addition, the WEFA analysis of the Archer-Andrews-Boren bill—which includes drilling and other provisions—shows little effect on oil reserves through the year 2000. If these proposed incentives were to stop in the year 2000, the WEFA estimates suggest that the small addition to oil reserves would be totally exhausted within a few years, given the increased pumping rate. Natural gas reserves are, however, more significantly affected. This bill would provide far greater incentives (and has much larger expected revenue losses, given revenue-estimating conventions) than the administration proposals.

3. We agree that EOR will become increasingly important in the future. However, Treasury does not explain why market prices and competition are insufficient—and additional tax subsidies are necessary—to encourage private firms to make proper investments in EOR.

4. The costs per barrel of genuinely increased production stimulated by repeal of the transfer rule appear to be very high, given administration

revenue and production estimates. The tax revenue lost per barrel of genuinely increased production will be $11 to $14 based on these estimates. Treasury does not explain why this high premium on top of market prices is appropriate. We do not know how high a premium is associated with raising the net income limit because DOE has not released a production estimate for this incentive.

5. The report focuses on production and costs, but recognizes that there can be some intangible gains from increased industry employment and capacity. We agree with Treasury that it is not clear how that could be measured. In general, however, we believe that energy security would be best increased by not favoring certain categories of producers.

6. Although Treasury's comments acknowledge the merits of continuing to fill the SPR, the administration's proposed 59,000 barrel per day fill rate for fiscal year 1991 continues the trend of fill rates that are below the targets suggested by prior legislation. Fill rates for fiscal years 1988, 1989, and 1990 of 57,000, 62,000, and 39,000 (estimated) barrels per day were also below these targets.[1]

7. Overall, we believe that Treasury's view—that the additional tax incentives are essential to a balanced approach for improving U.S. energy security—has not been demonstrated. The proposed incentives for which DOE has production estimates would have little effect as a percentage of U.S. production or consumption (see pp. 32-34). In addition, they would be relatively costly when compared with alternatives—such as the SPR—that would unambiguously increase U.S. energy security.

[1]Specifically, the Omnibus Budget Reconciliation Act of 1986, P.L. 99-509, required SPR oil acquisition at "the highest practicable fill rate achievable, subject to the availability of appropriated funds." In addition, the law prohibited sale of the Naval Petroleum Reserve No. 1 (in Elk Hills, California) until at least 750 million barrels of oil are in the SPR or the SPR is filled at a rate of at least 75,000 barrels per day.

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Glossary

Alternative Minimum Tax	A set of income tax provisions designed to tax income that has been offset by high levels of tax preferences. The alternative minimum tax (AMT) is determined by first applying a lower tax rate to a higher tax base than the regular income tax. This process results in determination of the tentative minimum tax. If the tentative minimum tax is greater than the regular income tax, then the difference between these two values is the AMT.
Average Effective Tax Rate	The average rate of tax actually paid on all of a taxpayer's income.
Bonus	Nonrefundable cash received by the lessor of a petroleum property agreeing to lease land for petroleum exploration and development and due regardless of the level of production.
Cost Depletion	A method of depletion under which the deduction equals the percentage of recoverable units (e.g., barrels of oil) pumped and sold during the year times the adjusted basis (the taxpayer's initial cost of the property minus total depletion deductions to date).
Crude Oil Equivalents	Output of oil and natural gas measured in terms of barrels of oil, where 6,000 cubic feet of natural gas is considered equivalent to 1 barrel of oil.
Depletable Costs	Initial acquisition costs (such as bonus payments and geological and geophysical expenses) that represent the taxpayer's interests in the petroleum reserves that are diminished by extraction. (This report considers only the tax treatment of petroleum producers, as opposed to recipients of bonus and royalty payments (i.e., royalty owners). Royalty owners may also be eligible for depletion allowances on certain income.)
Enhanced Oil Recovery	Tertiary enhanced oil recovery uses injections of steam, carbon dioxide, or chemicals to extract oil. (Secondary recovery involves injection of water to increase pressure for extraction; primary recovery refers to pumping without any injections).

Expensing	Writing off a cost immediately rather than deducting it over time.
Geological and Geophysical	Survey, seismic, and related activities used to determine the location of petroleum and that serve as the basis for the acquisition or retention of petroleum properties.
Independent Producer	Producers other than those having retail sales exceeding $5 million per year or refining runs of greater than 50,000 barrels on any day in the tax year.
Intangible Drilling Costs	Expenditures incurred that have no salvage value and are incurred in preparing sites and drilling wells. These include wages, fuel, supplies used in drilling, construction of derricks and other structures, and road building, even if used in connection with installation of property that has salvage value.
Integrated Producer	A producer having retail sales exceeding $5 million per year or refining runs of greater than 50,000 barrels on any day in the tax year.
Marginal Effective Tax Rate	The tax rate on income from the marginal, i.e., incremental, investment.
Net Income Limit	A provision of the tax code that limits percentage depletion deductions to no more than 50 percent of the net income from a property.
Percentage Depletion	A method of depletion under which, currently, 15 percent of the gross income from a petroleum property is deductible from income.
Severance Tax	A state tax imposed on extraction of petroleum or other minerals.
Sixty-Five Percent of Taxable Income Ceiling	A restriction that percentage depletion deductions are limited to 65 percent of the taxpayer's income from all sources.

Strategic Petroleum Reserve	U.S. oil reserves managed by DOE that can only be used if the President determines that a severe energy disruption has occurred. The Reserve is funded by annual budget appropriations and is currently planned to hold 750 million barrels of oil.
Stripper Well	A well that produces 10 barrels or less of oil per day.
Straight-Line Depreciation	Depreciation of equal amounts each year.
Transfer Rule	A rule that prevents producers from claiming percentage depletion deductions on acquired proven petroleum properties (i.e., properties with principal value that has been demonstrated by prospecting, exploration, or discovery work).
Windfall Profit Tax	A federal excise tax applied to the difference between a measure of the price of crude oil and an adjusted base price. This tax took effect in March 1980 and was repealed in 1988.

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