Fossil Fuel Taxation in the President’s 2013 Budget

by

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Abstract

The president’s fiscal year 2013 budget proposes changes to the taxation of fossil fuels in the United States by increasing tax rates, reinstating expired taxes, and eliminating production deductions. The stated rationale for these changes is to remove tax preferences that encourage more investment in fossil fuel production than would occur under a neutral tax system. This paper evaluates whether the proposal accomplishes this goal. We do so by looking at the neutrality of the individual changes proposed, the overall tax treatment of fossil fuel production, and the effect the proposal will have on fossil fuel production. We first identify the changes proposed in the budget and compare them to both current law and a neutral tax system. We find that some of the proposed changes increase the neutrality of the system while others decrease it. We then move to look at the overall tax treatment of fossil fuel production in order to determine if the tax code gives preferential treatment to fossil fuel production. Surveying past literature on the effective tax rate on capital shows a wide variety of estimated tax rates for the sector. We calculate our own measures of the effective tax rate for the sector using three different specifications. Under all three of our measures, the effective tax rate for fossil fuel production is higher than the average for other sectors. Finally, we predict the effect of the proposal on fossil fuel production using a general equilibrium model of the US economy. We find that the proposal would increase the price of fossil fuels by 2.2 to 2.5 percent, decrease demand for fossil fuels by 1.0 to 3.2 percent, and that the excess burden of the additional revenue is 18 percent of revenues higher than if the tax increase was spread over all sectors. The cost of the proposal’s reduction in carbon dioxide emissions is estimated to be $35 per metric ton.
I. INTRODUCTION

The Department of the Treasury and the Joint Committee on Taxation have stated that the US federal tax code contains tax preferences that favor the production of fossil fuels more than a neutral tax code would (Department of the Treasury 2012; Joint Committee on Taxation 2012). The president’s fiscal year 2013 budget proposes to make the Internal Revenue Code more neutral through significant changes to the taxation of fossil fuels production. The ten most important tax changes proposed by the budget are: (1) increasing the Oil Spill Liability Trust Fund financing rate, (2) repealing expensing of intangible drilling costs (IDCs), (3) repealing percentage depletion for fossil fuels, (4) repealing the domestic manufacturing deduction for fossil fuels, (5) increasing the geological and geophysical amortization period for independent producers, (6) repealing the capital gains treatment of coal royalties, (7) repealing expensing of exploration and development costs for coal, (8) repealing the last-in, first-out (LIFO) method of accounting for inventories, (9) reinstating the Superfund excise taxes, and (10) modifying the tax rules for dual capacity taxpayers.1

Revenue estimates of these changes from the Department of the Treasury (2012), hereafter Treasury, and the Joint Committee on Taxation (2012), hereafter JCT, are presented in Table 1. By either measure, the changes listed above will provide over 99 percent of the revenue increases brought about by the changes in the budget proposal that are specific to fossil fuel production.

Table 1: Revenue Estimates of Provisions of President’s 2013 Budget for 2013-22 ($ millions)

<table>
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<tr>
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<tbody>
<tr>
<td>Repeal LIFO inventory accounting for all sectors</td>
<td>66,872</td>
<td>73,782</td>
</tr>
<tr>
<td>Repeal percentage depletion for oil and gas</td>
<td>12,099</td>
<td>11,465</td>
</tr>
<tr>
<td>Modify tax rules for dual capacity taxpayers</td>
<td>9,571</td>
<td>10,724</td>
</tr>
<tr>
<td>Repeal expensing of intangible drilling costs</td>
<td>9,529</td>
<td>13,902</td>
</tr>
<tr>
<td>Repeal the domestic manufacturing deduction for fossil fuels</td>
<td>3,662</td>
<td>0</td>
</tr>
<tr>
<td>Repeal percentage depletion for coal and other hard mineral fossil fuels</td>
<td>1,310</td>
<td>1,744</td>
</tr>
<tr>
<td>Increase geological and geophysical amortization period</td>
<td>957</td>
<td>1,400</td>
</tr>
<tr>
<td>Repeal the capital gains treatment of coal royalties</td>
<td>612</td>
<td>422</td>
</tr>
<tr>
<td>Increase Oil Spill Liability Trust Fund financing rate</td>
<td>462</td>
<td>717</td>
</tr>
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1 These changes were earlier identified as the most important for fossil fuel production by Pirog (2012).
The Obama administration has made a standard tax neutrality argument to justify the need for these tax changes. The president has stated that because of these provisions, fossil fuel production faces a lower tax rate than other sectors of the economy (Office of the Press Secretary 2012). Treasury (2012) expands on this claim to explain how these provisions are tax preferences should be repealed because they distort markets by causing more investment in fossil fuel production than would occur under a neutral tax system. Treasury mentions reduced energy security, higher carbon emissions, and higher taxes on the rest of the economy as consequences of this distortion. In this paper, we attempt to evaluate these arguments. We examine the effect the proposals will have on the neutrality of the tax code, measure the tax preferences fossil fuel production receives compared to other industries, and predict the effect this proposal would have on fossil fuel production.

In this paper, we first discuss each change proposed by the budget and compare it to both current law and how previous literature has determined that the issue would be treated under a neutral tax system, i.e., one that does not change the allocation of investment across industries. Then we look at the taxation of fossil fuel production as a whole, specifically as it compares to other industries. We discuss different methods for calculating the tax rate for fossil fuel production and review past results. In addition, we present new estimates of the average effective tax rate of fossil fuel production.

In the last section, we look at the effects the tax changes will have on the prices and quantities of goods produced by each sector in the economy. We utilize a computable general equilibrium model of the United States and compare prices and quantities under the proposed budget to raising the same amount of revenue via a uniform increase in the corporate income tax. We find that the changes the budget proposes to the taxation of fossil fuels will lead to higher fossil fuel prices and lower demand. We also find that the excess burden of the revenue raised under the proposed budget is higher than if the revenue were instead raised with a broad based tax increase. We also calculate the implied cost of the carbon dioxide emission reductions attributable to the budget proposal.
This paper is organized as follows. Section II discusses each change proposed in the budget, and compares it to both current law and a neutral tax system. Section III discusses the overall tax treatment of fossil fuel production in comparison to other sectors. Section IV discusses the construction and results of the general equilibrium model. Section V summarizes and concludes.

II. COMPARISON OF CURRENT LAW, PROPOSED CHANGES, AND A NEUTRAL TAX SYSTEM

In this section, we list the major changes proposed by the president’s 2013 budget proposal, describe current law, discuss what the proposal will and will not change relative to current law, and then compare current law and the proposed changes to treatment of these issues under a neutral tax system. But before we can discuss why a neutral tax system is desirable, we first need to discuss what neutrality is and that requires explaining the costs of taxation. All taxes impose two types of costs on taxpayers: direct costs from money that is transferred from the taxpayer to the government and indirect costs due to firms and consumers expending resources to reduce their direct tax payments by substituting away from taxed activities. These additional costs from avoiding the tax are referred to as the excess burden of taxation.

The tax code is neutral if it does not influence economic choices such as firm organizational form, technology, and industry so that taxpayers make their decisions on economic and not tax criteria. By taxing all activities the same, it does not change relative prices and thus eliminates a major source of inefficiency. This is a general definition of a neutral tax system but the specific details of a neutral tax system are a subject of disagreement among scholars. In order to evaluate if a particular proposal in a budget is neutrality enhancing or reducing, we compare the proposal to expert recommendation and analysis. In cases where there is no consensus on how a particular feature of the tax code would look under a neutral tax system, we will compare present law to each of the options advocated by the literature.

II.A. Oil Spill Liability Trust Fund

Currently an excise tax of 8 cents per barrel is imposed on crude oil produced in the US and crude oil and petroleum products imported into the US. This tax is scheduled to increase to 9 cents per barrel in 2017 and then expire in 2018. However, the excise tax has been repeatedly extended since its creation in 1990 and is assumed to be permanent for federal budget scorekeeping purposes (JCT 2011). The proceeds from this excise tax are deposited in the Oil Spill Liability Trust Fund, which is used to pay for various costs resulting from oil spills and their subsequent cleanup and also government oil spill prevention and response programs (Treasury 2012). The fund pays for claims that are not covered by the responsible party, up to a $1 billion per incident limit and can reimburse the responsible party for some oil spill cleanup costs if the spill
was not caused by negligence or violation of Federal regulations.\footnote{Responsible parties are reimbursed for cleanup costs over a fixed amount that depends on the size of the vessel or facility the spill occurred at. However, Woods (2008) notes that the standards used to prove that the responsible party was not negligent can make it difficult for responsible parties to receive this reimbursement.} For the purposes of this tax, “crude oil” does not include synthetic petroleum or unconventional crudes. This means that domestically produced shale oil, refined oil, and liquids from coal, tar sands, and biomass are not taxed (JCT 2012). Refined oil is taxed if imported because it is included under “petroleum products” but imported tar sands are not (Internal Revenue Service 2011b).

The President’s 2013 Budget proposal increases the excise tax to 9 cents per barrel for 2013-2016 and to 10 cents per barrel for 2017 and onwards (Treasury 2012). The tax would also be extended to apply to crudes that are produced from bituminous deposits and kerogen-rich rock (Treasury 2012).

In the case of smaller oil spills, strict civil liability for the full costs of the oil spill is optimal as it fully internalizes both the cost of the oil spill and the cost of prevention. The main argument for a trust fund is the case of catastrophic oil spills where the damages exceed the ability of the responsible party to pay. Previous literature has advocated two solutions to dealing with catastrophic oil spills: mandatory insurance and a prospective excess liability tax (Viscusi and Zeckhauser 2011; Cohen et al. 2011). Under a prospective excess liability tax, responsible parties would still face full strict liability but a tax would also be imposed and the federal government would pay for any damages that exceed the value of the responsible party’s assets. This tax’s rate would need to be actuarially fair with respect to the probability the activity causes an accident that could not be covered by the responsible party’s assets.

The excise tax used to fund the Oil Spill Liability Trust Fund is much closer to a prospective excess liability tax than mandatory insurance, so that is the comparison we will make to judge the neutrality of the tax. However, the trust fund’s excise tax differs from a prospective excess liability tax in two ways: it does not have an actuarially fair rate and has only limited liability. And the president’s proposal to increase the financing rate and extend it to other forms of oil production would exacerbate the problem.

A neutral excess liability tax has an actuarially fair financing rate. However, there is no evidence the current rate of 8 cents per barrel or the president’s proposed increase to 9 cents per barrel are based on the expected cost to the trust fund per barrel produced. And ideally, the rate would also vary with the level of safety taken by the firm, although the benefits of a more accurate rate need to be weighed against the difficulty of administering such a tax. However extending the tax to include unconventional deposits would further decrease its accuracy since the extraction of crude from oil sands on land (or
in fact, any land based oil extraction) does not run the risk of the type of a catastrophic oil spill like the Deepwater Horizon (Macondo) spill.

In addition, it is worth noting that the purpose of the tax is to pay for catastrophic oil spills that exceed the responsible party’s ability to pay, not smaller oil spills for which the responsible party can pay. Thus a neutral tax rate would also need to take into account the lower rate of default for large firms with deep pockets by charging them a lower rate for the same activity. For the Deepwater Horizon oil spill, BP set up a $20 billion fund that had paid $4.7 billion as of July 2011, far exceeding the fund’s $1 billion cap (Yost 2011). The probability that an oil spill would exceed the roughly $100 billion assets of a major integrated oil company like BP would be extremely small, and thus the actuarially fair tax rate would be similarly small (Abraham 2011). This is one of the few places in the tax code where different tax treatment of small firms and major integrated oil companies can be justified.

Although firms would face full strict civil liability under a prospective excess liability tax regime, under current law liability is limited in two ways. First, total payouts by the trust fund are limited to $1 billion per incident. But with this cap, the trust fund could not fully cover the damages of the Deepwater Horizon oil spill if BP had defaulted. And second, the trust fund limits the liability of responsible parties for oil spill if they were not negligent and did not break federal regulation. This creates a moral hazard for firms to follow the minimum level of oil spill avoidance required by law, instead of the socially optimal level ensured by full strict civil liability.

II.B. Expensing of Intangible Drilling Costs

Intangible drilling costs (IDCs) are expenditures made in preparation of wells for the production of oil, natural gas, or geothermal energy that are not for the purchase of tangible property. For example, wages and fuel are examples of IDCs but pipelines are not (Treasury 1984). Most taxpayers may elect to either expense or capitalize these costs. Integrated oil companies, however, are not allowed to fully expense IDCs but must capitalize 30% of intangible drilling expenses over a 60-month period (JCT 2012).

The president’s 2013 budget proposal repeals both the expensing and 60-month amortization of IDCs (Treasury 2012). Intangible drilling costs instead would be capitalized as depreciable or depletable property (Treasury 2012).3 Although the expensing of intangible drilling costs is not exclusively for oil and natural gas but also geothermal energy, both JCT (2012) and Treasury (2012) only discuss repeal for fossil fuels, not geothermal.

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3 Typically, depreciable assets are used to recover depletable assets (JCT 2012).
Under a neutral income tax system, expenses relating to the creation of a capital asset should not be expensed, but capitalized, with the tax depreciation allowance equal to the economic depreciation rate of the capital asset produced. However, it is not clear what generally applicable rules would then apply to IDCs nor what the true rate of economic depreciation is. It is thus not possible to compare whether the old or new rates are closer to the economic rate of depreciation.\textsuperscript{4} However, one clear advantage of this change is that it would remove the different tax treatment between firms due to organizational form since it would remove a deduction not available to integrated oil companies.

II.C. Percentage Depletion

Depletion deductions are similar to depreciation deductions. They are both deductions taxpayers receive as an asset is reduced in value as it produces income. For fossil fuels, the cost of acquiring the lease for the property is allowed to be deducted through depletion instead of depreciation (JCT 2012). The tax code recognizes two methods for the calculation of depletion deductions: cost depletion and percentage depletion.\textsuperscript{5} Under the cost depletion method, each year the taxpayer deducts an amount equal to the amount of the resource recovered that year times the cost of acquiring the lease divided by the total amount of the resource in the property. Under the percentage depletion method, a constant percentage, varying from five to 22 percent (depending on the type of material extracted) of the taxpayer’s gross income from a producing property is allowed as a deduction from net income in each taxable year (JCT 2012).\textsuperscript{6}

A disadvantage of percentage depletion is that it does not depend on the costs of acquiring the property and thus has no direct relationship to cost recovery. GAO (2000) finds over the years 1968-2000 government revenue was decreased by a total of $82 billion in year 2000 dollars because of the greater deductions available to the petroleum industry in percentage depletion compared to cost depletion. In addition, cumulative depletion deductions may be greater than the amount expended by the taxpayer to acquire the property in the first place (JCT 2012).

The President’s 2013 Budget proposal would repeal the percentage depletion deduction for fossil fuels but retain it for other mining (Treasury 2012). All properties and firms engaged in fossil fuel extraction would use the cost depletion method instead (Treasury 2012).

\textsuperscript{4} There is no reference in the proposal to what the new rules are or if there even is a single set of rules which would now apply to all IDCs. It appears expenditures that were grouped together under the category of IDC would now have a variety of different treatments based on the type of expenditure they are.
\textsuperscript{5} Additional explanation of the two depletion methods is available in IRS (2011a).
\textsuperscript{6} Other limitations on percentage depletion exist as well. For example, for non-integrated oil companies, the deduction is limited to domestic US production on the first one thousand barrels per day per well and is also limited to 65 percent of net income on that particular property. Integrated oil companies are not allowed to use the percentage depletion deduction at all (Smalling 2012).
In isolation, percentage depletion is non-neutral. The percentages are chosen based on non-economic criteria such as the type of resource being extracted and eligibility varies depending on firm organizational form. Percentage depletion is also not directly linked to the cost of the actual capital invested. If this tax were revised to be neutral, it is unclear what the optimal depreciation rate would be. But using the rate at which minerals are removed from the property as the depreciation rate (as cost depletion does) would at least ensure that full write-off only occurs when all the minerals are removed from the property. So it appears to be a more neutral method than using percentage depletion.

However, including other taxes into the analysis increases the favorability of percentage depletion. In 2011, 35 of the 50 states imposed a severance tax on the extraction of natural resources (Telles, O'Sullivan, and Willhide 2012). These taxes are usually imposed at a flat rate per unit of the commodity (per ton of coal, per barrel of oil, etc.) (Zelio and Houlihan 2008). In addition, as part of the lease allowing companies to extract minerals from federal land, the federal government charges royalties which in 2006 were 12 ½ to 16 ⅜ percent of the value of oil and gas extracted and $0.15 to $1.75 per ton extracted for coal (Minerals Management Service Minerals Revenue Management 2006). However, such taxes or lease terms are distortionary because they reduce the marginal revenue of additional extraction compared to its marginal cost, causing early shutdown of otherwise still productive property. A percentage depletion allowance less than or equal to the severance tax or royalty rate would be efficiency enhancing by effectively canceling out part of the severance tax or royalty and thus increasing production.7

In addition, the percentage depletion deduction is repealed for fossil fuel extraction only, not all minerals. But the arguments for and against percentage depletion in fossil fuel extraction also apply to mining for other resources, which would retain their percentage depletion deduction under the proposal. Under a neutral tax system, all forms of extraction would have uniform depletion rules that do not vary based on the material extracted.

This means that the repeal of percentage depletion has two effects. It increases the neutrality of the code because percentage depletion is itself distortionary. But it also reduces the neutrality of the code by eliminating a deduction that offsets distortionary taxes and lease terms and through favoring non-fossil fuel extraction over fossil fuel extraction. The net effect of these two effects is unclear.

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7 Although using percentage depletion to cancel out royalties would mean the original purpose of the depletion deduction, recovering capital costs incurred in acquiring the property, would not be served.
II.D. Domestic Manufacturing Deduction

The domestic manufacturing deduction was added to the tax code with the American Jobs Creation Act of 2004 with the intent of encouraging domestic investment and improving the competitiveness of US manufacturers in global markets (Blouin, Krull, and Schwab 2007). It allows a taxpayer to deduct a percentage of their income derived from domestic manufacturing activities (Pirog 2012). The percentage of the deduction is six percent for oil and gas production and is otherwise nine percent.

The President’s 2013 Budget proposal would repeal the domestic manufacturing deduction for income derived from the domestic production of oil, gas, coal, other hard mineral fossil fuels, and certain other nonmanufacturing activities (Treasury 2012). The deduction rate would also be increased to 18 percent for activities involving the manufacture of certain advanced technology property (Treasury 2012). The domestic manufacturing deduction would be unchanged for other industries.

There are two margins on which this change needs to be considered: which industries receive the deduction and imports versus domestic production. In regards to first issue, the change would level the playing field between fossil fuels and industries that do not receive the deduction. But it would also increase the gap between still deductible industries and fossil fuels. In the case of the Treasury revenue estimate where this provision is revenue neutral, this is just the replacement of one non-neutral provision with equal spending on another that also causes a distortion and thus would have an unclear effect on the neutrality of the code.

The second dimension of the change is the choice between domestic production and importation. Eliminating the deduction would increase the favorability of importing fossil fuels instead of domestic production. The reverse effect would occur for the advanced technology property which would now receive a larger deduction. Although this paper will not attempt to weigh the merits of energy security against free trade, Treasury (2012) has mentioned improving energy security as one of the reasons for the tax changes. However, this effect would actually reduce US energy security by increasing the favorability of importing fossil fuels as compared to domestic production.

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8 The proposal is quite vague on some of these terms. It does not define what the “certain other nonmanufacturing activities” that would lose the deduction are nor does it define what the “activities involving the manufacture of certain advanced technology property” are.

9 Note that the JCT assumes the revenue gained from repeal is not fully channeled to funding additional deductions for advanced technology property and that the total amount spent on the deduction decreases (i.e. this provision generates revenue). If this were the case the net change in deadweight loss could easily be negative.
II.E. Geological and Geophysical Expense Amortization

Geological and geophysical (G&G) expenses are the costs incurred for acquiring data for minerals exploration and include expenditures on geologists, seismic surveys, gravity meter surveys, and magnetic surveys (JCT 2012). Independent producers and small integrated oil companies may amortize and deduct these costs over two years. Major integrated oil companies are required to amortize the deduction of G&G costs over seven years.

The President’s 2013 Budget proposal would increase the amortization period for independent producers and small integrated oil companies from two years to the same seven years as major integrated oil companies (Treasury 2012). Major integrated oil companies would be unaffected.

Under a neutral tax system, statutory G&G depreciation would equal economic depreciation and be the same for all firms regardless of organizational form. So it is appropriate that the President’s proposal is to treat independent producers, small integrated oil companies, and large integrated oil companies equally. BEA (2003) calculates the geometric economic depreciation rate for petroleum and natural gas mining exploration, shafts, and wells at .0751 and lists a service life of 12 years. So the increase in the amortization period for independent producers and small integrated oil companies would move their tax depreciation treatment closer to both economic depreciation and eliminate the difference in tax treatment due to firm organizational form. This change is thus neutrality enhancing.

II.F. Capital Gains Treatment of Coal Royalties

While in general royalties are taxed as ordinary income, royalty income from the sale of coal mined in the US and held for at least one year can be taxed instead as long term capital gains (JCT 2012). The President’s 2013 Budget proposal would repeal the capital gains treatment of gains from coal royalties under these circumstances (Treasury 2012).

There are a variety of considerations that must be taken in dealing with the taxation of ordinary income versus capital gains in a neutral tax system to ensure that income invested and then earned again in a subsequent period is not double taxed. However, in this case these concerns can be safely sidestepped by focusing on the coal itself. Coal and coal royalties are not assets like property or stocks but inventories. Income from the sale of inventories is typically treated as ordinary income, not capital gains. This provision is thus neutrality enhancing.11

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10 A summary of the BEA depreciation table as it is relevant to the energy industry is available in Table A1 in the Appendix of Metcalf (2009).
11 Although it brings coal in line with the current law treatment of other inventories, the budget proposal does still deviate somewhat from a neutral system, which would allow inflationary gains to be deducted from income. This point is explained in detail later in this paper under the discussion of LIFO.
II.G. Expensing of Coal Exploration

Exploration is the process of determining if there are sufficient minerals in an area to justify mining. Under current law, taxpayers may elect to expense (immediately deduct) exploration costs in all types of mining, not just coal. Unlike other organizational forms of firms, corporations may only expense 70 percent of the exploration expenses and must amortize over a 60-month period the remaining 30 percent (Treasury 2012). This deduction is subject to recapture by disallowing percentage depletion deduction on the property for which exploration costs were expensed until “adjusted exploration expenditures” are re-included in income (JCT 2012).

The President’s 2013 Budget proposal would repeal the option to expense and amortize over 60-months exploration and development costs for coal (including lignite) and certain types of oil shales (Treasury 2012). The costs would instead be capitalized and recovered through depreciation or depletion deductions, as appropriate (Treasury 2012). Other forms of mining would retain the option to expense and amortize exploration costs.

Under a neutral tax system, a taxpayer would be allowed to deduct costs that benefit future periods based on the economic rate of depreciation. Exploration costs for a mine that is found to not have sufficient quantity or quality of ore to justify mining should be immediately expensed since they will provide no future benefit. However, for a productive mine, they should be deducted at their economic depreciation rate. As was stated before, BEA (2003) calculates the geometric economic depreciation rate for petroleum and natural gas mining exploration, shafts, and wells at .0751 and a service life of 12 years, a longer lifetime than the 60-month amortization allowed now. Retaining the deduction for other forms of mining would make the tax system less neutral in regards to which type of mining to invest in but would make the system more neutral for the choice of what type of capital to employ in coal mining.

II.H. Repeal Last-in, First-out (LIFO) Method of Accounting for Inventories

In general, taxpayers are allowed a deduction equal to the cost of acquiring the goods they sell. However, the appropriate value to deduct becomes unclear when the firm is selling goods from an inventory containing goods acquired at multiple time periods, each of which was bought at a different price. The LIFO and FIFO methods determine which price to use in this situation. Under last-in, first-out (LIFO), when a unit of a good is removed from inventory, the price of the last (most recent) unit of that good put into the inventory is used to calculate net income from the sale of the good. Under first-in, first-out (FIFO), when a unit of a good is removed from inventory, the price of the first (least recent) unit of the good put in

12 Adjusted exploration expenditures are the amounts for which the taxpayer claimed an exploration deduction that would have been included in the basis of the property reduced by the excess of the percentage depletion over the depletion allowable had the expenses been capitalized instead (JCT 2012).
inventory is used to calculate net income from the sale of the good. In order to use LIFO for tax purposes, a firm must also use LIFO for financial accounting purposes (Treasury 2012). Although LIFO accounting is not unique to firms that produce fossil fuels, some sources indicate repeal of LIFO will have a disproportionately large impact on the sector.\(^\text{13}\)

When the price of an inventory item is increasing, such as due to inflation, current prices are above historical prices. In this case, cost of goods sold is higher under LIFO than FIFO. A higher cost of goods sold in a period translates to lower net taxable income and thus lower taxes paid in that period. The lower cost of goods sold from the less recent period is not used until inventories are drawn down. But if inventories are never drawn down, this lower cost of goods sold is never used and those inventory items’ appreciation, whether inflationary or not, is never taxed.

The President’s 2013 budget proposal would repeal the LIFO inventory accounting method for income tax purposes, regardless of the use of LIFO on the firm’s financial statement (Treasury 2012). 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 in 2013 (Treasury 2012). The resulting increase in income is taken into account ratably over 10 taxable years beginning with the first taxable year beginning in 2013 (Treasury 2012).

In a neutral tax system, taxes should be imposed on real economic income, not increases that are attributable to inflation. Gains from inflation should not be taxed, but neither should an incentive be created to retain inventories. And inventory appreciation that is not due to inflation should be taxed. Treasury (1984) recommends satisfying these goals by allowing firms to choose between FIFO indexed for inflation or LIFO.\(^\text{14}\) However, as previously noted, LIFO allows firms to defer taxes on the gains from their inventory appreciating by maintaining their inventory stock. So we recommend mandatory inflation indexed FIFO as the ideal method. However, the President’s proposal is for non-indexed FIFO. Without indexing, it is unclear if the FIFO requirement proposed by the president would be more or less neutral than the current system.

II.1. Reinstate Superfund Excise Taxes

The Environmental Protection Agency maintains a list of polluted sites called the National Priorities List. For 70 percent of the sites on the list, the EPA can locate potentially responsible parties (PRPs) who pay for the site’s cleanup (Ramseur, Reisch, and McCarthy 2008). For the remaining 30 percent of sites, either the EPA cannot locate the PRP or the

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\(^{13}\) The evidence on how much repealing LIFO would affect the energy sector is mixed. Przybyla (2011) and Knittel (2009) find that the energy industry has large LIFO reserves but have limited data sets. Table 1 of volume 2 of Treasury (1984) indicates the opposite but is much older.

\(^{14}\) Kleinbard, Plesko, and Goodman (2006) note that inflation affects all capital investment, not just inventories, and thus should be dealt with in a systematic manner instead of through LIFO as a piecemeal solution affecting only inventories would favor investment in one form over another. However, a neutral tax system would allow inflation indexation for both inventories and capital investment.
PRP cannot afford to pay for the cleanup (Ramseur, Reisch, and McCarthy 2008). Cleanup at these “orphaned” sites are paid out of the Hazardous Substance Superfund Trust Fund (Superfund). Since the expiration of three excise and one income tax which originally funded the Superfund, the Superfund is now paid for out of general revenues (Ramseur, Reisch, and McCarthy 2008).

The President’s 2013 Budget proposal would reinstate all four Superfund taxes for the years 2013 through 2022 (Treasury 2012). Two of the excise taxes would not apply to the energy industry while the income tax would apply to all corporations. The only tax of specific relevance to the energy industry is the remaining excise tax, a 9.7 cent per barrel excise tax on domestic crude and on imported petroleum products.

Under a neutral tax system, polluted site cleanup would be handled in the same manner as oil spills. We therefore propose the same solutions discussed in greater detail under the Oil Spill Liability Trust Fund: impose full civil liability for small amounts of pollution and either require firms to purchase excess liability insurance or impose an actuarially fair tax on activities with the possibility for catastrophic pollution that would exceed the firm’s ability to pay.

The Superfund excise tax has a similar problem to the Oil Spill Liability Trust Fund. The excise tax is not actuarially fair: it is paid by all firms who produce or import petroleum, at the same rate regardless of the care taken by any firm to avoid polluting or the firm’s risk of defaulting on cleanup costs. This creates a moral hazard for small firms with a high risk of default and therefore does not internalize the cost of pollution cleanup.

However, the Superfund is less problematic in that the excise tax is only used to pay for orphaned sites. Under current law, if the PRP can be identified and is able to pay, then the PRP pays for cleanup at the site. Yet for the orphaned sites, it does not internalize the cost of cleanup if a firm can avoid responsibility if its assets are less than the cost of the pollution damages. But the case of orphaned sites whose PRP cannot be identified complicate the analysis. It is not clear why the PRP cannot be identified in these cases. If the inability to identify the PRP would also prevent identification of their insurance, then an actuarially fair tax would be more neutral than requiring excess liability insurance.

II.J. Modify Dual Capacity Rules

The US taxes domestic corporations on the income they earn in foreign countries. However, since the host country can also impose income taxes on the income of corporations earned in that country, this can lead to double taxation of that income. To avoid double taxation, the US tax code allows firms to credit certain foreign levies against their US tax liability. A foreign levy is creditable against the firm’s US tax liability if it is compulsory and is not compensation by the firm to the
host nation for a specific economic benefit. A “dual-capacity taxpayer” is a taxpayer who is subject to a levy by a foreign
country that also receives a specific economic benefit from that country.

The tax code allows taxpayers to choose between two methods to determine the portion of the levy paid by the
taxpayer which is compulsory and creditable, and the portion which is compensation for a specific economic benefit and
deductable. Under the facts and circumstances method, a levy is creditable to the extent that the taxpayer is able to prove
that portion of the levy is not paid as compensation for specific economic benefits. Under the safe harbor method, if the
host country has a generally imposed income tax, the taxpayer may credit an amount equal to the tax payment that would
result from application of the host country’s generally imposed income tax (JCT 2012). In either case, the foreign tax credit is
limited to a taxpayer’s US tax liability on its foreign source income (JCT 2012).

The President’s 2013 Budget Proposal would eliminate the current safe harbor and facts and circumstances methods
for determining the fraction of a levy that is creditable (Treasury 2012). Under the new rules, dual capacity taxpayers would
be able to treat as creditable the portion of a foreign levy that does not exceed the foreign levy that the taxpayer would pay if
it were not a dual-capacity taxpayer (Treasury 2012). In effect, dual capacity companies would only be able to credit an
amount equal to the host nation’s general corporate tax rate applicable to other industries (Pirog 2012). This is similar to
simply forcing firms to choose the safe harbor method. In addition, the special limit for oil and gas income tax credits would
be removed and it would instead be treated as its own separate limitation category (Treasury 2012).

If US dual capacity firms operating outside the US are able to use creditable royalty payments to reduce their tax
rate below that faced by other US based firms operating outside the US, who have to pay for economic benefits through
deductible but not creditable expenses, then removing these credits enhances of the tax code. However, it is unclear that simply
forcing all firms to credit taxes using the general corporate tax rate separates the taxes are true income taxes from the taxes
that are payments for economic benefits more accurately than the nuanced calculation allowed by the facts and circumstance
rule. Indeed, to the extent that it is accurately applied, the facts and circumstances method seems ideal.

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15 Treasury Regulation section 1.901-2(a)(2)(i).
17 Treasury Regulation section 1.901-2A(c).
18 These rules were designed because of concerns that income taxes imposed on US oil companies by foreign governments
were not income taxes but disguised royalties, which are normally deductible but not creditable (JCT 2012).
19 Treasury Regulation section 1.901-2A(c)(2)(i).
20 JCT (2012) explains how two additional rules also apply. The credit is restricted by the category of income, generally
referred to as “separate limitation category,” so that tax credits from a particular category of income can only offset tax
liabilities from that same category of income. In addition to the special limitation categories, credits from oil and gas income
taxes may only offset oil and gas income tax liabilities.
Distinct from possible differentials between sectors, another issue is whether foreign source income of US based firms should be taxed at all. There are two major systems states use for the taxation (or non-taxation) of foreign source income. Under a pure residence base tax system, countries tax their residents (and domestic firms) on their worldwide income. Alternatively, under a territorial tax or source-based tax system, a country only taxes income that is earned within its borders.

Previous literature has not come to a consensus on which system is superior. However, Gravelle (2009) notes that the US is only nominally a residence based tax system. Under current law, firms only pay taxes on income that is repatriated back to the US and are allowed to indefinitely defer repatriation. This significantly reduces the US tax they pay on foreign source income. In this case, Gravelle (2009) states that a move towards either a more pure residence or territorial tax system would enhance the neutrality of the tax code. Exempting foreign source income entirely and moving to a territorial tax system would encourage the repatriation of income by reducing its tax rate. Alternatively, the tax code could move to a more effective residence system by ending deferral, which would encourage the repatriation of income and also increase the effective tax rate on foreign source income.

The President’s proposed changes use neither of these methods. By reducing deductions, the difference in effective tax rate between repatriated and deferred foreign source income increases. If the goal is to increase the effective tax rate on foreign source income to be closer to the effective tax rate on domestic income, it should not be done in such a way that would increase the incentive to defer repatriation of foreign source income. This decreases the neutrality of the tax code.

III. OVERALL TAX TREATMENT OF FOSSIL FUEL PRODUCTION

It is important to frame the discussion of the individual tax changes proposed by the President in the context of the existing taxes and deductions faced by fossil fuel producers. The President himself noted that “these companies pay a lower tax rate than most other companies on their investments, partly because we’re giving them billions in tax giveaways every year” (Office of the Press Secretary 2012). Treasury (2012) also stated that tax preferences encourage more investment in fossil fuel production than would occur under a neutral tax system. Although neither provided a citation for their claim, there has been significant research in recent years on the tax rates faced by the energy sector, and at least one paper that did find that the income from investment in energy capital faced a lower tax rate than the income from other types of capital investment (Congressional Budget Office 2005).

However, before we can discuss previous estimates of effective tax rates, we first need to discuss exactly which taxes we are interested in and how we plan to measure them. Which taxes to include depends on the inference to be drawn. For example, in order to calculate the effective long run tax rate on oil industry capital, severance taxes should not be included since they are borne by landowners in the form of lower resource payments (bonus bids, royalties, etc.). But a severance tax on oil could still be non-neutral, if the distortions occurred on different margins. Lowering the payments resource owners receive could lower the overall level of oil production from the pre-tax amount by encouraging alternate land use or early shutdown of the well. Therefore, since we are interested in total production, it is appropriate to look at all taxes.

We do so by looking at the effective tax rates on various activities in fossil fuel production compared to other sectors. However, this analysis is complicated by the different methods of calculating effective tax rates, each with their own advantages and disadvantages. We review a number of results in previous literature using the marginal effective tax rate and then add our own results using an alternative measure, the average effective tax rate.

Although we are looking at the actual effective tax rates, a separate issue is determining what the optimal tax rates are. For example, higher tax rates on fossil fuel production than on other sectors could be justified as Pigouvian taxation on negative externalities, in order to capture resource rents, or because their products are complements of untaxed leisure. For example, the aforementioned severance tax on oil could be efficiency enhancing if it was set equal to the cost of pollution remediation per barrel.

In order to determine whether the proposal is efficiency enhancing, we would need to compare the efficiency cost of this proposal due to differential taxation to the efficiency gains from a reduction in activities that create externalities. A full calculation of the external benefits of reduced fossil fuel production would require measuring the benefits from a number of sources of such gains such as reduced oil spill risk, local pollution, and carbon dioxide emissions and perhaps the national security costs of relying on foreign sources of oil. The difficulty of this task is further confounded by widely varying estimates in the size of these externalities when they exist, especially for carbon dioxide emissions. This is beyond the scope of the current paper and thus we are unable to completely answer the fundamental question of whether the budget proposal is efficiency enhancing.

However, we can partially answer the question by providing estimates of the economic costs differential taxation of the energy sector under the budget proposal that would need to be outweighed by gains from reduced externalities in order for the proposal to be net efficiency enhancing. In addition, even in cases where differential taxation is theoretically optimal, several factors make differential taxation more desirable in theory than practice. In particular, differential taxation raises
difficult classification issues and creates incentives for avoidance and evasion. Moreover, in practice differential rates are more likely to be set by political factors than by the prescriptions dictated by economic efficiency (Zodrow 2007).\(^{22}\)

**III.A. Types of Taxes on Fossil Fuel Production**

**III.A.1. Capital Taxes**

The main taxes imposed on capital income are state and federal corporate income taxes and personal income taxes on capital gains and dividends. The effect of these taxes on the pre-tax and post-tax rates of return can be summarized through the effective tax rate (ETR) on investment. The effective tax rate is the amount capital taxes reduce the pre-tax rate of return on investment. For example, if investment in a new oil well earned a pre-tax 10 percent return but taxes reduce that return to 6 percent, the effective tax rate would be \((10-6)/10 = 40\) percent. An effective tax rate differs from the statutory tax rate in that it applies to the income earned over the lifetime of an investment and is able to account for the effects of inflation, the difference between tax and economic depreciation, and the difference in the taxation of returns to debt and equity.

The marginal effective tax rate (METR) is the tax rate for the marginal investment, the investment that earns a rate of return exactly equal to the cost of capital. The marginal investment is the critical one for determining the aggregate level of investment because a firm will invest in all investments opportunities with higher post tax rates of return than the break even rate and not invest in any with lower. Reducing the rate of return of an investment which is currently at the break even rate would cause the firm to no longer undertake the project and thus reduce aggregate investment.

The literature has produced many estimates of the marginal tax rate for different types of capital assets, including Congressional Budget Office (CBO) (2005), Mackie (2002), Ernst & Young (2007), and Metcalf (2009). CBO (2005) calculates the METR from federal taxes for a wide variety of very broad asset categories.\(^{23}\) They find the overall METR on capital assets from all businesses is 24.2 percent and the METR on corporations is 26.3 percent. But the METRs for C corporation assets in the fossil fuel industry vary from 9.2 to 24.9 percent. However, note that these results are for particular assets used only by energy industries, not the industry as a whole.

Mackie (2002) calculates METRs for assets but also aggregates them over industries. He finds a high ETR on energy assets such as mining and oil field machinery (33.5 percent) and a lower ETR on mining, shafts, and wells (16.9 percent). When aggregated at the industry level, crude petroleum and gas has an METR of 24.6 percent while petroleum

\(^{22}\) Harberger (1990) and Slemrod (1990) provide more detailed discussion of these problems.

\(^{23}\) The taxes included in the CBO analysis are federal taxes on corporate profits, dividends, long-term capital gains, short-term capital gains, interest income, mortgage interest deductions, unincorporated business income, and distributions from nonqualified annuities. See CBO (2005) Table A-4 for more details.
refining’s METR is 35.6. By comparison, the METR for the corporate sector is on average 32.2 and the METR for the entire economy is 19.8 percent.

Other papers have calculated the METR for the energy sector but did not include estimates for other sectors. These papers are less helpful in determining the relative tax burdens of fossil fuel production and other sectors since they do not present comparable economy-wide average METRs using the same methodology. But if their methodology is not too different from others in the literature, they can still provide some perspective. Ernst & Young (2007) looks at the energy sector specifically but only includes the federal corporate income tax in their calculation. They find a 21.6 percent METR for petroleum refining. Metcalf (2009) provides another calculation of the METR of assets used in fossil fuel production. Metcalf’s calculation includes some tax credits, but the only taxes included are the federal corporate income tax and the average state corporate income tax. His results show significant variation in the METR faced by different capital assets in the energy sector, with METRs ranging from a high of 27.0 percent for other natural gas pipelines to a low of -13.5 percent for oil drilling by non-integrated firms. However, his METRs for oil drilling by integrated firms, petroleum refining, and natural gas gathering pipelines are all in the range of 15.2 to 19.1 percent.

III.A.2. Other Taxes

In addition to capital taxes, fossil fuel production faces a large number of other taxes such as sales, property, severance, and excise taxes. As seen in Table 2, total payments for these taxes, less subsidies, by fossil fuel producing sectors exceed payments for corporate income taxes. However, to the best of our knowledge, these taxes have not been combined and summarized, either with each other or with capital taxes, the way the METR literature has done for taxes on capital investment. In the next section, we attempt to do so for the combined effect of capital and other taxes by calculating average effective tax rates (AETR).

Table 2: Total Tax Payments by Industry, 1998-2009 ($ million)

<table>
<thead>
<tr>
<th>Sector</th>
<th>Corporate Income Taxes</th>
<th>Other Production Taxes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil and gas extraction</td>
<td>39,230</td>
<td>204,759</td>
</tr>
<tr>
<td>Petroleum and coal products</td>
<td>193,870</td>
<td>24,738</td>
</tr>
<tr>
<td>manufacturing</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pipeline transportation</td>
<td>3,738</td>
<td>17,595</td>
</tr>
<tr>
<td>All these particular energy</td>
<td>236,838</td>
<td>247,091</td>
</tr>
<tr>
<td>sectors</td>
<td></td>
<td></td>
</tr>
<tr>
<td>All sectors</td>
<td>3,627,248</td>
<td>9,785,265</td>
</tr>
</tbody>
</table>

Source: Author’s calculation from BEA US Input-Output Accounts and NIPA Table 6.18D.

Both corporate income tax statistics and the other production tax statistics include all such taxes at the federal, state, and local levels.
III.B. Average Effective Tax Rate

Although we are interested in calculating the ETR on fossil fuel production, there is no single ETR that captures every dimension of taxation. Therefore we will provide a number of ETR looking at different types of taxation and different bases. Our two main data sources are the Use of Commodities by Industries after Redefinitions tables for 1998-2009 in the US Input-Output accounts from the Bureau of Economic Analysis (BEA) and Table 6.18D: Taxes on Corporate Income by Industry in the 2012 National Income and Product Accounts, also by the BEA.\(^{25}\) We will calculate the average effective tax rate for a selection of energy sectors and the whole economy by dividing total tax payments by both value added and gross income. We also calculate the average effective tax rate on capital for those same sectors by dividing corporate income tax payments by gross operating surplus, a coarse measure of capital income.

Total tax payment equals taxes on production and imports plus state, local, and federal corporate income taxes minus subsidies.\(^{26}\) Taxes on production and imports include taxes on the product delivery or the sale of products and taxes on the ownership of assets used in production, such as federal excise, state and local sales taxes, and local real estate taxes. Corporate income taxes include those taxes at the federal, state, and local level. Value added is equal to gross operating surplus plus compensation of employees, plus taxes on production and imports, less subsidies.

We estimate tax burden using the average effective tax rates (AETR) as opposed to marginal effective tax rates (METR). Collins and Shackelford (1995) and Fullerton (1984) discuss each measure and their advantages and disadvantages. METR calculations are designed to measure the tax cost on marginal incentives to hire labor or employ capital. However they are calculated theoretically and require numerous assumptions about firm financing, asset purchase decisions, and depreciation (Collins and Shackelford 1995).\(^{27}\) In addition, the calculation must explicitly choose which provisions of the tax code (which deductions, which tax credits) to include and how to model them. As a practical matter, they must pick and choose what provisions to include and this will lead the calculation to miss the cumulative effect of numerous small or difficult to model features that are not included.

\(^{25}\) In an alternative specification, we instead use corporate income tax data from the Internal Revenue Service Statistics of Income Tax Stats on the Returns of Active Corporations by Minor Industry. These results show a smaller difference between all industries and the selected fossil fuel producers, but still indicate a lower tax rate for other industries than fossil fuels. However, this data set does not include state and local income taxes and has one less year of data. Full results are available upon request.


\(^{27}\) See CBO (2006) for a more detailed description of the general method used to calculate METRs.
AETRs are calculating empirically by dividing a measurement of taxes paid by a measurement of the base of economy activity taxed. Because it is calculated from actual tax payments, it avoids the problems METR calculations face of having to make numerous assumptions and being forced to pick and choose the features of the tax code to include. However, the AETR measures the average tax rates on all investments as opposed to finding the tax rate on the marginal investment. It thus reflects the total burden of taxation instead of marginal incentives (Collins and Shackelford 1995).28

We calculate the AETR on capital income by dividing corporate income tax payments by gross operating surplus. But to calculate the AETR inclusive of all taxes, we need to decide on the base. Since previous work has focused almost exclusively on the average (or marginal) effective tax rate on capital, it is unclear which base is the most appropriate to use for the denominator of our total AETR calculation. Which base is appropriate to use depends on who bears the burden of the tax. For example, if all taxes are fully forward shifted onto consumers, total industry tax payments divided by total industry gross receipts would be the appropriate measure. Alternatively, value added is the appropriate base if taxes are backwards shifted onto factors or to take into account the previous forward shifting of taxes on industries whose products are also being used as intermediate inputs in other industries.29 We present results using both measures.

III.C. Average Effective Tax Rate Estimates

Table 4 presents AETRs on capital for selected sectors for 1998-2009. The AETR on capital in these fossil fuel producing sectors is 13.0 percent. This tax rate is 5.5 percentage points or 73 percent higher than the rate of 7.5 percent for all sectors. These results are driven by the extremely high tax rate on capital in petroleum and coal products manufacturing which is 21.4 percent. The other two sectors, oil and gas extraction and pipeline transportation have lower AETR than the average for all sectors.

Table 3: Average Effective Tax Rates on Capital by Sector, 1998-2009 (Percent)

<table>
<thead>
<tr>
<th>Sector</th>
<th>Capital AETR</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil and gas extraction</td>
<td>4.6</td>
</tr>
<tr>
<td>Petroleum and coal products manufacturing</td>
<td>21.4</td>
</tr>
<tr>
<td>Pipeline transportation</td>
<td>6.4</td>
</tr>
<tr>
<td>Fossil fuel production¹</td>
<td>13.0</td>
</tr>
<tr>
<td>All sectors</td>
<td>7.5</td>
</tr>
</tbody>
</table>

Source: Author’s calculation from BEA US Input-Output Accounts and NIPA Table 6.18D.
Notes: (1) Fossil fuel production is defined as oil and gas extraction, petroleum and coal products manufacturing, and pipeline transportation.

28 The AETR method is certainly not without its own drawbacks. See Fullerton (1984) for a discussion of the problems of AETR.
29 Many other different fractional distributions of the tax burden are also possible.
Table 5 presents average effective tax rates of all firm taxes for energy and other sectors for 1998-2009. As a fraction of gross receipts, the total value of output, the average effective tax rate for these fossil fuel producing sectors is 7.4 percent. The AETR for all sectors is 1.5 percentage points lower at 5.9 percent. The AETR for oil and gas extraction is the highest at 12.1 percent. Petroleum and coal products manufacturing has the lowest AETR at 5.1 percent. If total taxes paid are instead divided by gross income, gross receipts minus cost of goods sold, the average effective tax rate for the entire economy is 10.9 percent. The average rate for fossil fuel producing sectors is 19.7 percent, a difference of 8.8 percentage points and 81 percent higher than the economy wide rate.

Table 4: Average Effective Tax Rates of All Taxes by Sector, 1998-2009 (Percent)

<table>
<thead>
<tr>
<th>Sector</th>
<th>Gross Income Base</th>
<th>Gross Receipts Base</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil and gas extraction</td>
<td>19.3</td>
<td>12.1</td>
</tr>
<tr>
<td>Petroleum and coal products manufacturing</td>
<td>20.4</td>
<td>5.1</td>
</tr>
<tr>
<td>Pipeline transportation</td>
<td>16.7</td>
<td>7.4</td>
</tr>
<tr>
<td>Fossil fuel production¹</td>
<td>19.7</td>
<td>7.4</td>
</tr>
<tr>
<td>All sectors</td>
<td>10.9</td>
<td>5.9</td>
</tr>
</tbody>
</table>

Source: Author’s calculation from BEA US Input-Output Accounts and NIPA Table 6.18D.
Notes: (1) Fossil fuel production is defined as oil and gas extraction, petroleum and coal products manufacturing, and pipeline transportation.

The AETR on fossil fuels is higher than the AETR for other sectors under all three specifications. So for this measure of taxation, fossil fuel production is more heavily, not less, taxed than other sectors. However, this is a calculation of the actual average level of taxation, not the optimal level of taxation. In the next section, we will look at this second issue and calculate the economic costs of the non-uniform taxation proposed in the budget.

IV. GENERAL EQUILIBRIUM MODEL

So far we have given descriptive analysis of the proposed changes and followed it with an analysis of the current law level of taxes on fossil fuel production. Now we turn to examine the aggregate effect the changes to fossil fuel taxation proposed in the President’s 2013 Budget will have on fossil fuel production and the rest of the US economy. We will calculate the effect the changes will have on the price of fossil fuels, their supply and demand, and calculate the excess burden of raising revenue by focusing on taxing fossil fuels as opposed to spreading the increase in tax burden over all sectors of the economy. As a final summary statistic, we also calculate a lower bound on the per ton cost of the proposal’s carbon dioxide emission reduction.
IV.A. Model Description

In this section, we briefly describe the construction of the model we will use to analyze the effects of the budget proposal. We begin by estimating cost functions for each industry and an expenditure function for consumers. We then insert the cost and expenditure functions into a general equilibrium model of the US economy. Our model is a simplified version of the model used by Jorgenson and Slesnick (2008) and Wilcoxen (1988). Finally, we look at the model under the proposed changes to the taxation of fossil fuels and compare the prices, output, demand, and excess burden that would result if the same amount of revenue was raised from taxing all sectors instead.

In the model, the cost function for an industry relates the cost producing the industry’s output to the cost of the industry’s inputs—labor, capital, and all the outputs. Following the general equilibrium models of Jorgenson and Slesnick (2008) and Wilcoxen (1988), we utilize a translog cost function for our industries. Although the functional form of the translog cost function is quite complex, its key features can be described simply: it allows varying degrees of substitution between all inputs, change in the relative importance of particular inputs over time due to technological progress, and change in overall productivity due to technological progress. The cost function is exactly the same whether a particular unit of output produced by an industry is used by consumers or as an intermediate good by another industry. However, the cost functions vary across the 22 industries. We assume all industries are perfectly competitive with constant returns to scale. These two assumptions ensure that the consumer price and post-tax cost of the output for each industry are identical. To get the consumer price, we take the pre-tax producer price given by the cost function and multiply it by one plus the production tax rate.

We assume capital and labor are perfectly mobile between sectors but in aggregate have an isoelastic supply functions determined by their after tax rate of return or wage rate. Expenditures are made by a government sector, a representative consumer, the industries, and the rest of the world through imports and exports. Imports and exports are also isoelastically supplied and demanded, respectively.

We perform a series of regressions to determine the values of the parameters that define the relationships in the cost functions. These regressions have an endogeneity problem that must be dealt with since prices, a right hand side variable, are dependent on cost shares, a left hand side variable. Additionally, since the cost shares of all the inputs must sum to one, the error terms of the regressions are correlated. We deal with both of these problems by performing the regressions via iterated three-stage least squares.

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30 The cost function is explained in more detail in the appendix.
The data used in the regressions and simulations come from several sources. The first is a system of U.S. national accounts covering the years 1960 to 2005 compiled by Jorgenson (2007). The data includes the quantity and price of output produced by all industries and all inputs purchased by all industries. This data is converted to NAICS basis using the 1997 Economic Census’s Bridge between NAICS and SIC. Additional data comes from the BEA Tables of the Use of Commodities by Industries from 1997-2010 and the BEA Gross Output Price Index from 1987-2010.

Most model parameters are parameterized using regressions as previously described. However, certain key parameters were not estimated from data. The elasticity of capital and labor were taken from other sources in the literature while the import and export elasticity chosen via calibration by picking values that gave a reasonable baseline case. The elasticity of capital supply is set equal to 1.5 based on results in Goolsbee (1998). The elasticity of labor supply is set equal to 0 based on results in McClelland and Mok (2012). The elasticity of import supply and export demand are -0.6 and 0.5 respectively.

In order to model the proposed changes in the budget, we have to model each proposal within the context of the general equilibrium model. For example, although crude oil from oil sands is not taxed under current law, it would be under the budget proposal. However, modeling the choices firms have to produce petroleum products from different types of crude oil is a level of detail too great for this general equilibrium model. The model-equivalent tax proposal is necessarily simpler than the actual proposal. For this reason, we model the proposed budget as an increase in the effective tax rate on capital of energy producing sectors. We calculate the effective tax rate increase of the proposal by taking the yearly JCT revenue estimate of the budget proposal and dividing by capital payments for that sector, BEA gross operating surplus. Thus this simulation does not attempt to evaluate the effects of the individual features of the budget proposal. Analysis of the desirability of those changes is only covered by Section II. This analysis instead looks at the effects of the aggregate tax increases on fossil fuel capital that would come about as a result of all the changes proposed by the budget.

Additionally, in order to determine the effects of a policy, it must be compared to the state of the economy under an alternative policy. One alternative is current law tax rates. But using that as an alternative would require additional assumptions about the tradeoff between immediate tax increases and debt finance. To simplify the comparison, we instead compare the president’s fiscal year 2013 budget proposal to a policy that raises the same amount of revenue by increasing the statutory corporate income tax at a uniform rate on all sectors. The current law tax system onto which one of these two tax increases is added is modeled as three taxes: a tax on capital, a tax on labor, and production taxes on output. The rates for the taxes on capital and production vary by industry and are taken from the results in Section III. The tax rate on labor income is set equal to 28.5 percent following Mendoza, Razin, and Tesar (1994).
IV.B. Effects of Proposal on Fossil Fuel Industry Prices and Production

Figure 1 shows the increase in the price of each sector’s output that would occur under the budget proposal. There is a large increase in price for the fossil fuel producing sectors. The largest price increase of 2.6 percent occurs for oil and gas mining, while pipeline transportation and petroleum and coal manufacturing have price increases of 0.8 and 2.2 percent. Sectors which heavily rely on fossil fuels such as transportation, utilities, and mining have smaller price increases on the order of 0.2 to 0.4 percent. Other sectors typically have negligible changes in the price of their goods.

Figure 1: Price Increase From the Budget Proposal by Sector

Figure 2 shows the decrease in the output of each sector that would occur under the budget proposal. As for the price changes, the largest decrease in output occurs in fossil fuel producing sectors. However, there is much more variance here than for price. Output in pipeline transportation decreases by 1 percent but petroleum and coal manufacturing output only falls 0.1 percent. We again see declines for sectors reliant on fossil fuels. Output in utilities falls 0.3 percent and transportation falls 0.2 percent. For most other sectors, there is no effect. But surprisingly, mining actually registers a very slight increase in output of 0.2 percent.

Figure 2: Output Decrease From the Budget Proposal by Sector
Figure 3 shows the decrease in demand for each sector’s goods that would occur under the budget proposal.\textsuperscript{31} Again, fossil fuel producing sectors see the largest decrease in demand. Oil and gas mining has the largest decrease with a decrease in demand of 3.2 percent. Demand for pipeline transportation decreases by 1.0 percent while demand for petroleum and coal manufacturing actually has a 0.1 percent increase in demand. As before, demand for the output of sectors reliant on fossil fuels also falls. Demand for utilities falls 0.2 percent and transportation demand falls 0.1 percent.

Note however that the listed price and quantity changes are for industries such as petroleum and coal manufacturing, not specific commodities such as petroleum and natural gas. However, we can calculate the implied to the price of fossil fuel commodities such as natural gas by calculating a weighted average of the industry price changes using the share of that

\textsuperscript{31} We define demand as domestic production plus imports, or equivalently, output minus exports.
commodity in the value of the industry’s output as the weight. 32 33 We find that coal commodities will increase in price by 2.2 percent, petroleum will increase by 2.3 percent, and natural gas will increase by 2.5 percent.

Our methodology also allows us compare the excess burden of revenue raised under the budget proposal to the alternative uniform increase in capital taxes. We calculate the equivalent variation consumers would be willing to pay if they were under a regime where taxes had been increased uniformly to avoid changing to a regime where the tax increase was focused on fossil fuels. We then divide the equivalent variation by the revenue raised by the budget proposal. We find that revenue raised under the budget proposal has an excess burden that is higher by 18 percent of revenues compared to raising the same amount of revenue under a uniform ad valorem excise tax.

Figure 3: Demand Decrease From the Budget Proposal by Sector

32 This is the same method as the BEA uses to calculate the change in the price of a sector’s output from the weighted average of individual price changes of its constituent subsectors.
33 The weights are the dollar values of shipments by product line taken from the 2007 Census. It is available at http://www.census.gov/econ/industry/.
Finally this leads us to the per ton cost of carbon dioxide emission reductions. The budget proposal will reduce demand for fossil fuels more than the baseline tax increase but at the cost a higher excess burden for consumers. If we make the assumption that the percentage reduction in total US carbon dioxide emissions is less than or equal to the largest reduction in demand faced by an energy sector (1.0 percent for pipeline transportation), we can calculate a lower bound for the cost per metric ton of carbon dioxide reduction from this budget proposal. We multiply the excess burden rate by the average yearly JCT revenue estimates to get the total yearly cost of the pollution reduction. We then divide this value by 1.0 percent times the total yearly US carbon dioxide emissions to get the cost per metric ton. This gives the cost of carbon dioxide reduction from the proposal a lower bound of $35 per metric ton. Therefore in order for the budget proposal to be efficiency enhancing, the cost of alternative sources of abatement and the cost of all externalities caused by the production and fossil fuels and their emissions must exceed $35 per metric ton.

V. CONCLUSIONS

The proposals in the president’s fiscal year 2013 budget to increase the Oil Spill Liability Trust Fund excise tax rate, target the domestic manufacturing deduction, modify the dual capacity rules, and reinstate the Superfund excise taxes reduce the neutrality of the tax code. The proposals to repeal the capital gains treatment of coal royalties and increase the G&G amortization period are neutrality enhancing. The neutrality of repealing LIFO, percentage depletion, and the expensing of IDCs and coal exploration is unclear.

Although some of the individual tax provisions identified for repeal in the President’s 2013 budget favor fossil fuel production, it is not clear that the tax code as a whole does. Previous studies calculating marginal effective tax rates on capital employed in fossil fuel production have had mixed results. Our calculations show the average effective tax rate on capital used in fossil fuel production is 2.9 percentage points higher than the economy wide rate. However these taxes are only a minority of taxes paid by the industry. Calculating average effective tax rates for all taxes on fossil fuel production gives a tax rate that is either 8.8 or 1.5 percentage points higher than the economy wide rate, depending on the basis used.

General equilibrium results indicate that the proposal will increase the price of fossil fuels by 2.2 to 2.5 percent, decrease their output by 0.1 to 1.0 percent, and decrease their demand by 1.0 to 3.2 percent. The price of commodities will also go up with a 2.2 percent increase for coal, a 2.3 percent increase for petroleum, and a 2.5 percent increase for natural gas.

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The excess burden of the additional revenue gained is an additional 18 percent of revenues higher than if the tax increase were applied uniformly across all sectors. The cost of the carbon dioxide reduction due to the proposal is at least $35 per ton.

Future work could improve this analysis in a number of ways. ETRs could also be calculated using the METR methodology. Greater detail could be added to the energy sector by including exploration and development decisions. And adding dynamics to the model could identify the short term effects of the policy change.

REFERENCES


Appendix A: Cost Function

In the model, there is not one single cost function for an entire industry but a series of nested cost functions, each
with the translog form. Nesting the cost function is required to reduce the number of parameters to be estimated to a
manageable number. The tier structure used to nest the cost functions is shown in the tree in Figure 4. An aggregate
commodity and its components inputs will be called a “node” of the structure. The top node has a sector’s final output created
from capital, labor, energy, and materials, while lower nodes are aggregates of particular energy and material commodities.
Except for final output at the top level, an aggregate commodity is not a good, but a basket of goods created from inputs
which, at the lowest level, are all goods.

For example, the aggregate commodity MO is made from the inputs MOT, commodity 23 (construction), and
commodity 53 (real estate and rental and leasing). MOT is itself an aggregate commodity made from commodities 42
(wholesale trade), 44 (retail trade), and 48 (transportation and warehousing). At the lowest level, aggregate commodities are
created from the 22 sector output commodities. Note that the price of a the sector output commodities are the same across all
industries at a particular time but the price of aggregate commodities like energy will vary across industries in the same time
period.

For each aggregate commodity (node) $x$ and each industry, the translog cost function to be estimated is

$$ln(c_{xot}) = \frac{1}{2} \sum_{i=1}^{N} \sum_{j=1}^{N} \beta_{xij}^{\text{substitution}} ln(p_{xiti}) ln(p_{xitj}) + \sum_{i=1}^{N} \beta_{xi}^{\text{shareconstant}} ln(p_{xiti}) + \sum_{i=1}^{N} \beta_{xi}^{\text{sharetrend}} ln(p_{xiti})t + \beta_{xo}^{\text{costtrend}} t$$

where $ln(c_{xot})$, the log cost of producing commodity $o$ for industry $x$ at time $t$, is a function of the log input prices $ln(p_{xiti})$ of the $N$ inputs.\(^{35}\) $ln(p_{xiti})$ is the log price of input $i$ at time $t$ to industry $x$. The variables $\beta_{xij}^{\text{substitution}}$, $\beta_{xi}^{\text{shareconstant}}$, $\beta_{xi}^{\text{sharetrend}}$, $\beta_{xo}^{\text{costtrend}}$, and $\beta_{xo}^{\text{constant}}$ for the inputs $i$ and $j$ are the parameters to be estimated at this node. Intuitively, $\beta_{xij}^{\text{substitution}}$ defines how use of input $i$ responds to changes in the price of input $j$ for industry $x$. $\beta_{xi}^{\text{shareconstant}}$ is an intercept that gives the value share of input $i$ for industry $x$ at this node when time and all log input prices are zero. $\beta_{xi}^{\text{sharetrend}}$ defines how much the value share of input $i$ changes in one year for industry $x$ if input prices do not change. $\beta_{xi}^{\text{costtrend}}$ is a productivity parameter that defines how much the cost of output changes over time for industry $x$. $\beta_{xo}^{\text{constant}}$ is the constant term of the cost function. It is the cost of output at time 0 when all input prices are 1. The final price of output is calculated

\(^{35}\) We omit the variable subscript which identifies the industry for which a variable applies since all variables except $t$ and $N$
\(^{36}\) The value of $N$, the number of inputs used to make a commodity, ranges from one to four and is defined for a particular
node according to Figure 4. It varies across nodes but is the same at any particular node across industries.
by taking the cost of output $ln(c_{x,t})$ and multiplying by the statutory production tax rate. For lower nodes, there is no tax and their “price” is equal to their cost.
Figure 4: The tier structure of production

Notes: K is capital, L is labor, O is output, and N is non-competing imports. Numbers give the NAICS code of the respective sector. All other letters are the names of aggregate commodities.