2. Tax Expenditures

Overview

This chapter discusses Federal programs directly affecting the energy industry through which the Federal Government provides a direct financial benefit to energy producers or consumers and receipt of the benefit is directly linked to primary energy production and consumption. In the succeeding chapters, programs are examined in which linkage to energy production and consumption is less direct. The type of Federal program considered in this chapter consists mainly of Federal Government tax expenditures. Energy tax expenditures are broadly defined as provisions of the tax code that permit special, beneficial tax treatment to taxpayers who produce, consume, or save energy in ways that are judged to be in the public interest. In addition, this chapter also includes one "direct expenditure" energy subsidy, the Renewable Energy Production Incentive (REPI). Direct expenditures are payments made by the Federal Government to particular energy producers or consumers because they are economically disadvantaged or have undertaken to produce or consume energy in a way that has desirable social consequences. The size of the REPI subsidy is relatively small, however, at $4 million in 1999.

Tax expenditures and direct expenditures do not involve large sums of money in comparison with the Federal civilian budget or the value of U.S. energy consumption. Tax expenditures, largely aimed at energy production, are modest, totaling some $2.4 billion in outlay equivalent in fiscal year 1999. Tax expenditures are concentrated: the largest single item is $1.0 billion for the Section 29 tax credit for alternative energy sources. Although the legislation permits the credit for a large array of possible energy sources, almost all the $1.0 billion in tax expenditures for this legislation is claimed for natural gas production. The other large item in this account is the excise tax exemption for ethanol, with an outlay equivalent value of $0.7 billion—less than 1 percent of the $138 billion value of retail gasoline sales in 1998 but still a significant subsidy for ethanol.

Definitions

Tax expenditures are reductions in Government revenues resulting from preferential tax treatment for particular taxpayers. They are termed "tax expenditures" because their objectives could also be reached by direct expenditure of Government funds. In this report, the term "tax expenditures" is applied to preferential tax treatment provided by Federal income tax laws, as requested in the study definition. All but one of the tax expenditure provisions reviewed in this chapter include Federal income taxes that are applied preferentially to energy. The exception is the partial exemption from Federal energy excise taxes that benefits alcohol fuels.[8]

Many tax expenditure programs are functionally equivalent to direct expenditure programs. The basis for selecting one or the other approach to provide benefits to taxpayers is not always clear. Several factors may be considered

[8]Excise taxes are reviewed in Chapter 4. Because the partial exemption of alcohol fuels from excise taxes on transportation fuels is closely related to energy tax expenditures, it is reviewed in this chapter.

during the selection process. The decision as to which approach to use in a subsidy program depends on the specific characteristics of each program.[9]

The economic basis, or justification, that is frequently asserted for adopting tax expenditures differs with the particular type of tax expenditure program. The typical justification for tax expenditures that relate to capital recovery is to bring tax depreciation into closer conformity with actual economic change in the market value of the asset. Examples of differential capital cost recovery for energy tax purposes that have used this rationale include immediate expensing of intangible drilling costs and percentage depletion.[10] Intangible drilling costs were asserted by producers to be conventional operating expenses that therefore should be expensed. A key element of this assertion is that intangible drilling costs lack any salvage value. Granting accelerated writeoffs for investment improves the present value of after-tax profits and encourages additional mineral exploration and development.[11] The use of percentage depletion rather than cost depletion has a similar consequence.[12] A second justification for tax expenditures is to stimulate the production of goods thought to provide benefits that are not sufficiently valued in the market. An example is the Alternative Fuel Production Credit, which encourages increased production of energy from nonconventional sources, with the goal of reducing reliance on petroleum imports.

Tax expenditures exist when actual tax treatment for particular kinds of taxpayers deviates from standard tax treatment. There is disagreement as to what constitutes standard treatment, both in principle and in practice. As a result, lists of tax expenditure items and associated values can and do differ. With minor modification, the list and values used in this report are those prepared by the U.S. Department of Treasury and reported by the Office of Management and Budget (OMB) in the U.S. Government's annual budget.[13] The OMB does not include preferential energy excise tax expenditures, which are included here, within its formulation of tax expenditures.[14] The status of the tax expenditure provisions covered in this report extends only through fiscal year 1999, although an OMB forecast is presented for subsequent years through 2004.

Generally, tax expenditures are both tax benefits to preferred taxpayers and revenue losses to the Federal Government. This distinction creates two alternative means of measuring the effects of tax expenditures: revenue losses and outlay equivalents. Revenue losses are defined as revenue foregone by Treasury. The benefits or losses can also be expressed as outlay equivalents, which are the amounts taxpayers would have to be paid in order to derive the same after-tax income obtained under the revenue loss approach. Outlay equivalents will exceed revenue losses whenever outlays add to the taxable income of those who benefit from the tax expenditure program. For example, producers pay no tax on the tax credit they receive for producing alternative fuels, and their net income increases by the full amount of the credit. The direct budget outlay required to produce the same increase in net

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[9]Some of the factors related to the two approaches are discussed in M. Feldstein, "A Contribution to the Theory of Tax Expenditures: The Case of Charitable Giving," in H.J. Aaron and M.J. Boskin, eds., *The Economics of Taxation* (Washington, DC: The Brookings Institution, 1980), pp. 99-122.

[10]Intangible drilling costs are defined as oil and gas well drilling expenses that do not have salvage value and are "incident to and necessary for the production of oil and gas." Typical intangible costs—well logging, labor, fuels, and site preparation expenses—usually account for about 70 percent of the cost of drilling wells. A textbook discussion of intangible drilling costs can be found in R.A. Gallun and J.W. Stevenson, *Fundamentals of Oil and Gas Accounting*, 2nd edition (Tulsa, OK: PennWell Books, 1988), pp. 224-227.

[11]Although accelerated writeoffs have no effect on the value of after-tax profits, they allow profits to be realized earlier and give companies the opportunity to take advantage of intertemporal interest rate effects.

[12]Each tax expenditure category, including those that relate to intangible drilling costs and percentage depletion, is discussed later in the report and in detail in the Fact Sheets in Appendix B.

[13]Office of Management and Budget, *Budget of the United States Government, Fiscal Year 2000* (Washington, DC, 1999), and earlier editions. Treasury's compilation of tax expenditures is limited to special exceptions in the Federal income tax code that serve specific programs listed in the budget, such as energy, health, and defense.

[14]The basic rationale against including preferential energy excise taxes in formulations of tax expenditures is that excise taxes lack a basic structure against which deviations (preferences) can be measured. See P.R. McDaniel and S.S. Surrey, "Tax Expenditures: How To Identify Them; How To Control Them," *Tax Notes* (May 24, 1982), p. 610.

income would be greater than the credit, because the outlay would be subject to income tax—as typically occurs when tax expenditures take the form of tax deferrals. Tax deferrals are essentially loans, such as those implicit when exploration and development costs are expensed (or immediately charged against income), and do not directly affect taxable income.

This report presents both revenue losses and outlay equivalents. The outlay equivalent approach makes it easier to compare tax expenditure subsidies with other types of subsidies, which usually are reported on an outlay basis. The effects of interactions among tax preferences on the aggregate value of energy tax expenditures are reported by the Treasury Department only on an outlay equivalent basis.

Aggregate Federal tax expenditures measured in terms of outlay equivalent have grown relatively quickly over the past 10 years, to approximately $664 billion in 1999 from $482 billion in 1992, in 1999 dollars (Table 5). The Commerce and Housing Credit program has consistently accounted for more than one-quarter of tax expenditures since at least 1983.[15] Tax expenditures for that program, together with those for Income Security[16] and Health and Medicare,[17] annually account for about two-thirds of total Federal tax expenditures. Energy currently accounts for only $2 billion, or 0.3 percent of all tax expenditures.

Types of Tax Expenditures and Their Measurement

Four major types of energy-related tax expenditures can be identified (Tables 6 and 7): tax credits, measures that reduce taxable income, preferential tax rates, and tax deferrals. They differ substantially in terms of dollar value:

- Tax credits are currently the most valuable type of tax expenditure. The credits, which apply to items such as investment in alternative fuel production, enhanced oil recovery, new technology, and alcohol fuels, are valued at $1,015 million in fiscal year 1999 on a revenue loss basis (Table 6) or $1,330 million on an outlay equivalent basis (Table 7). The $1,030 million Alternative Fuel Production Credit is the largest energy-related tax credit in 1999 on an outlay equivalent basis.
- The sole income-reducing measure—excess of percentage over cost depletion—has the second greatest value, totaling $260 million in 1999 on a revenue loss basis or $295 million on an outlay equivalent basis.
- Preferential tax rates, the third most valuable form of energy tax expenditures, are expected to amount to $65 million in fiscal year 1999 on a revenue loss basis or $85 million on an outlay equivalent basis. This type of tax expenditure is the only one that involves a lowering of the corporate tax rate.
- The least valuable group of tax expenditures is tax deferrals. Tax deferrals originate when tax laws and regulations allow income earned in one period to be reported and taxed in a later period or allow acceleration of the deduction of expenses. When deferred, taxes are reported as positive tax expenditures (that is, as a loss in Government revenue). When repaid, they are reflected as a negative tax expenditure (that is, as a gain in Government revenues). In fiscal year 1999, net energy tax deferrals were estimated to be a negative $35 million on a revenue loss basis or a negative $55 million on an outlay equivalent basis. The tax deferrals covered here originate from expensing certain energy exploration and development costs, and from the exception from the passive loss limitation for working interests in oil and gas properties.

[15]The Commerce and Housing income tax credit provides incentives to encourage business investment. It allows capital gains to be taxed at a lower rate than other income.
[16]The Income Security tax credit provision benefits certain classes of retirement savings.
[17]The Health and Medicare tax allows employers to exclude contributions for health insurance from taxable income.

Table 5. Estimated Outlay Equivalent of Federal Tax Expenditures by Program, Selected Fiscal Years, 1992 and 1999
(Billion 1999 Dollars)

Program	1992	1999
Commerce and Housing Credit	180	210
Income Security	105	145
Health	66	109
General Purpose Fiscal Assistance	46	68
Education, Training, etc.	29	74
Social Security	26	23
International Affairs	10	15
National Resources and Environment	3	2
General Science, Space and Technology	4	3
National Defense	3	2
Community and Regional Development	3	2
Veterans Benefits and Services	2	3
Energy[a]	2	2
Interest	1	1
Agriculture	1	1
Transportation	*	2
Total Before Program Interactions	**482**	**664**

*Less than $0.5 billion.
[a]Does not include the outlay equivalent of any preferential energy excise taxes.
Notes: The values shown for any given program are after interactions among components of the program but before interactions between programs. Technically, the program values are not additive because of their high degree of interaction. Actual totals with program interactions are not available but would probably differ substantially from those shown. Sum of components may not equal total due to independent rounding. All data have been rounded to the nearest billion.
Sources: Office of Management and Budget, *Budget of the United States Government, Fiscal Year 1993* (Washington, DC, 1992), and earlier issues; and Office of Management and Budget, *Analytical Perspectives, 2000* (Washington, DC, 1999), and earlier issues.

Table 6 also shows the only energy tax expenditure covered in this chapter that does not originate from the income tax system—the alcohol fuels excise tax preference. Its expected fiscal year 1999 value is $725 million, both on a revenue loss basis and on an outlay equivalent basis. Each type of energy tax expenditure is discussed in the following section. Additional details are provided in the fact sheets in Appendix B.

Individual Energy Tax Expenditures

Energy tax expenditures are among the smallest tax expenditures that correspond to specific budget programs (Table 5). In fiscal year 1999, when preferential energy excise taxes are included, they amounted to about $2.0 billion on a revenue loss basis (Table 6) or $2.4 billion on an outlay equivalent basis (Table 7).[18] Most of the energy tax expenditures and preferential energy excise taxes are accounted for by only a few provisions, but those provisions are important in terms of their effects. They apply principally to oil and gas and, to a lesser extent, to alcohol for motor fuels and to coal. Alternative forms of energy benefit to only a small degree. Solar, wind, biomass, and geothermal energy facilities are beneficiaries of the New Technology Credit.

[18]The tax expenditures in these tables are net of the effects of the Alternative Minimum Tax.

Table 6. Estimated Revenue Losses from Federal Energy Tax Expenditures by Type of Expenditure and Form of Energy, Fiscal Year 1999
(Million 1999 Dollars)

Tax Expenditures	Oil	Natural Gas	Coal	Oil, Gas, and Coal Combined	Alcohol[a]	Other Energy	Certain Energy Facilities	Total
Preferential Tax Rates								
Capital Gains Treatment of Royalties on Coal	0	0	65	0	0	0	0	**65**
Tax Deferrals								
Expensing of Exploration and Development Costs	NA	NA	NA	-70	0	[b]0	0	**-70**
Exception from Passive Loss Limitation for Working Interests in Oil and Gas Properties	[c]18	[c]18	0	0	0	0	0	**35**
Tax Credits								
Enhanced Oil Recovery Credit	160	0	0	0	0	0	0	**160**
Alternative Fuel Production Credit	[d]0	[e]810	0	0	0	[f]0	0	**810**
New Technology Credit	0	0	0	0	0	0	[g]30	**30**
Alcohol Fuel Credit[h]	0	0	0	0	15	0	0	**15**
Income-Reducing Measure								
Excess of Percentage Over Cost Depletion	NA	NA	NA	260	0	[b]0	0	**260**
Total Before Component Interactions	**178**	**828**	**65**	**190**	**15**	**0**	**30**	**1,305**
Alcohol Fuels Excise Tax	0	0	0	0	725	0	0	**725**

[a]Alcohol for use as motor fuel.
[b]There may be small values for uranium, oil shale, and geothermal. Any such values are included in the value for coal.
[c]Derived by allocating an aggregate value for oil and natural gas equally between the two forms of energy. The total value for oil and gas combined was $35 million.
[d]There may be small values for oil produced from shale and tar sands. Any such values are included in the value for natural gas.
[e]Although the tax expenditure provision applies to oil, natural gas, solids, and steam produced from other than conventional sources, the $810 million income tax credit is estimated to be almost entirely for nonconventional natural gas.
[f]There may be small values for synthetic fuels produced from coal, fuel from qualified processed wood, and steam from solid agricultural byproducts. Any such values are included in the value for natural gas.
[g]Solar, wind, biomass, and geothermal energy facilities.
[h]In addition to the income tax expenditures in the table, there is a gasoline excise tax preference which amounted to an estimated $725 million in fiscal year 1999.
NA = Not available.
Source: Office of Management and Budget, *Analytical Perspectives, 2000* (Washington, DC, 1999).

The most valuable Federal tax expenditure for energy is the Alternative Fuel Production Credit, which has been most effective in stimulating the production of nonconventional natural gas. The credit is available for production sold before January 1, 2003, for qualifying properties drilled after December 31, 1979, and before January 1, 1993.[19] The second-largest energy-related tax expenditure in 1999 resulted from the use of percentage depletion rather than cost depletion for mineral resources. Under percentage depletion, a specified percentage of gross income from a mineral resource property is deductible for tax purposes. Under cost depletion, the value of the deduction is limited to the amortization of the investment value committed to the depleting resource. Percentage depletion benefits principally oil and gas producers but also producers of other natural resources, particularly coal.

[19]The credit was extended to production from biomass and liquid, gaseous, or solid synthetic fuels produced before January 1, 1997, and production through January 1, 2008. These fuels are relatively minor recipients of the Alternative Fuel Production Credit.

Table 7. Estimated Outlay Equivalent of Federal Energy Tax Expenditures by Type of Expenditure and Form of Energy, Fiscal Year 1999
(Million Dollars)

Tax Expenditures	Oil	Natural Gas	Coal	Oil, Gas, and Coal Combined	Alcohol[a]	Other Energy	Certain Energy Facilities	Total
Preferential Tax Rates								
Capital Gains Treatment of Royalties on Coal	0	0	85	0	NA	0	0	**85**
Tax Deferrals								
Expensing of Exploration and Development Costs	NA	NA	NA	-90	0	[b]0	0	**-90**
Exception from Passive Loss Limitation for Working Interests in Oil and Gas Properties	[c]18	[c]18	0	0	0	0	0	**35**
Tax Credits								
Enhanced Oil Recovery Credit	245	NA	NA	0	0	0	0	**245**
Alternative Fuel Production Credit	[d]0	[e]1,030	0	0	0	[f]0	0	**1,030**
New Technology Credit	0	0	0	0	0	0	[g]40	**40**
Alcohol Fuel Credit[h]	0	0	0	0	15	0	0	**15**
Income-Reducing Measure								
Excess of Percentage Over Cost Depletion	NA	NA	NA	295	0	[b]0	0	**295**
Total Before Component Interactions	**263**	**1,048**	**85**	**205**	**15**	**0**	**40**	**1,656**
Alcohol Fuels Excise Tax	0	0	0	0	725	0	0	**725**

[a]Alcohol for use as motor fuel.
[b]There may be small values for uranium, oil shale, and geothermal. Any such values are included in the value for coal.
[c]Derived by allocating an aggregate value for oil and natural gas equally between the two forms of energy. The total value for oil and gas combined was $35 million.
[d]There may be small values for oil produced from shale and tar sands. Any such values are included in the value for natural gas.
[e]Although the tax expenditure provision applies to oil, natural gas, solids, and steam produced from other than conventional sources, the $1,030 million income tax credit is estimated to be almost entirely for nonconventional natural gas.
[f]There may be small values for synthetic fuels produced from coal, fuel from qualified processed wood, and steam from solid agricultural byproducts. Any such values are included in the value for natural gas.
[g]Solar, wind, biomass, and geothermal energy facilities.
[h]In addition to the income tax expenditures in the table, there is a gasoline excise tax preference which amounted to an estimated $725 million in fiscal year 1999.
NA = Not available.
Source: Office of Management and Budget, *Analytical Perspectives, 2000* (Washington, DC, 1999).

In 1969, the percentage depletion rate for oil and gas was reduced; and, beginning in 1975, integrated oil and gas producers were prohibited from using percentage depletion altogether. The rate that applied to the remaining oil and gas producers, the "independents," was further reduced between 1981 and 1984. Since EIA's 1992 *Federal Energy Subsidies* report was written, the Alternative Fuel Production Credit has supplanted the use of percentage depletion as the largest energy-related Federal tax expenditure program, primarily because the oil and gas wells eligible for the percentage depletion credit had to have been drilled between 1980 and 1992, leading to a surge in subsequent sales (and tax expenditures) in the early to mid-1990s. The value of the percentage depletion tax expenditure has dropped primarily as a result of weak U.S. oil and gas prices since the mid-1980s.

Preferential Tax Rates

Only one type of energy tax expenditure involving preferential tax rate treatment is currently operative. It applies to royalty income derived from certain coal operations. The royalty income of individual owners of coal leases is taxed at the lower individual capital gains tax rate of 28 percent rather than at the higher regular individual top tax rate of 39.6 percent, if the owners so choose. Corporate owners have the same option, but because the corporate income and corporate capital gains tax rates are both 35 percent, the option is of little or no advantage to them. Individuals and corporations opting for the capital gains tax rate cannot also use the percentage depletion tax expenditure provision discussed below. In practice, the percentage depletion provision is generally more beneficial, particularly for corporations. The small preferential rate tax expenditure (revenue loss) for coal of $65 million in Table 6 (and its $85 million outlay equivalent in Table 7) benefits only individual owners at present.

Tax Deferrals

Tax deferrals generate tax expenditures that have a unique feature, in that they can be negative. Tax deferrals can be viewed as interest-free loans by the Government to taxpayers. These temporary revenue losses are recorded as positively valued tax expenditures. When the loans are repaid they are treated as negative tax expenditures.[20] In any given year the measured net value of newly made loans and loans repaid can therefore be either positive or negative. Actual subsidies associated with tax deferrals can never be negative, however, because interest-free loans always benefit the recipient. The value of the subsidy in any given year can be viewed as the amount that can be earned by investing the loans that are outstanding in that year. Two tax deferral types of energy tax expenditures exist: the expensing of exploration and development expenditures and the exception from the passive loss limitation for working interests in oil and gas properties.

Exploration and Development Expenditures

Tax law allows energy producers, principally oil and gas producers, to expense certain exploration and development (E&D) expenditures rather than capitalizing them and cost-depleting them over time. The most important of these expenditures consist of intangible drilling costs (IDCs) associated with oil and gas investments. IDCs are costs incurred in developing and drilling oil, gas, and geothermal wells up to the point of production.[21] Major (or integrated) oil companies can expense 70 percent of their IDCs for successful domestic wells and 100 percent for unsuccessful domestic wells.[22] The remaining 30 percent must be amortized over 5 years. Independent (or nonintegrated) oil producers can expense 100 percent of their IDCs for all domestic wells. Producers of other fuel minerals can also expense certain E&D expenditures. For example, coal producers can expense 70 percent of their surface stripping and other selected expenditures. The remainder must be amortized over 5 years.

The value of the E&D tax expenditure provision applied to oil, gas, and coal is an estimated negative $70 million in fiscal year 1999 (Table 6) or a negative $90 million in outlay equivalent (Table 7). The negative value represents a gain in Government revenue rather than a loss. The gain represents, in effect, a repayment of the principal on a Government loan (or prior tax deferral).

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[20]Technically, this is referred to either as a reversal or a turnaround of deferred taxes, depending on whether the emphasis is on all loans or individual loans.

[21]IDCs include costs such as labor, fuels, and site preparation. They exclude the cost of acquiring the property itself, as well as costs such as pipelines and other tangible facilities to control and transport the oil and gas produced.

[22]A major oil company is one that has integrated operations from exploration and development through refining or distribution to end users.

The value of the E&D tax expenditure provision is small by historical standards. Before 1986, positive tax expenditures occasionally exceeded $1 billion per year. The recent small values reflect reductions in the extent to which IDCs can be expensed, due to tax reform, and the adverse effects on petroleum investment resulting from the collapse of oil prices in 1986 and the relatively low oil and gas prices after that time.

The value of the subsidy associated with the expensing of E&D costs cannot be estimated precisely. By one measure, the subsidy is equal to the total interest charges the taxpayer would have had to pay to borrow the funds, which depends on the interest rate at which the taxpayer would borrow and the period of deferral. Since 1987, in all years but one, the value of expensing oil and gas development costs has been negative, meaning, on balance, that there has been no subsidy during the period.

The provision that allows the expensing of E&D costs for oil, gas, and other fuels increases the return on investment in those resources and adds to other E&D incentives. Domestic crude oil and natural gas production is greater than it otherwise would be, and capital is diverted from other productive activities. Also, all IDCs that are incurred outside the United States must be capitalized, thus providing a disincentive for foreign oil and gas exploration. The deferral particularly benefits the development of coal mines rather than the exploration efforts that precede development.[23] Additionally, on a per-dollar-of-investment basis, the expensing provision benefits mines with high capital costs and low variable costs (such as deep underground mines in the East) to a greater degree than those with a less capital-intensive ratio (such as strip mines in the West).

Title XIX of the Energy Policy Act of 1992 increased the future value of these provisions for independent oil and gas producers by limiting the extent to which intangible drilling costs are treated as tax preference items for purposes of computing the Alternative Minimum Tax. This provision will reduce the Alternative Minimum Tax liability of independent producers.

Passive Loss Limitation

The second tax deferral is an exemption from passive loss limitations for working interests in oil and gas properties.[24] The exemption allows owners of working interests to offset their losses from passive activities against active income. Under normal rules, passive losses remaining after being netted against passive incomes can only be carried over to future period passive incomes. The passive loss limitation provision and the oil and gas exception to it apply principally to partnerships and individuals rather than corporations.

The value of this tax expenditure in fiscal year 1999 is an estimated $35 million (Table 6). The value of the subsidy does not equal the value of the tax expenditure for the same reason cited above: the expenditure is equivalent to a loan, and the subsidy is equivalent to the gross interest that the loan earned, or could have earned, for the taxpayer. The value of the subsidy in fiscal year 1999 is equal to the interest not only on the net new loans of $35 million for that year but also to the interest on the cumulative net new loans in prior years.

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[23]Mine development expenses can be written off immediately. Typically, exploration costs can also be written off immediately, but the benefits of the early writeoff are nullified if the mines become profitable. See National Research Council, *Energy Taxation: An Analysis of Selected Taxes*, DOE/EIA-0201/14, prepared for the Energy Information Administration (Washington, DC, September 1980), pp. 78-79.

[24]A working interest is an interest in a mineral property that entitles the owner to explore, develop, and operate a property. The owner of the working interest bears the costs of exploration, development, and operation of the property and any liabilities arising from those activities. In return, the owner is entitled to a share of the mineral production from the property or to a share of the proceeds.

The impact of the subsidy may be greater than its small value for 1999 suggests. One reason for the small subsidy value is that the subsidy generally applies only to the noncorporate and closely related segments of the industry, and the level of funds obtained by independents through limited partnerships in recent years has been low.[25]

Tax Credits

The four energy tax credit expenditure provisions are the Enhanced Oil Recovery Credit, Alternative Fuel Production Credit, Alcohol Fuel Credit, and New Technology Credit. The credits have one common feature: they apply to unconventional forms of energy or means of producing energy.

Enhanced Oil Recovery Credit

Section 43 of the Internal Revenue Code provides taxpayers an enhanced oil recovery (EOR) credit equal to 15 percent of their qualified EOR costs. Section 43 was a part of the Omnibus Budget Reconciliation Act of 1990, which made several changes to capital cost recovery methods. The Section 43 credit is phased out if oil prices rise above a certain level, i.e., $28 per barrel (in 1991 dollars).[26]

The value of this tax expenditure is estimated at $160 million for fiscal year 1999 or $245 million in terms of outlay equivalent (Tables 6 and 7). The subsidy prolongs the lives of some wells, thus increasing the total volume of hydrocarbons recovered from those wells. In order to be eligible for the credit, the taxpayer must employ certain tertiary recovery methods,[27] such as miscible fluid replacement, steam drive injection, microemulsion, *in situ* combustion, polymer-augmented water flooding, cyclic steam injection, alkaline flooding, carbonated water flooding, and immiscible carbon dioxide replacement. EIA's *Annual Energy Outlook 1999* estimated that EOR contributed 580,000 barrels per day to U.S. oil production in 1997.[28]

Alternative Fuel Production Credit

This tax credit provision applies to the production of alternative (or nonconventional) fuels. It is the largest energy tax credit and stems from Section 29 of the Internal Revenue Code. Section 29 was established by the Windfall Profits Tax of 1980 (see box on page 20). At the end of fiscal year 1999, the qualifying fuels had to be produced from specified wells drilled or certain facilities placed in service between January 1, 1980, and December 31, 1992, and sold through the year 2002.

The credit is reduced if other subsidies are used.[29] The current value of the credit is an estimated $810 million for fiscal year 1999 and $1,030 million in terms of its outlay equivalent (Tables 6 and 7), making the Alternative Fuel Production Credit the largest energy-related tax expenditure. Its value has doubled since 1992, when EIA's previous energy subsidy report was produced.

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[25]The passive loss rules generally apply to individuals, trusts, estates, personal service corporations, and closely held corporations.

[26]The Section 43 tax credit is phased out when the average unregulated wellhead price per barrel of crude oil exceeds $28 in inflation-adjusted dollars. In 1999 dollars this value was $32.83, after adjusting for inflation using the 1992 GDP inflator (GDP92 = 1.00). Source: Joint Committee on Taxation.

[27]Tertiary injectants can also be expensed under Section 193 of the U.S. tax code. The value of this tax expenditure fell beneath the U.S. Treasury's *de minimis* amount ($5 million) over fiscal years 1999-2004 and thus was not reported.

[28]Energy Information Administration, *Annual Energy Outlook 1999*, DOE/EIA-0383(99) (Washington, DC, December 1998), Table A15.

[29]The credit is offset by any benefits received from energy investment credits, tax-exempt financing, and benefits received from Government grants.

Article 29: The Alternative Fuel Production Credit

The Alternative Fuel Production Credit (Section 29 of the Internal Revenue Code) was established by the Windfall Profit Tax of 1980 and became operational in the same year. Section 29 was designed to encourage the production of domestic energy from certain nonconventional sources and to reduce the Nation's dependence on energy imports. The credit applies to qualified fuels from wells drilled or facilities placed in service between January 1, 1980, and December 31, 1992. Production from qualifying wells can receive the credit on volumes produced through December 31, 2002; thus, the Section 29 credit affects the industry for 10 years after the qualifying deadline. The qualified fuels are:

- Oil produced from shale and tar sands
- Gas from geopressurized brine, Devonian shale, coal seams, tight formations, and biomass
- Liquid, gaseous, or solid synthetic fuels produced from coal
- Fuel from qualified processed formations or biomass
- Steam from agricultural products.

The principal changes that have occurred since 1980 have been to extend the time limits by which wells or facilities must be placed in service and fuels sold in order to be eligible for the credit. The initial time limit for qualification was December 31, 1989, but the deadline has been extended twice by subsequent legislation. In 1989, legislation allowed a 1-year extension of the time limits. The Omnibus Budget Reconciliation Act of 1990 provided an additional 2-year extension. The 1990 act also eased the qualifying requirements for gas produced from tight sands after 1990.[a,b]

The tax credit for nonconventional fuels is $3 per barrel of oil equivalent produced. (All prices as well as the credit are specified in 1979 dollars, but for actual use they are indexed for inflation relative to that base. Conversion factors are used to convert the various fuels into their crude oil equivalent for purposes of calculating the credit.) The credit is fully effective when the price of crude oil is $23.50 per barrel or less and phases out gradually as the price rises to $29.50 per barrel.[c] The credit is reduced if certain other energy subsidies, such as government grants and tax-exempt financing, are used.

The tax credit appears to have had a substantial impact on the production of alternative fuels. Initially, it stimulated the development of nonconventional gas wells, but the early rates of growth were not sustained through the mid-1990s, as the 1992 deadline slipped further into the past. According to one study, in 1992, just before the deadline when newly drilled wells would no longer be eligible for the tax credit, 78 percent of gas wells completed were drilled for the exploitation of gas in coal seams, tight sands, and shale oil.[d] The following year, their share had fallen to 61 percent. Although tight gas formations volumetrically account for the greatest share of U.S. nonconventional energy production, coalbed methane production has been affected most by the credit in recent years.[e] Coalbed methane recovery totaled only 91 billion cubic feet in 1989 out of total U.S. gas production of 17 trillion cubic feet. By 1994 it had risen to 1.0 trillion cubic feet, or 5 percent of U.S. production. Since then, growth in coalbed methane recovery has been less dramatic. Its share of the market reached 6 percent in 1997, which is the latest year for which production data are available. The majority of production takes place in Colorado, New Mexico, and the Black Warrior Basin of Alabama.

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[a]Section 29 was retained when the Windfall Profits Act was repealed in the late 1980s.

[b]Other changes under the 1990 Act included extending the credit as it applies to production from biomass and liquid, gaseous, or solid synthetic fuels produced from coal. The extension is allowed for facilities placed in service before 1997 and in production through 2007. These fuels are relatively minor recipients of the alternative fuel production credit. The credit no longer applies to fuel from qualified processed formations or biomass or steam from agricultural products.

[c]The actual conversion formula is: $3 - (($3 * (reference price - $23.50) / $6). For reference, the $3 credit and range of $23.50 to $29.50 in 1979 dollars are the equivalent in 1999 dollars of a $6.20 credit based on a range from $48.55 to $60.95. The GDP deflator was used to convert 1979 dollars to 1999 dollars.

[d]V.A. Kuuskraa and S.H. Stevens, "How Unconventional Gas Prospers Without Tax Incentives, *Oil and Gas Journal* (December 11, 1995).

[e]Production data for tight formation gas are difficult to compile, because it is often difficult to distinguish between tight formation gas and conventional gas being produced from the same field.

Investment Credit for New Technology

This credit formerly included a wide variety of items, but now it is limited to investment in solar and geothermal energy facilities. The Energy Tax Act of 1978 established a 10-percent investment tax credit for solar photovoltaic projects, as well as a 15-percent energy tax credit added to an existing 10-percent investment tax credit for solar thermal and wind generation facilities. The Tax Reform Act of 1986 eliminated the 10-percent investment tax credit and extended the energy tax credit to 1988, but it reduced that credit from 15 percent to 10 percent and eliminated wind as a candidate for any credits. The business tax credit was extended on a year-to-year basis until 1992, when passage of the Energy Policy Act of 1992 made the 10-percent business credit for solar (photovoltaic and thermal) and geothermal permanent. The Energy Policy Act of 1992 also provided a credit of 1.5 cents per kilowatthour for electricity produced from renewable resources such as wind and biomass.[30] The latter credit expired in July 1999.

The Investment Credit for New Technology, also known as the Investment (Business) Energy Tax Credit, is valued at $30 million for fiscal year 1999 ($40 million in terms of outlay equivalent) (Tables 6 and 7). Anyone who invests in or purchases a qualified solar,[31] wind, biomass, or geothermal energy property can take the credits, which are intended to encourage the production and consumption of energy generated by those facilities. Production costs have declined over time but still exceed those for conventional fuel.[32] Present levels of nonhydroelectric renewable energy production are small despite the subsidies.

Production Credit for Alcohol Fuels

The Production Credit for Alcohol Fuels is the only income tax expenditure for which there is also a preferential excise tax, in the form of an exemption. Motor fuels containing at least 10 percent alcohol are exempt from 6.0 cents of the per-gallon Federal excise tax on gasoline, diesel fuel, and other motor fuels. The income tax credit is 60 cents per gallon for alcohol used as a motor fuel and can be taken in lieu of the excise tax exemption. (For ethanol-based alcohol fuels, the excise tax exemption is 5.4 cents, and the credit equals 54 cents per gallon.) The income tax credit is granted to producers of alcohol fuels, defined as distributors who blend the alcohol and motor fuels. The credit may differ from 60 cents, depending on the proof of the alcohol. A new Federal income tax credit of an extra 10 cents per gallon is also available to eligible small producers of ethanol.[33]

The alcohol fuels income tax credit was not used to any significant degree until 1999, and in fiscal year 1999 it amounts to only $15 million (Tables 6 and 7), a value that could reflect the initial use of the new “small producers of ethanol” credit. Blenders generally use the excise tax exemption rather than the income tax credit, because the excise tax exemption provides them with an immediate cash flow. The subsidy they receive from this exemption in fiscal year 1999 is estimated at $725 million.

The alcohol fuels income tax expenditure and preferential excise tax programs affect not only the motor fuels industry but other industries and the environment as well. The alcohol fuels industry can exist for motor fuel

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[30]The tax expenditure “New Technology Credit” is an aggregation of the investment tax credit for solar and geothermal energy coupled with the renewable resource production tax credit directed at wind and biomass energy. These values are not reported separately in U.S. budget documents. The U.S. Treasury does not disaggregate these items separately as tax expenditures. They provided estimates of the production tax credit for wind and investment tax credit for solar and geothermal for 1999 to 2004. See the fact sheet “New Technology Credit: Investment Energy Tax Credit” in Appendix B.

[31]Solar property eligible for the investment credit uses solar energy to generate electricity or to heat or cool.

[32]Energy Information Administration, *Renewable Energy Annual 1998: Issues and Trends*, DOE/EIA-0628(98) (Washington, DC, March 1999), p. 7.

[33]An eligible small producer of ethanol generally is a person who, at all times during a year, has a productive capacity for alcohol not in excess of 30 million gallons.

purposes only with the aid of Government subsidies, because the price of alcohol fuels otherwise would not be competitive with gasoline or other alternatives. Because of the subsidies, gasoline/ethanol blends account for somewhat less than one-tenth of U.S. motor fuel consumption and production.[34] The result is a small (less than 1 percent) reduction in the volume of gasoline required to meet the demand for motor fuels and a probably negligible reduction in the prices of gasoline and other petroleum products relative to those that would otherwise prevail. Corn prices are higher, because nearly all U.S. ethanol is made from corn.[35]

Income-Reducing Measure

The Percentage Depletion Allowance is the only energy-related tax expenditure that reduces taxable income. Independent oil and gas producers and royalty owners, and all producers and royalty owners of certain other natural resources, including mineral fuels, may take percentage depletion deductions rather than cost depletion deductions to recover their capital investments.[36] Under cost depletion, the annual deduction is equal to the reduction in the remaining value of the resource that results from the current year's additional production.[37] Under percentage depletion, taxpayers deduct a percentage of gross income[38] from resource production at rates of 10 percent for coal, 15 percent for oil, gas, and oil shale, and 22 percent for uranium. Two special provisions also apply to oil and gas. First, percentage depletion for independent producers[39] and royalty owners is limited to 1,000 barrels oil equivalent per day. Second, for oil and gas wells with marginal production and wells whose production is substantially heavy oil, the 15-percent rate is increased by 1 percentage point for each dollar that the average wellhead price of domestically produced crude oil is below $20 a barrel.[40] The maximum increase allowed is 10 percentage points. Marginal production eligible for the higher rate has a prior claim on the 1,000-barrel-per-day limitation.

The percentage depletion deductions based on gross income are subject to net income limitations. The annual deduction for oil and gas is limited to 100 percent of net income from the property, and for other mineral fuels the deduction is limited to 50 percent. Geothermal production is eligible for percentage depletion at 65 percent of net income. Because percentage depletion is based on gross income rather than on the cost of the underlying assets, the resulting allowances generally will exceed the actual acquisition and development costs for the property from which the resource is extracted.

In fiscal year 1999, the reduction in tax revenue totals $260 million for oil, gas, and coal (Table 6). (Small reductions for uranium, oil shale, and geothermal energy are included in the values for coal.) The outlay equivalent of these revenue losses is greater, at $295 million (Table 7).

Percentage depletion will continue to provide incentives for resource development in the future. The incentives result in part from differences in the net income limitations and differences in production and distribution costs. However,

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[34]Ethanol is an alcohol that, when blended with gasoline, provides an effective fuel additive. Gasohol commonly is a blend of 10 percent ethanol and 90 percent gasoline.

[35]One study has estimated that approximately 7 percent of the U.S. corn crop was used for ethanol production in 1997, and that the subsidy raised corn prices by 45 cents per bushel. See M. Evans, *The Economic Impact of the Demand for Ethanol* (Lombard, IL: Midwestern Governors' Conference, February 1997).

[36]The excess depletion allowance is classified as a deduction because it permanently reduces income tax expense. If it merely deferred the expense it would be classified as a tax deferral.

[37]Specifically, the annual deduction is equal to the unrecovered cost of acquisition and development of the resource times the proportion of the resource removed during that year.

[38]Gross income amounts to oil and gas revenues, less transportation costs to the point of sale and any allocable lease bonus payments.

[39]For purposes of percentage depletion, an independent producer is defined, in general, as one who does not retail petroleum or petroleum products or refine crude oil. However, if the aggregate retail sales of the oil, natural gas, and products do not exceed $5 million per year, and if refinery runs do not exceed 50,000 barrels a day on any day during a tax year, the producer still is classified as an independent.

[40]Generally, for purposes of this provision, a marginal well property is one that produces a daily average of 15 barrels of oil equivalent or less per producing well over the course of a calendar year. Marginal wells include stripper wells.

the many constraints imposed on the use of percentage depletion for oil and gas since 1975, including the use of percentage depletion by only independent producers and royalty owners and then only up to 1,000 barrels per day, have and will continue to limit that tax expenditure provision to small-scale oil and gas operations. Independent producers would not generally engage in large offshore operations or in areas such as the North Slope even with the advantage of the depletion allowance. Nevertheless, they will continue to enjoy after-tax profits and royalties that are greater than they would be in the absence of percentage depletion.

The Alternative Minimum Tax Provision of the Energy Policy Act of 1992 reduced the tax burden on oil and gas producers and royalty holders by repealing, for them, excess percentage depletion tax adjustment for oil and gas for taxable years beginning after December 31, 1992. Excess preferences were preferences added back to the regular tax base in calculating income tax liabilities under the Alternative Minimum Tax System.[41] The Alternative Minimum Tax System has been in effect since 1986. Its purpose is to ensure that all individuals or business entities that benefit from certain exemptions within the tax code pay at least a minimum amount of tax. One effect of the tax, initially, was to reduce the value of percentage depletion.

Coal, uranium, oil shale, and geothermal operations will continue to be affected differentially by the percentage depletion provision. The differential effect reflects in large part the different depletion rates for the sources of energy as well as different net income limitations. As a practical matter, coal is the only energy industry, other than oil and gas, of any consequence with respect to percentage depletion, because the other industries operate at very low levels.

Department of Energy Renewable Energy Production Incentives

The Renewable Energy Production Incentive (REPI) program is part of an integrated strategy in the Energy Policy Act of 1992 to promote increases in the generation and utilization of electricity from renewable sources and to advance renewable energy technologies. The program provides financial incentive payments for electricity produced and sold by new qualifying renewable energy generation facilities. Qualified generation sources receive a payment of about $0.015 per kilowatthour, except that the amount of money is capped by a budgetary allocation. If the available funds are insufficient to cover the full production incentive payments, partial payments are made on a *pro rata* basis. Actual appropriations were $2.00 million for fiscal year 1997, $2.95 million for fiscal year 1998, and $4.00 million for fiscal year 1999.

[41]Energy Information Administration, *Performance Profiles of Major Energy Producers 1992*, DOE/EIA-0206(92) (Washington, DC, January 1994), p. 17.

Unreported Tax Expenditures

The reporting of tax expenditures was mandated by the Congressional Budget Act of 1974 (Public Law 93-344). The Budget of the U.S. Government defines tax expenditures as "revenue losses due to preferential provisions of the Federal tax laws, such as special exclusions, exemptions, deductions, credits, deferrals, or tax rates." Although the concept of what constitutes a tax expenditure is clear, the determination of what exactly is a preferential provision is subject to interpretation. In preparing this section on energy-related tax expenditures, the Energy Information Administration relied entirely on the definitions of tax expenditures presented in Office of Management and Budget (OMB) documents.

Expenditures below the U.S. Treasury *de minimis* amount ($5 million) are not reported in standard OMB budget documents and therefore are not included in this report. A case in point is the tax expenditure resulting from deepwater royalty relief in the outer continental shelf. To date, these expenditures have fallen well below the $5 million cutoff. The Outer Continental Deep Water Royalty Relief Act was signed into law on November 28, 1995.[a] The Act provides incentives for oil and gas production in the deep waters of the Gulf of Mexico by eliminating certain royalties on deepwater leases. "Specifically, it mandates volumes of royalty-free production from fields in water depths exceeding 200 meters, both for new leases . . . and for existing leases."[b] The program is administered by the U.S. Department of Interior's Minerals Management Service. As of August 1999, four requests had been granted for deepwater tax relief.[c] To date, the value of royalty reductions has been relatively small: $1.5 million in 1998 and $1.1 million in 1999 through April.[d]

This report does not address quantitatively recently passed energy legislation whose budgetary impact has not yet been assessed by the OMB for the current fiscal year (1999) or for future years. A case in point is the Emergency Oil and Gas Guaranteed Loan Program Act (Public Law 106-51), signed into law on August 17, 1999, which provides $500 million in loan guarantees to independent producers who have experienced layoffs, production losses, or financial losses since January 1, 1997.

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[a]The Outer Continental Deep Water Royalty Relief Act was included as an amendment to the Alaska Power Administration Sale Act legislation (S. 395).

[b]U.S. Department of Interior, Minerals Management Service, web site www.gomr.mms.gov/homep/whatsnew/newsreal/980115.html.

[c]U.S. Department of Interior, Minerals Management Service, Gulf of Mexico Offshore Region Office.

[d]U.S. Department of Interior, Minerals Management Service, Gulf of Mexico Offshore Region Office.