

**OIL AND GAS TAX PROVISIONS: A CONSIDERATION
OF THE PRESIDENT'S FISCAL YEAR 2010
BUDGET PROPOSAL**

Scheduled for a Public Hearing
Before the
SUBCOMMITTEE ON ENERGY, NATURAL RESOURCES,
AND INFRASTRUCTURE
of the
SENATE COMMITTEE ON FINANCE
on September 10, 2009

Prepared by the Staff
of the
JOINT COMMITTEE ON TAXATION



September 9, 2009
JCX-34-09

CONTENTS

	<u>Page</u>
INTRODUCTION	1
I. OIL AND GAS PRODUCTION PROPOSALS.....	2
A. Levy Tax on Certain Offshore Oil and Gas Production	2
B. Repeal Existing Oil and Gas Preferences	6
II. PROVISIONS OF GENERAL APPLICATION	25
A. Repeal Last-In, First-Out Inventory Accounting Method.....	25
B. Modify the Tax Rules for Dual Capacity Taxpayers	30

INTRODUCTION

The Subcommittee on Energy, Natural Resources, and Infrastructure of the Senate Committee on Finance has scheduled a public hearing on September 10, 2009. This document,¹ prepared by the staff of the Joint Committee on Taxation, provides a description and analysis of the Administration's fiscal year 2010 revenue proposals affecting oil and gas production.

¹ This document may be cited as follows: Joint Committee on Taxation, *Oil and Gas Tax Provisions: A Consideration of the President's Fiscal Year 2010 Budget Proposal*, (JCX-34-09) September 9, 2009. This document can also be found on our website at www.jct.gov.

I. OIL AND GAS PRODUCTION PROPOSALS

A. Levy Tax on Certain Offshore Oil and Gas Production

Present Law

Under present law, there is no Federal severance tax on oil and gas produced on the Outer Continental Shelf (“OCS”). The Department of the Interior estimates reserves of OCS inventory at 8.5 billion barrels of oil and 29.3 trillion cubic feet of natural gas. Approximately another 86 billion barrels of oil and 420 trillion cubic feet of natural gas are classified as undiscovered resources.²

The United States leases Federal lands containing oil and gas deposits in offshore or submerged lands under the Outer Continental Shelf Lands Act of 1953, as amended.³ Revenues are returned to the Federal government in the form of bonus bids (discussed below), rents, and royalties. The offshore leasing program is administered by the Minerals Management Service (“MMS”) within the Department of the Interior. Figure 1 is a map of the OCS oil and gas leasing program.

² Department of Interior, *Report to the Secretary: Survey of Available Data of OCS Resources and Identification of Data Gaps* (2009) p. 5.

³ 43 U.S.C. sec. 1331 et seq.

Figure 1



Source: Minerals Management Service, U.S. Department of the Interior.

Leases are awarded to the highest bidder in a competitive, sealed bidding process. Successful bidders make an up-front cash payment, called a “bonus bid,” to secure a lease. In addition to the bonus bid, generally a royalty rate of 12.5 percent or 16.7 percent is imposed on the value of production, depending on location factors, or the royalty received in kind. The royalty rate could be higher than 16.7 percent depending on the lease sale. According to the Congressional Research Service, MMS officials have indicated that a royalty rate of 18.75 percent is likely for future lease sales.

The Outer Continental Shelf Deep Water Royalty Relief Act (the “DWRRA”) authorized MMS to provide royalty relief on oil and gas produced in the deep waters of the Gulf of Mexico from certain leases issued from 1996 through 2000. Royalty relief waives or reduces the amount of royalties that companies would otherwise be obligated to pay on the initial volumes of production from leases (“suspension volumes”).

In implementing the DWRRA for leases sold in 1996, 1997 and 2000, MMS specified that royalty relief would be applicable only if oil and gas prices were below certain prices thresholds. MMS did not include these price thresholds for leases issued in 1998 and 1999.

Kerr-McGee Corporation (“Kerr McGee,” now owned by Anadarko Petroleum Corporation) filed suit challenging the government’s authority to include price thresholds in DWRRA leases issued from 1996-2000. The district court for the Western District of Louisiana ruled in favor of Kerr-McGee. It held that the DWRRA suspended the payment of royalties on amounts severed up to certain specified production volume thresholds and the Department of the Interior could not collect royalties when the volume thresholds had not yet been met. Thus, because the statute specified that certain amounts are to be royalty free, the Department of Interior had no authority to collect royalties, regardless of whether the price threshold had been exceeded. On January 12, 2009, the Court of Appeals for the Fifth Circuit affirmed the district court’s ruling.⁴

With respect to the 1998 and 1999 leases (with no price thresholds), the Government Accountability Office (“GAO”) has estimated that the Federal government could lose royalties between \$4.3 billion and \$14.7 billion.⁵ In light of the Kerr-McGee ruling, with respect to the 1996, 1997, and 2000 leases, the GAO asserts that the Federal government may have to refund over \$1.13 billion in royalties already collected and forgo additional royalty revenues on future production from these leases. The GAO estimates additional forgone royalties between \$21 billion and \$53 billion.⁶

⁴ *Kerr-McGee Oil and Gas Corp. v. United States Department of Interior*, 554 F.3d 1082 (5th Cir. 2009).

⁵ Government Accountability Office, GAO 08-792R, *Oil and Gas: Litigation over Royalty Relief Could Cost the Federal Government Billions of Dollars* (June 5, 2008) p. 3.

⁶ *Ibid.* p. 4.

Description of Proposal

The Administration does not have a proposal at this time. The Administration is developing a proposal to impose an excise tax on certain oil and gas produced offshore in the future and indicates that the Administration will work with Congress to develop the details of this proposal.

Analysis

At this time, the Administration does not have a proposal to analyze.

B. Repeal Existing Oil and Gas Preferences

Present Law

In general

The Code provides a number of tax incentives that increase the after-tax return on investment in domestic oil and gas production projects. These incentives include the enhanced oil recovery credit, the marginal wells credit, the expensing of intangible drilling costs, the deduction for using tertiary injectants, the passive loss exemption for working interests in oil and gas properties, percentage depletion, the domestic manufacturing deduction for oil and gas production, and accelerated amortization for geological and geophysical expenses.

Some of these incentives are available to all domestic producers and all domestic production, while others target smaller producers or production that utilizes specific types of extractive technologies. Some of the incentives are not available (or are only partially available) to oil and gas producers whose production activities are integrated with refining and retail sales activities and one⁷ is further restricted in the case of major integrated oil companies.⁸

Credit for enhanced oil recovery costs (sec. 43)

Taxpayers may claim a credit equal to 15 percent of qualified enhanced oil recovery (“EOR”) costs.⁹ Qualified EOR costs consist of the following designated expenses associated with an EOR project: (1) amounts paid for depreciable tangible property; (2) intangible drilling and development expenses; (3) tertiary injectant expenses; and (4) construction costs for certain Alaskan natural gas treatment facilities. An EOR project is generally a project that involves increasing the amount of recoverable domestic crude oil through the use of one or more tertiary recovery methods (as defined in section 193(b)(3)), such as injecting steam or carbon dioxide into a well to effect oil displacement.

The EOR credit is ratably reduced over a \$6 phase-out range when the reference price for domestic crude oil exceeds \$28 per barrel (adjusted for inflation after 1991; \$42.01 per barrel for 2009). The reference price is determined based on the annual average price of domestic crude oil

⁷ See sec. 167(h) (relating to the amortization of geological and geophysical expenditures, discussed *infra*). Unless otherwise provided, all section references are to the Internal Revenue Code of 1986, as amended.

⁸ Integrated oil companies subject to these limitations are oil and gas producers that sell more than \$5 million of retail product per year or refine more than 75,000 barrels of oil per year. Major integrated oil companies are a subset of integrated oil companies that (1) have average daily worldwide production exceeding 500,000 barrels per year, (2) had gross receipts in excess of \$1 billion in 2005, and (3) own at least a 15 percent interest in a refinery that produces more than 75,000 barrels of oil per year.

⁹ Sec. 43.

for the calendar year preceding the calendar year in which the taxable year begins.¹⁰ The EOR credit is currently phased out.

Taxpayers claiming the EOR credit must reduce by the amount of the credit any otherwise allowable deductions associated with EOR costs. In addition, to the extent a property's basis would otherwise be increased by any EOR costs, such basis is reduced by the amount of the EOR credit.

Marginal well tax credit (sec. 45I)

The Code provides a \$3-per-barrel credit (adjusted for inflation) for the production of crude oil and a \$0.50-per-1,000-cubic-foot credit (also adjusted for inflation) for the production of qualified natural gas. In both cases, the credit is available only for domestic production from a "qualified marginal well."

A qualified marginal well is defined as a domestic well: (1) production from which is treated as marginal production for purposes of the Code percentage depletion rules; or (2) that during the taxable year had average daily production of not more than 25 barrel equivalents and produces water at a rate of not less than 95 percent of total well effluent. The maximum amount of production for a taxable year on which a credit may be claimed is 1,095 barrels or barrel equivalents.

The credit is not available if the reference price of oil exceeds \$18 (\$2.00 for natural gas). The credit is reduced proportionately for reference prices between \$15 and \$18 (\$1.67 and \$2.00 for natural gas). Currently the credit is phased out completely.

In the case of production from a qualified marginal well which is eligible for the credit allowed under section 45K for the taxable year, no marginal well credit is allowable unless the taxpayer elects not to claim the credit under section 45K with respect to the well. The section 45K credit is currently expired with respect to qualified natural gas and oil production. The credit is treated as a general business credit. Unused credits can be carried back for up to five years rather than the generally applicable carryback period of one year.

Expensing of intangible drilling costs (sec. 263(c))

The Code provides special rules for the treatment of intangible drilling and development costs ("IDCs"). Under these special rules, an operator or working interest owner¹¹ that pays or incurs IDCs in the development of an oil or gas property located in the United States may elect either to expense or capitalize those costs.¹²

¹⁰ Secs. 43(b) and 45K(d)(2)(C).

¹¹ An operator or working interest owner is defined as a person that holds an operating or working interest in any tract or parcel of land either as a fee owner or under a lease or any other form of contract granting operating or working rights.

¹² Sec. 263(c).

IDCs include all expenditures made by an operator for wages, fuel, repairs, hauling, supplies, etc., incident to and necessary for the drilling of wells and the preparation of wells for the production of oil and gas. In addition, IDCs include the cost to operators of any drilling or development work done by contractors under any form of contract, including a turnkey contract. Such work includes labor, fuel, repairs, hauling, and supplies which are used (1) in the drilling, shooting, and cleaning of wells; (2) in the clearing of ground, draining, road making, surveying, and geological works as necessary in preparation for the drilling of wells; and (3) in the construction of such derricks, tanks, pipelines, and other physical structures as are necessary for the drilling of wells and the preparation of wells for the production of oil and gas. Generally, IDCs do not include expenses for items that have a salvage value (such as pipes and casings) or items that are part of the acquisition price of an interest in the property.¹³ They also do not include (1) the cost to operators payable only out of production or gross or net proceeds from production, if the amounts are depletable income to the recipient, and (2) amounts properly allocable to the cost of depreciable property.

If an election to expense IDCs is made, the taxpayer deducts the amount of the IDCs as an expense in the taxable year the cost is paid or incurred. Generally, if IDCs are not expensed, but are capitalized, they may be recovered through depletion or depreciation, as appropriate. In the case of a nonproductive well (“dry hole”), IDCs may be deducted at the election of the operator.¹⁴ For an integrated oil company that has elected to expense IDCs, 30 percent of the IDCs on productive wells must be capitalized and amortized over a 60-month period.¹⁵

Notwithstanding the fact that a taxpayer has made the election to deduct IDCs, the Code provides an additional election under which the taxpayer is allowed to capitalize and amortize certain IDCs over a 60-month period beginning with the month the expenditure was paid or incurred.¹⁶ This election applies on an expenditure-by-expenditure basis; that is, for any particular taxable year, a taxpayer may deduct some portion of its IDCs and capitalize the rest under this provision. The election allows a taxpayer to reduce or eliminate the IDC adjustments or preferences under the alternative minimum tax (“AMT”).

The election to deduct IDCs applies only to those IDCs associated with domestic properties.¹⁷ For this purpose, the United States includes certain wells drilled offshore.¹⁸

¹³ Treas. Reg. sec. 1.612-4(a).

¹⁴ Treas. Reg. sec. 1.612-4(b)(4).

¹⁵ Sec. 291(b)(1)(A). The IRS has ruled that, if a company that has capitalized and begun to amortize IDCs over a 60-month period pursuant to section 291 ceases to be an integrated oil company, it may not immediately write off the unamortized portion of the capitalized IDCs, but instead must continue to amortize the IDCs so capitalized over the 60-month amortization period. Rev. Rul. 93-26, 1993-1 C.B. 50.

¹⁶ Sec. 59(e)(1).

¹⁷ In the case of IDCs paid or incurred with respect to an oil or gas well located outside of the United States, the costs, at the election of the taxpayer, are either (1) included in adjusted basis for purposes of computing

Pursuant to a special exception, the uniform capitalization rules do not apply to IDCs incurred with respect to oil or gas wells that are otherwise deductible under the Code.¹⁹

Deduction for qualified tertiary injectant expenses (sec. 193)

Taxpayers engaged in petroleum extraction activities may generally deduct qualified tertiary injectant expenses used while applying a tertiary recovery method, including carbon dioxide augmented waterflooding and immiscible carbon dioxide displacement.²⁰ The deduction is available even if such costs are otherwise subject to capitalization. The deduction is permitted for the later of—(1) the tax year in which the injectant is injected or (2) the tax year in which the expenses are paid or incurred.²¹ No deduction is permitted for expenditures for which a taxpayer has elected to deduct such costs under section 263(c) (intangible drilling costs) or if a deduction is allowed for such amounts under any other income tax provision.²²

A “qualified tertiary injectant expense” is defined as any cost paid or incurred for any tertiary injectant (other than a recoverable hydrocarbon injectant) which is used as part of a tertiary recovery method.²³ The cost of a recoverable hydrocarbon injectant (which includes natural gas, crude oil and any other injectant with more than an insignificant amount of natural gas or crude oil) is not a qualified tertiary injectant expense unless the amount of the recoverable hydrocarbon injectant in the qualified tertiary injectant is insignificant.²⁴

the amount of any deduction allowable for cost depletion or (2) capitalized and amortized ratably over a 10-year period beginning with the taxable year such costs were paid or incurred (sec. 263(i)).

¹⁸ The term “United States” for this purpose includes the seabed and subsoil of those submarine areas that are adjacent to the territorial waters of the United States and over which the United States has exclusive rights, in accordance with international law, with respect to the exploration and exploitation of natural resources (i.e., the Continental Shelf area) (sec. 638).

¹⁹ Sec. 263A(c)(3).

²⁰ Sec. 193. Prior to the enactment of section 193, the income tax treatment of tertiary injectant costs was unclear. In enacting section 193, Congress sought to clarify the tax treatment and encourage the use of qualified tertiary injectants. See e.g., Joint Committee on Taxation, *General Explanation of the Crude Oil Windfall Profit Tax Act of 1980* (JCS-1-81), at 114-115.

²¹ Treas. Reg. sec. 1.193-1.

²² Sec. 193(c).

²³ Sec. 193(b). A tertiary recovery method is any of the nine methods described in section 212.78(c)(1) - (9) of the June 1979 energy regulations, as defined in former section 4996(b)(8)(C), or any other method approved by the IRS.

²⁴ Sec. 193(b)(2). Treas. Reg. sec. 1.193-1(c)(3) provides that an injectant contains more than an insignificant amount of recoverable hydrocarbons if the fair market value of the recoverable hydrocarbon component of the injectant, in the form in which it is recovered, equals or exceeds 25 percent of the cost of the injectant.

Exception from passive loss rules for working interests in oil and gas property (sec. 469)

The passive loss rules limit deductions and credits from passive trade or business activities.²⁵ A passive activity for this purpose is a trade or business activity in which the taxpayer owns an interest, but in which the taxpayer does not materially participate. A taxpayer is treated as materially participating in an activity only if the taxpayer is involved in the operation of the activity on a basis that is regular, continuous, and substantial.²⁶ Deductions attributable to passive activities, to the extent they exceed income from passive activities, generally may not be deducted against other income. Deductions and credits that are suspended under these rules are carried forward and treated as deductions and credits from passive activities in the next year. The suspended losses from a passive activity are allowed in full when a taxpayer disposes of his entire interest in the passive activity to an unrelated person.

Losses from certain working interests in oil and gas property are not limited under the passive loss rule.²⁷ Thus, losses and credits from such interests can be used to offset other income of the taxpayer without limitation under the passive loss rule. Specifically, a passive activity does not include a working interest in any oil or gas property that the taxpayer holds directly or through an entity that does not limit the liability of the taxpayer with respect to the interest. This rule applies without regard to whether the taxpayer materially participates in the activity. If the taxpayer has a loss from a working interest in any oil or gas property that is treated as not from a passive activity, then net income from the property for any succeeding taxable year is treated as income of the taxpayer that is not from a passive activity.

In general, a working interest is an interest with respect to an oil and gas property that is burdened with the cost of development and operation of the property. Rights to overriding royalties, production payments, and the like, do not constitute working interests, because they are not burdened with the responsibility to share expenses of drilling, completing, or operating oil and gas property. Similarly, contract rights to extract or share in oil and gas, or in profits from extraction, without liability to share in the costs of production, do not constitute working interests. Income from such interests generally is considered to be portfolio income.

When the taxpayer's form of ownership limits the liability of the taxpayer, the interest possessed by such taxpayer is not a working interest for purposes of the passive loss provision. Thus, for purposes of the passive loss rules, an interest owned by a limited partnership is not treated as a working interest with regard to any limited partner, and an interest owned by an S corporation is not treated as a working interest with regard to any shareholder. The same result follows with respect to any form of ownership that is substantially equivalent in its effect on liability to a limited partnership interest or interest in an S corporation, even if different in form.

²⁵ Sec. 469. These rules were enacted in 1986 to curtail tax shelters. They apply to individuals, estates and trusts, and closely held corporations.

²⁶ Regulations provide more detailed standards for material participation. See Treas. Reg. secs. 1.469-5 and -5T.

²⁷ Sec. 469(c)(3). See also Treas. Reg. sec. 1.469-1T(e)(4).

When an interest is not treated as a working interest because the taxpayer's form of ownership limits his liability, the general rules regarding material participation apply to determine whether the interest is treated as a passive activity. Thus, for example, a limited partner's interest generally is treated as in a passive activity. In the case of a shareholder in an S corporation, the general facts and circumstances test for material participation applies and the working interest exception does not apply, because the form of ownership limits the taxpayer's liability.

A special rule applies in any case where, for a prior taxable year, net losses from a working interest in a property were treated by the taxpayer as not from a passive activity. In such a case, any net income realized by the taxpayer from the property (or from any substituted basis property, e.g., property acquired in a sec. 1031 like kind exchange for such property) in a subsequent year also is treated as active. Under this rule, for example, if a taxpayer claims losses for a year with regard to a working interest and then, after the property to which the interest relates begins to generate net income, transfers the interest to an S corporation in which he is a shareholder, or to a partnership in which he has an interest as a limited partner, his interest with regard to the property continues to be treated as not passive.

Percentage depletion for oil and natural gas (secs. 613 and 613A)

In general

Depletion, like depreciation, is a form of capital cost recovery. In both cases, the taxpayer is allowed a deduction in recognition of the fact that an asset is being expended to produce income.²⁸ Certain costs incurred prior to drilling an oil or gas property or extracting minerals are recovered through the depletion deduction. These include the cost of acquiring the lease or other interest in the property.

Depletion is available to any person having an economic interest in a producing property. An economic interest is possessed in every case in which the taxpayer has acquired by investment any interest in minerals in place, and secures, by any form of legal relationship, income derived from the extraction of the mineral, to which it must look for a return of its capital. Thus, for example, both working interests and royalty interests in an oil- or gas-producing property constitute economic interests, thereby qualifying the interest holders for depletion deductions with respect to the property. A taxpayer who has no capital investment in the mineral deposit, however, does not acquire an economic interest merely by possessing an economic or pecuniary advantage derived from production through a contractual relation.

Two methods of depletion are currently allowable under the Code: (1) the cost depletion method, and (2) the percentage depletion method.²⁹ Under the cost depletion method, the

²⁸ In the context of mineral extraction, depreciable assets are generally used to recover depletable assets. For example, natural gas gathering lines, used to collect and deliver natural gas, have a class life of 14 years and a depreciation recovery period of seven years.

²⁹ Secs. 611- 613A.

taxpayer deducts that portion of the adjusted basis of the depletable property which is equal to the ratio of units sold from that property during the taxable year to the number of units remaining as of the end of taxable year plus the number of units sold during the taxable year. Thus, the amount recovered under cost depletion may never exceed the taxpayer's basis in the property.

A taxpayer is required to determine the depletion deduction for each property under both the percentage depletion method (if the taxpayer is entitled to use this method) and the cost depletion method. The taxpayer must use whichever method produces the larger deduction for any taxable year.³⁰

In the case of domestic oil and gas wells, independent producers and royalty owners generally are allowed a deduction under the percentage depletion method of 15 percent of the gross income from the property. The deduction may not exceed the net income from the oil and gas property in any year (the "net-income limitation").³¹ Additionally, the percentage depletion deduction for all oil and gas properties may not exceed 65 percent of the taxpayer's overall taxable income for the year (determined before such deduction and adjusted for certain loss carrybacks and trust distributions).³²

Percentage depletion for eligible taxpayers is allowed for up to 1,000 barrels of average daily production of domestic crude oil or an equivalent amount of domestic natural gas.³³ For producers of both oil and natural gas, this limitation applies on a combined basis. All production owned by businesses under common control and members of the same family must be aggregated,³⁴ each group is then treated as one producer in applying the 1,000-barrel limitation.

Because percentage depletion, unlike cost depletion, is computed without regard to the taxpayer's basis in the depletable property, cumulative depletion deductions for any property may be greater than the amount expended by the taxpayer to acquire and develop the property.³⁵

³⁰ Sec. 613(a).

³¹ Sec. 613(a). For marginal production, discussed *infra*, this limitation is suspended for taxable years beginning in 2009.

³² Sec. 613A(d)(1).

³³ Sec. 613A(c).

³⁴ Sec. 613A(c)(8).

³⁵ In the case of iron ore and coal (including lignite), a corporate preference reduces the amount of percentage depletion calculated by 20 percent of the amount of percentage depletion in excess of the adjusted basis of the property at the close of the taxable year (determined without regard to the depletion deduction for the taxable year). Sec. 291(a)(2).

Limitation on oil and gas percentage depletion to independent producers and royalty owners

As stated above, percentage depletion of oil and gas properties generally is not permitted to persons other than independent producers and royalty owners. For purposes of the percentage depletion allowance, an independent producer is any producer that is not a “retailer” or “refiner.” A retailer is any person that directly, or through a related person, sells oil or natural gas (or a derivative thereof): (1) through any retail outlet operated by the taxpayer or related person, or (2) to any person that is obligated to market or distribute such oil or natural gas (or a derivative thereof) under the name of the taxpayer or the related person, or that has the authority to occupy any retail outlet owned by the taxpayer or a related person.³⁶

Bulk sales of crude oil and natural gas to commercial or industrial users, and bulk sales of aviation fuel to the Department of Defense, are not treated as retail sales. Further, if the combined gross receipts of the taxpayer and all related persons from the retail sale of oil, natural gas, or any product derived therefrom do not exceed \$5 million for the taxable year, the taxpayer will not be treated as a retailer.

A refiner is any person that directly or through a related person engages in the refining of crude oil in excess of an average daily refinery run of 75,000 barrels during the taxable year.³⁷

Percentage depletion for eligible taxpayers is allowed for up to 1,000 barrels of average daily production of domestic crude oil or an equivalent amount of domestic natural gas.³⁸ For producers of both oil and natural gas, this limitation applies on a combined basis. All production owned by businesses under common control and members of the same family must be aggregated,³⁹ each group is then treated as one producer in applying the 1,000-barrel limitation.

Percentage depletion on marginal production

In the case of oil and gas production from so-called marginal properties held by independent producers or royalty owners,⁴⁰ the statutory percentage depletion rate is increased (from the general rate of 15 percent) by one percent for each whole dollar that the average price of crude oil for the immediately preceding calendar year is less than \$20 per barrel. In no event may the rate of percentage depletion under this provision exceed 25 percent for any taxable year. The increased rate applies for the taxpayer’s taxable year that immediately follows a calendar year for which the average crude oil price falls below the \$20 floor. Because the price of oil

³⁶ Sec. 613A(d)(2).

³⁷ Sec. 613A(d)(4).

³⁸ Sec. 613A(c).

³⁹ Sec. 613A(c)(8).

⁴⁰ Sec. 613A(c)(6).

currently is above the \$20 floor, there is no increase in the statutory depletion rate for marginal production.

The Code defines the term “marginal production” for this purpose as domestic crude oil or domestic natural gas which is produced during any taxable year from a property which (1) is a stripper well property for the calendar year in which the taxable year begins, or (2) is a property substantially all of the production from which during such calendar year is heavy oil (i.e., oil that has a weighted average gravity of 20 degrees API or less, corrected to 60 degrees Fahrenheit).⁴¹ A stripper well property is any oil or gas property that produces a daily average of 15 or fewer equivalent barrels of oil and gas per producing oil or gas well on such property in the calendar year during which the taxpayer’s taxable year begins.⁴²

The determination of whether a property qualifies as a stripper well property is made separately for each calendar year. The fact that a property is or is not a stripper well property for one year does not affect the determination of the status of that property for a subsequent year. Further, a taxpayer makes the stripper well property determination for each separate property interest (as defined under section 614) held by the taxpayer during a calendar year. The determination is based on the total amount of production from all producing wells that are treated as part of the same property interest of the taxpayer. A property qualifies as a stripper well property for a calendar year only if the wells on such property were producing during that period at their maximum efficient rate of flow.

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

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

Deduction for income attributable to domestic production of oil and gas (sec. 199)

Section 199 of the Code provides a deduction from taxable income (or, in the case of an individual, adjusted gross income) that is equal to a portion of the lesser of a taxpayer’s taxable

⁴¹ Sec. 613A(c)(6)(D).

⁴² Sec. 613A(c)(6)(E).

income or its qualified production activities income.⁴³ For taxable years beginning after 2009, the deduction is nine percent of such income. For taxable years beginning in 2005 and 2006, the deduction was three percent and, for taxable years beginning in 2007, 2008 and 2009, the deduction is six percent. With respect to a taxpayer that has oil related qualified production activities income for taxable years beginning after 2009, the deduction is limited to six percent of the least of its oil related production activities income, its qualified production activities income, or its taxable income.⁴⁴

A taxpayer's deduction under section 199 for a taxable year may not exceed 50 percent of the wages properly allocable to domestic production gross receipts paid by the taxpayer during the calendar year that ends in such taxable year.⁴⁵

Qualified production activities income

In general, "qualified production activities income" is equal to domestic production gross receipts (defined by section 199(c)(4)), reduced by the sum of: (1) the costs of goods sold that are allocable to such receipts; (2) other expenses, losses, or deductions which are properly allocable to such receipts.

Domestic production gross receipts

"Domestic production gross receipts" generally are gross receipts of a taxpayer that are derived from: (1) any sale, exchange or other disposition, or any lease, rental or license, of

⁴³ In the case of an individual, the deduction is equal to a portion of the lesser of the taxpayer's adjusted gross income or its qualified production activities income. For this purposes, adjusted gross income is determined after application of sections 86, 135, 137, 219, 221, 222, and 469, and without regard to the section 199 deduction.

⁴⁴ "Oil related qualified production activities income" means the qualified production activities income attributable to the production, refining, processing, transportation, or distribution of oil, gas or any primary product thereof (as defined in section 927(a)(2)(C) prior to its repeal). Treas. Reg. sec. 1.927(a)-1T(g)(2)(i) defines the term "primary product from oil" to mean crude oil and all products derived from the destructive distillation of crude oil, including volatile products, light oils such as motor fuel and kerosene, distillates such as naphtha, lubricating oils, greases and waxes, and residues such as fuel oil. Additionally, a product or commodity derived from shale oil which would be a primary product from oil if derived from crude oil is considered a primary product from oil. Treas. Reg. sec. 1.927(a)-1T(g)(2)(ii) defines the term "primary product from gas" as all gas and associated hydrocarbon components from gas wells or oil wells, whether recovered at the lease or upon further processing, including natural gas, condensates, liquefied petroleum gases such as ethane, propane, and butane, and liquid products such as natural gasoline. Treas. Reg. sec. 1.927(a)-1T(g)(2)(iii) provides that these primary products and processes are not intended to represent either the only primary products from oil or gas or the only processes from which primary products may be derived under existing and future technologies. Treas. Reg. sec. 1.927(a)-1T(g)(2)(iv) provides as examples of non-primary oil and gas products petrochemicals, medicinal products, insecticides, and alcohols.

⁴⁵ For purposes of the provision, "wages" include the sum of the amounts of wages as defined in section 3401(a) and elective deferrals that the taxpayer properly reports to the Social Security Administration with respect to the employment of employees of the taxpayer during the calendar year ending during the taxpayer's taxable year. Elective deferrals include elective deferrals as defined in section 402(g)(3), amounts deferred under section 457, and, for taxable years beginning after December 31, 2005, designated Roth contributions (as defined in section 402A).

qualifying production property (“QPP”) that was manufactured, produced, grown or extracted (“MPGE”) by the taxpayer in whole or in significant part within the United States;⁴⁶ (2) any sale, exchange or other disposition, or any lease, rental or license, of qualified film produced by the taxpayer; (3) any sale, exchange or other disposition of electricity, natural gas, or potable water produced by the taxpayer in the United States; (4) construction activities performed in the United States;⁴⁷ or (5) engineering or architectural services performed in the United States with respect to the construction of real property in the United States.

Drilling oil or gas wells

The Treasury regulations provide that qualifying construction activities performed in the United States include activities relating to drilling an oil or gas well.⁴⁸ Under the regulations, activities the cost of which are intangible drilling and development costs within the meaning of Treas. Reg. sec. 1.612-4 are considered to be activities constituting construction for purposes of determining domestic production gross receipts.⁴⁹

Qualifying in-kind partnerships

In general, an owner of a pass-through entity is not treated as conducting the qualified production activities of the pass-thru entity, and vice versa. However, the Treasury regulations provide a special rule for “qualifying in-kind partnerships,” which are defined as partnerships engaged solely in the extraction, refining, or processing of oil, natural gas, petrochemicals, or products derived from oil, natural gas, or petrochemicals in whole or in significant part within the United States, or the production or generation of electricity in the United States.⁵⁰ In the case of a qualifying in-kind partnership, each partner is treated as having MPGE the property MPGE or produced by the partnership that is distributed to that partner.⁵¹ If a partner of a qualifying in-kind partnership derives gross receipts from the lease, rental, license, sale, exchange, or other disposition of the property that was MPGE by the qualifying in-kind partnership, then, provided such partner is a partner of the qualifying in-kind partnership at the time the partner disposes of

⁴⁶ Domestic production gross receipts include gross receipts of a taxpayer derived from any sale, exchange or other disposition of agricultural products with respect to which the taxpayer performs storage, handling or other processing activities (other than transportation activities) within the United States, provided such products are consumed in connection with, or incorporated into, the manufacturing, production, growth or extraction of qualifying production property (whether or not by the taxpayer).

⁴⁷ For this purpose, construction activities include activities that are directly related to the erection or substantial renovation of residential and commercial buildings and infrastructure. Substantial renovation would include structural improvements, but not mere cosmetic changes, such as painting, that is not performed in connection with activities that otherwise constitute substantial renovation.

⁴⁸ Treas. Reg. sec. 1.199-3(m)(1)(i).

⁴⁹ Treas. Reg. sec. 1.199-3(m)(2)(iii).

⁵⁰ Treas. Reg. sec. 1.199-9(i)(2).

⁵¹ Treas. Reg. sec. 1.199-9(i)(1).

the property, the partner is treated as conducting the MPGE activities previously conducted by the qualifying in-kind partnership with respect to that property.⁵²

Alternative minimum tax

The deduction for domestic production activities is allowed for purposes of computing AMTI (including adjusted current earnings). The deduction in computing AMTI is determined by reference to the lesser of the qualified production activities income (as determined for the regular tax) or the AMTI (in the case of an individual, adjusted gross income as determined for the regular tax) without regard to this deduction.

Amortization period for geological and geophysical costs (sec. 167(h))

Geological and geophysical expenditures (“G&G costs”) are costs incurred by a taxpayer for the purpose of obtaining and accumulating data that will serve as the basis for the acquisition and retention of mineral properties by taxpayers exploring for minerals.⁵³ G&G costs incurred by independent producers and smaller integrated oil companies in connection with oil and gas exploration in the United States may generally be amortized over two years.⁵⁴

Major integrated oil companies are required to amortize all G&G costs over seven years for costs paid or incurred after December 19, 2007 (the date of enactment of the Energy Independence and Security Act of 2007).⁵⁵ A major integrated oil company, as defined in section 167(h)(5)(B), is an integrated oil company⁵⁶ which has an average daily worldwide production of crude oil of at least 500,000 barrels for the taxable year, had gross receipts in excess of one billion dollars for its last taxable year ending during the calendar year 2005, and generally has an ownership interest in a crude oil refiner of 15 percent or more.

In the case of abandoned property, remaining basis may not be recovered in the year of abandonment of a property, but instead must continue to be amortized over the remaining applicable amortization period.

⁵² *Ibid.*

⁵³ Geological and geophysical costs include expenditures for geologists, seismic surveys, gravity meter surveys, and magnetic surveys.

⁵⁴ This amortization rule applies to G&G costs incurred in taxable years beginning after August 8, 2005, the date of enactment of the Energy Policy Act of 2005, Pub. L. No. 109-58. Prior to the effective date, G&G costs associated with productive properties were generally deductible over the life of such properties, and G&G costs associated with abandoned properties were generally deductible in the year of abandonment.

⁵⁵ Pub. L. No. 110-140. Prior to the enactment of the Energy Independence and Security Act of 2007, major integrated oil companies were required to amortize G&G costs paid or incurred after May 17, 2006 over five years, as provided in Energy Tax Incentives Act of 2005.

⁵⁶ Generally, an integrated oil company is a producer of crude oil that engages in the refining or retail sale of petroleum products in excess of certain threshold amounts.

Description of Proposal

The proposal repeals (1) the enhanced oil recovery credit, (2) the marginal wells credit, (3) the expensing of IDCs, (4) the deduction for tertiary injectants,⁵⁷ (5) the exception for passive losses from working interests in oil and gas properties, (6) percentage depletion for oil and gas, and (7) the domestic manufacturing deduction for income derived from the domestic production of oil, gas, or primary products thereof. With respect to IDCs, in lieu of expensing, the proposal requires that such costs be capitalized and recovered through depletion or depreciation as applicable.

The proposal also increases the amortization period for G&G costs of independent producers from two to seven years. The seven-year amortization period would apply even if the property is abandoned such that any remaining unrecovered basis of the abandoned property would continue to be recovered over the remainder of the seven-year period.

Effective Date

The repeal of the enhanced oil recovery credit, the marginal wells credit, the exception for passive losses from working interests in oil and gas properties, percentage depletion for oil and gas, and the domestic manufacturing deduction for oil production is effective for taxable years beginning after December 31, 2010. The capitalization of IDCs, the repeal of the deduction for tertiary injectant costs, and the increased amortization period for G&G expenses are effective for amounts paid or incurred after December 31, 2010.

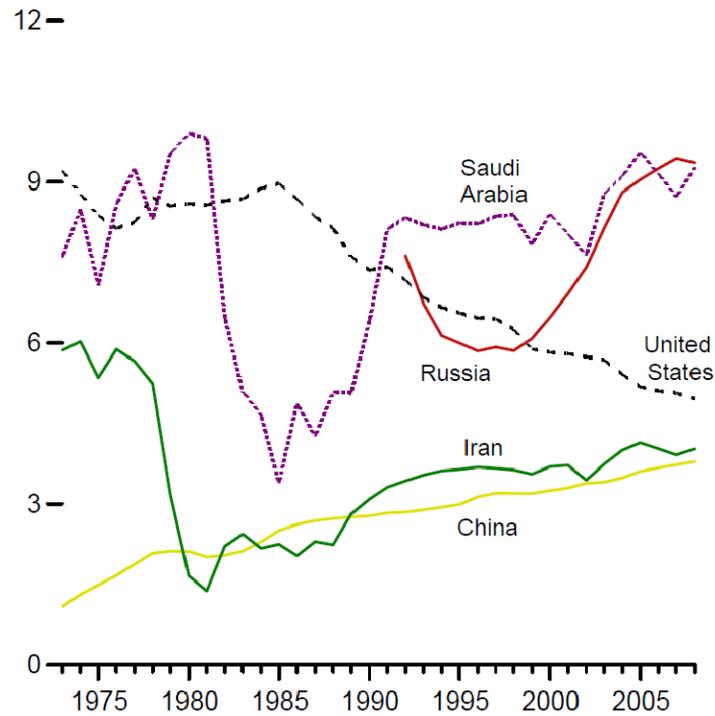
Analysis

Overview of domestic oil and gas production

Although domestic oil production has declined steadily since the mid-1980s, the United States remains one of the largest oil producers in the world.

⁵⁷ If section 193 were repealed, the treatment of tertiary injectant expenses would revert to prior law and might include capitalization and recovery through depreciation, capitalization and recovery as consumed (e.g., as a supply), or deduction as loss in the year of abandonment or the year production benefits ceased. Amounts expensed as depreciation, depletion, or supplies may be subject to capitalization under section 263A. See e.g., Treas. Reg. sec. 1.263A-1(e)(3).

**Figure 2.—Crude Oil Production in Selected Countries
(millions of barrels per day)**



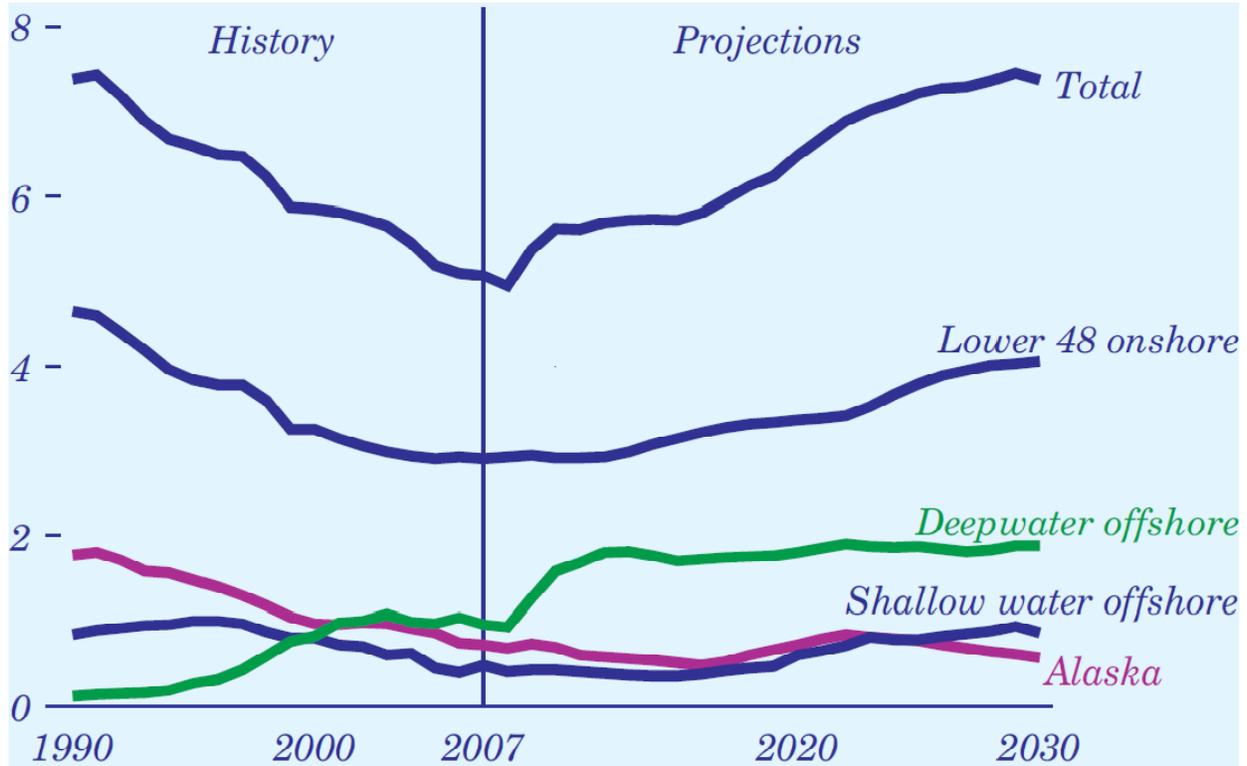
Source: Energy Information Administration, Monthly Energy Review, May 2009, Table 11.1a

Despite declining output in recent decades, domestic oil production is predicted to increase over the next twenty years, with most of the near-term increase resulting from deepwater offshore drilling.⁵⁸ Domestic onshore crude oil production is also projected to increase, primarily as the result of increased application of carbon dioxide-enhanced oil recovery techniques and the startup of liquids production from oil shale.⁵⁹

⁵⁸ Energy Information Administration, *Annual Energy Outlook 2009*, March 2009, p. 79.

⁵⁹ *Ibid.*

Figure 3.—Projected Domestic Crude Oil Production by Source, 1990-2030
(millions of barrels per day)



Source: Energy Information Administration, Annual Energy Outlook 2009, March 2009, Figure 70, p. 79.

Because the remaining domestic oil reserves generally require more costly secondary or tertiary recovery techniques, domestic crude oil production is highly sensitive to world crude oil prices.⁶⁰

Domestic production of natural gas is also expected to increase, with most of the increase attributable to onshore unconventional production (such as natural gas produced from tight sand and shale formations).⁶¹ For 2008, the oil and gas extraction sector employed a seasonally adjusted average of 161,600 workers.⁶²

History of specific provisions

The tax rules governing oil and gas production have undergone numerous changes over the past half century. The following table lists some of the major changes.

⁶⁰ *Ibid.*

⁶¹ *Ibid.* p. 77.

⁶² Bureau of Labor Statistics, *Monthly Labor Review*, vol. 132, no. 5, May 2009, Table 12, p. 87.

Chronology of Major Post-1954 Tax Law Changes Affecting Oil and Gas Production Activities

Year	Act	Code Section	Description of Modification
1969	Tax Reform Act of 1969 (Pub. L. No. 91-172)	613(b)	Percentage depletion rates for oil and gas wells decreased from 27.5 percent to 15 percent.
1975	Tax Reduction Act of 1975 (Pub. L. No. 94-12)	613A	Percentage depletion eliminated for integrated oil and gas companies; taxable income limitation to independent producers and royalty owners claiming percentage depletion added to the Code.
1980	Crude Oil Windfall Profit Tax Act of 1980 (Pub. L. No. 96-223)	193	Deduction for qualified tertiary injectant expenses added to the Code.
1982	Tax Equity and Fiscal Responsibility Act of 1982 (Pub. L. No. 97-248)	291(b)	Provision requiring amortization over 36 months of 15 percent of intangible drilling costs (IDCs) not currently deductible by integrated oil and gas companies added to the Code.
1984	Deficit Reduction Act of 1984 (Pub. L. No. 98-369)	291(b)	IDC capitalization percentage increased from 15 percent to 20 percent.
1986	Tax Reform Act of 1986 (Pub. L. No. 99-514)	291(b)	IDC capitalization percentage increased to 30 percent and extended the amortization period to 60 months.
		469(c)(3)	Provision excluding working interests in oil and gas property from the definition of a passive activity for purposes of the limitation on passive activity losses added to the Code.
1990	Omnibus Budget Reconciliation Act of 1990 (Pub. L. No. 101-508)	43	Enhanced oil recovery credit added to the Code.
		613	Maximum percentage depletion allowance for oil and gas properties increased from 50 percent to 100 percent of income from the property.
1997	Taxpayer Relief Act of 1997 (Pub. L. No. 105-34)	613A	Temporary suspension of taxable income limit for marginal production. ⁶³
2004	American Jobs Creation Act of 2004 (Pub. L. No. 108-357)	45I	Marginal wells credit added to the Code.
		199	Deduction for domestic production activities (including domestic oil and gas production) added to the Code.

⁶³ This temporary suspension has been extended multiple times, most recently in the Energy Improvement and Extension Act of 2008 (Pub. L. No. 110-343) through December 31, 2009.

Chronology of Major Post-1954 Tax Law Changes Affecting Oil and Gas Production Activities

Year	Act	Code Section	Description of Modification
2005	Energy Policy Act of 2005 (Pub. L. No. 109-58)	167(h)	Two-year amortization of geological and geophysical (G&G) costs added to the Code. Prior to this, G&G costs incurred with respect to abandoned sites could be expensed, while G&G costs associated with producing wells had to be recovered over the life of the well.
2006	Tax Increase Prevention and Reconciliation Act of 2005 (Pub. L. No. 109-222)	167(h)	Two-year amortization period of G&G costs extended to five years for major integrated oil companies.
2007	Energy Independence and Security Act of 2007 (Pub. L. No. 110-140)	167(h)	Five-year amortization period of G&G costs extended to seven years for major integrated oil companies.
2008	Energy Improvement and Extension Act of 2008 (Pub. L. No. 110-343)	199	Section 199 deduction percentage for oil-related qualified production activities capped at six percent for taxable years beginning after 2009.
		907	Distinction between foreign oil and gas extraction income (FOGEI) and foreign oil-related income (FORI) eliminated; FOGEI rules applied to all foreign oil and gas income.

As the table makes apparent, Congressional action with respect to domestic oil and gas production incentives has varied over time. With some exceptions, during the 1970s and 1980s, the trend of Congressional action was to reduce or limit the tax benefits available to oil and gas producers. During the 1990s and the early part of this decade, the trend reversed direction and favored expanded incentives. More recently, Congress has begun reducing incentives once again. In the broadest sense, these trends tend to coincide with periods of high and low oil prices.

Effect of repealing oil and gas production incentives

A common rationale for favorable tax treatment of certain activities (tax credits or other forms of subsidy), or unfavorable treatment (taxes), is that there exist externalities in the consumption or production of certain goods. An externality exists when, in the consumption or production of a good, there is a difference between the cost or benefit to an individual and the cost or benefit to society as a whole. When the social costs of consumption or production exceed the private costs of consumption or production, a negative externality exists. When the social benefits from consumption or production exceed private benefits, a positive externality exists. When negative externalities exist, there will be over-consumption of the good causing the negative externality relative to what would be socially optimal. When positive externalities exist, there will be under-consumption or under-production of the good producing the positive externality. The reason for the over-consumption or under-consumption is that private actors will in general not take into account the effect of their consumption on others, but only weigh their personal cost and benefits in their decisions. Thus, they will consume goods up to the point where their marginal benefit of more consumption is equal to the marginal cost that they face.

But from a social perspective, consumption should occur up to the point where the marginal social cost is equal to the marginal social benefit. Only when there are no externalities will the private actions lead to the socially optimal level of consumption or production, because in this case private costs and benefits will be equal to social costs and benefits.

Pollution is an example of a negative externality, because the costs of pollution are borne by society as a whole rather than solely by the polluters themselves. In the case of pollution, one intervention that could produce a more socially desirable level of pollution would be to set a tax on the polluting activity that is equal to the social cost of the pollution. Thus, if burning a gallon of gasoline results in pollution that represents a cost to society as a whole of 20 cents, it would be economically efficient to tax gasoline at 20 cents a gallon. By so doing, the externality is said to be internalized, because now the private polluter faces a private cost equal to the social cost, and the socially optimal amount of consumption will take place. In the case of a positive externality, an appropriate economic policy would be to impose a negative tax (i.e. a credit) on the consumption or production that produces the positive externality. By the same logic as above, the externality becomes internalized, and the private benefits from consumption become equal to the social benefits, leading to the socially optimal level of consumption or production. The favorable tax treatment accorded the oil and gas industry represent other, less direct, means of subsidizing an activity through the tax code by reducing the tax burden on capital employed in the sector, thus encouraging more capital to be employed in that sector of the economy.

Many observers today would agree that there are negative externalities to the consumption of fossil fuels, including both pollution and increased dependence on foreign sources of oil. For this reason, many feel that fossil fuels should be taxed heavily rather than granted certain favorable treatment in the Code. Repealing incentives for oil and gas production would increase the after-tax costs associated with these activities, reduce the amount of capital employed in these activities in the long run, and potentially increase the prices of oil and gas. To the extent that oil and gas prices rise, there could be substitution from oil and gas and into other energy sources, including coal, nuclear, or renewable sources of energy. The impact on pollution of any such substitution is unclear and would depend on the type and quantity of pollution associated with the alternative energy resource. To the extent that addressing pollution concerns was a major objective, economic theory would suggest the need for a tax on the externality from the consumption of oil and gas that equaled the social harm from the consumption. Simply removing selected subsidies related to the production of oil and gas does not address the issue of establishing proper prices on the consumption of goods that cause pollution.

If the proposals cause substitution into alternative sources of energy, reliance on foreign sources of oil and gas could be reduced because nuclear and renewable energy sources are domestically produced, and the United States has an abundance of domestic coal resources. Alternatively, to the extent that the proposals primarily affect domestic production of oil and gas, it is possible that any substitution into these alternate energy sources reflects a substitution from domestic production of oil and gas into domestic production of these alternate sources, thus leaving the United States' reliance on foreign oil and gas unchanged. Furthermore, as the proposals are likely to have no effect on the world price of oil and gas, any increase in prices for domestically consumed oil and gas is likely to be attenuated, and the proposals could primarily result in substitution of foreign oil and gas sources for domestic sources whose production is more reliant on the subsidies provided in current law. Such an outcome would further imply that

the proposals would not lead to any shift into the alternate energy sources of coal, nuclear, or renewables. Lastly, other observers have argued that current prices and expected future demand for oil and gas provide sufficient market-based incentives for domestic exploration and production, and have argued that the present law subsidies are unnecessary to secure a viable domestic oil and gas production industry.

Additional motivations may also support specific proposed changes. For example, with respect to tertiary injectants opponents of repeal have also argued that the deduction for tertiary injectants encourages the use of carbon dioxide in enhanced oil recovery projects. Such projects represent a primary method of carbon sequestration, which reduces greenhouse gas emissions by capturing and storing carbon dioxide that would otherwise be released into the atmosphere.⁶⁴ Proponents of the proposal might argue that encouraging carbon dioxide sequestration is better handled through incentives directly targeting carbon sequestration.

Another example is the exception to the passive loss rules for working interests in oil and gas properties, which in addition to providing an incentive to produce oil and gas, creates the potential to shelter income that would otherwise be taxable. It could be argued that tax sheltering has become an increasing problem in the Federal tax system as some of the base-broadening and rate-lowering changes made by the Tax Reform Act of 1986 have been reversed or modified by subsequent legislation. From a tax policy perspective (rather than an energy policy perspective), some might argue that the perception of fairness in the tax system, as well as the need for improved horizontal equity among individual taxpayers, support repeal of the special tax benefits for oil and gas working interests.

Those in favor of retaining incentives for domestic production might argue that a healthy domestic oil and gas production base serves national security goals, by reducing our dependence on foreign sources of oil. However, it can be argued that such reliance is more effectively addressed through a direct tax on imported oil or an import fee, which could encourage less consumption and promote the use of lower emission, renewable energy alternatives. Others might argue that in the current economic environment, eliminating the incentives might adversely affect employment in domestic oil and gas production. Furthermore, the deduction for domestic production activities is a broadly available incentive for all domestic production industries, and thus does not bias investment in favor of the oil and gas sector. Repealing the deduction for the oil and gas sector alone would bias investment away from this sector.

Finally, it could be argued that some of the President's oil and gas proposals might reintroduce administrative complexity currently absent under present law, such as in the case of the repeal of the deduction for tertiary injectants.

⁶⁴ See also, sec. 45Q, which provides a credit for certain qualified tertiary injectant projects that use carbon sequestration.

II. PROVISIONS OF GENERAL APPLICATION

A. Repeal Last-In, First-Out Inventory Accounting Method

Present Law

In general

In general, for Federal income tax purposes, taxpayers must account for inventories if the production, purchase, or sale of merchandise is a material income-producing factor to the taxpayer.⁶⁵

Under the last-in, first-out (“LIFO”) method, it is assumed that the last items entered into the inventory are the first items sold. Because the most recently acquired or produced units are deemed to be sold first, cost of goods sold is valued at the most recent costs; the effect of cost fluctuations is reflected in the ending inventory, which is valued at the historical costs rather than the most recent costs.⁶⁶ Compared to first-in, first-out (“FIFO”), LIFO produces net income which more closely reflects the difference between sale proceeds and current market cost of inventory. When costs are rising, the LIFO method results in a higher measure of cost of goods sold and, consequently, a lower measure of income when compared to the FIFO method. The inflationary gain experienced by the business in its inventory is generally not reflected in income, but rather, remains in ending inventory as a deferred gain until a future period in which sales exceed purchases.⁶⁷

Dollar-value LIFO

Under a variation of the LIFO method, known as dollar-value LIFO, inventory is measured not in terms of number of units but rather in terms of a dollar-value relative to a base cost. Dollar-value LIFO allows the “pooling” of dissimilar items into a single inventory calculation. Thus, depending upon the taxpayer’s method for defining an item, LIFO can be applied to a taxpayer’s entire inventory in a single calculation even if the inventory is made up of different physical items. For example, a single dollar-value LIFO calculation can be performed for an inventory that includes both yards of fabric and sewing needles. This effectively permits

⁶⁵ Sec. 471(a) and Treas. Reg. sec. 1.471-1.

⁶⁶ Thus, in periods during which a taxpayer produces or purchases more goods than the taxpayer sells (an inventory increment), a LIFO method taxpayer generally records the inventory cost of such excess (and separately tracks such amount as the “LIFO layer” for such period), adds it to the cost of inventory at the beginning of the period, and carries the total inventory cost forward to the beginning inventory of the following year.

⁶⁷ Accordingly, in periods during which the taxpayer sells more goods than the taxpayer produces or purchases (and inventory decrement), a LIFO method taxpayer generally determines the cost of goods sold of the amount of the decrement by treating such sales as occurring out of the most recent LIFO layer (or most recent LIFO layers, if the amount of the decrement exceeds the amount of inventory in the most recent LIFO layer) in reverse chronological order.

the deferral of inflationary gain to continue even as the inventory mix changes or certain goods previously included in inventory are discontinued by the business.

Simplified rules for certain small businesses

In 1986, Congress enacted a simplified dollar-value LIFO method for certain small businesses.⁶⁸ In doing so, the Congress acknowledged that the LIFO method is generally considered to be an advantageous method of accounting, and that the complexity and greater cost of compliance associated with LIFO, including dollar-value LIFO, discouraged smaller taxpayers from using LIFO.⁶⁹

To qualify for the simplified method, a taxpayer must have average annual gross receipts of \$5 million or less for the three preceding taxable years.⁷⁰ Under the simplified method, taxpayers are permitted to calculate inventory values by reference to changes in published price indexes rather than comparing actual costs to base period costs.

Special rules for qualified liquidations of LIFO inventories

In general, assuming rising prices, taxpayers using LIFO have an incentive to maintain or build inventory levels rather than allowing them to fall. So long as inventory levels are steady or growing the taxpayer never is deemed to have sold any of its older, lower-cost inventory, and inflationary gain is deferred indefinitely. However, in a period in which the inventory level falls, the taxpayer necessarily will (absent a special rule) be deemed to have sold some units purchased in a prior period, and the inflationary gain in those periods will be recognized in taxable income.⁷¹

In certain circumstances, reductions in inventory levels may be beyond the control of the taxpayer. Section 473 of the Code mitigates the adverse effects in certain specified cases by allowing a taxpayer to claim a refund of taxes paid on LIFO inventory profits resulting from the liquidation of LIFO inventories if the taxpayer purchases replacement inventory within a defined replacement period. The provision generally applies when a decrease in inventory is caused by reduced supply due to government regulation or supply interruptions due to the interruption of foreign trade.

⁶⁸ Sec. 474(a).

⁶⁹ Joint Committee on Taxation, *General Explanation of the Tax Reform Act of 1986 (H.R. 3838, 99th Congress; Public Law 99-514)*, (JCS-10-87), May 4, 1987, p. 482.

⁷⁰ Sec. 474(c).

⁷¹ By contrast, inflationary gain is generally recognized in earlier periods under the FIFO method, so taxpayers using FIFO do not have a similar incentive to maintain or build inventory levels.

Description of Proposal

The proposal repeals the LIFO inventory accounting method. Taxpayers that currently use LIFO would be required to write up their beginning LIFO inventory to its FIFO value in the first taxable year beginning after December 31, 2011. The resulting increase in income is taken into account ratably over eight taxable years beginning with the first taxable year the taxpayer is required to use FIFO.

Effective Date

The proposal is effective for taxable years beginning after December 31, 2011.

Analysis

Proponents of the LIFO method argue that in periods of rising costs, the method provides the most accurate reflection of current-period income because it matches current costs against current sales revenues. They point out that the taxpayer will have to replace the inventory to continue in business and that by including the most recent additions to the inventory in cost of goods sold, the required cost of replacing the inventory is more closely projected.⁷²

Alternatively, proponents of the FIFO method argue that LIFO permits deferral of inflationary gains in a taxpayer's inventory even when those gains arguably have been realized by the business. They note that outside of the inventory context, inflationary gains are generally taxed when the gain is realized (i.e., upon sale of the appreciated asset) and LIFO offers self-help against inflation that is not available in other contexts. FIFO proponents further assert that the use of earlier acquired items to value ending inventory understates net worth in times of rising prices resulting in an understatement of the income that measures the change in net worth for a given period.⁷³

Proponents of FIFO also argue that a business whose inventory turns over with regularity during a taxable year should not value inventory as if it includes items purchased in prior years.

⁷² See e.g., LIFO Coalition letter to then-Senate Finance Chairman Grassley and Ranking Member Baucus dated June 26, 2006 (2006 TNT 125-18), wherein author Leslie J. Schneider explains that, "If a business is faced with the situation that, because of inflation, each time that it sells any item from its inventory, it must expend a larger amount of capital than the FIFO cost of the item to simply replace the item of inventory that has been sold, the business would continually be required to increase its capital investment in inventory to simply maintain the status quo. Presumably, this increased capital investment would ordinarily be financed from the proceeds of the sale of the inventory, but if that profit were taxed on a FIFO basis, the after-tax proceeds from the sale of the inventory would in many cases not be sufficient to finance the acquisition of the necessary replacement inventory."

⁷³ Commentators favoring FIFO have also noted that since ending inventory under LIFO can be controlled through the purchase of additional units at year-end, LIFO is susceptible to manipulation by taxpayers through timing year-end purchases or sales of inventory. See e.g., Testimony of George A. Plesko before the Committee on Finance United States Senate, June 13, 2006. However, proponents of LIFO point out that court decisions and IRS rulings effectively preclude taxpayers from acquiring unneeded inventory at year end to avoid liquidation of low-cost LIFO layers. See, LIFO Coalition letter to Senate Finance Chairman Grassley and Ranking Member Baucus dated June 26, 2006 (2006 TNT 125-18).

However, LIFO advocates counter that, although there may be inventory turnover, it is highly unlikely that there is a time when there are no units in inventory. They view this perpetual inventory “layer” as a required condition of doing business and best valued at the time the layer was established, which is accomplished under LIFO. Thus, supporters of LIFO argue that during inflationary periods, using LIFO improves cash flow, thereby facilitating a business’s use of retained capital to finance its physical inventory levels. In this respect, they note that LIFO functions much like accelerated depreciation for capital investment in productive machinery and equipment.⁷⁴

Commentators contend that LIFO and, more specifically dollar-value LIFO (the most commonly used method of valuing inventory under LIFO), does not simply isolate changes in inventory cost resulting from inflation, but includes increases and decreases due to other factors outside of normal inflation such as changes in technology and changes in relative values as market supply and demand changes.⁷⁵ These commentators also note that a taxpayer’s definition of an “item” for purposes of establishing its dollar-value LIFO pools can result in changes to inventory costs that are not attributable solely to inflation.⁷⁶ For example, a broad item definition generally results in fewer pools lessening the likelihood of that a previously established LIFO layer will be liquidated, which has the effect of deferring gain which results not from inflation, but from a change in the goods that comprise a particular dollar-value LIFO pool.

Supporters of LIFO have also pointed out the potential adverse economic effects of the recapture of the LIFO reserve, especially for those businesses that have used LIFO for decades. The tax imposed on the recapture of the reserve, even where the recapture is spread over a period of years (e.g., eight as is currently proposed), could be substantial, and could severely restrict the ability of such taxpayers to invest in capital, including maintaining their current physical inventory levels.⁷⁷ Moreover, studies of financial statement LIFO reserves indicate that oil and gas companies would be disproportionately affected by repeal of LIFO.⁷⁸

⁷⁴ LIFO Coalition letter to then-Senate Finance Chairman Grassley and Ranking Member Baucus dated June 26, 2006 (2006 TNT 125-18). See also, Alan D. Viard, “Why LIFO Repeal is Not the Way to Go,” *Tax Notes*, Nov. 6, 2006, p. 574.

⁷⁵ See Edward D. Kleinbard, George A. Plesko, and Corey M. Goodman, “Is it Time to Liquidate LIFO?” *Tax Notes*, Oct. 16, 2006, p. 237.

⁷⁶ *Ibid.*

⁷⁷ This effect could be moderated by modifying the LIFO reserve recapture, for example, specifying partial reserve recapture based on business size or other mitigating factors, or extending the spread period for recapturing the LIFO reserve.

⁷⁸ See e.g., David Coffee, Reed Roig, Roger Lierly, and Phillip Little, “*The Materiality of LIFO accounting Distortions on Liquidity Measurements*,” *Journal of Finance and Accountancy* (Vol. 2 2009), noting that “the six largest [financial accounting LIFO] reserves and nine of the twenty largest reserves belong to oil and gas producers.”

Recent discussion has surrounded the potential required use of international financial reporting standards (“IFRS”) under which LIFO is not a permitted method of accounting.⁷⁹ The Securities and Exchange Commission has proposed the full adoption of IFRS by large U.S. companies by 2014.⁸⁰ The seemingly inevitable shift from Generally Accepted Accounting Principles (“GAAP”) to IFRS raises the issue of whether companies will be able to continue using LIFO for tax purposes in light of the conformity requirement.⁸¹

⁷⁹ International Accounting Standards Board, International Accounting Standard (IAS) No. 2, *Inventories*, (rev. 2003).

⁸⁰ RIN 3235-AJ93, 73 Fed. Reg. 70816 (November 21, 2008).

⁸¹ Some commentators have noted that the conformity requirement is a requirement “in form only” because changes to the regulations allowing alternative inventory valuations be disclosed in the financial statements provided the face of the income statement reflects LIFO. See Michael J. R. Hoffman and Karen S. McKenzie, “Must LIFO Go to Make Way for IFRS?” *The Tax Adviser* (March 2009).

B. Modify the Tax Rules for Dual Capacity Taxpayers

Present Law

Foreign tax credit - generally

The United States taxes its citizens and residents (including U.S. corporations) on their worldwide income. Because the countries in which income is earned also may assert their jurisdiction to tax the same income on the basis of source, foreign-source income earned by U.S. persons may be subject to double taxation. To mitigate this possibility, the United States generally provides a credit against U.S. tax liability for foreign income taxes paid or accrued.⁸²

A foreign tax credit is available only for foreign income, war profits, and excess profits taxes, and for certain taxes imposed in lieu of such taxes. Other foreign levies generally are treated as deductible expenses. Treasury regulations under section 901 provide detailed rules for determining whether a foreign levy is a creditable income tax. In general, a foreign levy is considered a creditable tax if it is substantially equivalent to an income tax under U.S. tax principles. Under the present Treasury regulations, a foreign levy is considered a tax if it is a compulsory payment under the authority of a foreign country to levy taxes and is not compensation for a specific economic benefit provided by a foreign country.⁸³

Dual capacity taxpayers

A taxpayer that is subject to a foreign levy and also receives a specific economic benefit from the foreign country is considered a “dual capacity taxpayer.”⁸⁴ A “specific economic benefit” is broadly defined as an economic benefit that is not made available on substantially the same terms to substantially all persons who are subject to the income tax that is generally imposed by the foreign country, or, if there is no such generally imposed income tax, an economic benefit that is not made available on substantially the same terms to the population of the country in general.⁸⁵ An example of a specific economic benefit includes a concession to extract government-owned petroleum. Other examples of economic benefits that may be specific if not provided on substantially the same terms to the population in general, include property; a service; a fee or other payment; a right to use, acquire or extract resources, patents, or other property that a foreign country owns or controls (as defined within the regulations); or a reduction or discharge of a contractual obligation.

Treasury regulations addressing payments made by dual capacity taxpayers were developed in response to the concern that payments which purported to be income taxes imposed on U.S. oil companies by mineral-owning foreign governments were at least partially, in

⁸² Sec. 901.

⁸³ Treas. Reg. sec. 1.901-2(a)(2)(i).

⁸⁴ Treas. Reg. sec. 1.901-2(a)(ii).

⁸⁵ Treas. Reg. sec. 1.901-2(a)(2)(ii)(B).

substance, royalties or some other business expense.⁸⁶ To the extent that a taxpayer meets the definition of a dual capacity taxpayer, the taxpayer may not claim a foreign tax credit for the portion of the foreign levy that is paid for the specific economic benefit.⁸⁷ Treasury regulations require that a dual capacity taxpayer, similar to other taxpayers, must establish that the foreign levy meets the requirements of section 901 or section 903.⁸⁸ However, the regulations require that a dual capacity taxpayer use either a facts and circumstances method or a safe harbor method in establishing the foreign levy is an income tax.⁸⁹

Under the facts and circumstances method, a separate levy is creditable to the extent that the taxpayer establishes, based on all the relevant facts and circumstances, the amount of the levy that is not paid as compensation for the specific economic benefit.⁹⁰ For purposes of applying the facts and circumstances method, the foreign country need not have a generally imposed income tax.

A dual capacity taxpayer alternatively may choose to apply the safe harbor method on a country-by-country basis to determine whether a levy is a creditable tax.⁹¹ Under the safe harbor method, if the foreign country has a generally imposed income tax, the taxpayer may credit the portion of the levy that application of the generally imposed income tax would yield provided that the levy otherwise constitutes an income tax or an in lieu of tax. The balance of the levy is treated as compensation for the specific economic benefit.⁹² If the foreign country does not generally impose an income tax, the portion of the payment that does not exceed the applicable U.S. federal tax rate, applied to net income, is treated as a creditable tax.⁹³ In general, a foreign tax is treated as generally imposed for this purpose even if it applies only to persons who are not residents or nationals of that country.⁹⁴

⁸⁶ Testimony of Treasury Secretary Schultz, Hearings on “Windfall” Excess Profits Tax before the House Committee on Ways and Means, 93rd Cong., 2d Sess. 151 (1974).

⁸⁷ Treas. Reg. sec. 1.901-2(a)(i).

⁸⁸ Treas. Reg. sec. 1.901-2A(b)(1).

⁸⁹ Treas. Reg. sec. 1.901-2A(c).

⁹⁰ Treas. Reg. sec. 1.901-2A(c)(2).

⁹¹ A taxpayer may make an election to use the safe harbor method with respect to one or more foreign states. The election applies to the year of the election and to all subsequent taxable years unless revoked. The election is made by the common parent and applies to all members of the affiliated group. See Treas. Reg. sec. 1.902-2A(d).

⁹² Treas. Reg. sec. 1.901-2A(d) and (e). Detailed rules are provided for determining the amount that imposition of the generally applicable tax to the dual capacity taxpayer would yield, based on the taxpayer’s gross receipts, costs and expenses, and other factors.

⁹³ Treas. Reg. sec. 1.901-2A(e)(5).

⁹⁴ See Treas. Reg. sec. 1.903-1(b)(3), Ex. 4.

Limitation on the use of foreign tax credits

The foreign tax credit generally is limited to a taxpayer's U.S. tax liability on its foreign-source taxable income (as determined under U.S. tax accounting principles). This limit is intended to ensure that the credit serves its purpose of mitigating double taxation of foreign-source income without offsetting U.S. tax on U.S.-source income.⁹⁵ The limit is computed by multiplying a taxpayer's total U.S. tax liability for the year by the ratio of the taxpayer's foreign-source taxable income for the year to the taxpayer's total taxable income for the year. If the total amount of foreign income taxes paid and deemed paid for the year exceeds the taxpayer's foreign tax credit limitation for the year, the taxpayer may carry back the excess foreign taxes to the immediately preceding taxable year or carry forward the excess taxes forward 10 years.⁹⁶

In addition, this limitation is calculated separately for various categories of income, generally referred to as "separate limitation categories." The total amount of foreign taxes attributable to income in a separate limitation category that may be claimed as credits may not exceed the proportion of the taxpayer's total U.S. tax liability which the taxpayer's foreign-source taxable income in that separate limitation category bears to the taxpayer's worldwide taxable income. The separate limitation rules are intended to reduce the extent to which excess foreign taxes paid in a high-tax foreign jurisdiction can be "cross-credited" against the residual U.S. tax on low-taxed foreign-source income.⁹⁷

Special rule for foreign oil and gas income

A special limitation applies with respect to taxes on combined foreign oil and gas income applied prior to the foreign tax credit limitation discussed above.⁹⁸ This limitation was adopted prior to the issuance of the regulations providing the rules discussed above for dual capacity and were intended to address the concern that payments made by oil companies to many oil-

⁹⁵ Secs. 901 and 904.

⁹⁶ Sec. 904(c).

⁹⁷ Sec. 904(d). For taxable years beginning prior to January 1, 2007, section 904(d) generally provides eight separate limitation categories (or "baskets") and effectively many more in situations in which various special rules apply. The American Jobs Creation Act of 2004 reduced the number of baskets from nine to eight for taxable years beginning after December 31, 2002, and further reduced the number of baskets to two (i.e., "general" and "passive") for taxable years beginning after December 31, 2006. Pub. L. No. 108-357, sec. 404 (2004).

⁹⁸ Sec. 907. For taxable years beginning before January 1, 2009, the components of what is now defined as combined foreign oil and gas income included foreign oil and gas extraction income ("FOGEI") and foreign oil related income ("FORI"). Under the prior rules, FOGEI and FORI were subject to separate limitations under section 907. Pub. L. No 110-343, Sec. 402(a). Amounts claimed as taxes paid on FOGEI of a U.S. corporation qualified as creditable taxes (if they otherwise so qualified), if they did not exceed the product of FOGEI multiplied by the highest marginal U.S. tax rate on corporations. A separate limitation was deemed to apply to FORI which theoretically applied in certain cases where the foreign law imposing such amount of tax is structured, or in fact operated, so that the amount of tax imposed with respect to FORI generally was "materially greater," over a "reasonable period of time," than the amount generally imposed on income that was neither FORI nor FOGEI. Joint Committee on Taxation, *General Explanation of Tax Legislation Enacted in the 110th Congress*, (JCS-1-09), March 2009, at 358.

producing nations were royalties disguised as tax payments.⁹⁹ Additionally, the limitation sought to prevent the crediting of high foreign taxes on foreign oil and gas income against the residual U.S. tax on other types of lower-taxed foreign source income.¹⁰⁰

Under this special limitation, amounts claimed as taxes paid on combined foreign oil and gas income are creditable in a given taxable year (if they otherwise qualify as creditable taxes) only to the extent they do not exceed the applicable U.S. tax on that income. The applicable U.S. tax is determined for a corporation as the product of the amount of such combined foreign oil and gas income for the taxable year and the highest marginal tax rate for corporations.¹⁰¹ Any excess foreign taxes may be carried back to the immediately preceding taxable year and carried forward 10 taxable years and credited (not deducted) to the extent that the taxpayer otherwise has excess limitation with regard to combined foreign oil and gas income in a carryover year.¹⁰² Amounts that are not limited under section 907 (relating to combined foreign oil and gas income discussed above) are included in the general basket or passive basket (as applicable) for purposes of applying the section 904 limitation.

Description of Proposal

In the case of a dual capacity taxpayer, the proposal treats a foreign levy that would otherwise qualify as an income tax or in lieu of tax as a creditable tax only if the foreign country generally imposes an income tax. An income tax is considered generally imposed for this purpose only if the income tax applies to trade or business income from sources in that country, and only if the income tax has substantial application to non-dual capacity taxpayers and to persons who are nationals or residents of that country. The proposal replaces the part of the present regulatory safe harbor that applies when a foreign country does not generally impose an income tax, but retains the present law rule where the foreign country does generally impose an income tax.

The proposal converts the special foreign tax credit limitation rules of section 907 into a separate category within section 904 for foreign oil and gas income. However, the proposal does not override existing U.S. treaty obligations that allow a credit for taxes paid or accrued on certain oil or gas income.

Effective Date

The proposal is effective for taxable years beginning after December 31, 2010.

⁹⁹ Joint Committee on Taxation, *Explanation of the Revenue Provisions of the Tax Equity and Fiscal Responsibility Act of 1982*, (JCS-38-82), December 31, 1982, sec. IV.A.7.a, footnote 63.

¹⁰⁰ H.R. Conf. Rept. No. 103-213, at 646 (1993).

¹⁰¹ Sec. 907(a). For an individual, the limitation is the product of the amount of such combined foreign oil and gas income for the taxable year and a fraction, the numerator of which is the tax against which the credit under section 901(a) is taken and the denominator of which is the taxpayer's entire taxable income.

¹⁰² Sec. 907(f).

Analysis

The proposal would address the distinction between creditable taxes and non-creditable payments that are made in exchange for a specific economic benefit and would modify the rules provided under the present Treasury regulations in two respects. First, the proposal would deny a foreign tax credit for amounts paid by a dual capacity taxpayer to any foreign country that does not have a generally applicable income tax. Thus, under the proposal, a taxpayer using the safe harbor would no longer be permitted to treat the portion of a foreign levy that does not exceed the applicable U.S. tax as a creditable tax if the foreign jurisdiction did not generally impose an income tax. Similarly, under the facts and circumstances method, no amount of a foreign levy paid to a foreign country without a generally imposed income tax would qualify as a creditable foreign tax.

Second, the proposal would modify the present regulatory criteria for determining whether a foreign income tax is “generally imposed” to require that the income tax apply to trade or business income from sources in that country, and that it have substantial application to non-dual capacity taxpayers as well as to persons who are nationals or residents of that country.¹⁰³ Thus, the proposal effectively would eliminate the provision in the present regulations that permits taxpayers to treat a foreign country generally imposing an income tax notwithstanding that such tax is inapplicable to persons who are nationals or residents of the foreign country.

The provisions in the regulations governing dual capacity taxpayers derive from a concern that payments which purported to be income taxes imposed on U.S. oil companies by mineral-owning foreign governments were at least partially, in substance, royalties or some other business expense. Nonetheless the present-law regulatory regime permits a foreign levy to be treated as a creditable tax, despite the lack of a generally imposed income tax on the foreign country’s residents. The regulations thus presume that the foreign levy represents a special type of income tax, even where the tax is imposed solely on dual capacity taxpayers. The proposal would eliminate this presumption and only permit a dual capacity taxpayer to treat all or part of a foreign levy as an income tax if the country imposes a general income tax with substantial application to non-dual capacity taxpayers and to nationals or residents of the country.

Although primarily applicable to oil and gas producers (and other companies engaged in mineral extraction businesses), the “dual capacity” taxpayer provisions are broadly applicable to

¹⁰³ This part of the proposal appears to be in response to the taxpayers using the facts and circumstances method following the Tax Court’s decision in *Exxon Corp., et. al. v. Commissioner*, 113 T.C. 338 (1999). In that decision, the Tax Court concluded that the entire amount of the petroleum revenue tax paid by Exxon to the United Kingdom was not compensation for a specific economic benefit, but instead constitutes an excess profit or income tax creditable under section 901. The Court considered that Exxon entered into an arm’s length licensing agreement with the U.K. government to gain access to the North Sea oil fields prior to the enactment of the petroleum revenue tax and Exxon’s right to explore, develop and exploit petroleum was dependent on the licensing agreement and payment of license fees under that agreement and not in exchange for payment of the tax.

Anecdotal evidence suggests that subsequent to the court’s decision in *Exxon*, a significant number of dual capacity taxpayers revoked their safe harbor elections and adopted the facts and circumstances method, which resulted in treating the entire foreign levy as a creditable tax under section 901.

any taxpayer that is treated under the regulations as receiving a specific economic benefit from a foreign government. Thus, for example, a corporation engaged in a banking business that loans funds to a foreign government may meet the definition of a dual capacity taxpayer and therefore be subject to the provisions in the Administration’s proposal with the result that if the foreign country has no generally imposed income tax, the taxes paid by the bank would not be creditable.¹⁰⁴

The proposal does not specify what constitutes a “substantial application” of an income tax. Presumably, Treasury would have the authority to issue guidance for determining when a country’s income tax satisfies the “substantial application” requirement. Arguably, a country that imposes a comprehensive income tax similar to the United States would satisfy the definition. However, uncertainty arises when the tax applies to some portion of the residents or nationals of the country—for example, if a tax applies to a particular industry.

The proposal also does not provide a definition for “resident.” It is likely that Treasury would have the authority to issue guidance defining “resident” for purposes of the provision. It is not clear whether any such guidance would provide that a controlled foreign corporation operating in the country and subject to tax in the country would be considered a resident, notwithstanding that its parent company has no direct operations in such country. Moreover it is not clear how such guidance would apply to joint ventures with resident and non-resident investors.

Under the proposal, dual capacity taxpayers and non-dual capacity taxpayers would be treated differently for foreign tax credit purposes solely on the basis of whether the taxing jurisdiction generally imposes an income tax. Thus, a non-dual capacity taxpayer would be entitled to claim foreign tax credits on foreign levies that otherwise meet the definition of an income tax notwithstanding that the foreign country does not generally impose an income tax. However, a dual capacity taxpayer that is assessed the same levy that is properly characterized as an income tax, would be denied a foreign tax credit for such amount if the country does not generally impose an income tax.

Proponents of the proposal argue that present law fails to achieve the appropriate allocation between a payment for specific economic benefit and a creditable tax in those cases where the foreign country imposes a levy on an item, but does not otherwise generally impose an income tax. Thus, they assert that the requirement that the foreign country generally impose an income tax ensures that the levy is not a payment for a specific economic benefit.

Opponents of the proposal also contend that the potential for double taxation created under the proposal does not constitute sound tax policy. Instead, they argue that if the dual capacity taxpayer can establish that it is paying fair compensation to the foreign country for the economic benefit received from that country, amounts paid pursuant to the foreign levy on net income or a levy on excess profits should constitute a creditable tax, notwithstanding that the

¹⁰⁴ Treas. Reg. sec. 1.901-2A(c)(2)(ii), Example 1. In this example, the taxes paid by the bank were creditable because the bank met its burden of proof under the facts and circumstances method.

foreign country does not generally impose an income tax. Thus, they assert that the current rules adequately address the misallocation concern noted as a reason for the proposed change.

It is also asserted that the major U.S. based oil companies would be disadvantaged relative to foreign competitors in bidding for new projects as a result of the increased costs. This reduced competitiveness could, it is contended, impair energy security in the United States.

The proposal also creates a separate foreign tax credit limitation category for combined foreign oil and gas income, and eliminates the provisions for foreign oil and gas income under section 907. Replacing section 907 with a separate section 904 limitation category for combined foreign oil and gas income restricts cross-crediting of oil and gas-related taxes as well as simplifying the foreign tax credit limitation calculation.