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STATEMENT OF  
JOSEPH MIKRUT  
TAX LEGISLATIVE COUNSEL  
DEPARTMENT OF THE TREASURY  
BEFORE THE SUBCOMMITTEE ON OVERSIGHT  
COMMITTEE ON WAYS AND MEANS

Mr. Chairman, Mr. Coyne, and Members of the Subcommittee:

I appreciate the opportunity to discuss with you today the current tax incentives for the domestic production of oil and gas and for energy conservation.

**Increasing Domestic Oil and Gas Production**

Before I turn to my discussion of the present tax treatment of oil and gas activities, I would like to provide a brief overview of this sector.

**Overview**

Oil is an internationally traded commodity with its domestic price set by world supply and demand. Domestic exploration and production activity is affected by the world price of crude oil. Historically, world oil prices have fluctuated substantially. From 1970 to the early 1980s, there was a fivefold increase in real oil prices. World oil prices fell sharply in 1986 and were relatively more stable from 1986 through 1997. During that period, average refiner acquisition prices ranged from \$14.91 to \$23.59 in real 1992 dollars. In 1998, however, oil prices at the refiner declined to \$12.52 per barrel in nominal dollars (\$11.14 per barrel in 1992 dollars), their lowest level in 25 years in real terms. Since 1998, the decline has reversed with refiner acquisition costs (in nominal dollars) rising to \$17.46 per barrel in 1999 and \$30.92 per barrel in November 2000, the latest month for which composite figures are available. The equivalent prices in 1992 dollars are \$15.31 per barrel in 1999 and \$26.56 per barrel in November 2000.

Domestic oil production has been on the decline since the mid-1980's. From 1978 to 1983 oil consumption in the United States also declined, but increasing consumption since 1983 has more than erased this decline. In 2000, domestic oil consumption was 15 percent higher than in 1970. The decline in oil production and increase in consumption have led to an increase in oil

imports. Net petroleum (crude and product) imports have risen from approximately 38 percent of consumption in 1988 to 51 percent in 1999.

A similar pattern of large recent price increases and increasing dependence on imports has occurred in the natural gas market. During the second half of the 1990s, spot prices for natural gas exceeded \$4.00 per million Btu (MMBtu) in only one month (February 1996). The spot price again exceeded \$4.00 per MMBtu in May 2000, rose above \$5.00 per MMBtu in September 2000, and has recently exceeded \$10.00 per MMBtu.<sup>1</sup>

The United States has large natural gas reserves and was essentially self-sufficient in natural gas until the late 1980s. Since 1986, natural gas consumption has increased by more than 30 percent but natural gas production has increased by only 17 percent. Net imports as a share of consumption more than tripled from 1986 to 1999, rising from 4.2 percent to 15.4 percent. Natural gas from Canada makes up nearly all of the imports into the United States.

These increases in energy prices over the past two years have focused attention on the impact of shortages and high prices on individual consumers and businesses. In announcing this hearing, the Chairman noted the three-fold increase in crude oil prices, the four- to seven-fold increase in natural gas prices, and the near doubling of the price of home heating oil. He also said we “have to find out where the tax code helps, where it causes problems, and whether it needs to be changed.” To assist the Subcommittee in this effort, I would now like to discuss the current tax incentives for domestic oil and gas production.

### **Current law tax incentives for oil and gas production**

The importance of maintaining a strong domestic energy industry has been long recognized and the Internal Revenue Code includes a variety of measures to stimulate domestic exploration and production. They are generally justified on the ground that they reduce vulnerability to an oil supply disruption through increases in domestic production, reserves, and exploration and production capacity. The tax incentives contained in present law address the drop in domestic exploratory drilling that has occurred since the mid-1950s and the continuing loss of production from mature fields and marginal properties.

Incentives for oil and gas production in the form of tax expenditures are estimated to total \$9.8 billion for fiscal years 2002 through 2006.<sup>2</sup> They include the nonconventional fuels (i.e., oil

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<sup>1</sup> All price references are to the spot price at the Henry Hub and are in nominal dollars.

<sup>2</sup> Estimates prepared by the Office of Tax Analysis, Department of the Treasury, for inclusion in *Analytical Perspectives, Budget of the United States Government, Fiscal Year 2002*, U.S. Government Printing Office, Washington, DC (publication expected in March 2001). These estimates are measured on an “outlay equivalent” basis. They show the amount of outlay that would be required to provide the taxpayer the same after-tax income as would be received

produced from shale and tar sands, gas produced from geopressured brine, Devonian shale, coal seams, tight formations, or biomass, and synthetic fuel produced from coal) production credit (\$2.4 billion), the enhanced oil recovery credit (\$4.4 billion), the allowance of percentage depletion for independent producers and royalty owners, including increased percentage depletion for stripper wells (\$2.3 billion), the exception from the passive loss limitation for working interests in oil and gas properties (\$100 million), and the expensing of intangible drilling and development costs (\$640 million). In addition to those tax expenditures, oil and gas activities have largely been eliminated from the alternative minimum tax. These provisions are described in detail below.

### Percentage Depletion

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). Any taxpayer having an economic interest in a producing property may use the cost depletion method. Under this method, the basis recovery for a taxable year is proportional to the exhaustion of the property during the year. The cost depletion method does not permit cost recovery deductions that exceed the taxpayer's basis in the property or that are allowable on an accelerated basis. Thus, the deduction for cost depletion is not generally viewed as a tax incentive.

Independent producers and royalty owners (as contrasted to integrated oil companies)<sup>3</sup> may qualify for percentage depletion. A qualifying taxpayer determines the depletion deduction for each oil or gas property under both the percentage depletion method and the cost depletion method and deducts the larger of the two amounts. Under the percentage depletion method, generally 15 percent of the taxpayer's gross income from an oil- or gas-producing property is

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through the tax preference. This outlay equivalent measure allows a comparison of the cost of the tax expenditure with that of a direct Federal outlay.

<sup>3</sup> 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 that is obligated to market or distribute such oil or natural gas (or product derived therefrom) under the name of the taxpayer or the related person, or that has the authority to occupy any retail outlet owned by the taxpayer or a related person. Bulk sales of crude oil and natural gas to commercial or industrial users, and bulk sales of aviation fuel to the Department of Defense, are not treated as retail sales for this purpose. 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 person or related person has a refinery run in excess of 50,000 barrels per day on any day during the taxable year.

allowed as a deduction in each taxable year. The amount deducted may not exceed 100 percent of the net income from that property in any year (the "net-income limitation").<sup>4</sup> Additionally, the percentage depletion deduction for all oil and gas properties may not exceed 65 percent of the taxpayer's overall taxable income (determined before such deduction and adjusted for certain loss carrybacks and trust distributions).<sup>5</sup>

A taxpayer may claim 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. For producers of both oil and natural gas, this limitation applies on a combined basis. 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 limitation.

Special percentage depletion provisions apply to oil and gas production from marginal properties. The statutory percentage depletion rate is increased (from the general rate of 15 percent) by one percentage point for each whole dollar that the average price of crude oil (as determined under the provisions of the nonconventional fuels production credit of section 29) for the immediately preceding calendar year is less than \$20 per barrel. In no event may the rate of percentage depletion under this provision exceed 25 percent for any taxable year. The increased rate applies for the taxpayer's taxable year which immediately follows a calendar year for which the average crude oil price falls below the \$20 floor. To illustrate the application of this provision, the average price of a barrel of crude oil for calendar year 1999 was \$15.56; thus, the percentage depletion rate for production from marginal wells was increased by four percent (to 19 percent) for taxable years beginning in 2000. The 100-percent-of-net-income limitation has been suspended for marginal wells for taxable years beginning after December 31, 1997, and before December 31, 2002.

Marginal production is defined for this purpose as domestic crude oil or domestic natural gas which is produced during any taxable year from a property which (1) is a stripper well property for the calendar year in which the taxable year begins, or (2) is a property substantially all of the production from which during such calendar year is heavy oil (i.e., oil that has a weighted average gravity of 20 degrees API or less corrected to 60 degrees Fahrenheit). A stripper well property is any oil or gas property for which daily average production per producing oil or gas well is not more than 15 barrel equivalents in the calendar year during which the

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<sup>4</sup> By contrast, for any other mineral qualifying for the percentage depletion deduction, the deduction may not exceed 50 percent of the taxpayer's taxable income from the depletable property.

<sup>5</sup> Amounts disallowed as a result of this rule may be carried forward and deducted in subsequent taxable years, subject to the 65-percent-of-taxable-income limitation for those years.

taxpayer's taxable year begins.<sup>6</sup> A property qualifies as a stripper well property for a calendar year only if the wells on such property were producing during that period at their maximum efficient rate of flow.

If a taxpayer's property consists of a partial interest in one or more oil- or gas-producing wells, the determination of whether the property is a stripper well property or a heavy oil property is made with respect to total production from such wells, including the portion of total production attributable to ownership interests other than the taxpayer's. If the property satisfies the requirements of a stripper well property, then each owner receives the benefits of this provision with respect to its allocable share of the production from the property for its taxable year that begins during the calendar year in which the property so qualifies.

The allowance for percentage depletion on production from marginal oil and gas properties is subject to the 1,000-barrel-per-day limitation discussed above. Unless a taxpayer elects otherwise, marginal production is given priority over other production for purposes of utilization of that limitation.

Because percentage depletion, unlike cost depletion, is computed without regard to the taxpayer's basis in the depletable property, cumulative depletion deductions may be far greater than the amount expended by the taxpayer to acquire or develop the property. The excess of the percentage depletion deduction over the deduction for cost depletion is generally viewed as a tax expenditure.

#### Intangible Drilling and Development Costs

In general, costs that benefit future periods must be capitalized and recovered over such periods for income tax purposes, rather than being expensed in the period the costs are incurred. In addition, the uniform capitalization rules require certain direct and indirect costs allocable to property to be included in inventory or capitalized as part of the basis of such property. In general, the uniform capitalization rules apply to real and tangible personal property produced by the taxpayer or acquired for resale.

Special rules apply to intangible drilling and development costs ("IDCs").<sup>7</sup> Under these

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<sup>6</sup> Equivalent barrels is computed as the sum of (1) the number of barrels of crude oil produced, and (2) the number of cubic feet of natural gas produced divided by 6,000. If a well produced 10 barrels of crude oil and 12,000 cubic feet of natural gas, its equivalent barrels produced would equal 12 (i.e.,  $10 + (12,000 / 6,000)$ ).

<sup>7</sup> IDCs include all expenditures made by an operator for wages, fuel, repairs, hauling, supplies, etc., incident to and necessary for the drilling of wells and the preparation of wells for the production of oil and gas. In addition, IDCs include the cost to operators of any drilling or development work (excluding amounts payable only out of production or gross or net proceeds

special rules, an operator (i.e., a person who holds a working or operating interest in any tract or parcel of land either as a fee owner or under a lease or any other form of contract granting working or operating rights) who pays or incurs IDCs in the development of an oil or gas property located in the United States may elect either to expense or capitalize those costs. The uniform capitalization rules do not apply to otherwise deductible IDCs.

If a taxpayer elects to expense IDCs, the amount of the IDCs is deductible as an expense in the taxable year the cost is paid or incurred. Generally, IDCs that a taxpayer elects to capitalize may be recovered through depletion or depreciation, as appropriate; or in the case of a nonproductive well ("dry hole"), the operator may elect to deduct the costs. In the case of an integrated oil company (i.e., a company that engages, either directly or through a related enterprise, in substantial retailing or refining activities) that has elected to expense IDCs, 30 percent of the IDCs on productive wells must be capitalized and amortized over a 60-month period.<sup>8</sup>

A taxpayer that has elected to deduct IDCs may, nevertheless, elect to capitalize and amortize certain IDCs over a 60-month period beginning with the month the expenditure was paid or incurred. This rule applies on an expenditure-by-expenditure basis; that is, for any particular taxable year, a taxpayer may deduct some portion of its IDCs and capitalize the rest under this provision. This allows the taxpayer to reduce or eliminate IDC adjustments or preferences under the alternative minimum tax.

The election to deduct IDCs applies only to those IDCs associated with domestic properties.<sup>9</sup> For this purpose, the United States includes certain wells drilled offshore.<sup>10</sup>

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from production, if the amounts are depletable income to the recipient, and amounts properly allocable to the cost of depreciable property) done by contractors under any form of contract (including a turnkey contract). Such work includes labor, fuel, repairs, hauling, and supplies which are used in the drilling, shooting, and cleaning of wells; in such clearing of ground, draining, road making, surveying, and geological works as are necessary in preparation for the drilling of wells; and in the construction of such derricks, tanks, pipelines, and other physical structures as are necessary for the drilling of wells and the preparation of wells for the production of oil and gas. Generally, IDCs do not include expenses for items which have a salvage value (such as pipes and casings) or items which are part of the acquisition price of an interest in the property.

<sup>8</sup> The IRS has ruled that if an integrated oil company ceases to be an integrated oil company, it may not immediately write off the unamortized portion of the IDCs capitalized under this rule, but instead must continue to amortize those IDCs over the 60-month amortization period.

<sup>9</sup> In the case of IDCs paid or incurred with respect to an oil or gas well located outside of the United States, the costs, at the election of the taxpayer, are either (1) included in adjusted basis for purposes of computing the amount of any deduction allowable for cost depletion or (2)

Intangible drilling costs are a major portion of the costs necessary to locate and develop oil and gas reserves. Because the benefits obtained from these expenditures are of value throughout the life of the project, these costs would be capitalized and recovered over the period of production under generally applicable accounting principles. The acceleration of the deduction for IDCs is viewed as a tax expenditure.

#### Nonconventional fuels production credit

Taxpayers that produce certain qualifying fuels from nonconventional sources are eligible for a tax credit ("the section 29 credit") equal to \$3 per barrel or barrel-of-oil equivalent.<sup>11</sup> Fuels qualifying for the credit must be produced domestically from a well drilled, or a facility treated as placed in service, before January 1, 1993.<sup>12</sup> The section 29 credit generally is available for qualified fuels sold to unrelated persons before January 1, 2003.<sup>13</sup>

For purposes of the credit, qualified fuels include: (1) oil produced from shale and tar sands; (2) gas produced from geopressured brine, Devonian shale, coal seams, a tight formation, or biomass (i.e., any organic material other than oil, natural gas, or coal (or any product thereof); and (3) liquid, gaseous, or solid synthetic fuels produced from coal (including lignite), including

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capitalized and amortized ratably over a 10-year period beginning with the taxable year such costs were paid or incurred.

<sup>10</sup> The term "United States" for this purpose includes the seabed and subsoil of those submerged lands that are adjacent to the territorial waters of the United States and over which the United States has exclusive rights, in accordance with international law, with respect to the exploration and exploitation of natural resources (i.e., the Continental Shelf area).

<sup>11</sup> A barrel-of-oil equivalent generally means that amount of the qualifying fuel which has a Btu (British thermal unit) content of 5.8 million.

<sup>12</sup> A facility that produces gas from biomass or produces liquid, gaseous, or solid synthetic fuels from coal (including lignite) generally will be treated as being placed in service before January 1, 1993, if it is placed in service by the taxpayer before July 1, 1998, pursuant to a written binding contract in effect before January 1, 1997. In the case of a facility that produces coke or coke gas, however, this provision applies only if the original use of the facility commences with the taxpayer. Also, the IRS has ruled that production from certain post-1992 "recompletions" of wells that were originally drilled prior to the expiration date of the credit would qualify for the section 29 credit.

<sup>13</sup> If a facility that qualifies for the binding contract rule is originally placed in service after December 31, 1992, production from the facility may qualify for the credit if sold to an unrelated person before January 1, 2008.

such fuels when used as feedstocks. The amount of the credit is determined without regard to any production attributable to a property from which gas from Devonian shale, coal seams, geopressured brine, or a tight formation was produced in marketable quantities before 1980.

The amount of the section 29 credit generally is adjusted by an inflation adjustment factor for the calendar year in which the sale occurs.<sup>14</sup> There is no adjustment for inflation in the case of the credit for sales of natural gas produced from a tight formation. The credit begins to phase out if the annual average unregulated wellhead price per barrel of domestic crude oil exceeds \$23.50 multiplied by the inflation adjustment factor.<sup>15</sup>

The amount of the section 29 credit allowable with respect to a project is reduced by any unrecaptured business energy tax credit or enhanced oil recovery credit claimed with respect to such project.

As with most other credits, the section 29 credit may not be used to offset alternative minimum tax liability. Any unused section 29 credit generally may not be carried back or forward to another taxable year; however, a taxpayer receives a credit for prior year minimum tax liability to the extent that a section 29 credit is disallowed as a result of the operation of the alternative minimum tax. The credit is limited to what would have been the regular tax liability but for the alternative minimum tax.

This provision provides a significant tax incentive (currently about \$6 per barrel of oil equivalent or \$1 per thousand cubic feet of natural gas, over one quarter of the average wellhead price of gas in 2000. Coalbed methane and gas from tight formations currently account for most of the credit.

#### Enhanced oil recovery credit

Taxpayers are permitted to claim a general business credit, which consists of several different components. One component of the general business credit is the enhanced oil recovery credit. The general business credit for a taxable year may not exceed the excess (if any) of the taxpayer's net income over the greater of (1) the tentative minimum tax, or (2) 25 percent of so much of the taxpayer's net regular tax liability as exceeds \$25,000. Any unused general business credit generally may be carried back one taxable year and carried forward 20 taxable years.

The enhanced oil recovery credit for a taxable year is equal to 15 percent of certain costs attributable to qualified enhanced oil recovery ("EOR") projects undertaken by the taxpayer in the

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<sup>14</sup> The inflation adjustment factor for the 1999 taxable year was 2.0013. Therefore, the inflation-adjusted amount of the credit for that year was \$6.00 per barrel or barrel equivalent.

<sup>15</sup> For 1999, the inflation adjusted threshold for onset of the phaseout was \$47.03 ( $\$23.50 \times 2.0013$ ) and the average wellhead price for that year was \$15.56.



United States during the taxable year. To the extent that a credit is allowed for such costs, the taxpayer must reduce the amount otherwise deductible or required to be capitalized and recovered through depreciation, depletion, or amortization, as appropriate, with respect to the costs. A taxpayer may elect not to have the enhanced oil recovery credit apply for a taxable year.

The amount of the enhanced oil recovery credit is reduced in a taxable year following a calendar year during which the annual average unregulated wellhead price per barrel of domestic crude oil exceeds \$28 (adjusted for inflation since 1990).<sup>16</sup> In such a case, the credit would be reduced ratably over a \$6 phaseout range.

For purposes of the credit, qualified enhanced oil recovery costs include the following costs which are paid or incurred with respect to a qualified EOR project: (1) the cost of tangible property which is an integral part of the project and with respect to which depreciation or amortization is allowable; (2) IDCs that the taxpayer may elect to deduct;<sup>17</sup> and (3) the cost of tertiary injectants with respect to which a deduction is allowable, whether or not chargeable to capital account.

A qualified EOR project means any project that is located within the United States and involves the application (in accordance with sound engineering principles) of one or more qualifying tertiary recovery methods which can reasonably be expected to result in more than an insignificant increase in the amount of crude oil which ultimately will be recovered. The qualifying tertiary recovery methods generally include the following nine methods: miscible fluid displacement, steam-drive injection, microemulsion flooding, in situ combustion, polymer-augmented water flooding, cyclic-steam injection, alkaline flooding, carbonated water flooding, and immiscible non-hydrocarbon gas displacement, or any other method approved by the IRS. In addition, for purposes of the enhanced oil recovery credit, immiscible non-hydrocarbon gas displacement generally is considered a qualifying tertiary recovery method, even if the gas injected is not carbon dioxide.

A project is not considered a qualified EOR project unless the project's operator submits to the IRS a certification from a petroleum engineer that the project meets the requirements set forth in the preceding paragraph.

The enhanced oil recovery credit is effective for taxable years beginning after December 31, 1990, with respect to costs paid or incurred in EOR projects begun or significantly expanded after that date.

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<sup>16</sup> The average per-barrel price of crude oil for this purpose is determined in the same manner as for purposes of the section 29 credit.

<sup>17</sup> In the case of an integrated oil company, the credit base includes those IDCs which the taxpayer is required to capitalize.

Conventional oil recovery methods do not recover all of a well's oil. Some of the remaining oil can be extracted by unconventional methods, but these methods are generally more costly and uneconomic at current world oil prices. In this environment, the EOR credit can increase recoverable reserves. Although recovering oil using EOR methods is more expensive than recovering it using conventional methods, it may be less expensive than producing oil from new reservoirs. Although the credit could phase out at higher oil prices, it is fully effective at present world oil prices.

#### Alternative minimum tax

A taxpayer is subject to an alternative minimum tax ("AMT") to the extent that its tentative minimum tax exceeds its regular income tax liability. A corporate taxpayer's tentative minimum tax generally equals 20 percent of its alternative minimum taxable income in excess of an exemption amount. (The marginal AMT rate for a noncorporate taxpayer is 26 or 28 percent, depending on the amount of its alternative minimum taxable income above an exemption amount.) Alternative minimum taxable income ("AMTI") is the taxpayer's taxable income increased by certain tax preferences and adjusted by determining the tax treatment of certain items in a manner which negates the deferral of income resulting from the regular tax treatment of those items.

As a general rule, percentage depletion deductions claimed in excess of the basis of the depletable property constitute an item of tax preference in determining the AMT. In addition, the AMTI of a corporation is increased by an amount equal to 75 percent of the amount by which adjusted current earnings ("ACE") of the corporation exceed AMTI (as determined before this adjustment). In general, ACE means AMTI with additional adjustments that generally follow the rules presently applicable to corporations in computing their earnings and profits. As a general rule a corporation must use the cost depletion method in computing its ACE adjustment. Thus, the difference between a corporation's percentage depletion deduction (if any) claimed for regular tax purposes and its allowable deduction determined under the cost depletion method is factored into its overall ACE adjustment.

Excess percentage depletion deductions related to crude oil and natural gas production are not items of tax preference for AMT purposes. In addition, corporations that are independent oil and gas producers and royalty owners may determine depletion deductions using the percentage depletion method in computing their ACE adjustments.

The difference between the amount of a taxpayer's IDC deductions and the amount which would have been currently deductible had IDCs been capitalized and recovered over a 10-year period may constitute an item of tax preference for the AMT to the extent that this amount exceeds 65 percent of the taxpayer's net income from oil and gas properties for the taxable year (the "excess IDC preference"). In addition, for purposes of computing a corporation's ACE adjustment to the AMT, IDCs are capitalized and amortized over the 60-month period beginning with the month in which they are paid or incurred. The preference does not apply if the taxpayer elects to capitalize and amortize IDCs over a 60-month period for regular tax purposes.

IDCs related to oil and gas wells are generally not taken into account in computing the excess IDC preference of taxpayers that are not integrated oil companies. This treatment does not apply, however, to the extent it would reduce the amount of the taxpayer's AMTI by more than 40 percent of the amount that the taxpayer's AMTI would have been if those IDCs had been taken into account.

In addition, for corporations other than integrated oil companies, there is no ACE adjustment for IDCs with respect to oil and gas wells. That is, such a taxpayer is permitted to use its regular tax method of writing off those IDCs for purposes of computing its adjusted current earnings.

Absent these rules, the incentive effect of the special provisions for oil and gas would be reduced for firms subject to the AMT. These rules, however, effectively eliminate AMT concerns for independent producers.

#### Passive activity loss and credit rules

A taxpayer's deductions from passive trade or business activities, to the extent they exceed income from all such passive activities of the taxpayer (exclusive of portfolio income), generally may not be deducted against other income.<sup>18</sup> Thus, for example, an individual taxpayer may not deduct losses from a passive activity against income from wages. Losses suspended under this "passive activity loss" limitation are carried forward and treated as deductions from passive activities in the following year, and thus may offset any income from passive activities generated in that later year. Losses from a passive activity may be deducted in full when the taxpayer disposes of its entire interest in that activity to an unrelated party in a transaction in which all realized gain or loss is recognized.

An activity generally is treated as passive if the taxpayer does not materially participate in it. A taxpayer is treated as materially participating in an activity only if the taxpayer is involved in the operations of the activity on a basis which is regular, continuous, and substantial.

A working interest in an oil or gas property generally is not treated as a passive activity, whether or not the taxpayer materially participates in the activities related to that property. This exception from the passive activity rules does not apply if the taxpayer holds the working interest through an entity which limits the liability of the taxpayer with respect to the interest. In addition, if a taxpayer has any loss for any taxable year from a working interest in an oil or gas property which is treated pursuant to this working interest exception as a loss which is not from a passive activity, then any net income from such property (or any property the basis of which is determined in whole or in part by reference to the basis of such property) for any succeeding taxable year is

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<sup>18</sup> This provision applies to individuals, estates, trusts, personal service corporations, and closely held C corporations.

treated as income of the taxpayer which is not from a passive activity.

Similar limitations apply to the utilization of tax credits attributable to passive activities. Thus, for example, the passive activity rules (and, consequently, the oil and gas working interest exception to those rules) apply to the nonconventional fuels production credit and the enhanced oil recovery credit. However, if a taxpayer has net income from a working interest in an oil and gas property which is treated as not arising from a passive activity, then any tax credits attributable to the interest in that property would be treated as credits not from a passive activity (and, thus, not subject to the passive activity credit limitation) to the extent that the amount of the credits does not exceed the regular tax liability which is allocable to such net income.

As a result of this exception from the passive loss limitations, owners of working interests in oil and gas properties may use losses from such interests to offset income from other sources.

### Tertiary injectants

Taxpayers are allowed to deduct the cost of qualified tertiary injectant expenses for the taxable year. Qualified tertiary injectant expenses are amounts paid or incurred for any tertiary injectant (other than recoverable hydrocarbon injectants) which is used as a part of a tertiary recovery method.

The provision allowing the deduction for qualified tertiary injectant expenses resolves a disagreement between taxpayers (who considered such costs to be IDCs or operating expenses) and the IRS (which considered such costs to be subject to capitalization).

## **Energy Efficiency and Alternative Energy Sources**

Incentives for energy efficiency and alternative energy sources are also essential elements of national energy policy. Individuals and businesses do not invest in energy-saving and alternative energy technologies at a level that reflects the benefits the technologies provide to society in excess of their private returns. If a new technology reduces pollution or emissions of greenhouse gases, those “external benefits” should be included in the decision about whether to undertake the investment. But potential investors have an incentive to consider only the private benefits in making decisions. Thus, they avoid technologies that are not profitable even though their benefits to society exceed their costs. Tax incentives can offset the failure of market prices to signal the desirable level of investment in energy-saving technologies because they increase the private return from the investment by reducing its after-tax cost. The increase in private return encourages additional investment in energy-saving technologies.

The continuing strength of our economy over the past two years, despite oil price rises, underscores the dramatic improvements in energy efficiency we have achieved over the past quarter century, as well as the changing economy. While past oil shortages have taken a significant toll on the U.S. economy, the recent increases in oil prices have not affected the

economy much. Increased energy efficiency in cars, homes, and manufacturing has helped insulate the economy from these short-term market fluctuations. In 1974, we consumed 15 barrels of oil for every \$10,000 of gross domestic product. Today we consume only 8 barrels of oil for the same amount of economic output.

### **Current law tax incentives for energy efficiency and alternative fuels**

Tax incentives currently provide an important element of support for energy-efficiency improvements and increased use of renewable and alternative fuels. Current incentives in the form of tax expenditures are estimated to total \$1.2 billion for fiscal years 2002 through 2006. They include a tax credit for electric vehicles and expensing for clean-fuel vehicles (\$20 million), a tax credit for the production of electricity produced from wind or biomass and a tax credit for certain solar energy property (\$590 million), and an exclusion from gross income for certain energy conservation subsidies provided by public utilities to their customers (\$580 million).<sup>19</sup>

#### Electric and clean-fuel vehicles and clean-fuel vehicle refueling property

A 10-percent tax credit is provided for the cost of a qualified electric vehicle, up to a maximum credit of \$4,000. A qualified electric vehicle is a motor vehicle that is powered primarily by an electric motor drawing current from rechargeable batteries, fuel cells, or other portable sources of electric current, the original use of which commences with the taxpayer, and that is acquired for use by the taxpayer and not for resale. The full amount of the credit is available for purchases prior to 2002. The credit begins to phase down in 2002 and does not apply to vehicles placed in service after 2004.

Certain costs of qualified clean-fuel vehicles and clean-fuel vehicle refueling property may be deducted when such property is placed in service. Qualified electric vehicles do not qualify for the clean-fuel vehicle deduction. The deduction begins to phase down in 2002 and does not apply to property placed in service after 2004.

#### Energy from wind or biomass

A 1.5-cent-per-kilowatt-hour tax credit is provided for electricity produced from wind, “closed-loop” biomass (organic material from a plant that is planted exclusively for purposes of being used at a qualified facility to produce electricity), and poultry waste. The electricity must be sold to an unrelated third party and the credit is limited to the first 10 years of production. The credit applies only to facilities placed in service before January 1, 2002. The credit amount is indexed for inflation after 1992.

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<sup>19</sup> Estimates prepared by the Office of Tax Analysis, Department of the Treasury, for inclusion in *Analytical Perspectives, Budget of the United States Government, Fiscal Year 2002*, U.S. Government Printing Office, Washington, DC (publication expected in March 2001).

Solar energy

A 10-percent investment tax credit is provided to businesses for qualifying equipment that uses solar energy to generate electricity, to heat or cool or provide hot water for use in a structure, or to provide solar process heat.

Energy conservation subsidies

Subsidies provided by public utilities to their customers for the purchase or installation of energy conservation measures are excluded from the customers' gross income. An energy conservation measure is any installation or modification primarily designed to reduce consumption of electricity or natural gas or to improve the management of energy demand with respect to a dwelling unit.

**Administration proposals**

The Administration's budget proposals for fiscal year 2002 will include tax incentives for renewable energy resources. The proposals would extend the credit for electricity produced from wind and biomass and expand eligible biomass sources. The proposals also would provide a new 15-percent tax credit for residential solar energy property, up to a maximum credit of \$2,000. We are developing the details of these proposals and will provide a complete description when the Administration presents its budget to Congress later this month.

Mr. Chairman, this concludes my prepared testimony. I will be pleased to answer any questions you or other members of the Subcommittee may have.