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Oil and Gas Tax Subsidies: Current Status and Analysis

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Summary

The CLEAN Energy Act of 2007 (H.R. 6) was introduced by the House Democratic leadership to revise certain tax and royalty policies for oil and natural gas and to use the resulting revenue to support a reserve for energy efficiency and renewable energy. Title I proposes to repeal certain oil and natural gas tax subsidies, and use the resulting revenue stream to support the reserve. The Congressional Budget Office (CBO) estimates that Title I would repeal about $7.7 billion in oil and gas tax subsidies over the 10-year period from 2008 through 2017. In House floor debate, opponents argued that the cut in oil and natural gas subsidies would dampen production, cause job losses, and lead to higher prices for gasoline and other fuels. Proponents counterargued that record profits show that the oil and natural gas subsidies were not needed. The bill passed the House on January 18 by a vote of 264-123. This report presents a detailed review of oil and gas tax subsidies, including those targeted for repeal by H.R. 6.

The Energy Policy Act of 2005 (EPACT05, P.L. 109-58) included several oil and gas tax incentives, providing about $2.6 billion of tax cuts for the oil and gas industry. In addition, EPACT05 provided for $2.9 billion of tax increases on the oil and gas industry, for a net tax increase on the industry of nearly $300 million over 11 years. Energy tax increases comprise the oil spill liability tax and the Leaking Underground Storage Tank financing rate, both of which are imposed on oil refineries. If these taxes are subtracted from the tax subsidies, the oil and gas refinery and distribution sector received a net tax increase of $1,356 million ($2,857 million minus $1,501 million).

EPACT05 was approved and signed into law at a time of very high petroleum and natural gas prices and record oil industry profits. The House approved the conference report on July 28, 2005, and the Senate on July 29, 2005, clearing it for the President's signature on August 8 (P.L. 109-58). However, the tax sections originated in the106th Congress, with its effort in 1999 to help the ailing domestic oil and gas producing industry, particularly small producers, deal with depressed oil prices. Subsequent price spikes prompted concern about insufficient domestic energy production capacity and supply. All the early bills appeared to be weighted more toward stimulating the supply of conventional fuels, including capital investment incentives to stimulate production and transportation of oil and gas.

In addition to the tax subsidies enacted under EPACT05, the U.S. oil and gas industry qualifies for several other targeted tax subsidies (FY2006 revenue loss estimates appear in parenthesis): (1) percentage depletion allowance ($1 billion); (2) expensing of intangible drilling costs for successful wells and non-geological and geophysical costs for dry holes, including the exemption from the passive loss limitation rules that apply to all other industries ($1.1 billion); (3) a tax credit for small refiners of low-sulfur diesel fuel that complies with Environmental Protection Agency (EPA) sulfur regulations ($ 50 million); (4) the enhanced oil recovery tax credit ($0); and (5) marginal oil and gas production tax credits ($0).

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Action in the 110th Congress

The CLEAN Energy Act of 2007 (H.R. 6) was introduced by the House Democratic leadership to revise certain tax and royalty policies for oil and natural gas and to use the resulting revenue to support a reserve for energy efficiency and renewable energy. The bill is one of several introduced on behalf of the Democratic leadership in the House as part of its "100 hours" package of legislative initiatives conducted early in the 110th Congress.

Title I proposes to repeal certain oil and natural gas tax subsidies, and use the resulting revenue stream to support the reserve. According to the Congressional Budget Office (CBO), the provisions in Title I would make about $7.7 billion available for the reserve over the 10-year period from 2008 through 2017.[1]

H.R. 6 came to the House floor for debate on January 18, 2007. In the floor debate, opponents argued that the reduction in oil and natural gas incentives would dampen production, cause job losses, and lead to higher prices for gasoline and other fuels. Opponents also complained that the proposal for the Reserve does not identify specific policies and programs that would receive funding. Proponents of the bill counterargued that record profits show that the oil and natural gas incentives were not needed. They also contended that the language that would create the Reserve would allow it to be used to support a variety of research and development (R&D), deployment, tax incentives, and other measures for renewables and energy efficiency, and that the specifics would evolve as legislative proposals come forth to draw resources from the Reserve. The bill passed the House on January 18 by a vote of 264-123.

Background

The Energy Policy Act of 2005 (P.L. 109-58), enacted on August 8, 2005, expanded some of the existing tax subsidies for the oil and gas industry and created several new ones.[2] The oil and gas tax incentives in EPACT05 were added on top

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[1] U.S. Congress. Congressional Budget Office. H.R. 6, CLEAN Energy Act of 2007. (Letter to Chairman Nick Rahall, Committee on Natural Resources.) Jan. 12, 2007. 4 p. [http://www.cbo.gov/ftpdocs/77xx/doc7728/hr6prelim.pdf]

[2] For a summary and analysis of this law, see CRS Report RL33302, *Energy Policy Act of*

(continued...)

of several existing special tax subsidies for oil and gas. The industry also benefits from provisions of current tax law that are not strictly tax subsidies (or tax expenditures) but that nevertheless provide advantages for and reduce effective tax rates of the oil and gas industry.

The remainder of this report discusses these tax provisions in detail. The first section, below, discusses the origin and evolution of the oil and gas tax subsidies that were incorporated into the 2005 act. The second section summarizes each of the oil and gas tax subsidy provisions in the 2005 energy act and reports its corresponding revenue loss estimate. Section three describes other oil and gas tax subsidies, those that existed before EPACT05 and were generally not affected by it. The final section describes several tax provisions that benefit the oil and gas industry; these are not tax subsidies per se — they are not considered to be tax expenditures — but are deemed by some observers to confer excessive (or unfair) benefits for the industry.

Policy Context and Analysis

Tax incentives for oil and gas supply have historically been an integral (if not the primary) component of the nation's energy policy. The domestic oil and gas industry was granted three tax code preferences, or subsidies: (1) expensing of intangible drilling costs (IDCs) and dry hole costs, introduced in 1916; (2) the percentage depletion allowance, first enacted in 1926 (coal was added in 1932); and (3) capital gains treatment of the sale of oil and gas properties.[3] These tax subsidies reduced marginal effective tax rates in the oil and gas industries, reduced production costs, and increased investments in locating reserves (increased exploration). They also led to more profitable production, some acceleration of oil and gas production, and more rapid depletion of energy resources than would otherwise occur. Partially in response to tax incentives, but also due to the low cost of discovering and developing the huge new resource base, there were discoveries during the 1930s of vast reserves in Texas, which led to a period of overproduction of oil and gas and concomitant declines in prices, which led to demand to prorationing under the Texas Railroad Commission.[4]

Beginning in the 1970s and through much of the 1990s, energy tax policy shifted away from fossil fuel supply and moved toward energy conservation through both energy efficiency and the development of alternative and renewable fuels. However, rising and repeated spikes in petroleum prices that began around 2000 and

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[2] (...continued)
2005: Summary and Analysis of Enacted Provisions. The two-year amortization period was slowed down to five years for integrated producers under 2006 tax legislation, as discussed in the text.

[3] As discussed later, these subsidies were largely eliminated on much of the oil production and assets, but other, less significant subsidies — the special exemption from the passive loss limitation rules and some special tax credits — were added to the tax code.

[4] Glasner, David, *Politics, Prices, and Petroleum: The Political Economy of Energy*, Pacific Institute for Public Policy Research, 1985, pp. 142-144.

were repeated over the next six years (combined with high and spiking natural gas prices, an electricity crisis, and blackouts) caused policymakers to focus on increasing energy production and supply of many diverse energy sources, including oil and gas.

The tax incentives for the oil and gas industry in the EPACT05 originated in the106th Congress's effort in 1999 to help the ailing domestic oil and gas producing industry, particularly small producers, deal with depressed oil prices. This situation fostered proposals for economic relief through the tax code, particularly for small independent drillers and producers. Proposals focused mainly on production tax credits for marginal or stripper well oil,[5] but they also included carry-back provisions for net operating losses, and other fossil fuel supply provisions.[6] Subsequent comprehensive energy policy legislation, including H.R. 4 in the107th Congress, proposed an expanded list of oil and gas tax incentives. The energy tax breaks in this bill (the Securing America's Future Energy Act of 2001, as approved by the House on August 1, 2001) were larger in terms of tax revenue loss than any other comprehensive energy policy legislation proposed during this period. They also were larger than those proposed in EPACT05: $33.5 billion of energy tax cuts, compared with the $14.5 billion loss eventually enacted under P.L. 109-58.

Interest in incentives and subsidies was boosted by the belief that much of the crisis was caused by insufficient domestic production capacity and supply. All the early bills appeared to be weighted more toward stimulating the supply of conventional fuels, including capital investment incentives to stimulate production and transportation of oil and gas. These proposals were further repackaged and expanded into the first broadly based energy bills and comprehensive energy policy legislation, such as H.R. 6 in the 109th, that evolved further and ultimately became EPACT05.[7] The House approved the conference report on July 28, 2005, and the Senate on July 29, 2005, clearing it for the President's signature on August 8 (P.L. 109-58).

The 2005 act became law at a time of very high prices for crude oil, petroleum products, and natural gas, and record oil and gas industry profits. This engendered the enmity of the general public and congressional proposals to (1) revoke the incentives enacted under the 2005 act; (2) repeal or pare back the historical, but

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[5] A stripper well is one that produces small quantities of oil and natural gas. The tax law currently defines this limit as 15 barrels of oil or the equivalent amount of natural gas per day; the oil and gas industry defines it 10 barrels per day or less.

[6] Although no tax bill was passed that reduced taxes on oil and gas, the 106th Congress did enact a package of $500 million in loan guarantees for small independent producers, which became law (P.L. 106-51), in August 1999.

[7] After some existing energy tax incentives expired in 2003, the 108th Congress enacted retroactive extension of several of the provisions as part of the Working Families Tax Relief Act of 2004 (P.L. 108-311). That law, which reduced revenues by about $1.3 billion over 10 years, was enacted on October 4, 2004. About $5 billion in energy tax incentives — both expansion or liberalization of some of the more popular energy tax provisions, as well as some new energy tax incentives — were part of the American Jobs Creation Act of 2004 (P.L. 108-357) enacted on October 22, 2004.

extant, tax subsidies and other tax advantages; and (3) impose sizeable new taxes on the industry such as a windfall profit tax.[8]

Public and congressional outcry did lead to a paring back of one of the tax subsidies liberalized in the 2005 act: two-year amortization, rather than capitalization, of geological and geophysical (G&G) activity costs, including those associated with abandoned wells (dry holes).[9] This exploration subsidy was the largest upstream tax subsidy (as opposed to a "downstream" or a refinery subsidy), in terms of federal revenue loss, enacted under the 2005 act, although it was and still is a relatively small tax subsidy. The Tax Increase Prevention and Reconciliation Act (P.L. 109-222), signed into law in May 2006, reduced the value of the subsidy by raising the amortization period for major integrated oil companies from two years to five years, still faster than the capitalization treatment before the 2005 act, but slower than the treatment under that act. Independent (nonintegrated) oil companies may continue to amortize all G&G costs over two years.

This relatively minor cutback has not muted the calls for rolling back oil and gas tax subsidies, as petroleum prices (and industry profits) remain somewhat high, particularly those of the biggest oil and gas companies. On September 1, 2006, the House Democratic leadership reportedly sent a letter to the House Speaker proposing a rollback of all of the 2005 energy act tax subsidies.[10] On October 25, 2006, then-House Democratic Leader Nancy Pelosi, urged the Congress to repeal those tax breaks.

Many bills were introduced in the 109th Congress to pare back or repeal the oil and gas industry tax subsidies and other loopholes. Many of the bills focused on the oil and gas exploration and development (E&D) subsidy — expensing of intangible drilling costs (IDCs). This subsidy, which has been in existence since the early days of the income tax, is available to integrated and independent oil and gas companies, both large and small alike.[11] It is an exploration and development incentive, which allows the immediate tax write-off of what economically are capital costs, that is, the costs of creating a capital asset (the oil and gas well). On September 18, 2006, Senators Wyden and Bennett introduced a bill (S. 3908) to give consumers a discount on the purchase of more fuel efficient vehicles that would have been paid for by reducing the IDCs deduction for major integrated oil companies. Comprehensive energy legislation (S. 2829) unveiled by Senate Democrats on May 17, 2006, would have not only eliminated expensing of IDCs, but would have also reduced several other tax benefits (or loopholes) to the oil and gas industry (such the foreign tax

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[8] For an analysis of the windfall profit tax, see CRS Report RL33305, *The Crude Oil Windfall Profits Tax of the 1980s: Implications for Current Energy Policy*, by Salvatore Lazzari.

[9] Prior to the 2005 act, G&G costs for dry holes were expensed in the first year and capitalized for successful wells.

[10] Bureau of National Affairs, Daily Tax Report. *House Democratic Leadership Letter to Speaker Hastert Asking for Rollback of Tax Breaks for Oil Companies,* Sept. 5, 2006.

[11] As discussed below, many of the remaining tax subsidies are available only to independent oil and gas producers, which, however, may be very large.

credits). The latter are not subsidies (or tax expenditures) in the strict sense of special tax measures unavailable generally, but as discussed below, some consider these unnecessary tax benefits nonetheless.[12] H.R. 5234 focused on repealing three of the seven fossil fuel tax provisions in the 2005 act: temporary expensing of equipment costs for crude oil refining, the small refiner exception to percentage depletion, and the amortization of geological and geophysical (G&G) costs. H.R. 5218 would have denied oil and gas companies the new domestic manufacturing deduction under IRC § 199.

There is speculation that in the 110th Congress, the Democratic leadership in both the House and Senate will begin to examine these breaks more closely, particularly because many of their legislative priorities (such as cutting back the increasingly heavy burden of the alternative minimum tax) will have to be paid for.[13]

Oil and Gas Tax Provisions in EPACT05 and their Revenue Effects

EPACT05 included a plethora of spending, tax, and deregulatory incentives to stimulate the production of conventional and unconventional oil and natural gas, such as gas from Alaska, deep water oil and gas in the outer continental shelf, and oil from marginal wells or private and federal lands. These incentives include tax breaks, royalty relief, streamlined permitting procedures, and other measures. The tax incentives include approximately $14.5 billion over 11 years of incentives to both stimulate domestic production and distribution of fossil fuels and reduce the demand for these fuels through energy efficiency and production of alternative and renewable fuels.

Title XIII, subtitle B, of EPACT05 includes the tax incentives for fossil fuel supply — for production, transportation, and distribution — of oil and gas, as well as capital incentives for expanded refinery capacity. The subtitle does not include coal supply incentives, which are subsumed in the electricity infrastructure subtitle. Although many of the oil and gas tax incentives in EPACT05 are production tax credits and other such "upstream" production incentives, some are capital incentives for natural gas infrastructure (accelerated depreciation of natural gas pipelines). In total, the tax incentives alone are worth about $2.6 billion over 11 years to the industry (an average of about $250 million a year in tax breaks).[14]

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[12] There is an important economic distinction between a subsidy and a tax benefit. As is discussed elsewhere in this report, firms receive a variety of tax benefits that are not necessarily targeted subsidies (or tax expenditures) because they are available generally.

[13] McKinnon, John D. "Are Higher Taxes in the Offing?" *The Wall Street Journal*, Oct. 30, 2006, p. A-6; Bureau of National Affairs, "Menu of Proposals Available to Democrats Looking to Roll Back Oil, Energy Tax Breaks," *Daily Tax Report*, Nov. 14, 2006, p. G-2.

[14] These are CRS compilations based on Joint Committee on Taxation estimates. See U.S. Congress, Joint Committee on Taxation, *Estimated Budget Effects of the Conference Agreement for Title XIII of H.R. 6, The "Energy Tax Incentives Act of 2005,"* July 27, 2005,

(continued...)

Subtitle B, thus, applies specifically to the oil and gas industry, including the refinery industry, for increased supply incentives. Tax incentives are provided — again mostly by liberalization of existing tax code provisions. The incentives are both production incentives (i.e., tax benefits are based on quantities of oil and gas) and capital incentives (i.e., tax benefits are based on magnitude of capital investment, such as pipelines). Both unconventional and conventional oil and gas supply are targeted for tax cuts.

Amortization of Geological and Geophysical Expenditures

Firms engaged in the exploration and development (E&D) of oil and gas incur a variety of costs prior to actual extraction. The tax treatment of these "upstream" E&D costs differs depending on the specific type of activity and depending on whether they are incurred by an integrated or nonintegrated (i.e., independent) producer. An independent producer is defined by Internal Revenue Code (IRC) § 613A(d), as described below.

E&D costs may be generally categorized as four types. First, there are the geological and geophysical costs (G&G). These are exploratory costs (such as for seismic surveys) associated with determining the precise location and potential size of a mineral deposit. A second type of cost is the mineral acquisition or lease rights expenses — the costs of buying or leasing the land under which deposits are thought to exist — such as lease bonuses.

If a property is considered prospective for containing economically recoverable deposits of oil or gas, the firm drills exploratory (and, if successful, subsequently development) wells to ascertain the magnitude of the deposits. These activities have associated various types of drilling costs. Tangible drilling costs, the third type of E&D costs, are amounts paid for tangible drilling and nondrilling equipment such as drilling rigs, casings, valves, pipelines, and other tangible machinery and equipment that have a salvage value. Finally, there are intangible drilling costs, or IDCs as they are frequently called. IDCs are amounts paid by the lease operator for fuel, labor, repairs to drilling equipment, materials, hauling, and supplies. They are expenditures incident to and necessary for the drilling of wells and preparing a site for production of oil and gas. For example, roads may have to be constructed to move in derricks and other types of drilling equipment; often a camp may have to be built with residences to house employees. The power for the equipment and the water supplies are also IDCs. IDCs also may include the cost to operators of any exploratory drilling or development work done by contractors under any form of contract, including a turnkey contract.

In general, as noted above, prior to EPACT05, all four types of costs — G&G costs, mineral rights, tangible equipment, and intangible drilling costs — associated with a dry hole were expensable (i.e., deductible in the year in which the well was determined to be dry). Under the 2005 act, both integrated and independent producers were required to amortize the G&G component of the dry hole costs over

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[14] (...continued)
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two years. This reduced the incentive for G&Gs associated with a dry hole but increased the incentive for G&Gs associated with most successful wells. This provision became effective for G&G amounts paid or incurred in taxable years beginning after the date of enactment.

Two-year amortization of G&G costs is still allowed for independent producers, but as a result of a provision in the Tax Increase Prevention and Reconciliation Act (P.L. 109-222, enacted in May 2006), integrated producers must now amortize such costs over five years.[15] Amortization means that the costs are deducted evenly — the same absolute dollars are taken as deductions every year over a specified period of time, in this case two or five years. It is also called straight-line depreciation.[16]

Determination of Independent Producer Status for Purposes of the Oil Depletion Deduction

Firms that extract oil, gas, or other minerals are permitted a deduction to recover their capital investment in a mineral reserve, which depreciates due to physical and economic depletion or exhaustion as the mineral is recovered (IRC § 611). Depletion, like depreciation, is a form of capital recovery: an asset, the mineral reserve itself, is being expended to produce income. Under the income tax, such a loss in value or cost is deductible.

There are two methods of calculating this deduction: cost depletion and percentage depletion. Cost depletion allows for the recovery of the actual capital investment — the costs of discovering, purchasing, and developing a mineral reserve. Each year, and over the period during which the reserve produces income, the taxpayer deducts a portion of the adjusted basis (original capital investment less previous deductions) equal to the fraction of the estimated remaining recoverable reserves that have been extracted and sold. Under this method, the total deductions cannot exceed the original capital investment.

Under percentage depletion, the deduction for recovery of capital investment is a fixed percentage as set by law of the "gross income" (i.e., revenue) from the sale of the mineral. Under this method, total deductions typically exceed, despite the limitations, the capital invested to acquire and develop the reserve.

IRC § 613 states that mineral producers must claim the higher of cost or percentage depletion. The percentage depletion rate for oil and gas is 15% and is limited to average daily production of 1,000 barrels of oil, or its equivalent in gas. For producers of both oil and gas, the limit applies on a combined basis. For example, an oil-producing company with 2006 oil production of 100,000 barrels and natural gas production of 1.2 billion cubic feet (the statutory equivalent of 200,000 barrels of oil) has average daily production of 821.92 barrels (300,000 ÷ 365 days).

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[15] The 2006 amendment constitutes a reduction in the tax benefits and was part of the compromise for allowing the G&G costs of successful wells to be amortized over two years rather than capitalized.

[16] The term *amortization* is also used in tax parlance as referring to the depreciation of intangible property, such as patents and copyrights.

Percentage depletion is not available to integrated major oil companies; it is available only for independent producers and royalty owners.

Beginning in 1990, the percentage depletion rate was raised on production from marginal wells — oil from stripper wells (those producing no more than 15 barrels per day, on average) and heavy oil. This rate starts at 15% and increases by one percentage point for each whole $1 that the reference price of oil for the previous calendar year is less than $20 per barrel (subject to a maximum rate of 25%). This higher rate is also limited to independent producers and royalty owners, and for up to 1,000 barrels, determined as before on a combined basis (including non-marginal production). Small independents operate nearly 400,000 small stripper wells in about 28 states, about 78% of the nearly 510,000 producing wells in the United States. Output from stripper wells represented about 16% of total domestic production (about 850,000 barrels per day) in the United States in 2004.[17]

The percentage depletion deduction is limited to 65% of the taxable income from all properties for each producer. A second limitation, the 100% net-income limitation, which applied to each individual property rather than to all the properties, was retroactively suspended for oil and gas production from marginal wells by the Working Families Tax Relief Act of 2004 (P.L. 108-311) through December 31, 2005. The 100% net-income limitation also had been suspended from 1998 to 2003. The difference between percentage depletion and cost depletion is considered a subsidy. It was once a tax preference item for purposes of the alternative minimum tax, but this was repealed by the Energy Policy Act of 1992 (P.L. 102-486).

The percentage depletion allowance is available for other types of fuel minerals, at rates ranging from 10% (coal, lignite) to 22% (uranium), and for mined hard rock minerals. The rate for regulated natural gas and gas sold under a fixed contract is 22%; the rate for geo-pressurized methane gas is 10%. Oil shale and geothermal deposits qualify for a 15% allowance. The net-income limitation to percentage depletion for coal and other fuels is 50%, compared with 100% for oil and gas. Under code section 291, percentage depletion on coal mined by corporations is reduced by 20% of the excess of percentage over cost depletion.

For purposes of percentage depletion, before EPACT05, an independent oil producer was one that, on any given day, (1) did not refine more than 50,000 barrels of oil and (2) did not have a retail operation grossing more than $5 million a year (IRC § 613A[d]). EPACT05 raised the 50,000 barrel daily limit to 75,000. In addition, the act changed the refinery limitation from actual daily production to average daily production for the taxable year. Accordingly, the average daily refinery runs for the taxable year may not exceed 75,000 barrels. For this purpose, the taxpayer would calculate average daily refinery runs by dividing total refinery runs for the taxable year by the total number of days in the taxable year. This is effective for taxable years ending after the date of enactment.

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[17] Both the number of stripper wells and oil output from such wells is reported in American Petroleum Institute, *Basic Petroleum Data Book*, vol. 26, no. 2, (section IV, table 3), August 2006.

Natural Gas Distribution Lines Treated as 15-Year Property

For purposes of determining the depreciation deduction, EPACT05 established a 15-year recovery period for natural gas distribution lines. Prior to this amendment, natural gas distribution lines were assigned a 20-year recovery period. This provisions is effective for property, the original use of which begins with the taxpayer after April 11, 2005, which is placed in service after April 11, 2005, and before January 1, 2011, and does not apply to property subject to a binding contract on or before April 11, 2005.

Temporary Expensing for Equipment Used in Oil Refining

Before the enactment of EPACT05, depreciation rules (the Modified Accelerated Cost Recovery System, MACRS) required oil refinery assets to be depreciated over 10 years using the double declining balance method.[18] Under the 2005 act, refineries are allowed to irrevocably elect to expense 50% of the cost of qualified refinery property, with no limitation on the amount of the deduction. This provision was enacted to increase investments in existing refineries so as to increase petroleum product output and reduce prices.

The expensing deduction is allowed in the taxable year in which the refinery is placed in service. The remaining 50% of the cost remains eligible for regular cost recovery provisions. To qualify for the deduction (1) original use of the property must commence with the taxpayer; (2)(a) construction must be pursuant to a binding construction contract entered into after June 14, 2005, and before January 1, 2008, (b) in the case of self-constructed property, construction began after June 14, 2005, and before January 1, 2008, or (c) the refinery is placed in service before January 1, 2008; (3) the property must be placed in service before January 1, 2012; (4) the property must meet certain production capacity requirements if it is an addition to an existing refinery; and (5) the property must meet all applicable environmental laws when placed in service. Certain types of refineries, including asphalt plants, are not eligible for the deduction, and there is a special rule for sale-leasebacks of qualifying refineries. If the owner of the refinery is a cooperative, it may elect to allocate all or a part of the deduction to the cooperative owners, allocated on the basis of ownership interests. This provision is effective for qualifying refineries placed in service after date of enactment (i.e., it became effective on August 9, 2005).

Arbitrage Rules Not To Apply to Prepayments for Natural Gas

EPACT05 creates a safe harbor exception to the general rule that tax-exempt, bond-financed prepayments violate the tax code's arbitrage restrictions. The term *investment-type property* does not include a prepayment under a qualified natural gas supply contract. The act also provides that such prepayments are not treated as private loans for purposes of the private business tests. Thus, a prepayment financed with tax-exempt bond proceeds for the purpose of obtaining a supply of natural gas

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[18] Under the double declining balance method of calculating depreciation deductions, the annual deduction is a fixed percentage (200% or double the straight-line rate) of the difference between asset cost and prior year depreciation deductions.

for service area customers of a governmental utility would not be treated as the acquisition of investment-type property. The safe harbor provisions do not apply if the utility engages in intentional acts to render (1) the volume of natural gas covered by the prepayment to be in excess of that needed for retail natural gas consumption and (2) the amount of natural gas that is needed to fuel transportation of the natural gas to the governmental utility. This provision is effective for obligations issued after date of enactment.

Natural Gas Gathering Lines Treated as Seven-Year Property

Under tax law prior to the enactment of EPACT05, the recovery period for natural gas gathering lines could be either 7 or 15 years, depending on whether they were classified as production or transportation equipment. Several court cases reflected the ambiguous tax treatment. Natural gas pipelines had a recovery period of 15 years, whereas natural gas distribution lines had a recovery period of 20 years (which, as noted above, was reduced to 15 years). EPACT05 assigned natural gas gathering lines a seven-year recovery period for MACRS depreciation deductions.

EPACT05 defined a natural gas gathering line as the pipe, equipment, and appurtenances determined to be a gathering line by the Federal Energy Regulatory Commission (FERC) or used to deliver natural gas from the well-head or common point to the point at which the gas first reaches (1) a gas processing plant, (2) an interconnection with an interstate transmission line, (3) an interconnection with an intrastate transmission pipeline, or (4) a direct connection with a local distribution company, a gas storage facility, or an industrial consumer. Also, the act requires that the original use of the property begin with the taxpayer. This provision became effective for property placed in service after April 11, 2005, excluding property with respect to which the taxpayer or related party had a binding acquisition contract on or before April 11, 2005.

Pass Through to Owners of Deduction for Capital Costs Incurred by Small Refiner Cooperatives in Complying with EPA Sulfur Regulations

IRC § 45H allows a small refiner to claim a tax credit for the production of low-sulfur diesel fuel that is in compliance with Environmental Protection Agency (EPA) sulfur regulations (the Highway Diesel Fuel Sulfur Control Requirements). The credit is $2.10 per barrel of low-sulfur diesel fuel produced; it is limited to 25% of the capital costs incurred by the refiner to produce the low-sulfur diesel fuel. The 25% limit is phased out proportionately as a refiner's capacity increases from 155,000 to 205,000 barrels per day.

Section 179B allows a small refiner to also claim a current year tax deduction (i.e., expensing), in lieu of depreciation, for up to 75% of the capital costs incurred in producing low-sulfur diesel fuel that is in compliance with EPA sulfur regulations. This incentive is also prorated for refining capacity between 155,000 and 205,000 barrels per day. The taxpayer's basis in the property that receives the exemption is reduced by the amount of the production tax credit. In the case of a refinery organized as a cooperative, both the credit and the expensing deduction may be passed through to patrons.

For both incentives, a small business refiner is a taxpayer who (1) is in the business of refining petroleum products, (2) employs not more than 1,500 employees directly in refining, and (3) has less than 205,000 barrels per day (averaged over the year) of total refining capacity. The incentives took effect retroactively beginning on January 1, 2003.

EPACT05 provided that cooperative refineries that qualify for § 179B expensing of capital costs incurred in complying with EPA sulfur regulations could elect to allocate all or part of the deduction to their owners, determined on the basis of their ownership interests. The election is made on an annual basis and is irrevocable once made. The provision became effective as if included in § 338(a) of the American Jobs Creation Act of 2004, which introduced the tax credit.

Modification and Extension of Credit for Producing Fuel from a Nonconventional Source for Facilities Producing Coke or Coke Gas[19]

Section 45K of the Internal Revenue Code (IRC) provides for a production tax credit of $3 per barrel of oil-equivalent (in 1979 dollars) for certain types of liquid, gaseous, and solid fuels produced from selected types of alternative energy sources (so-called "non-conventional fuels") and sold to unrelated parties. The full credit is available if oil prices fall below $23.50 per barrel (in 1979 dollars); the credit is phased out as oil prices rise above $23.50 (in 1979 dollars) over a $6 range (i.e., the inflation-adjusted $23.50 plus $6).

Both the credit and the phase-out ranges are adjusted for inflation (multiplied by an inflation adjustment factor) since 1979. With an inflation adjustment factor of 2.264 (meaning that prices, as measured by the Gross Domestic Product deflator, have more than doubled since 1979), the credit for 2005 production was $6.79 per barrel of oil equivalent, which is the amount of the qualifying fuel that has a British Thermal Unit (Btu) content of 5.8 million. The credit for gaseous fuels was $1.23 per thousand cubic feet (mcf). The credit for tight sands gas is not indexed to inflation; it is fixed at the 1979 level of $3 per barrel of oil equivalent (about $0.50 per mcf). In 2005, the reference price of oil, which was $50.76 per barrel, still below the inflation adjustment phase-out threshold oil price of $53.20 for 2005 ($23.50 multiplied by 2.264), the full credit of $6.56 per barrel of equivalent was available for qualifying fuels.

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[19] Two of the nine special tax subsidies for oil and gas in EPACT05 were for unconventional gases and synfuels from coal under the § 45K tax credit. These provisions are discussed because the § 45K tax credit has been important to the development of unconventional gases such as coalbed methane and tight sands gas. However, its revenue losses are subsumed under the coal category of **Table 1** largely because in recent years the provision has benefitted primarily the coal industry by increasing the demand for coal.

Qualifying fuels include synthetic fuels (liquid, gaseous, and solid) produced from coal, and gas produced from either geopressurized brine, Devonian shale, tight formations, or biomass. To qualify for the credit, synthetic fuels from coal must undergo a significant chemical transformation, defined as a measurable and reproducible change in the chemical bonding of the initial components. In most cases, producers apply a liquid bonding agent to the coal or coal waste (coal fines), such as diesel fuel emulsions, pine tar, or latex, to produce a solid synthetic fuel. The coke made from coal and used as a feedstock, or raw material, in steel-making operations also qualifies as a synthetic fuel, as does the breeze (small pieces of coke) and the coke gas (produced during the coking process). Depending on the precise Btu content of these synfuels, the § 45K tax credit could be as high as $26 per ton or more, which is a significant fraction of the market price of coal. Qualifying fuels must be produced within the United States. The credit for coke and coke gas is also $3 per barrel of oil equivalent and is also adjusted for inflation, but the credit is set to a base year of 2004, making the nominal unadjusted tax credit less than for other fuels.

The section 45K credit for gas produced from biomass, and synthetic fuels produced from coal or lignite, is available through December 31, 2007, provided that the production facility was placed in service before July 1, 1998, pursuant to a binding contract entered into before January 1, 1997. The credit for coke and coke gas is available through December 31, 2009, for plants placed in service before January 1, 1992, and after June 30, 1998. The section 45K credit used to apply to oil produced from shale or tar sands, and coalbed methane (a colorless and odorless natural gas that permeates coal seams and that is virtually identical to conventional natural gas). However, the credit for these fuels terminated on December 31, 2002 (and the facilities had to have been placed in service, or wells drilled, by December 31, 1992).

The section 45K credit is part of the general business credit. It is not claimed separately; it is added together with several other business credits and is also subject to the limitations of that credit. The section 45K credit is offset (or reduced) by certain other types of government subsidies that a taxpayer may benefit from: government grants, subsidized or tax-exempt financing, energy investment credits, and the enhanced oil recovery tax credit that may be claimed with respect to such projects. Finally, the credit is nonrefundable and cannot be used to offset a taxpayer's alternative minimum tax liability. Any unused section 45K credits generally may not be carried forward or back to another taxable year. (However, under the minimum tax section 53, a taxpayer receives a credit for prior-year minimum tax liability to the extent that a section 45K credit is disallowed as a result of the operation of the alternative minimum tax.)

The Energy Policy Act of 2005 made several amendments to the section 45K tax credit. First, the credit's provisions were moved from § 29 of the tax code to new § 45K. Before this, this credit was commonly known as the "section 29 credit." Second, the credit was made available for qualified facilities that produce coke or coke gas that were placed in service before January 1, 1993, or after June 30, 1998, and before January 1, 2010. Coke and coke gas produced and sold during the period beginning on the later of January 1, 2006, or the date the facility is placed in service, and ending on the date which is four years after such period begins, are eligible for the production credit, but at a reduced rate and only for a limited quantity of fuel. The tax credit for coke and coke gas is $3.00 per barrel of oil equivalent, but the credit is indexed for inflation starting with a 2004 base year, compared with a 1979 base year for other fuels. A facility producing coke or coke gas and receiving a tax credit under the previous § 29 rules is not eligible to claim the credit under the new section 45K. The new provision also requires that the amount of credit-eligible coke produced not exceed an average barrel-of-oil equivalent of 4,000 barrels per day. Third, the 2005 act provided that with respect to the IRS moratorium on taxpayer-specific guidance concerning the credit, the IRS should consider issuing rulings and guidance on an expedited basis to those taxpayers who had pending ruling requests at the time that the IRS implemented the moratorium. Finally, the 2005 legislation made the general business limitations applicable to the tax credit. Any unused credits can be carried back one year and forward 20 years, except that the credit cannot be carried back to a taxable year ending before January 1, 2006. These new rules were made effective for fuel produced and sold after December 31, 2005, in taxable years ending after that date.

Revenue Effects

Table 1 shows the revenue effects of the tax provisions in EPACT05, organized by type of incentive. These are the original revenue effects estimated for EPACT05, signed into law on August 8, 2005, by the Joint Committee on Taxation (JCT). Because of changes to energy prices, energy markets, and general economic conditions, revenue loss estimates of the same provisions calculated today would most likely differ from those original estimates.

JCT's estimated revenue losses were projected over an 11-year time frame, from FY2005 to FY2015. The total revenue losses are reported in two ways: the absolute dollar value of tax cuts over 11 years, and the percentage distribution of total revenue losses by type of incentive. Each of the seven tax subsidies for the oil and gas industry are shown separately, as well as the aggregate for upstream (exploration, development, and production) operations and downstream operations (refining and transportation/distribution). Also, for perspective, the oil and gas tax revenue losses are compared with those for other industries and with the tax subsidies for energy efficiency and alternative/renewable fuels.

Table 1. Energy Tax Provisions in the Energy Tax Act of 2005 (P.L. 109-58): 11-Year Estimated Revenue Loss, by Type of Incentive

	Amount ($ millions)	**Percentage**
INCENTIVES FOR FOSSIL FUELS SUPPLY		
(1) Oil & Gas Production:	-1,132	7.8%
a) amortize all G&G costs over 2 years	-974	
b) liberalize the definition of independent producer	-158	
(2) Oil & Gas Refining and Distribution:	-1,501	10.4%
a) gas pipelines treated as 15-year property	-1,019	
b) temporary expensing in refining of liquid fuels	-406	
c) exempt prepayment of natural gas from arbitrage	-53	
d) gas gathering lines treated as 7-year property	-16	
e) expensing for coop refinery of low-sulfur diesel	-7	
(3) Coal	-2,948	20.4%
(4) Subtotal	-5,581	38.6%
ELECTRICITY RESTRUCTURING PROVISIONS		
(5) Nuclear	-1,571	10.9%
(6) Other	-1,549	10.7%
(7) Subtotal	-3,120	21.6%
INCENTIVES FOR EFFICIENCY, RENEWABLES, AND ALTERNATIVE FUELS		
(8) Energy Efficiency	-1,260	8.7%
(9) Renewable Energy & Alternative Fuels	-4,500	31.1%
(10) Subtotal	-5,760	39.8%
(11) Net Energy Tax Cuts	-14,461	100.0%
(12) Non Energy Tax Cuts[a]	-92	
(13) Total Energy and Non-Energy Tax Cuts	-14,553	
(14) Energy Tax Increases[b]	+2,857	
(15) Other Tax Increases	171	
(15) NET TAX CUTS	-11,525	

Source: CRS compilation based on Joint Committee of Taxation estimates.

a. The act includes a provision to expand R&D for all energy activities. This provision is listed as a non energy tax cut to simplify the table.

b. Energy tax increases comprise the oil spill liability tax and the Leaking Underground Storage Tank financing rate, both of which are imposed on oil refineries. If these taxes are subtracted from the tax subsidies (row 2), the oil and gas refinery and distribution sector received a net tax increase of $1,356 ($2,857-$1,501).

The JCT estimates that the 2005 act provides about $2.6 billion in tax cuts for the oil and gas industry as a whole over 11 years, comprising about $1.1 billion for upstream operations and $1.5 billion for downstream, or refining and distribution, operations. For energy conservation and efficiency, the 2005 act provides about $1.3 billion, including a deduction for energy-efficient commercial property, fuel cells, and micro-turbines. Renewables incentives include a two-year extension of the tax code § 45 credit, renewable energy bonds, and business credits for solar. The total renewable tax subsidies in EPACT05 were about $4.5 billion.

Although the above oil and gas tax subsidies may not be justified based on economic theory, and considering the high oil and gas prices over much of the policy period, they are not large when measured relative to the industries' gross product, which measures in the hundreds of billions of dollars.[20] Another misconception is that industry was the beneficiary of many and significant tax breaks before these provisions were enacted. The industry did benefit historically from significant tax subsidies; however, most of these had been either eliminated or pared back since the 1970s.

Tax Increases

Subtitle F of EPACT05 describes the four tax increases or revenue offsets. Two of the tax increases — modification of the § 197 amortization, and an increase in the excise taxes on tires — are negligible, raising taxes by just under an estimated $200 million over 11 years. However, the other two are sizeable tax increases for the oil and gas industry: reinstatement of the Oil Spill Liability Trust Fund and extension of the Leaking Underground Storage Tank (LUST) trust fund rate, which would be expanded to all fuels.

The total oil and gas industry tax increases are roughly $2.8 billion over 11 years, for a net increase in taxes on the industry of about $200 million, according to the JCT estimates. However, because the oil spill liability tax and the Leaking Underground Storage Tank financing taxes are excise taxes on oil and petroleum products, and are imposed on oil refineries, the net effect of the 2005 act on the oil and gas refinery sector was a tax increase of about $1.3 billion over 11 years.

Other Oil and Gas Tax Subsidies

The Energy Policy Act of 2005 expanded some (but not all) of the preexisting tax subsidies for oil and gas and introduced several new ones. Thus, some of the recent proposals to roll back tax subsidies to oil and gas focus on the subsidies that were in effect before the 2005 act, and which continue be in effect.

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[20] For the economic theory of taxation of exhaustible natural resources, see CRS Report RL30406, *Energy Tax Policy: An Economic Analysis*, by Salvatore Lazzari.

Other Oil and Gas Tax Subsidies

A list of the preexisting federal tax subsidies (incentives) available for the U.S. oil and gas industry — those in effect before EPACT05 and still in effect today — (and their corresponding revenue loss estimates) appears in **Table 2**. The corresponding revenue losses, as estimated by the JCT in its latest tax expenditures compendium, appear in the last column.[21] Note that the table defines tax subsidies or incentives targeted for the oil and gas industry as those that are due to provisions in the tax law that apply only to this industry and not to others.

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[21] U.S. Congress, Joint Committee Print, *Estimates of Federal Tax Expenditures for Fiscal Years 2006-2010*, prepared for the House Committee on Ways and Means and the Senate Committee on Finance by the Joint Committee on Taxation Staff, Apr. 25, 2006.

Table 2. Special Tax Incentives Targeted for the Oil and Gas Industry and Estimated Revenue Losses, FY2006

Category	Provision	Major Limitations	Original Enacting Legislation/ Regulation	Federal Revenue Losses FY2006($ millions)
Expensing of Intangible Drilling Costs (IDCs) and Amortization of Exploration and Development Expenses	Firms engaged in the exploration and development of oil or gas properties may expense (deduct in the year paid or incurred) rather than capitalize certain types of drilling expenditures. Geological and geophysical expenses paid or incurred in connection with the domestic exploration for, or development of, oil or gas can be amortized ratably (evenly) over five years.	Integrated oil/gas corporations may expense only 70% of IDCs; the remaining 30% must be amortized and all of the excess IDCs over the 10-year amortizable amount are subject to the alternative minimum tax.	1916 Treasury Regulation T.D. 45, article 223	1,100[a]
Percentage Depletion Allowance	Firms that extract oil or gas are permitted to deduct 15% of sales (up to 25% for marginal wells depending on oil prices) to recover their capital investment in a mineral reserve.	Percentage depletion is available only for independent producers (and royalty owners) and only up to 1,000 barrels or equivalent per day; it is limited to 100% of the net income from any individual property and to 65% of the taxable income from all properties for each producer.	Revenue Act of 1926	1,000
Incentives for Small Refiners to Comply with EPA Sulfur Regulations	IRC § 45H allows a small refiner to claim a $2.10 credit per barrel of low-sulfur diesel produced that complies with EPA sulfur regulations. IRC§ 179B allows a small refiner to expense, in lieu of depreciation, up to 75% of the capital costs incurred in producing low-sulfur diesel fuel that is in compliance with EPA sulfur regulations.	Credit limited to 25% of capital costs; expensing phases out for refining capacity of 155,000-205,000 barrels per day.	P.L. 108-357	50[b]

Category	Provision	Major Limitations	Original Enacting Legislation/ Regulation	Federal Revenue Losses FY2006($ millions)
Tax Credits for Enhanced Oil Recovery Costs	IRC § 43 provides for a 15% income tax credit for the costs of recovering domestic oil by qualified "enhanced oil recovery" (EOR) methods, to extract oil that is too viscous to be extracted by conventional primary and secondary water-flooding techniques.	The EOR credit is nonrefundable and is allowable provided that the average wellhead price of crude oil (using West Texas Intermediate as the reference), in the year before credit is claimed, is below the statutorily established threshold price of $28 (as adjusted for inflation since 1990), in the year the credit is claimed. With average wellhead oil prices for 2005 (about $65) well above the reference price (about $38) the EOR credit was not available.	P.L. 101-508	0
Marginal Production Tax Credit	A $3 tax credit is provided per barrel of oil ($0.50/thousand cubic feet [mcf]) of gas from marginal wells, and for heavy oil.	The credit phases out as oil prices rise from $15 to $18 per barrel (and as gas prices rise from $1.67 to $2.00/thousand cubic feet), adjusted for inflation. The credit is limited to 25 barrels per day or equivalent amount of gas and to 1,095 barrels per year or equivalent. Credit may be carried back up to five years. At 2005 oil and gas prices, the marginal production tax credit was not available.	P.L. 108-357	0

Source: Joint Tax Committee estimates and Internal Revenue Service data.

a. The revenue loss estimate excludes the benefit of expensing costs of dry tracts and dry holes, which includes expensing some things that would otherwise be capitalized. This is a normal feature of the tax code but confers special benefits on an industry where the cost of finding producing wells includes spending money on a lot that turn out dry. The revenue loss estimates also include revenue losses associated with the passive loss limitation rule exemption for the oil and gas industry.

b. The JCT reports this revenue loss at less than $50 million but does not report the actual figure.

General Tax Provisions that May Benefit the Oil and Gas Industry

This discussion has so far excluded current-law tax provisions and incentives that may apply to non-oil and gas businesses but that may also confer tax benefits to the oil and gas industry. There are numerous such provisions in the tax code, which some have called loopholes — they are not strictly considered to be tax expenditures. A complete listing of them is beyond the scope of this report; however, four examples, which have been under discussion as possible revenue raisers, follow to illustrate the point.

For example, the current system of depreciation generally allows the writeoff of equipment and structures somewhat faster than would be the case under both general accounting principles and economic theory; the JCT treats the excess of depreciation deductions over the alternative depreciation system as a tax subsidy (or tax expenditure). In FY2006, the JCT estimates that the aggregate economy-wide revenue loss from this accelerated depreciation deduction (including the expensing under IRC § 179) is $6.7 billion. A certain, but unknown, fraction of this revenue loss or tax benefit accrues to the domestic oil and gas industry, but separate estimates are unavailable.

A second example is the deduction for domestic production (or manufacturing) activities under IRC § 199, which, as noted above is the target of H.R. 5218 (109th Congress). Enacted under the American Jobs Creation Act of 2004 (P.L. 108-357, also known as the JOBS bill), the domestic production deduction (IRC § 199) generally allows taxpayers to receive a deduction based on qualified production activities income resulting from domestic production. The deduction is 3% of income for 2006, rising to 6% between 2007 and 2009, and 9% thereafter; it is subject to a limit of 50% of the wages paid that are allocable to domestic production during the taxable year. The revenue impact of this provision is anticipated by the JCT to be a loss of $4.8 billion of federal revenue in FY2007, and $76 billion over the first 10 years of its life. A certain (as yet unknown) fraction of the tax benefits from the deduction will accrue to the domestic oil and gas industry. The deduction applies to oil and gas or any primary product thereof, provided that such product was "manufactured, produced, or extracted in whole or in significant part in the United States." Recently, the JCT estimated the revenues that would be gained by repealing this deduction for the domestic oil and gas industry at about $0.2 billion in FY2007, and about $2 billion from FY2007-FY2012.[22]

A third example concerns the "last-in/first-out" (LIFO) system of inventory accounting under IRC § 472. This method values the goods sold as the most recent inventory purchase. During a period of rising prices, this method of inventory accounting increases production costs and reduces taxable income and tax liabilities. A provision in the Senate version of H.R. 4297 (109th Congress) would have eliminated a portion of the tax benefits from LIFO inventory accounting for major

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[22] U.S. Congress, Joint Committee on Taxation, *JCT Cost Estimate for McDermott-Kerry Legislation (H.R. 5218, S. 2672) to Eliminate Oil Company Eligibility for JOBS Act Section 199 Tax Breaks*, May 10, 2006.

integrated oil companies with gross receipts in excess of $1 billion. Under threat of presidential veto, this provision, which would have increased taxes on such companies by an estimated $3.5 billion in FY2006, was deleted from the final law, the Tax Increase Prevention and Reconciliation Act of 2006 (P.L. 109-222).[23]

A fourth example is the foreign tax credit, which is a federal tax credit against U.S. tax liabilities for *income* taxes paid to foreign countries. This section of the tax code is intended to prevent the double taxation of foreign source income (income earned abroad by U.S. residents and corporations). However, many countries in which domestic U.S. oil companies conduct business (either through branches or foreign subsidiaries) impose levies that are not strictly considered to be creditable income taxes, which may have the effect of going beyond prevention of double taxation of foreign source income — it may actually lead to a reduction of taxes on domestic source income. A provision in the Senate version of H.R. 4297 (109th Congress) would have denied the foreign tax credit, under certain conditions, for major integrated oil companies with gross receipts in excess of $1 billion. The foreign tax credit would have been denied in the event that the foreign levy was assessed in exchange for an economic benefit provided by the foreign jurisdiction to the domestic oil company and if the foreign jurisdiction did not generally impose an income tax. This provision, which would have increased taxes on such companies by an estimated $0.8 billion over the 10-year period from FY2006 to FY2015, was deleted from the final law, the Tax Increase Prevention and Reconciliation Act of 2006 (P.L. 109-222).[24]

Finally, **Table 2** excludes targeted taxes that impose special tax liabilities on the domestic oil and gas industry — taxes that are not imposed on other industries. These would include taxes such as the motor fuels excise taxes (e.g., the 18.4¢ per gallon tax on gasoline, the 24.4¢ per gallon tax on diesel) and the oil spill liability trust fund excise tax, which imposes a $0.05 per barrel tax on every barrel of crude oil refined domestically.[25] These taxes are imposed on refiners, although under normal (and stable) market conditions they are shifted forward (or passed through the distribution and retailing chain) and largely paid by consumers. The motor fuels excise taxes (including the Leaking Underground Storage Tank Trust Fund Tax) represent a tax liability — the amount of revenues collected by the federal

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[23] U.S. Congress. Joint Committee on Taxation. *Comparison of Estimated Revenue Effects of the Tax Provisions Contained in H.R. 4297, "The Tax Relief Extension Reconciliation Act of 2005," As Passed by the House, and H.R. 4297, "The Tax Relief Act of 2005," As Passed by the Senate*. February 9, 2006.

[24] U.S. Congress. Joint Committee on Taxation. *Comparison of Estimated Revenue Effects of the Tax Provisions Contained in H.R. 4297, "The Tax Relief Extension Reconciliation Act of 2005," As Passed by the House, and H.R. 4297, "The Tax Relief Act of 2005," As Passed by the Senate*. February 9, 2006.

[25] Moneys are allocated into a fund for cleaning up oil spills.

government — of about $36 billion in FY2006;[26] revenues collected from the oil spill liability excise tax are estimated by the JCT at $0.150 billion.

[26] Revenues from motor fuels excise taxes are allocated primarily to the Highway Trust Fund (HTF) and various trust funds, depending on the mode of transportation. The HTF also includes revenue from excise taxes on tires, a heavy vehicle use tax, and retail sales tax on trucks and tractors.