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**Subject:** Historical Revenue Losses Associated with Tax Incentives for Oil and Gas

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**This memorandum was prepared to enable distribution to more than one congressional office.**

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This memorandum provides background information on tax incentives available to the oil and gas industry. Specifically, this memorandum focuses on oil and gas related tax expenditures that support the petroleum industry.[1] In addition to providing background information on individual provisions, this memorandum presents historical information on federal revenue losses associated with selected oil and gas tax provisions.

# Federal Tax Incentives for Oil and Gas[2]

In examining tax provisions that benefit the oil and gas industry, the first incentives reviewed are those that are targeted specifically for the oil and gas industry.[3] The focus is exclusively on tax incentives, excluding other federal incentives that accrue to oil and gas producers such as reduced royalty rates or federal acquisition of oil for reserve purposes.[4] The following sections provide background information on individual tax provisions benefitting oil and gas. This background information is followed with estimates of historical federal revenue loss.

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[1] Provisions directly related to natural gas, such as natural gas pipelines being treated as 15-year property, are not included.

[2] This memorandum specifically addresses tax incentives for oil and gas. There are additional tax incentives that benefit other fossil fuels that were excluded. For example, the credit for the production of nonconventional fuels historically provided an incentive for producing fuel using oil from shale or tar sands as well as gas from geopressurized brine, Devonian shale, coal seams, tight formations, biomass, and coal-based synthetic fuels. The GAO included the unconventional fuel credit in their 2000 report (see below), citing total revenue losses of $10.5 billion from 1980 through 2000 (inflation adjusted year 2000 dollars). Since much of the benefits for this provision have gone to coal producers, it is excluded from the current analysis. Other provisions that benefit coal include the characterization of coal royalty payments as capital gains, credits for clean-coal investments and coal pollution control, and incentives for coal mine safety equipment.

[3] Additional broad-based incentives are discussed below.

[4] For background information on the Strategic Petroleum Reserve, see CRS Report RS22567, *Royalty Relief for U.S. Deepwater Oil and Gas Leases*, by Marc Humphries and CRS Report RL33341, *The Strategic Petroleum Reserve: History, Perspectives, and Issues*, by Robert Bamberger.

## Expensing of Intangible Drilling Costs[5]

Intangible drilling costs (IDCs) include all expenditures made for wages, fuel, repairs, hauling, and other various supplies necessary for the drilling of wells and the preparation of wells for the production of oil and gas. Firms engaged in the exploration and development of oil, gas, or geothermal properties have the option of expensing (deducting in the year paid or incurred) rather than capitalizing (*i.e.*, recovering such costs through depletion or depreciation) certain intangible drilling and development costs (IDCs) for domestic properties.[6] Expenditures on tangible equipment, such as pipes and casings (items that have salvage value), cannot be expensed as IDCs and are instead capitalized and recovered through depreciation.

As an alternative to expensing, firms may amortize (deduct the cost evenly) IDCs over a five-year period. Independent producers may elect to fully expense IDCs.[7] Integrated oil companies, generally large producers that have both refining and marketing operations, may elect to expense 70% of IDCs.[8] The remaining 30% is then amortized over a five-year period.

The President's FY2011 Budget proposed repealing expensing of IDCs and the five-year amortization period for capitalized IDCs. Instead, all IDCs would have been capitalized and depreciated in accordance with generally applicable rules.[9] This provision would have raised an estimated $5.6 billion over the 2011 through 2015 budget window and $7.8 billion over the 2011 through 2020 budget window.[10]

## Reduced Geological and Geophysical Amortization Period

Geological and geophysical (G&G) costs—exploratory costs associated with determining the location and size of mineral deposits—are amortized by independent producers over two years. Integrated oil companies may amortize G&G costs over seven years.[11]

Prior to 2005, G&G costs associated with dry holes (abandoned property) were expensed while other G&G costs were capitalized and the costs recovered through depletion over the life of the asset. Under the

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[5] For additional details and further background on this provision see U.S. Congress, Senate Committee on the Budget, *Tax Expenditures: Compendium of Background Material on Individual Provisions*, committee print, prepared by Congressional Research Service, 111th Cong., 2nd sess., December 2010, pp. 127-132 [henceforth referenced as the "2010 Tax Expenditure Compendium"].

[6] Owners of natural resources, such as oil, reduce the value of the asset on their balance sheet through depletion. For non-renewable resources, the value of the asset declines as the resource is extracted and sold. Owners of natural resources are generally allowed to deduct depletion allowances from income before determining tax liability. Owners of assets that decline in value over time are also allowed to depreciate, or deduct from taxable income, the value of the asset over time.

[7] For the purposes of IDCs and percentage depletion (see below), independent producers are those whose refinery operations refine on average less than 75,000 barrels of oil per day and whose retail oil and gas operations gross less than $5 million per year (IRC §613A(d)).

[8] Integrated producers have had expensing of IDCs limited to 70% since the Tax Reform Act of 1986 (P.L. 99-514).

[9] More information on this proposal can be found in Department of the Treasury, *General Explanation of the President's FY2011 Revenue Proposals*, Washington, DC, February 2010, http://www.treas.gov/offices/tax-policy/library/greenbk10.pdf, pp. 85-86 [henceforth referenced as the "Treasury Green Book"].

[10] There are two reasons why the revenue estimates presented by the JCT are different than those provided by Treasury in this context. First, the Treasury and the JCT use different methodologies for estimating tax expenditures. Second, as was noted above, the methodology used for estimating revenue losses from tax expenditures differs from that used to estimate revenue gains associated with a provisions repeal.

[11] For further background see the 2010 Tax Expenditure Compendium, pp. 127-132.

Energy Policy Act of 2005 (EPACT05; P.L. 109-58) independent and integrated producers were able to amortize G&G costs over two years. The two-year amortization period applied to abandoned property as well as active sites. Generally, this change reduced the incentive for G&G exploration associated with dry holes but increased the incentive for G&G activities associated with successful wells. Overall, allowing G&G costs to be recovered over two years encourages oil and gas exploration.

Following EPACT05, the amortization period for G&G costs has been increased for integrated oil companies. The Tax Increase Prevention and Reconciliation Act of 2006 (P.L. 109-222) raised the amortization period for G&G costs to five years for integrated oil companies. The Energy Independence and Security Act of 2007 (P.L. 110-140) further raised the amortization period for G&G expenditures incurred by integrated oil companies from five to seven years.

The President's FY2011 Budget proposed increasing the amortization period for G&G costs incurred by independent producers from two to seven years.[12] This provision would have raised an estimated $0.8 billion over the 2011 through 2015 budget window and $1.1 billion over the 2011 through 2020 budget window.

## Excess of Percentage over Cost Depletion

Firms that extract oil, gas, or other minerals are permitted a deduction to recover their capital investment in a mineral reserve. For owners of natural resources, such as oil and gas, the value of their asset declines due to the physical and economic depletion or exhaustion as the asset is recovered. Depletion, like depreciation, is a form of capital recovery that attempts to measure the portion of the asset being used through production. With depletion, an asset, the mineral reserve itself, is being expended, or removed, in order to produce income. Under an income tax, such costs are deductible.

There are two methods for calculating this deduction for depletion: 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—over the period during which the reserve produces income. Each year, 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 of the "gross income"—*i.e.*, revenue—from the sale of the mineral. Under this method, total deductions typically exceed the capital invested to acquire and develop the reserve, despite limitations.

Independent producers and royalty owners are eligible to compute percentage depletion for a limited amount of domestic production. The percentage depletion rate for oil and gas is 15% of gross income and is limited to average daily production of 1,000 barrels of oil or its equivalent in gas. Percentage depletion is not available for integrated oil companies. The percentage depletion rate on production from marginal wells may be higher, as the rate increases (to a maximum of 25%) when oil prices are low.[13] Overall,

[12] See Treasury Green Book, p. 84.

[13] The rate starts at 15% and increases by one percentage point for each $1 that the reference price of oil for the previous calendar year is below $20 per barrel, subject to maximum rate of 25%. The reference price of oil has not fallen below $20 per barrel in recent years.

percentage depletion cannot exceed 65% of a taxpayer's taxable income (determined before the deduction and other adjustments).[14]

The President's FY2011 Budget proposed to repealing percentage depletion for oil and gas wells.[15] This provision would have raised an estimated $4.3 billion over the 2011 through 2015 budget window and $10.0 billion over the 2011 through 2020 budget window.

## Temporary Expensing for Equipment Used in Oil Refining

Oil 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.[16] The remaining 50% of the cost is capitalized and recovered via depreciation over the normal recovery period (in the case of refinery assets, generally 10 years). In order to be eligible, the original use of the property must commence with the taxpayer and a binding construction contract must have been established after June 14, 2005, but before January 1, 2010.[17] The property must then be placed-in-service before January 1, 2014.[18]

The option to expense 50% of refinery costs was enacted on a temporary basis under EPACT05. The purpose of the provision was to increase investments in refinery capacity, with the goal of increasing petroleum output and reducing petroleum prices. When initially enacted, the option to expense 50% of qualified investments in refinery property was available for property with construction contracts in place by January 1, 2008, and a placed-in-service date prior to January 1, 2012. Both of these deadlines were extended by two years under the Emergency Economic Stabilization Act of 2008 (P.L. 110-343).

## Credit for Enhanced Oil Recovery Costs[19]

Taxpayers are eligible for a 15% income tax credit for the costs of recovering domestic oil using a qualified "enhanced-oil-recovery" (EOR) method. Qualifying EOR methods inject fluids, gases, and other chemicals into an oil reservoir, and use heat to extract oil that is too viscous to be extracted by conventional water-flooding techniques. Qualifying EOR costs include tangible equipment costs, IDCs, and the costs of the injectants.

The EOR credit is phased-out as the reference price of oil in the previous calendar year exceeds a certain threshold price.[20] For 2010, the threshold price above which the credit phases-out is $42.57. The credit phases-out over a $6 range, such that if the reference price exceeds the threshold price by more than $6, the credit is not available. The reference price of oil for 2009 was $56.39. This credit was not available in 2010, since the reference price exceeded the threshold price by more than $6.[21]

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[14] For further information regarding this provisions see the 2010 Tax Expenditure Compendium, pp. 115-122.

[15] See Treasury Green Book, pp. 81-82.

[16] A qualified refinery means a refinery which is designed to serve the primary purpose of processing liquid fuel from crude oil or qualified fuels (see IRC §45K), or directly from shale or tar sands.

[17] For more information on this provision see the 2010 Tax Expenditure Compendium, pp. 214-216.

[18] In the case of self-constructed property, construction must have begun between June 14, 2005 and January 1, 2010 with the property placed-in-service before January 1, 2010.

[19] Prior to 2003, oil produced from shale or tar sands may also have been eligible for the nonconventional fuel production credit.

[20] The threshold price is $28 in 1990 dollars, and is adjusted annually for inflation using the inflation adjustment factor.

[21] See IRS Notice 2010-72.

The President's FY2011 Budget proposed eliminating the credit for enhanced oil recovery.[22] Eliminating this provision was not expected to generate additional revenue, as oil prices were expected to remain above the credit's threshold price.

## Other Oil and Gas Tax Incentives[23]

### Expensing of Tertiary Injectants

Currently, taxpayers are allowed to expense (deduct immediately) the cost of tertiary injectants. Tertiary injectants are used to extract oil that is too viscous to be extracted using other techniques. The President's FY2011 Budget proposed to eliminating the expensing of tertiary injectants.[24] Eliminating this provision would have raised an estimated $38 million over the 2011 through 2015 budget window and $67 million over the 2011 through 2020 budget window.

### Credit for Production from Marginal Wells

Taxpayers are also provided a credit for oil and gas production from marginal wells.[25] This provision provides a $3 per barrel tax credit for the first 3 barrels of production from a marginal well. This credit phases-out once the average price of crude oil exceeds a certain threshold. Since inception, the price of oil has remained above this threshold and this credit has never been claimed. Oil prices are expected to remain above the threshold price in coming years. Consequently, it is not expected that this provision will generate revenue losses. The President's FY2011 Budget proposed eliminating the credit for production from marginal wells.[26] Eliminating this provision was not expected to result in additional revenues.

### Oil and Gas Exemption from Passive Loss Limitation

Taxpayers with working interests in oil and gas are exempt from passive loss limitation rules.[27] Passive loss limitation rules, established under the Tax Reform Act of 1986 (P.L. 99-514), state that passive losses can only be deducted from income resulting from passive activities.[28] Further, losses from one passive activity (e.g., as a publicly traded partnership), can only be used to offset income from other

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[22] See Treasury Green Book, p. 75.

[23] In addition to the tax incentives listed here, oil and gas companies benefit from preferential royalty rates paid for oil and gas production on federally owned land. A 2010 GAO report notes that oil and gas companies may not be measured accurately and royalties may be underpaid. This report does not quantify royalty underpayments. U.S. Government Accountability Office, *Interior's Oil and Gas Production Verification Efforts Do Not Provide Reasonable Assurance of Accurate Measurement of Production Volumes*, GAO-10-313, March 2010. In a separate report released by a non-governmental organization, it is estimated that the reduced government take from oil as gas leasing was approximately $7 billion between 2002 and 2008. See Environmental Law Institute, *Estimating U.S. Government Subsidies to Energy Sources: 2002-2008*, Washington, DC, September 2009, pp. 12-13, http://www.elistore.org/reports_detail.asp?ID=11358.

[24] See Treasury Green Book, p. 79.

[25] This credit is part of the general business credit. Marginal wells are those with average production of 15 barrels per day or less, those producing heavy oil, or wells producing 95% or more water with average production of 25 barrels per day or less.

[26] See Treasury Green Book, p. 76.

[27] A working interest in oil and gas property is one that is burdened with the cost of development and operation of the property. Those with a working interest are expected to share in expenses. Costs include drilling costs as well as general costs associated with operating oil and gas property. Rights to royalties and production payments are not considered working interests, as these parties are not expected to share in expenses.

[28] Passive activities are trade or business activities in which the taxpayer does not materially participate.

passive activities (e.g., other publicly traded partnerships). Passive losses that cannot be used to offset passive income in the current tax year can generally be carried forward to offset passive income in future tax years. Exempting working interests in oil and gas from passive loss limitation rules, effectively allowing for losses incurred through oil and gas exploration to offset ordinary non-oil and gas income, creates an added incentive for investments in oil and gas.[29] The JCT does not consider exemptions from passive loss rules to be a tax expenditure, since the effects of the exceptions are already incorporated in the estimates of related tax expenditures. Thus, estimates of historical revenue losses from this provision are not included. Nonetheless, eliminating this provision may result in additional federal revenues.

The President's FY2011 Budget proposed repealing the exception from passive loss limitations for oil and gas.[30] This provision would raised an estimated $98 million over the 2011 through 2015 budget window and $180 million over the 2011 through 2020 budget window.

# Federal Revenue Losses

## Interpreting Estimates of Federal Revenue Loss

Quantifying the amount of federal revenue loss associated with oil and gas provisions is a complex process. There are a number of qualifications associated with these figures, which are reviewed in the following paragraphs. The total revenue losses associated with various oil and gas tax provisions presented in this memorandum are unlikely to be equal to the actual federal revenue losses, but are instead a best approximation given the data and resources available at the time of the estimate.

This memorandum relies on tax expenditure estimates provided by the Joint Committee on Taxation (JCT).[31] The tax expenditure estimates provided by the JCT are forecasted revenue losses. These revenue losses are not re-estimated on the basis of actual economic conditions. Thus, revenue losses presented in this memorandum indicate what was projected rather than the actual revenue losses incurred.

Individual tax expenditures cannot be simply summed to estimate the aggregate revenue loss from multiple tax provisions. This is because of interaction effects. When the revenue loss associated with a specific tax provision is estimated, the estimate is made assuming that there are no changes in other provisions or in taxpayer behavior. When individual tax expenditures are summed the former assumption is violated. Consequently, aggregate tax expenditure estimates, derived from summing the estimated revenue effects of individual tax expenditure provisions, are unlikely to reflect the actual change in federal receipts associated with removing various tax provisions.[32]

[29] The JCT does not provide tax expenditure estimates for the provision allowing oil and gas an exemption from passive loss limitations. The Treasury estimates reported in the President's Budget estimate that this provision generates revenue losses of approximately $20 million annually.

[30] See Treasury Green Book, p. 80.

[31] The Congressional Budget and Impoundment Act of 1974 (the Budget Act; P.L. 93-344) defines tax expenditures as "revenue losses attributable to provisions of the federal tax laws which allow a special exclusion, exemption, or deduction from gross income or which provide a special credit, a preferential rate of tax, or a deferral of tax liability." JCT is the official scorekeeper for Congressional budget purposes. The Treasury also provides a list of tax expenditures annually.

[32] See CRS Report RL33641, *Tax Expenditures: Trends and Critiques*, by Thomas L. Hungerford and 2010 Tax Expenditure Compendium.

The estimated revenue losses associated with a specific tax expenditure provision is not necessarily equivalent to the revenue estimate for the repeal of a provision. Tax expenditure revenue loss estimates are calculated as the difference between tax liability under current law and the tax liability that would result assuming a particular provision did not exist. Tax expenditure estimates do not account for potential changes in behavior. When the JCT and Treasury provide revenue estimates for the repeal of a provision, these estimates incorporate behavioral changes that are expected to result following the elimination of the provision.

Finally, there are a number of tax incentives that benefit the oil and gas industry, but are not specific to the industry. For example, the production activity deduction (Section 199) is a tax deduction available to all domestic manufacturers, including those in the oil and gas industry. JCT does not provide annual tax expenditure estimates by industry. Thus, the data available does not provide information on how much a broadly applied tax incentive benefits a specific industry. Some of the broadly applied tax incentives from which the oil and gas industry benefits are addressed at the end of this memorandum.

## Federal Revenue Loss Estimates

A 2000 Government Accountability Office (GAO) study summed the value of petroleum-related tax incentives through the year 2000.[33] **Table 1** summarizes the GAO's findings. Data on tax expenditures prior to 1968 are limited, as annual tax expenditures were not regularly provided by both the JCT and Treasury prior to this date. Thus, data on historical revenue losses does not extend back beyond 1968. For provisions enacted prior to 1968, such as the ability to claim the excess of percentage over cost depletion and to expense IDCs, the cumulative revenue losses in **Table 1** do not capture revenue losses over the lifetime of the provision.

**Table 1. Petroleum-Related Tax Incentives Through 2000**

billions of dollars

| Tax Incentive | Years Included | Revenue Loss in Constant Year 2000 Dollars |
|---|---|---|
| Excess of Percentage over Cost Depletion | 1968 - 2000 | $81.7 |
| Expensing of IDCs | 1968 - 2000 | 54.6 |
| Credit for Enhanced Oil Recovery Costs | 1994 - 2000 | 0.5 |
| Expensing of Tertiary Injectants | 1980 - 2000 | 0.3 |

**Source:** GAO

**Notes:** Revenue losses reported the sum of JCT's annual estimates, and were adjusted for inflation by GAO. The Treasury estimates that the value of the exemption from passive loss limits for oil and gas companies was worth $1.1 billion over the 1998 – 2000 time period. The JCT does not view the exemption from passive loss limits as a tax expenditure. Thus, it has not been included in this analysis.

**Table 2** presents historical revenue losses over the 2009 through 2010 period as well as projected future revenue losses through 2014. As was the case in the earlier time period referenced above, the percentage depletion allowance and ability to expense IDCs continues to make up the majority of oil and gas related federal revenue losses.

[33] U.S. General Accounting Office, *Petroleum and Ethanol Fuels: Tax Incentives and Related GAO Work*, GAO/RCED-00-301R, September 25, 2000, pp. 1-25, http://www.gao.gov/new.items/rc00301r.pdf.

**Table 2. Estimated Revenue Losses Associated with Oil and Gas Tax Preferences**

billions of dollars

| Tax Incentive | 2000-2009 (2009 Dollars) | 2010 | 2011 | 2012 | 2013 | 2014 | 2010-2014 |
|---|---|---|---|---|---|---|---|
| Excess of Percentage over Cost Depletion | 7.9 | 0.5 | 0.8 | 0.9 | 0.9 | 1.0 | 4.1 |
| Expensing of IDCs | 8.4 | 0.7 | 0.7 | 0.9 | 1.0 | 1.0 | 4.2 |
| Credit for Enhanced Oil Recovery Costs | 1.8 | -i- | -i- | | | | 0.1 |
| Reduced G&G Amortization Period | 0.2 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.6 |
| Election to Expense 50% of Refinery Costs | 0.9 | 0.7 | 0.8 | 0.7 | 0.6 | 0.2 | 2.7 |

**Source:** CRS calculations using annual JCT tax expenditure estimates.

**Notes:** Values are adjusted to 2009 dollars using the Office of Management and Budget (OMB)'s GDP price index. Years 2010 through 2014 are presented in current dollars. An -i- indicates positive revenue losses of less than $50 million dollars. Rows may not sum due to rounding. Oil and gas related tax expenditures with annual estimates of *de minimis* value (less than $50 million) are not presented in JCT's annual tax expenditure tables and thus not included. These include the expensing of tertiary injectants and the credit for production from marginal wells. The JCT does not classify exemptions to passive loss rules as a tax expenditure as the effects of the exemption are reflected in the value of related tax expenditures.

Cumulative revenue losses, combining the data from **Table 1** and **Table 2**, are presented in **Table 3**. Since 1968, the percentage depletion allowance has resulted in an estimated $111 billion in federal revenue loss. The ability to expense IDCs has resulted in an estimated $78 billion over the same time period. The majority of historical revenue losses associated with targeted tax incentives for oil and gas are attributable to these two provisions.

**Table 3. Cumulative Revenue Losses: 1968 - 2010**

billions of dollars

| Tax Incentive | Revenue Loss in Constant Year 2010 Dollars |
|---|---|
| Excess of Percentage over Cost Depletion | $111.0 |
| Expensing of IDCs | 77.7 |
| Credit for Enhanced Oil Recovery Costs | 2.4 |
| Expensing of Tertiary Injectants | 0.4 |
| Reduced G&G Amortization Period | 0.3 |
| Election to Expense 50% of Refinery Costs | 1.6 |

**Source:** CRS calculations using GAO and JCT data.

**Notes:** Values are adjusted to 2010 dollars using the Office of Management and Budget (OMB)'s GDP price index.

# Broad-Based Tax Incentives that Benefit Oil and Gas

There are numerous provisions in the tax code that a number of industries, including the oil and gas industry. Notable broad-based provisions that benefit the oil and gas industry are briefly addressed below.

## The Production Activity Deduction

The Section 199 production activities deduction provides a deduction for qualified production activities.[34] Eligible domestic manufacturers may qualify for a deduction of up to 9% of taxable income. Oil extraction is limited to a 6% deduction. The limitation for oil extraction was enacted as part of the American Jobs Creation Act of 2004 (P.L. 108-357). The JCT estimated that this provision would result in revenue losses of $9.4 billion in 2010 and $62.1 billion over the 2010 through 2014 budget window, across all eligible industries.

The President's FY2011 Budget proposed repealing the production activity deduction for oil and gas.[35] This provision would have raised an estimated $7.2 billion over the 2011 through 2015 budget window and $17.3 billion over the 2011 through 2020 budget window.

## Benefits for Dual-Capacity Taxpayers

Dual-capacity taxpayers are those that pay a foreign levy while receiving a specific economic benefit from the foreign country in return.[36] One example of a "specific economic benefit" may be an allowance to extract government-owned petroleum. While broadly, dual-capacity taxpayers are not allowed to claim foreign tax credits for payments associated with a specific economic benefit, the application of the rules in practice has allowed oil and gas companies to claim foreign tax credits for oil and gas royalty payments made to foreign countries.

The President's FY2011 Budget proposed to modify the foreign tax credits for dual-capacity taxpayers, limiting the ability of oil and gas companies to claim foreign tax credits for foreign levies paid above and beyond standard the foreign country's standard income tax.[37] This provision would have raised an estimated $3.4 billion over the 2011 through 2015 budget window and $8.5 billion over the 2011 through 2020 budget window.

## Last-In, First-Out Method for Inventory Accounting

Under the last-in, first-out (LIFO) method for inventory accounting, it is assumed that the last items that enter into inventory are the first items sold. When costs are rising, the LIFO method of inventory accounting results in a higher measure for cost of goods sold, thereby reducing taxable income. While the LIFO accounting method is not limited to oil and gas companies, evidence suggests that the oil and gas industry may benefit disproportionately.[38]

[34] See the 2010 Tax Expenditure Compendium, pp. 489-492.

[35] See Treasury Green Book, p. 83.

[36] U.S. Congress, Joint Committee on Taxation, *Present Law Energy-Related Tax Provisions and Proposed Modifications Contained in the President's Fiscal Year 2011 Budget*, committee print, 111th Cong., 2nd sess., April 14, 2010, pp. 85-87.

[37] See Treasury Green Book, pp. 49-50.

[38] U.S. Congress, Joint Committee on Taxation, *Present Law Energy-Related Tax Provisions and Proposed Modifications Contained in the President's Fiscal Year 2011 Budget*, committee print, 111th Cong., 2nd sess., April 14, 2010, pp. 78-80.

The President's FY2011 Budget proposed to disallow the use of LIFO inventory accounting.[39] This provision would have raised an estimated $22.9 billion over the 2011 through 2015 budget window and $59.1 billion over the 2011 through 2020 budget window.

## Exceptions for Publicly Traded Partnerships with Qualified Income from Energy-Related Activities

Natural resource activities, including oil and gas activities, may allow an entity to structure as a publicly traded partnership (PTP). Publicly traded partnership and partnership entities with pass-through tax treatment where partnership shares are traded on an established securities or secondary market.[40] While other entities are allowed to structure as PTPs, the majority of PTPs are in the energy sector.[41] The JCT estimates revenue losses of $2.8 billion over the 2010 through 2014 budget window associated with the exemption for energy-related PTPs.

[39] See Treasury Green Book, p. 37.

[40] See 2010 Tax Expenditure Compendium, pp. 111-113.

[41] The National Association of Publicly Traded Partnerships website provides additional background: http://www.naptp.org/.