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TAXATION OF ENERGY AND NATURAL RESOURCES

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INTRODUCTION

This pamphlet,[1] prepared by the staff of the Joint Committee on Taxation, provides a discussion of the taxation of energy and natural resources. The Senate Finance Subcommittee on Energy and Agricultural Taxation has scheduled public hearings on June 21 and 28, 1985, on the taxation of energy and natural resources.

The first part of the pamphlet is an overview and summary. The second part is a description of specific tax provisions and proposals relating to energy and natural resources, including present law, Administration tax reform proposal, other proposals, and analysis of issues.

[1] This pamphlet may be cited as follows: Joint Committee on Taxation, *Taxation of Energy and Natural Resources* (JCS-21-85), June 20, 1985.

I. OVERVIEW AND SUMMARY

A. Overview

Much of the nation's energy policy is located in the Internal Revenue Code rather than in Federal outlay and regulatory programs. Tax expenditures for energy in the Code, in the form of credits and other tax preferences, are estimated to be $5.2 billion in fiscal year 1986.[2] This is comparable to the total amount of budget authority for energy programs ($5.1 billion) requested by the Administration in the fiscal year 1986 budget.

The Code contains provisions that influence both energy supply and energy conservation. The most significant of the energy supply provisions from the standpoint of tax revenue involve the deduction of expenses associated with the exploration, development, and depletion of fossil fuels (primarily oil, natural gas, and coal). These provisions were added soon after the adoption of the income tax.

Following the 1974 Arab oil embargo, and the economic disruption associated with the subsequent quadrupling of the price of imported oil, Congress enacted several tax credits in the Energy Tax Act of 1978[3] that were explicitly designed to reduce U.S. dependence on energy imports. These new energy tax credits were designed to encourage private expenditures both for energy conservation and for the production of nonconventional energy. Congress also provided for the gradual deregulation of natural gas prices in the Natural Gas Policy Act of 1978, and the Administration decontrolled petroleum prices between 1979 and 1981. As a result, domestic petroleum and natural gas prices are now at or near world market levels.

Primarily as a result of energy price increases and conservation measures, U.S. petroleum consumption dropped by 16.4 percent over the 1979-1984 period, and U.S. petroleum production (including natural gas plant liquids) increased by 2.9 percent.[4] The decline in consumption and the rise in production has reduced net imports of crude oil and refined products by 42 percent from 1979 to 1984. Over the 1979-1984 period, net petroleum imports have declined from 43.1 to 29.7 percent of domestic supply. In 1984, Organization of Petroleum Exporting Countries ("OPEC") supplied 12.8 percent, and Arab members of OPEC supplied only 5.1 percent, of U.S. petroleum demand.[5]

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[2] Joint Committee on Taxation, *Estimates of Federal Tax Expenditures for Fiscal Years 1986-1990* (JCS-8-85), April 12, 1985.

[3] The Crude Oil Windfall Profit Tax Act of 1980 increased to 15 percent and extended through 1985 the energy investment credits for solar, wind, and geothermal equipment. The 1980 Act also added the alternative fuels production credit and the energy credits for ocean thermal, small-scale hydroelectric, and cogeneration equipment, and intercity buses. In addition, the Act provided for the expensing of injectants used in tertiary oil recovery and allowed tax-exempt industrial development bonds to be used to finance certain alternative energy facilities.

[4] U.S. Dept. of Energy, *Annual Energy Review 1984* (April 1985), p. 77.

[5] U.S. Dept. of Energy, *Monthly Energy Review: February 1985* (May 1985), p. 15.

U.S. vulnerability to petroleum supply disruptions to some extent has been reduced by the establishment of a Federal strategic petroleum reserve ("SPR"). The SPR contains 465 million barrels of oil (as of April 1985), capable of replacing 100 days of oil imports at 1984 import rates (4.66 million barrel per day). Although the decline and diversification of U.S. petroleum imports and the expansion of the SPR provide some protection against import curtailments, a national security threat remains to the extent that Western Europe and Japan continue to be dependent on Persian Gulf oil.

Over the 1976-1983 period, oil and gas reserve additions gradually caught up with production. In 1976, U.S. reserve additions were only 2.9 billion barrels compared to production of 6.7 billion barrels. By 1983, reserve additions had reached 6.4 billion barrels, slightly exceeding production. The 131-percent increase from 1979 to 1984 in the annual rate of reserve additions was primarily the result of intensified exploration and development activity. The number of oil and gas exploratory and development wells drilled increased by 65 percent, from 49,800 in 1979 to 82,000 in 1984.[6]

The Administration in 1981 proposed complete repeal of the residential and business energy credits. Congress allowed many of these energy tax credits to expire as scheduled on December 31, 1982, but continued the remaining credits through December 31, 1985. The Administration's tax reform proposal would allow all of the remaining energy tax credits to expire at the end of 1985 and would also reduce certain of the tax preferences for oil, gas, and mineral depletion. Some have criticized the Administration's tax reform proposed on the grounds that it undercuts national energy policy, while others contend that all energy tax preferences should be eliminated.

In evaluating the provisions of the Code affecting energy production and use, and proposed changes to these provisions, several important issues arise. First, should the Federal government attempt to influence the level and composition of private energy supply and demand, in view of national security considerations, or let free-market prices determine these decisions. Second, if national energy policy seeks to encourage certain energy production and conservation activities, is it more efficient to use direct outlay programs or tax provisions to influence the use of energy. Third, if present Code provisions are used to further energy policy objectives, can these current law provisions be made more efficient. Fourth, to what extent do energy-related tax provisions affect the distribution of income among individual taxpayers and between regions of the country.

B. Summary

1. Oil and Gas

Present law

Present law distinguishes three types of pre-production cost: (1) costs incurred prior to drilling; (2) purchases of equipment used to

[6] U.S. Dept. of Energy, *Monthly Energy Review: February 1985* (May 1985), p. 64.

drill a well; and (3) intangible drilling costs. Under this system, lease acquisition costs and geological and geophysical costs incurred prior to drilling are recovered through the depletion deduction. Tangible drilling costs, like ordinary equipment purchases, are recovered through the depreciation deduction (and are eligible for the investment credit). Intangible drilling costs, such as labor and materials, are recovered according to special rules.

Pre-drilling costs.—The tax Code provides different methods for recovering lease acquisition and other pre-drilling costs for independent and integrated producers (i.e., producers with refining or retailing operations). Integrated producers must use cost depletion which requires that costs be deducted at the same rate that reserves are produced. Independent producers and royalty owners may use percentage depletion (at a 15 percent rate) on up to 1000 barrels per day of oil production, or the equivalent amount of natural gas. Under this method, 15 percent of the gross income from the property may be deducted, up to 50 percent of net income from the property. Unlike cost depletion, percentage depletion deductions may continue to be claimed even after all costs have been recovered.

Tangible drilling costs.—Drilling rigs, bits, and other drilling equipment generally are treated as ordinary depreciable property in the 5-year class. Under the Accelerated Cost Recovery System ("ACRS"), property in the 5-year class is eligible for a 10-percent investment credit, and 95-percent of the purchase price may be written off over 5 years. For a company taxed at the 46-percent corporate rate, the combination of the investment credit and depreciation allowance is approximately equivalent to writing off the full cost of the property in the year of acquisition ("expensing").

Intangible drilling costs.—The rules for deducting intangible drilling costs (IDCs) also differ between independent and integrated producers. Independents may elect to expense intangible drilling costs in the year incurred. Integrated producers are allowed to expense only 80 percent of IDCs, and the remainder must be written off over 36 months.

Administration proposal

Pre-drilling costs.—The use of percentage depletion by independent producers other than for wells producing less than 10 barrels per day ("stripper" wells) would be phased out over 5 years by reducing the depletion rate by 3 percentage points per year beginning on January 1, 1986. In the case of stripper wells, percentage depletion (at the current rate of 15 percent) would continue to be available to independent producers (but not royalty owners). Pre-drilling costs of non-stripper wells would be recovered by cost depletion, as under current law; however, depletion deductions would be indexed to adjust for inflation.

Tangible drilling costs.—Drilling equipment would be depreciated as ordinary equipment under the proposed Capital Cost Recovery System ("CCRS"). Under CCRS, equipment costs would be depreciated somewhat faster than under a tax system based on economic depreciation (such as that contained in the original Treasury proposal[7]); however, CCRS is less generous than the current-law system (accelerated depreciation plus the investment tax credit).

Intangible drilling costs.—The Administration would not change current law, but would adjust the treatment of IDCs for purposes of the individual and corporate minimum tax.

2. Mineral Deposits, etc.

Present law

Percentage depletion.—Percentage depletion is allowed in the case of mines, wells, and other natural deposits, at rates varying from 5 to 22 percent.

Development and exploration costs.—Mining development and exploration costs generally may be expensed.

Capital gains.—Royalty income from the disposition of coal, domestic iron ore and timber is allowed capital gains treatment.

Administration proposal

Percentage depletion.—The proposal would phase-out percentage depletion for all hard minerals over a 5-year period. Cost depletion would be indexed for inflation.

Development and exploration costs.—The proposal would not change present law with respect to these costs.

Capital gains.—The proposal would phase out the special capital gains rules for coal, iron ore, and timber over a 3-year period.

3. Energy Credits

Present law

Present law provides both residential and business energy credits. There are two types of residential energy tax credits: the conservation credit and the renewable energy credit.

Residential conservation credit.—The conservation credit is equal to 15 percent of the first $2000 of expenditures on insulation, storm windows and doors, and certain other types of equipment that increase the energy efficiency of a dwelling.

Residential renewal energy credit.—The renewable energy credit is equal to 40 percent of the first $10,000 of expenditures for solar, geothermal, and wind energy property that meets certain standards.

Under present law, there are three types of business energy tax credits: the energy investment credit, the nonconventional fuels production credit, and the alcohol fuels credit.

Energy investment credit.—Depending on the category of energy property, the energy investment tax credit is 10, 11, or 15 percent of the property's cost. Currently the energy investment credit is available for six classes of property: (1) geothermal equipment (15 percent); (2) ocean thermal equipment (15 percent); (3) biomass property (10 percent); (4) solar and wind property (15 percent); (5) small-scale hydroelectric property (11 percent); and (6) intercity buses (10 percent).

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[7] Dept. of the Treasury, *Tax Reform for Fairness, Simplicity, and Economic Growth,* (November 1984).

Nonconventional fuels production credit.—The nonconventional fuels production credit is a tax credit for certain alternative fuels equal to $3 per barrel of oil (or energy equivalent), adjusted for inflation since 1979.[8] The inflation adjustment increased the credit to approximately $4.10 in 1984. The credit phases out as the price of oil rises above $23.50 per barrel in 1979 prices (about $32.10 in 1984), and is eliminated at a price of $29.50 per barrel (about $40.30 in 1984). However, the current price of oil is below the phase-out range, so the full credit will be available in 1985 if current market conditions persist.[9]

Alcohol fuels credit.—Certain alcohol that is derived from crops and other biomass (but not from fossil fuels) and is used or sold as a fuel is eligible for an income tax credit of up to 60 cents per gallon.[10]

The residential and business energy credits other than the alcohol and nonconventional fuels production credits are scheduled to expire after December 31, 1985. The nonconventional fuels production credit does not apply to nonconventional fuel produced from wells drilled after, or produced in a facility placed in service after, December 31, 1989. The alcohol fuels credit does not apply to the sale or use of alcohol fuel after December 31, 1992.

Administration proposal

The Administration proposal allows all energy credits other than the alcohol and nonconventional fuels production credits to expire after December 31, 1985. The nonconventional fuels production credit would be terminated for fuels produced from facilities completed after December 31, 1985. (The credit would continue for eligible fuel produced from a well drilled, or facility completed, before January 1, 1986, and sold before January 1, 1990.) The alcohol fuels credit would be terminated for alcohol fuels produced from facilities completed after December 31, 1985. (The credit would continue for qualified alcohol fuels produced from facilities completed before January 1, 1986, and sold before January 1, 1993.)

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[8] The credit is available for the following fuels: (1) oil produced from shale and tar sands; (2) gas produced from geopressured brine, Devonian shale, coal seams, and tight formations; (3) gas produced from biomass; (4) synthetic fuel produced from coal (including lignite); (5) qualifying processed wood fuels; and (6) steam from certain agricultural byproducts.

[9] As of February 1985, the average refiner acquisition cost of crude oil was $26.53 per barrel.

[10] The credit is 60 cents for alcohol that is at least 190 proof and 45 cents for alcohol that is between 150 and 190 proof. No credit is available for alcohol that is less than 150 proof.

II. DESCRIPTION OF TAX PROVISIONS AND PROPOSALS

A. Tax Provisions Relating To Oil And Gas Production

1. Intangible Drilling and Development Costs

Present Law and Background

General rules

Costs incurred by an operator to develop an oil or gas property for production are of two types: (1) intangible drilling and development costs, and (2) depreciable costs.

Under present law, intangible drilling and development costs ("IDCs") may either be currently expensed or else may be capitalized and recovered through depletion or depreciation deductions (as appropriate), at the election of the operator. In general, IDCs include expenditures by the property operator incident to and necessary for the drilling of wells and the preparation of wells for the production of oil or gas (or geothermal energy) which are neither for the purchase of tangible property nor part of the acquisition price of an interest in the property.[11] IDCs include amounts paid for labor, fuel, repairs, hauling, supplies, etc., to clear and drain the well site, make an access road, and do such survey and geological work as is necessary to prepare for actual drilling. Other IDCs are paid or accrued by the property operator for the labor, etc., necessary to construct derricks, tanks, pipelines, and other physical structures necessary to drill the wells and prepare them for production. Finally, IDCs may be paid or accrued to drill, shoot, and clean the wells. IDCs also include amounts paid or accrued by the property operator for drilling or development work done by contractors under any form of contract.

Depreciable costs are amounts paid or accrued during the development of a property to acquire tangible property ordinarily considered to have a salvage value. For example, the costs of drilling tools, pipe, cases, tubing, engines, boilers, machines, etc., fall into this category. This class of expenditures also includes amounts paid or accrued for wages, fuel, repairs, etc., in connection with equipment or facilities not incidental or necessary for the drilling of wells, such as structures to store or treat oil or natural gas. These expenditures must be capitalized and depreciated in the same manner as ordinary items of equipment, and they are treated the same for both independent and integrated producers.

Only persons holding an operating interest in a property are entitled to deduct IDCs. This includes an operating or working interest in any tract or parcel of oil- or gas-producing land either as a

[11] The acquisition price for the actual oil- or gas-producing property, together with certain other costs, is recovered through depletion deductions (see discussion of depletion below).

fee owner, or under a lease or any other form of contract granting working or operating rights. In general, the operating interest in an oil or gas property must bear the cost of developing and operating the property. The term operating interest does not include royalty interests or similar interests such as production payment rights or net profits interests.

Generally, if IDCs are not expensed, but are capitalized, they can be recovered through depletion or depreciation, as appropriate. However, if IDCs are capitalized and are paid or incurred with respect to a nonproductive well ("dry hole"), they may be deducted, at the election of the operator, as an ordinary loss in the taxable year in which the dry hole is completed. Thus, a taxpayer has the option of capitalizing IDCs for productive wells while expensing those relating to dry holes.

Twenty percent reduction for integrated producers

In the case of a corporation which is not an independent producer[12] (i.e., which is an "integrated" producer), the allowable deduction with respect to IDCs is reduced by 20 percent. The disallowed amount must be added to the basis of the property and amortized over a 36-month period, starting with the month in which the costs are paid or accrued. (These capitalized IDCs are not, however, taken into account for purposes of determining cost depletion.) Amounts paid or accrued with respect to non-productive wells (dry hole costs) remain fully deductible when the non-productive well is completed.

Recapture

If an operator elects to expense IDCs paid or accrued after 1975 and then disposes of the oil, gas, or geothermal property, a portion of the expensed IDCs must be treated as ordinary income (instead of capital gain). This portion is equal to the lower of (1) the amount of IDCs deducted since January 1, 1976 (which, but for being deducted, would have been reflected in the adjusted basis of the property), reduced by the amount (if any) by which the depletion deduction with respect to such property would have been increased if such amounts had been capitalized, or (2) the gain on the sale, exchange, or involuntary conversion of the property.

Minimum taxes

While IDCs are currently deductible (at the election of the operator), the economic value of this current deduction election is reduced by the effect of the alternative minimum tax with respect to noncorporate operators.

In the case of an individual, trust, or estate (noncorporate taxpayer), the taxpayer's alternative minimum tax is equal to 20 percent of the excess of that taxpayer's alternative minimum taxable income over a statutory exemption amount.[13] Alternative mini-

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[12] This term is defined in the same manner as it is for purposes of percentage depletion (discussed below).

[13] The exemption amount is equal to $30,000 for single persons and $40,000 for married couples.

mum taxable income is adjusted gross income, less certain deductions, plus the amount of the taxpayer's tax preference items.

In general, IDC deductions on successful wells are a tax preference item for purposes of the alternative minimum tax to the extent they exceed the amount which would have been deductible in that year had the IDCs been capitalized and recovered over a 10-year, straight-line amortization period, but only to the extent of the excess of such deductions over the taxpayer's income for the taxable year from the oil or gas property. (Geothermal properties are treated in a similar manner.) Thus, IDCs are treated as a preference item only to the extent they are used to offset non-oil or gas income. The 10-year amortization period applies on a well by well basis, starting with the month in which production for the well begins. At the election of the operator, the cost depletion method may be substituted for the 10-year amortization schedule in determining the amount of tax preference.

IDCs paid or accrued by an individual are not treated as tax preference items if the individual elects to capitalize the IDCs and deduct them ratably over a 10-year period. In addition, in the case of any IDC expenditure in the United States by an individual which is not allocable to a limited partnership interest or certain subchapter S corporation shareholdings of such individual (e.g., individuals with operating interests, general partners, and sole proprietors), the IDCs are not treated as items of tax preference if the individual elects to deduct the IDCs over a 5-year period. If the 5-year schedule (which is the same as the ACRS 5-year recovery schedule) is chosen, the amount of the IDC is also treated as a qualified investment for purposes of the investment tax credit.

Under present law, IDCs are not treated as a preference item for purposes of the "add-on" minimum tax on corporations.

Administration Proposal

The Administration proposal would retain the present law tax treatment of IDCs. However, 8 percent of the IDCs paid or incurred on productive wells in any taxable year would constitute a tax preference item for purposes of the proposed noncorporate and corporate minimum taxes under the Administration proposal.[14] The 8-percent figure was derived by estimating the difference between (1) the value of expensing IDCs in the year paid or incurred, and (2) the present value of the deductions to which the taxpayer would have been entitled under the Capital Cost Recovery System ("CCRS") included in the Administration proposal. The 8-percent

[14] Under the Administration proposal, the minimum tax for noncorporate taxpayers would continue to be structured as an alternative tax, with a rate of 20 percent. Alternative minimum taxable income would be computed by adding to adjusted gross income the excess of preference items over $10,000 ($5,000 for married persons filing separately), and subtracting (a) allowable itemized deductions (generally, all itemized deductions with the exception of excess nonbusiness interest), (b) personal exemptions, and (c) a threshold exemption amount. The threshold exemption amount would be $15,000 for joint returns ($7,500 for married persons filing separately), $12,000 for heads of households, and $10,000 for single persons. The minimum tax for corporations would be restructured as an alternative minimum tax with a 20 percent rate, and would operate similarly to the noncorporate minimum tax. Thus, under this proposal, the minimum tax on IDCs, for a taxpayer subject to that tax, would be at the rate of 1.6 percent on its expensed IDCs (i.e., 20 percent tax rate multiplied by 8 percent IDC inclusion).

figure assumes that IDCs would be indexed for inflation and recovered over a 6-year CCRS period, the same as tangible drilling costs.

Under the Administration proposal, the amount of the tax preference for IDCs would not be reduced by the taxpayer's net income from oil and gas (or geothermal) property. Thus, expensed IDCs would be treated as a preference regardless of whether they were used to offset oil and gas income or other taxable income.

The expensing of amounts with respect to nonproductive wells (dry holes) would not be treated as a preference item under the Administration proposal.

These proposals would be effective for costs paid or incurred on or after January 1, 1986.

Other Proposals

1984 Treasury Report

Under the 1984 Treasury proposal, the option to expense IDCs would be repealed. Instead, these costs would be capitalized as depreciable or depletable costs, depending on the nature of the cost incurred. Depreciable costs would be recovered over a 12-year period under the Real Cost Recovery System ("RCRS") included in the 1984 Treasury proposal. Depletable costs would be recovered using the cost depletion method. (Depreciation incurred during the pre-production stage would also be recovered through cost depletion). Both the depreciation and cost depletion basis would be indexed for inflation.[15]

S. 1006

S. 1006 (Senators Kasten and Wallop) would retain present law.

S. 409

Under S. 409 (Senator Bradley), the option to expense IDCs would be repealed. Instead of expensing, these costs would be added to the basis for depreciation or cost depletion (as appropriate). Amounts included in the basis for cost depletion would be recovered on an accelerated method over a 10-year period, under rules similar to those applied for depreciable property generally. Immediate deductions would continue to be allowed upon the abandonment of an unproductive well.

Analysis

The taxation of oil and gas investments can be compared with other capital investments, such as investments in plant and equipment. Under the Administration proposal, pre-drilling costs (i.e., depletable costs), except in connection with stripper wells, would be deducted using indexed cost depletion. This is generally equivalent to a system of economic depreciation, such as RCRS depreciation contained in the 1984 Treasury proposal. However, under the Administration proposal, equipment and structures would be depreci-

[15] The repeal of IDC expensing would not affect the expensing of costs associated with nonproductive wells ("dry holes"). However, it is understood that, under the 1984 Treasury proposal, taxpayers would be allowed to expense dry hole costs only when an entire property was unproductive, rather than on a well-by-well basis as under present law.

ated using the proposed CCRS system which is more generous than RCRS. Consequently, depletable property would be treated less favorably than most equipment and structures. Tangible drilling costs would be recovered using CCRS and would as a result receive the same treatment as depreciable equipment. However, most intangible drilling costs would be expensed, as under present law, which is a more generous recovery method than CCRS. Whether or not a particular well would be at a disadvantage relative to depreciable property in the Administration proposal thus depends on the magnitude of the well's pre-drilling costs relative to intangible drilling costs.

One issue is whether investments in oil and gas should be given preferential treatment, relative to other capital investments. The Administration contends that preferential treatment of IDCs is necessary to stem the recent "substantial decline in oil drilling activity" that could reduce domestic oil production and increase vulnerability to oil import interruptions.

Evidence that drilling activity has fallen over recent years is not clear. According to Department of Energy statistics, the number of exploratory and development oil wells drilled in 1984 (41,130) was larger than the number drilled in any year since 1949.[16] The number of seismic crews and rotary rigs in use increased from 1983 to 1984; however the 1984 levels are below the records attained during the 1980-82 period. These data indicate that despite the retrenchment in manpower, the oil industry has managed to drill a record number of wells by increasing labor productivity.

The Administration proposal takes the position that providing tax incentives for drilling activity is necessary to increase U.S. energy security. In 1984, the U.S. imported 4.7 million barrels of oil per day, accounting for 29.7 percent of domestic petroleum supply. In the event of a complete curtailment of imports, the Strategic Petroleum Reserve could, at current levels, replace all imports for at most 100 days. If the SPR were depleted, domestic production would have to increase by about 40 percent to replace imports. As of 1983, proved reserves of crude oil amounted to just 8.7 years of production. If production rates were increased to replace all imports, proved reserves would be exhausted in less than 6½ years. To respond to a complete oil import curtailment, it is argued that proved reserves must be increased now in preparation because it can take several years from initial discovery of a petroleum reservoir to reach maximum production. It is argued that energy security would be increased by retaining tax preferences in current law for intangible drilling costs and percentage depletion. It is also argued that these tax incentives should be retained in order to maintain adequate levels of labor and equipment in the oil and gas industry in the event of an energy crisis.

Some have questioned this view on the grounds that drilling incentives may lead to a substitution of domestic oil for imports—arguably "draining America first". They argue that oil production is likely to rise along with reserve additions yielding little net in-

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[16] Dept. of Energy, *Annual Energy Review 1984* (April 1985), p. 73. Excludes service well, stratigraphic tests, and core tests. Note that the oil well footage drilled in 1984 (161.7 million) was greater than in any other year except 1981.

crease in field reserves. Some argue that it may be more efficient to stockpile petroleum by filling the SPR with oil purchased in the world market at the current depressed prices. It is also argued that the decline and diversification of U.S. imports, and the collapse of the OPEC price structure, have reduced the likelihood of a sharp curtailment of oil imports.

Others argue that the object of energy policy should be complete energy independence. In this view, tax incentives for oil and gas exploration serve energy policy by increasing domestic production and replacing imports. This might also improve the merchandise trade balance since net petroleum imports accounted for almost 20 percent of all imports in 1984.[17] However, energy self-sufficiency might be achieved more efficiently by a tax on imported oil.[18] Such a tax would encourage conservation and fuel switching, as well as production, by raising the price of domestic oil.

From an accounting standpoint, part of the reason that IDCs have historically been allowed to be expensed[19] (aside from the implicit tax subsidy) is the difficulty of establishing an alternate recovery period, because the "useful life" of a well may not be known in advance and its production may occur at an uneven rate. (This is similar to the problem faced in determining a proper oil and gas depletion method.) If Congress decides to modify the present law treatment of IDCs, it may wish to establish a statutory recovery period which, if desired, contains some incentive element. Alternatively, IDCs may be merged with general depreciation provisions in order to provide similar tax incentives. Likewise, as under present law, differentiation between integrated producers and other taxpayers could be maintained. To the extent that Congress is concerned principally with domestic exploration, different rules could be provided for domestic and foreign production.

It has been argued that the expensing of costs associated with "dry holes" is consistent with general tax accounting principles, which allow deductions for ordinary business losses incurred during the year. However, this depends upon whether one defines a "loss" as an event occurring on a well-by-well, or, alternatively, a property-by-property, basis. Advocates of allowing dry hole costs to be expensed argue that whenever a well proves not to have any recoverable oil, the money spent on drilling that well has been irrecoverably lost and accordingly should be regarded as deductible. Others argue that this is inconsistent with common business practice in the oil and gas field. They assert that oil and gas operators, when beginning operations on properties which they know to contain valuable reserves, will commonly drill several wells in the knowledge that some, but not all, of them will likely prove productive. Thus, these advocates argue, the dry holes on a productive property are most accurately viewed as expenses related to an

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[17] Dept. of Energy, *Monthly Energy Review: February 1985* (May 1985), p. 11.

[18] The Administration's 1984 fiscal year budget contained a provision which would have imposed a $5 per barrel tax (the so-called "contingency" tax) on domestic and imported oil under certain circumstances.

[19] The option to expense IDCs has been permitted by regulations since the Revenue Act of 1918. In 1945, in response to a case casting doubt on this treatment, Congress passed a concurrent resolution which specifically approved the Treasury regulations granting the option to expense IDCs. The Internal Revenue Code of 1954 (sec. 263(c)) directs the Treasury Department to promulgate regulations allowing for the option to expense IDCs.

overall productive project, and accordingly cannot properly be expensed under general tax accounting rules.

2. Depletion

Present Law and Background

General rules

Depletion, like depreciation, is a species of ordinary and necessary business expense. In both cases, the taxpayer is allowed a deduction in recognition of the fact that an asset—in the case of depletion, the oil or gas reserve itself—is being expended in order to produce income. Certain costs incurred prior to drilling an oil -or gas-producing property are recovered through the depletion deduction. These include costs of acquiring the lease or other interest in the property, and geological and geophysical costs (in advance of actual drilling). Depletion is available to any person having an economic interest in a producing property (including royalty interests).

Two methods of depletion are currently allowable under the Internal Revenue Code: the cost depletion method, and the percentage depletion method. Under the cost depletion method, the taxpayer deducts that portion of the adjusted basis of the property which is equal to the ratio of units sold from that property during the taxable year to the number of units remaining as of the taxable year (in general, the number of units remaining in the property at the end of the taxable year to be recovered, plus the number of units sold during the taxable year). The amount recovered under cost depletion thus may not exceed the taxpayer's basis in the property.

Under percentage depletion, 15 percent of the taxpayer's gross income from an oil -or gas-producing property is allowed as a deduction in each taxable year. The amount deducted may not exceed 50 percent of the net income from that property in any year (the "net income limitation"). Additionally, the deduction for all oil and gas properties may not exceed 65 percent of the taxpayer's overall taxable income. Because percentage depletion is computed without regard to the taxpayer's basis in a property, it may result in eventual recovery of an amount greater than that actually expended by the taxpayer to acquire or develop the property.

A taxpayer is required to determine its depletion deduction for each oil and gas property under both the percentage depletion method (if the taxpayer is entitled to use this method) and cost depletion method. If the cost depletion deduction is larger, the taxpayer must utilize that method for the taxable year in question.

Similar rules apply to geothermal deposits located in the United States, except that the 65 percent of taxable income limitation does not apply.

Limitation to independent producers, etc.

The Tax Reduction Act of 1975 repealed percentage depletion with respect to much oil and gas production. Under that Act, independent producers and royalty owners[20] (as contrasted to integrated oil companies) are allowed to take percentage depletion with respect to up to 1,000 barrels of average daily production of domestic crude oil or an equivalent amount of domestic natural gas.[21] For producers of both oil and natural gas, this limitation applies on a combined basis.

For purposes of percentage depletion, an independent producer is any producer who is not a "retailer" or "refiner." A retailer is any person who directly, or through a related person, sells oil or natural gas or any product derived therefrom, (1) through any retail outlet operated by the taxpayer or related person, or (2) to any person obligated to market or distribute such oil or natural gas (or product derived therefrom) under the name of the taxpayer or the related person. In determining whether or not a person is a retailer, bulk sales to commercial or industrial users, and bulk sales of aviation fuel to the Department of Defense, are excluded. Further, a person is not a retailer within the meaning of this provision if the combined gross receipts of that person and all related persons from the retail sale of oil natural gas, or any product derived therefrom, do not exceed $5 million for the taxable year.

A refiner is any person who directly or through a related person engages in the refining of crude oil, but only if such taxpayer or related person has a refiner run in excess of 50,000 barrels per day on any day during the taxable year.

In addition to the independent producers exception, certain sales of natural gas under a fixed contract in effect on February 1, 1975, and certain natural gas from geopressurized brine,[22] are eligible for percentage depletion, at rates of 22 percent and 10 percent respectively. These exceptions apply without regard to the 1,000 barrel per day limitation and regardless of whether the producer is an independent producer or an integrated oil company.

To prevent proliferation of the independent producer exception, all production owned by businesses under common control and members of the same family must be aggregated. Each group is then treated as one producer for application of the 1,000-barrel amount. Further, if an interest in a proven oil or gas property is transferred after 1974 (subject to certain exceptions), the production from such interest does not qualify for percentage depletion. The exceptions to this rule include transfers at death, certain transfers to controlled corporations, and transfers between controlled corporations or other business entities.

Minimum taxes

The excess of percentage depletion over the taxpayer's adjusted basis for each oil or gas property,[23] for any taxable year, is treated

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[20] Percentage depletion is available to lease bonuses and advance royalty payments. *Commissioner v. Engle*, 464 U.S. 206 (1984). See also I.R. Ann 84-59, IRB 1984-23 (June 4, 1984).

[21] As originally enacted, the depletable oil quantity was 2,000 barrels of average daily production. This was gradually to be phased down to 1,000 barrels for 1980 and thereafter. The 1975 Act also phased down the percentage depletion rate from 22 percent in 1975 to 15 percent in 1984 and thereafter.

[22] This exception is limited to wells the drilling of which began between September 30, 1978, and January 1, 1984.

[23] In general, the term "property", for depletion purposes, means each separate interest owned by the taxpayer in each separate tract or parcel of land. In the case of oil and gas wells

Continued

as a preference item for purposes of the noncorporate (i.e., individual) alternative minimum tax and the corporate "add-on" minimum tax under present law.

Administration Proposal

General rules

The Administration proposal would generally phase out percentage depletion for oil and gas properties over a 5-year period, beginning on January 1, 1986. This would be accomplished by reducing the percentage depletion rate by 3 percentage points for each of calendar years 1986 through 1990. Taxpayers for whom percentage depletion was repealed would be required to use cost depletion, the basis for which would now be indexed for inflation.

Under the Administration proposal, percentage depletion would continue to be available for so-called "stripper" wells (i.e., wells producing less than 10 barrels per day) owned by independent producers. The proposal specifies that this exception would not apply to royalty owners.

The phase-out of percentage depletion would be effective for production beginning on or after January 1, 1986.

Minimum taxes

For depletable property placed in service on or after January 1, 1986, the Administration proposal would include as a preference item, for purposes of the proposed noncorporate and corporate alternative minimum taxes, the excess of percentage depletion over the amount which would have been deductible had the taxpayer capitalized its costs and recovered them through cost depletion. For property placed in service before 1986, the amount of the preference would be the excess of the depletion deduction over the adjusted basis of the property (as under the present law noncorporate minimum tax).

Other Proposals

1984 Treasury Report

The 1984 Treasury proposal would repeal percentage depletion for all oil and gas properties, effective for production on or after January 1, 1986. The basis for cost depletion would be indexed for inflation.

S. 1006

S. 1006 (Senators Kasten and Wallop) would retain present law.

S. 409

Under S. 409 (Senator Bradley), percentage depletion would be repealed for all oil and gas properties from which production begins after December 31, 1986. Depletable expenses would be recovered over a 10-year period, using rules similar to those applied

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and geothermal deposits, all of a taxpayer's operating interests in each separate tract or parcel of land are generally treated as one property, subject to an election to separate certain interests in the same tract or parcel.

for depreciable property generally. These rules would replace the present law cost depletion system (which is based on the annual ratio of units sold to remaining production units), as well as the percentage depletion method.

Analysis

Under the Administration proposal, pre-drilling (i.e., depletable) costs, except in connection with stripper wells, would be deducted using indexed cost depletion. This is generally equivalent to a system of economic depreciation such RCRS contained in the 1984 Treasury proposal. However, under the Administration proposal, equipment and structures would be depreciated using CCRS which is more generous than RCRS. Consequently, depletable costs would be treated less favorably than most equipment and structures. However, indexed cost depletion would be more generous, during periods of inflation, than the cost depletion in current law.

The Administration proposal retains percentage depletion for stripper wells. The proposal states that repeal of this tax preference could lead to early abandonment of these wells, reduced oil production, and a consequent increase in U.S. vulnerability. Others argue that energy security would be better served by leaving this oil in the ground so that it would be available for production, at a profit to the owner, in the event prices rise due to a supply disruption. However, in circumstances where State law requires that an abandoned well be capped, the cost of reopening might be prohibitive.

The phasing out, over 5 years, of the percentage depletion allowance for independent producers (other than for stripper wells) raises an energy policy issue. A gradual tax increase of this kind may create an incentive for independent producers to accelerate production over the next 5 years in order to obtain the benefits of percentage depletion. This could decrease imports over the next 5 years, but increase import dependence in the future. Rapid production also may decrease the total amount of recoverable oil in a reserve. As a result, accelerated depletion of existing oil reserves may not further the objectives of energy policy. If Congress decides to reduce the current allowance for percentage depletion, a shorter phase-out period might mitigate these potentially adverse effects.

Cost recovery for the oil and gas (or mining) industries is especially complex because the amount and accessibility of those substances, and the rate of production, vary widely between different properties. Cost depletion attempts to resolve these problems by estimating the total amount of each individual reserve and allowing annual cost recovery in proportion to that percentage of the reserve which is extracted in any year. If the estimate of the total reserve is accurate, this system may be superior (in a pure economic sense) to ordinary depreciation methods, which assign assets to prearranged categories that may not match the actual rate of decline of an asset's value.

Under percentage depletion, producers are allowed a deduction for a set percentage of gross income from a given property in each year (15 percent, in the case of independent oil and gas producers and royalty owners). Under present law, this allowance may reduce the net (i.e, taxable) income from a property by up to 50 percent in each year. Although nominally a form of cost recovery, percentage depletion has come to be seen as an implicit tax subsidy to the oil and gas industry, in order to encourage production, because the total deductions with respect to a property may substantially exceed the actual costs invested in the property.[24] Since the Tax Reduction Act of 1975, this incentive has been limited to specified amounts of production by independent producers and royalty owners.

Advocates of retaining percentage depletion argue that it serves to encourage domestic oil and gas production. These arguments are similar to those made in connection with the treatment of intangible drilling costs.[25] Opponents argue that percentage depletion is an ineffective subsidy. In contrast to intangible drilling costs, percentage depletion is based on production from existing wells, and may thus be less significant in encouraging the development of new properties. It has also been noted that the 50 percent of net income limitation reduces the subsidy for marginally profitable wells, which are more likely to be affected by a subsidy.[26]

The Administration proposal would limit percentage depletion to "stripper" wells only (i.e., wells producing less than 10 barrels per day). This is essentially a continuation of the process begun in 1975, of limiting percentage depletion to a progressively smaller number of properties which are deemed to require the most subsidy. If Congress decides to modify existing law, it may wish to limit percentage depletion to a differently defined group, or else to eliminate it altogether (as in the 1984 Treasury proposal). Alternatively, Congress may wish to replace percentage depletion with a new recovery system, more favorable than cost depletion, for all producing properties. Such a system could be designed to integrate depletion into a general cost recovery system in order to provide the same treatment of oil and gas investments as investments in other capital equipment, or it could be structured so as to provide a higher degree of incentive for oil and gas production. Depending upon the methods adopted, it may be appropriate to integrate the treatment of some or all IDCs (and perhaps tertiary injectants) into such a new system.

3. Tertiary Injectants

Present Law and Background

Under present law, the Internal Revenue Code, expenditures for tertiary injectants used in tertiary recovery methods for oil and gas production may be deducted in the year of injection (i.e., such

[24] Percentage depletion was originally enacted in 1926 as a replacement for recovery based on "discovery values" of oil and gas properties, the determination of which had resulted in substantial litigation. The original statutory rate of 27.5 percent was reduced to 22 percent by the Tax Reform Act of 1969 and subsequently repealed for integrated producers and phased down for others to 15 percent (for 1984 and thereafter) by the Tax Reduction Act of 1975. The 50 percent "net income limitation" dates from the industry-wide recession of the 1920s, during which depletion deductions (which were based on pre-recession values) frequently exceeded the income from oil and gas properties. The preference nature of percentage depletion is formally recognized in the individual and corporate minimum tax.

[25] An analysis of issues relating to IDCs is included in the previous section.

[26] See Administration Proposal, p. 229.

amounts may be expensed, rather than capitalized). Tertiary recovery methods are various chemical, fluid, or gaseous recovery techniques (including miscible fluid displacement, steam drive injection, and augmented water flooding) specified in the Crude Oil Windfall Profit Tax Act of 1980 or under subsequent Treasury regulations. Expensing does not apply to crude oil or natural gas injectants which are recoverable from the reservoir. The rule regarding tertiary injectants also does not apply to cost which are subject to an election to be treated as intangible drilling costs.

Amounts which may be expensed under the tertiary injectants rule are subject to recapture upon a sale or other disposition of the property under sections 1245 and 1250 of the Code.

Administration Proposal

The Administration proposal would retain the present law treatment of qualified tertiary injectant expenses.

Other Proposals

1984 Treasury Report

The 1984 Treasury proposal would repeal the deduction for qualified tertiary injectant expenses, effective January 1, 1986. In place of current deductions, these costs would be added to the depletable basis of the property and recovered through cost depletion. Waterflooding and similar pressure maintenance techniques, which enhance production for a period of less than one year, could continue to be expensed.

S. 1006

S. 1006 (Senators Kasten and Wallop) would retain present law.

S. 409

S. 409 (Senator Bradley) would allow 50 percent of qualified tertiary injectant expenses to be deducted in the year of injection, and 50 percent in the succeeding taxable year.

Analysis

The tax treatment of tertiary injectant expenses raises similar issues to that of intangible drilling costs (discussed above). Tertiary injectants also suggest issues of (1) which enhanced recovery techniques (if any) should be singled out for advantageous tax treatment, and (2) what constitutes "normal" tax treatment for enhanced recovery procedures, which may increase production for unpredictable periods, or not at all. (This latter issue resulted in significant confusion prior to 1980, when Congress legislatively approved expensing.) If Congress decides to modify the present law treatment of tertiary injectant expenses, it may attempt to resolve these issues by adopting a new statutory recovery period (as in the Bradley-Gephardt bills), by adding the expenses to the basis for cost depletion (as in the 1984 Treasury proposal), or by integrating the treatment of tertiary injectant expenses into a new, broader recovery system.

4. Crude Oil Windfall Profit Tax

Present Law

Present law imposes an excise tax on the windfall profit element of the price of domestically produced crude oil when it is removed from the premises on which it was produced. Generally, the windfall profit element is the excess of the sale price over the sum of its an adjusted base price plus the applicable State severance tax adjustment. The windfall profit element may not exceed 90 percent of net income attributable to a barrel of crude oil.

The tax rates applicable to taxable crude oil are as follows:

Tier	Tax rate
Tier one oil (oil not in tier 2 or tier 3)	70 percent: 50 percent for independent producers.
Tier two oil (stripper oil, Petroleum Reserve oil)	60 percent: 30 percent for independent producers.
Tier three oil:	
Newly discovered oil.	22.5 percent for 1985–1987, 20 percent for 1988, and 15 percent for 1989 and thereafter.
Heavy oil and incremental tertiary oil.	30 percent.

Crude oil from a qualified governmental interest or a qualified charitable interest, certain front-end oil, certain Indian oil, certain Alaskan oil, certain independent producer stripper well oil, and, in the case of qualified royalty owners, up to three barrels per day of royalty production, are exempt from the tax.

The windfall profit tax is scheduled to phase out over a 33-month period, beginning after December 31, 1987, if the cumulative revenue raised by the tax reach $227.3 billion, but in any event no later than January 1991.

Administration Proposal

The Administration proposal would not affect the crude oil windfall profit tax.

Other Proposal

The 1984 Treasury Report proposed beginning the scheduled phase-out of the windfall profit tax on January 1, 1988.

Analysis

The windfall profit tax was enacted in 1980 in response to the perceived "windfall" accruing to oil producers as a result of the decontrol of domestic oil prices. As oil prices have stagnated and even declined in the 1980s, the tax has come to be seen less as a tax on excess profits, and more as an ordinary excise tax. Because the tax is based on sale price, declining prices have also caused receipts from the tax to be substantially lower than expected.

The 1984 Treasury proposal would accelerate the scheduled expiration of the windfall profit tax in connection with the proposed repeal of existing tax preferences benefitting the oil and gas industry (i.e., intangible drilling costs and percentage depletion). With the repeal of these preferences, it was thought that a neutral "playing field" required repeal of the windfall profit tax, as well.

B. Tax Provisions Relating to Mineral Deposits, etc.

1. Expensing of Hard Mineral Exploration And Development Costs

Present Law and Background

Under present law, taxpayers may elect to expense (i.e., currently deduct) exploration costs associated with mines and other hard mineral deposits (sec. 617). Additionally, once the existence of commercially marketable ores is established, the taxpayer may expense development costs associated with the preparation of the mine for production (sec. 616).

Mining exploration costs are expenditures for the purpose of ascertaining the existence, location, extent or quality of any deposit of ore or other depletable mineral, which are paid or incurred by the taxpayer prior to the development state of the mine or deposit. Expensed mining exploration costs (but not development costs) reduce the depletion deductions for the mine concerned (alternatively, these costs may be "recaptured" in income once the mine reaches the producing stage). Exploration costs are also subject to recapture if the property is disposed of by a taxpayer after expensing these amounts (secs. 1245 and 1250). Foreign exploration costs cannot be expensed after the taxpayer has total foreign and domestic exploration costs of $400,000.

Development costs include expenses incurred for the development of a mine or other natural deposit, after the existence of ores in commercially marketable quantities has been determined. These costs generally include costs for construction of shafts and tunnels and, in some cases, drilling and testing to obtain additional information for mining operations.

In the case of a corporation, 20 percent of mining exploration and development costs may not be expensed, but must instead be capitalized using the schedule for 5-year ACRS property. For mines located in the United States, expenses recovered under ACRS also qualify for an investment tax credit. The expensing of mining exploration and development costs is further treated as a preference item for purposes of the noncorporate alternative minimum tax, to the extent that such expensing exceeds the deduction which would have been allowable if the costs had been amortized over a 10-year period.

Administration Proposal

The Administration proposal would retain the present law treatment of mining exploration and development costs, effective January 1, 1986. The expensing of such costs (in excess of the deduction allowable under a 10-year amortization schedule) would be treated as a preference item under the proposed corporate and noncorporate alternative minimum taxes.

Other Proposals

1984 Treasury Report

The 1984 Treasury proposal would repeal the option to expense hard mineral exploration and development costs. Instead of expensing, these costs would be capitalized and recovered through cost depletion, with the depletable basis being indexed for inflation. Capitalizable costs would be determined using the general cost accounting rates contained in the Treasury proposal.

S. 1006

S. 1006 (Senators Kasten and Wallop) would retain present law.

S. 409

S. 409 (Senator Bradley) would also repeal the option to expense hard mineral exploration and development costs. In place of expensing, costs relating to depletable mineral property would be recovered under the general cost recovery system contained in the proposal. Recovery periods would be determined based on the anticipated productive life of the property.[27] The proposal would not affect the current deduction of losses sustained by reason of abandonment of a nonproductive mine or other deposit.

Analysis

The expensing of mining exploration and development costs raises issues which parallel those concerning intangible drilling and development costs (IDCs) for oil and gas wells (discussed in Part II. A. 1. above). As in the case of IDCs, general accounting principles suggest that these amounts be recovered over a multiyear period, as income is generated by the property. However, immediate deductions are arguably necessary to encourage production of the minerals in question, and may be no more arbitrary than any replacement recovery system. (The persuasiveness of the incentive argument depends upon the market for the particular material concerned and on the adequacy of the present strategic stockpiles for dealing with national security issues.) If Congress decides to modify the present law treatment of mining expenses, it may desire to establish new, statutory recovery periods, or else to require these costs to be recovered as part of a general depreciation or depletion system.

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[27] These recovery periods are equivalent to the proposed class lives for depreciable property generally, except that they are determined based on anticipated productive lives rather than present class lives.

2. Depletion of Hard Mineral Deposits

Present Law and Background

Taxpayers are permitted to recover the acquisition and certain related costs of mines or other mineral deposits [28] under one of two methods: the cost depletion method, or the percentage depletion method.

Under the cost depletion method, the taxpayer deducts that portion of the adjusted basis of the property which is equal to the ratio of units sold from that property during the taxable year to the number of units remaining as of that year. The amount recovered under cost depletion thus may not exceed the taxpayer's basis in the property.

Under percentage depletion, a deduction is allowed in each taxable year for a fixed statutory percentage of the taxpayer's gross income from the property. The percentages applicable to various minerals are summarized in the following table (Table 1).[29]

Table 1.—Percentage Depletion Rates For Selected Hard Minerals Under Code Section 613

Mineral	Percentage depletion rate
Antimony	*22
Asbetos	*22
Asphalt (rock)	14
Bauxite	*22
Beryllium	*22
Borax	14
Cadmium	*22
Chromite	*22
Coal	10
Cobalt	*22
Copper	*15
Feldspar	14
Garnet	14
Gold	*15
Granite	14
Graphite	*22
Gravel	5
Iron ore	*15
Lead	*22
Lignite	10
Limestone	14
Lithium	*22
Magnesite	14

[28] The recovery of hard mineral exploration and development costs is discussed in the previous section.

[29] The complete list of percentage depletion rates is included in section 613(b) of the Code. Generally, percentage depletion is allowed for all minerals. However, it is not allowed in the case of soil, dirt, turf, water, or mosses, or in the case of minerals from sea water, the air, or similar inexhaustible sources.

Table 1.—Percentage Depletion Rates For Selected Hard Minerals Under Code Section 613—Continued

Mineral	Percentage depletion rate
Manganese	*22
Marble	14
Mercury	*22
Mica	*22
Mollusk shells	14
Molybdenum	*22
Nickel	*22
Oil shale	15
Peat	5
Phosphate rock	14
Platinum	*22
Potash	14
Pumice	5
Quartz (radio grade)	*22
Quartzite	14
Sand	5
Shale	5
Silver	*15
Slate	14
Soapstone	14
Sodium Chloride	10
Stone	5
Stone (ornamental)	14
Sulphur	22
Thorium	*22
Tin	*22
Titanium	*22
Tungsten	*22
Uranium	22
Vanadium	*22
Zinc	*22
Zircon	*22

*A 14-percent rate applies to these minerals if mined outside the United States.

The amount deducted for any mineral may not exceed 50 percent of the net income from a particular property in any year (the "net income limitation"). Because percentage depletion is computed without regard to the taxpayer's basis in the property, it may result in eventual recovery of an amount greater than that actually expended by the taxpayer to acquire the property.

In general, a taxpayer is required to determine its depletion deduction under both the percentage and cost depletion methods. If the cost depletion deduction is larger, the taxpayer must utilize that method for the taxable year in question.

In the case of a corporation, the amount of the percentage depletion for coal (including lignite) and iron ore, to the extent that such deduction exceeds the adjusted basis of the property, is reduced by 15 percent. Percentage depletion of all materials, to the extent it exceeds adjusted basis, is also treated as a preference item for purposes of the noncorporate (i.e., individual) and corporate minimum taxes.[30]

Administration Proposal

The Administration proposal would phase out percentage depletion for all minerals[31] over a 5-year period, beginning January 1, 1986. This would be accomplished by reducing the applicable percentage depletion rate for any mineral by 20 percent in each of calendar years 1986 through 1990. Mineral deposits would continue to qualify for cost depletion, with the depletable basis now to be indexed for inflation.

This phase out of percentage depletion would be effective for production beginning on or after January 1, 1986.

Under the Administration proposal, for depletable property placed in service on or after January 1, 1986, the excess of percentage over cost depletion in any taxable year would be treated as a preference item for purposes of the proposed noncorporate and corporate alternative minimum taxes. For property placed in service before 1986, the amount of the preference would be the excess of percentage depletion over the adjusted basis of the property (as under the present law noncorporate minimum tax).

Other Proposals

1984 Treasury Report

The 1984 Treasury proposal would repeal percentage depletion for all minerals, effective for production on or after January 1, 1986. Cost depletion would continue to be available, with the depletable basis to be indexed for inflation.

S. 1006

S. 1006 (Senators Kasten and Wallop) would retain present law.

S. 409

S. 409 (Senator Bradley) would repeal percentage depletion for properties from which production began after December 31, 1986. Depletable costs associated with mineral deposits would be recovered under the general cost recovery system contained in the proposal, with recovery periods based on the anticipated productive life of the property. The recovery periods are equivalent to those used for other productive assets, except that they are based on anticipated productive life rather than present law class lifes. This new recovery system would replace present law cost depletion (which requires a determination of the ratio of expended to remain-

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[30] An adjustment is made in the case of coal and iron ore to prevent the combination of the 15 percent reduction and the minimum tax from reducing the tax benefit from the taxpayer's marginal dollar of preference more than under pre-1983 law.

[31] Percentage depletion would continue to be allowed for oil and gas "stripper" wells (see discussion of oil and gas depletion above).

ing production units in each taxable year), as well as percentage depletion.[32]

Analysis

Depletion of hard mineral costs raises essentially the same issues as oil and gas depletion, discussed above.[33] While nominally a form of cost recovery, percentage depletion has come to be seen as an implicit tax subsidy for the extraction of mineral substances, the extent of which varies depending upon the depletion rate. This view is reflected in the inclusion of "excess" percentage depletion as a minimum tax preference item, and in the cutback of corporate coal and iron ore percentage depletion.

The Administration proposal calls for the repeal of percentage depletion for all hard mineral substances, over a 5-year period. If Congress agrees to modify present law, it may wish to consider preserving percentage depletion for particular substances for which a continued production subsidy is considered appropriate. Alternatively, percentage depletion could be targeted only to specified producers of some or all minerals, similarly to the present law treatment of oil and gas. (This would reduce the scope of production incentives, but arguably heighten their efficiency.) Congress may also wish to consider integrating the tax treatment of depletion and hard mineral exploration and development costs.

3. Royalty Income From Coal and Domestic Iron Ore

Present Law

Under present law, subject to certain special limits, royalties received on the disposition of coal and domestic iron ore qualify for capital gains treatment. For capital gain treatment to apply, the coal or iron ore must have been held for more than six months before mining. Capital gain treatment does not apply to income realized by an owner as a co-adventurer, partner, or principal in the mining of the coal or iron ore or to certain related party transactions. If capital gain treatment applies, the royalty owner is not entitled to percentage depletion with respect to the coal or iron ore disposed of.

Administration Proposal

The Administration proposal would repeal the capital gain treatment for coal or iron ore royalties, by phasing out the special treatment over a three-year period beginning in 1986.[34]

Analysis

The special capital gain treatment for coal and domestic iron ore royalties functions as an alternate benefit to percentage depletion,

[32] These bills would also repeal a provision of existing law (sec. 621) relating to the exclusion of certain payments by the United States to explore, develop, and mine for defense purposes. It appears that this provision is obsolete.
[33] See Part II.A.2., above.
[34] Other Congressional proposals deal with capital gains generally. These proposals will be discussed in a future Joint Committee pamphlet discussing capital gains.

and may be more valuable in certain cases. Because the relative value of this treatment depends upon the availability of percentage depletion, and the treatment of capital gains, generally it may be appropriate to consider these items together.

4. Capital Gains Rules Applicable To Timber

Present Law and Background

Royalty income received by the owner of a timber royalty interest qualifies for long-term capital gain treatment, where the timber has been held for 6 months before being cut (sec. 631(b)). Additionally, the owner of timber (or a contract right to cut timber) may elect to treat the cutting of timber as a sale or exchange qualifying for long-term capital gain treatment, although the timber is sold or used in the taxpayer's trade or business (sec. 631(a)). This provision also generally requires that the timber (or contract right) be held for 6 months prior to cutting.

Administration Proposal

The Administration proposal would phase out the special capital gain rules regarding timber over a three-year period, beginning January 1, 1986.

Analysis

The special rules regarding timber have been described as a recognition of the long period necessary to grow timber, and the historic characterization of timber as a part of real property, which it sold itself would generally be entitled to capital gains treatment. The issue is whether these factors distinguish timber income from income from the sale of ordinary farming inventories, which are treated as ordinary income.

C. Energy-Related Credits and Other Incentives

1. Residential Energy Credits

Present Law and Background

Individuals are allowed a 15-percent credit on the first $2,000 of qualifying expenditures, up to a maximum credit of $300, for installations made through 1985 of eligible insulation and other energy conservation items. Each conservation item must be capable of reducing heat loss or gain, increasing the efficiency of the heating system, or reducing fuel consumption.

Individuals also are allowed a 40-percent credit on expenditures up to $10,000, for a maximum credit of $4,000, for renewable energy source property (i.e., solar, wind and geothermal energy property). The credit for individuals for renewable energy sources applies to expenditures made through 1985.

Installations of qualified renewable energy property must be made in or on a taxpayer's principal residence. The conservation credit is available only for expenditure with respect to equipment installed in or on a principal residence in existence or substantially completed on April 19, 1977. There is a credit carryover provision that allows unused credits for both energy conservation property and renewable energy source equipment to be carried over to subsequent taxable years but not to any taxable year beginning after 1987.

As defined in the regulations, renewable energy source property includes equipment (and parts solely related to the functioning of such equipment) necessary to transmit or use energy from a geothermal deposit. A geothermal deposit is defined as a geothermal reservoir consisting of natural heat, which is from an underground source and is stored in rocks or in an aqueous liquid or vapor, having a temperature exceeding 50 degrees Celsius, which is 122 degrees Fahrenheit. The regulations also provide that equipment which serves both a geothermal function and a nongeothermal function does not qualify as geothermal energy property. However, the existence of a backup system designed for use only in the event of failure of the geothermal energy system would not be disqualifying.

Administration Proposal

The Administration proposal would allow the residential energy tax credits to expire at the end of 1985, as scheduled under present law.

Other Proposals

S. 1220

Solar energy property.—S. 1220 (Senator Hatfield and others) would extend and phase out the tax credit for residential solar renewable energy source expenditures. The credit would be phased out over a 5-year period according to the following schedule:

Taxable year	Residential energy tax credit
1986	35%
1987	30%
1988	25%
1989	20%
1990	15%
1991 and after	0%

The bill generally retains the $10,000 upper limit for qualified expenditures, but specifically limits allowable expenditures to $6,000 for solar hot water systems.

For photovoltaic cells, the energy tax credit would be kept at 40 percent in taxable years before 1991.

Wind energy property.—The wind energy credit would be extended for 3 years, from 1986 through 1988, at 35, 30 and 25 percent, respectively. This credit would expire after 1988. The credit would be allowed for wind energy expenditures up to $20,000.

Geothermal energy property.—The credit for geothermal property would be extended through 1986 at the present 40-percent rate, and would decline by 10 percentage points in each of 1987 and 1988. It would expire at the end of 1988. The bill also amends the definition of qualifying property in cases where geothermal property is used with nonrenewable energy: all equipment qualifies when geothermal energy provides 80 percent of annual energy use (measured on a Btu basis); if geothermal energy is the source of more than 50 percent but less than 80 percent, only geothermal energy equipment would qualify.

Energy conservation credit.—The conservation credit would be increased to 25 percent of expenditures of $700 or less, limited to taxpayers with AGI of $30,000 or less. For married individuals filing separate returns, AGI for these purposes would be the sum of the AGI of husband and wife. Storm doors no longer would be eligible for the credit. These credits would expire after December 31, 1988.

Carryforward of unused credits.—Residential credits that remain unused after the expiration date for the property involved may be carried forward for 2 additional years.

S. 1006, S. 409, S. 243

S. 1006 (Senators Kasten and Wallop), S. 409 (Senator Bradley), and S. 243 (Senator Roth) would allow the residential energy tax credits to expire at the end of 1985.

S. 1201

S. 1201 (Mrs. Hawkins and others) would phase out the credit for residential solar property following the same schedule as in S. 1220, and also would limit to $6,000 qualified expenditures for solar hot water use in a dwelling. In addition, a 40-percent credit would be provided for photovoltaic cells used solely to provide electricity. Performance standards would be enacted for qualified solar hot water systems and active space heating systems.

Analysis and Issues

The Administration argues that the energy credits for conservation and production are no longer needed because the investments yielding the greatest conservation gains have been made during the 8 years the credits have been in effect. At free-market prices it is argued that adequate incentives for investment in conservation equipment and nonconventional fuels already exist.

The energy credits have also been criticized as inefficient. For some energy credit claimants, the credit may be a windfall because the qualifying property would have been installed even if tax credits were not available.[35] Another potential inefficiency is that the same rate of credit may be available for equipment with different energy saving capabilities, while systems with the same energy effectiveness may qualify for different credit rates. Some conservation expenditures receive no credit if the equipment serves a structural as well as a conservation purpose (i.e., certain passive solar equipment). Similar inefficiencies arise because alcohol fuels re-

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[35] H. Craig Peterson, "Survey Analysis of the Impact of Conservation and Solar Tax Credits," Final Report, submitted to the National Science Foundation, (July 15, 1982), p. 33. Less than 10 percent of residential credit claimants reported that they probably or definitely would not have made conservation expenditures if the tax benefits had not been available.

ceive a larger credit than nonconventional fuels on an equivalent energy basis (alcohol fuel facilities may qualify for the energy investment credit, as well). In general, it is argued that a unified incentive for production of alternative energy sources and for conservation, such as an oil import tax, would meet any energy security objectives while avoiding these problems.

The energy credits also have been criticized on equity grounds. Individuals and firms that have little or no tax liability are unable to take advantage of most of these credits. Also, the bulk of residential energy credits have been claimed by middle and upper income taxpayers.[36]

On the other hand, proponents of the credits argue that incentives for energy conservation and for production of energy from sources other than oil and gas are needed in view of the national security considerations (discussed above in connection with the tax treatment of production expenditures for oil and gas.) It is further argued that it would be especially harmful to continue incentives for oil and gas production, (e.g., expensing of intangible drilling costs) while discontinuing incentives for conservation and use of alternative energy sources. It is argued that conservation and use of alternative energy sources may directly and indirectly reduce oil imports at much less cost than incentives for production of oil and gas. Further, the problems of inefficiency and redistributional effects listed above also apply to oil and gas incentives. In any case, it is possible to adjust for disproportionate use of the credits by any particular income class by designing the tax rates to take this pattern into account. It is argued that the case for continuing tax incentives for conservation and for production of energy from non-oil and gas sources is as persuasive as the case for tax incentives for oil and gas production.

2. Business Energy Credits

Present Law and Background

A 15-percent energy credit is allowed through 1985 for solar, wind, geothermal and ocean thermal property. (The rate was increased from 10 to 15 percent starting in 1980.) Qualified intercity buses and biomass property are eligible for a 10-percent energy credit through 1985. Small scale hydroelectric projects are eligible for an 11-percent credit. Solar, wind and geothermal properties are defined in the same manner as for the residential solar credits.

Prior to 1983, a general 10-percent investment credit was allowed for certain energy property in addition to the regular investment credit. Property eligible for the general 10-percent energy credit included alternative energy property, specially defined energy property, recycling equipment, shale oil equipment, equipment for producing natural gas from geopressured brine, and cogeneration equipment. The energy credit for most of these types of property terminated after 1982, except that the credit will be allowed

[36] Congressional Research Service, "An Economic Evaluation of Federal Tax Credits for Residential Energy Conservation," Report No. 82-204E (December 2, 1982).

through 1990 for long-term projects for which certain affirmative commitments were made.

Under the affirmative commitment rules, the 10-percent energy tax credit remains available after 1982 for credits that expired in 1982, if specified requirements are satisfied with respect to qualified property that is part of a project with a normal construction period of two years or more. The credit is allowed through December 31, 1990, for property that is constructed or acquired after 1982 if (1) all engineering studies on the project were completed, and applications for all environmental and construction permits required to commence construction were filed, before 1983, (2) before 1986, binding contracts are entered into to construct or acquire equipment that is specially designed for the project and which represents at least 50 percent of the aggregate cost of all such equipment, and (3) the project is completed before January 1, 1991.

Administration Proposal

Under the Administration proposal, the business energy tax credits would be allowed to expire at the end of 1985. The present law affirmative commitment rules would continue to apply.

Other Proposals

S. 1220

Under S. 1220 (Senator Hatfield and others), the energy tax credits for solar, wind, geothermal and ocean thermal property would be extended after 1985, under the following schedule:

Property	Credit rate	Termination date
Solar property:		
Low temperature	15%	Dec. 31, 1990
Other solar	25%	Dec. 31, 1990
Geothermal property	15%	Dec. 31, 1988
Wind property	10%	Dec. 31, 1987
	5%	Dec. 31, 1988
Ocean thermal property	15%	Dec. 31, 1990
Biomass property	15%	Dec. 31, 1987
	10%	Dec. 31, 1988

For the most part, these credits would be extended at the present law rate of tax credit. Solar property, other than low temperature, would receive a 25-percent credit instead of 15 percent, and it would consist of property to generate electricity, provide solar process heat, or provide hot water at a temperature more than 300 degrees Fahrenheit.

The credit for wind energy property would be phased down during the 3-year extension period.

In a mixed use geothermal energy situation, all energy property qualifies for the alternative energy property tax credit, if geothermal sources provide 50 percent of the energy used and the remainder is supplied from an alternate substance. When the other source does not use an alternate substance, the property would qualify for the credit to the proportionate use of geothermal energy. If geothermal energy supplies less than 50 percent of the energy, no property qualifies for the credit.

The definition of biomass property would be expanded to include (1) any synthetic gaseous fuel produced from wood and (2) methane-containing gas for fuel or electricity produced by anaerobic digestion from nonfossil waste materials at farms or other agricultural facilities which include processing of agricultural products.

Affirmative commitment rules would be modified with respect to certain long-term energy projects relating to solar energy and geothermal energy properties. If these properties meet the modified affirmative commitment rules, they would qualify for the credit over a longer period. In certain prescribed circumstances, a longer period would be made available also for certain hydroelectric projects.

The energy tax credits for intercity buses and small scale hydroelectric generating property would be allowed to expire after December 31, 1985.

S. 1201

S. 1201 (Mrs. Hawkins and others) would extend the energy tax credit for solar property as does S. 1220.

S. 1006 and S. 409

Under S. 1006 (Senators Kasten and Wallop) and S. 409 (Senator Bradley) the business energy tax credits would be repealed as part of repeal of the general investment tax credit.

Analysis and Issues

The issues with respect to business renewable energy tax credits fundamentally are the same as those with respect to residential credits, namely, whether the credits have been available for a sufficiently long period of time to encourage production and sales at efficient, self-sustaining levels, and if such production levels have not been reached, whether those levels will be attained solely because a tax credit is available.

3. Alternative Fuels Production Credits

Present Law

A tax credit is provided for the domestic production and sale of qualified fuels to unrelated persons. The credit applies to such fuels produced and sold from (1) facilities placed in service after December 31, 1979, and before January 1, 1990, or (2) wells drilled after December 31, 1979, and before January 1, 1990, on properties which first begin production after December 31, 1979. Qualifying fuels may be sold at any time after December 31, 1979, and before January 1, 2001.

The credit equals $3 for each 5.8 million Btu's of energy. (One barrel of crude oil contains approximately 5.8 million Btu's.) All Btu measurements must be made without regard to any Btu's attributable to materials or energy sources other than the qualified fuel. Except for gas produced from a tight formation, the $3 amount is indexed for post-1979 increases in the GNP deflator.

The credit phases out as the annual average wellhead price of uncontrolled domestic oil rises from $23.50 to $29.50 a barrel ($32.10 and $40.30, respectively, in terms of 1984 prices). The phase-out range is adjusted for post-1979 changes in the GNP deflator.

The credit is available for production and sale of the following fuels:

(1) Oil produced from shale and tar sands;

(2) Gas produced from geopressured brine, Devonian shale, coal seams, or a tight formation;

(3) Gas produced from biomass;

(4) Liquid, gaseous, or solid synthetic fuel (including alcohol) produced from coal (including ignite), including such fuels when used as feedstocks;

(5) Qualifying processed wood fuels; and

(6) Steam from solid agricultural byproducts (not including timber byproducts).

Administration Proposal

The credits for producing fuels from nonconventional sources would be terminated after December 31, 1985. However, the credit would continue for eligible fuel produced from a well drilled, or facility completed, before January 1, 1986, and sold before January 1, 1990.

Other Proposals

S. 1006 and S. 409

S. 1006 (Senators Kasten and Wallop) and S. 409 (Senator Bradley) would repeal the credits allowable for producing fuel from a nonconventional source.

S. 243

Under S. 243 (Senator Roth), no credit for producing fuel from nonconventional sources would be allowed after December 31, 1984, to a person other than a subchapter C corporation.

Analysis and Issues

The energy production credits were enacted in 1980 when oil prices had doubled within a period of one year. Since net imports were about 37 percent of U.S. petroleum and products in 1980, there was extensive interest in the United States to encourage development and production of alternative energy sources. Production of other fuels was to be encouraged by a production credit that was related to the price of oil, the rate of inflation, and the Btu content of the fuel relative to that of petroleum.

Since 1981, the price of petroleum has been falling on world markets reflecting increased production from new sources, conservation efforts, and industrial fuel switching.

Declining oil prices have squeezed the ability of alternative fuels to compete with oil because the costs of producing alternative fuels has not fallen. Consequently, efforts to produce such fuels profitably have been stymied.

On the one hand, it is argued that it is undesirable to continue the production credits in view of the present noncompetitive economic situation and the prospect that alternative fuels production will need to be subsidized, possibly for long periods of time. The needed subsidies may be so large that the credits clearly would be subsidizing very inefficient sources of energy production. Further, it is argued that a uniform incentive for conservation and for production of alternative energy sources, such as an oil import tax, would encourage, on an even-handed basis, all alternatives for reducing oil imports.

On the other hand, the credits, no matter now expensive currently, may be viewed as an investment in research and development for long-term future energy needs. If successful, these could yield large future benefits.

4. Alcohol Fuels Credit and Related Provisions

Present Law

Alcohol fuels credit

A 60-cents-per-gallon credit is allowed for alcohol used in certain mixtures of alcohol and gasoline (i.e., gasohol), diesel fuel, or any special motor fuel if the mixture is sold by the producer for use as a fuel or is used as a fuel by the producer (sec. 40).[37] The credit also is permitted for alcohol (other than alcohol used in a mixture with other taxable fuels) if the alcohol is used by the taxpayer as a fuel in a trade or business or is sold at retail by the taxpayer and placed in the fuel tank of the purchaser's vehicle.

The amount of any person's allowable alcohol fuels credit is reduced to take into account any benefit received with respect to the alcohol under the excise tax exemptions for alcohol fuels mixtures or alcohol fuels.

The credit is scheduled to expire December 31, 1992.

Excise tax exemptions for alcohol fuels mixtures and alcohol fuels

Alcohol fuels mixtures

Present law provides a 6-cents-per-gallon exemption from the excise taxes on gasoline, diesel fuel, and special motor fuels for fuels consisting of mixtures of any of those fuels with at least 10-percent alcohol (secs. 4041, 4081, and 6427).[38] (This is equivalent to 60 cents per gallon of alcohol in a 10-percent mixture.) The term alcohol is defined to include only alcohol derived from a source other than petroleum, natural gas, or coal. This exemption is scheduled to expire December 31, 1992.

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[37] The Deficit Reduction Act of 1984 (P.L. 98-369) increased the credit from 50 cents to 60 cents per gallon, effective January 1, 1985.

[38] The Deficit Reduction Act of 1984 (P.L. 98-369) increased the exemption from 5 cents to 6 cents per gallon, effective January 1, 1985.

Alcohol fuels

Present law provides a 9-cents-per-gallon exemption from the excise tax on special motor fuels for certain "neat" methanol and ethanol fuels derived from a source other than petroleum or natural gas. A 4-1/2-cents-per-gallon exemption is provided for these fuels when derived from natural gas (sec. 4041).[39] "Neat" alcohol fuels are fuels comprised of at least 85 percent methanol, ethanol, or other alcohol. This exemption is scheduled to expire December 31, 1992.

Duty on imported alcohol fuels

A 60-cents-per-gallon duty is imposed on alcohol imported into the United States for use as a fuel (19 U.S.C. 1202).[40]

Administration Proposal

After December 31, 1985, the alcohol fuels credit would be available only for qualified alcohol fuels produced from facilities completed before January 1, 1986, and sold before January 1, 1993. The excise tax exemptions would be repealed, effective after December 31, 1985. The duty on alcohol imported for use as a fuel would not be changed.

Other Proposals

S. 1006 (Senators Kasten and Wallop) and S. 409 (Senator Bradley) would repeal the alcohol fuels credit, but would retain the excise tax exemptions and the import duty.

Analysis

Proponents of the alcohol fuels credit and excise tax exemptions suggest that these incentives are necessary to encourage development of viable alternatives to petroleum fuels. Proponents point to the United States dependence on imported oil and to actions by other countries disrupting international markets in recent years. Proponents argue that development of a domestic alternative fuels industry is essential to national security.

Opponents of these incentives suggest that the incentives are inefficient and further that they are unnecessary subsidies in light of current world oil market conditions. Opponents point out, for example, that the 60-cents-per-gallon alcohol fuels credit and the equivalent subsidy provided by the alcohol fuels excise tax exemption produce a Federal Government subsidy equal to $25.20 per barrel of oil equivalent.

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[39] This 4½-cent-per-gallon exemption was enacted in the Deficit Reduction Act of 1984, effective January 1, 1985.

[40] The Deficit Reduction Act of 1984 (P.L. 98-369) increased the duty from 50 cents per gallon, effective January 1, 1985.

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