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THE IMPACT OF REMOVING TAX PREFERENCES FOR U.S. OIL AND NATURAL GAS PRODUCTION: MEASURING TAX SUBSIDIES BY AN EQUIVALENT PRICE IMPACT APPROACH

Gilbert E. Metcalf

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ABSTRACT

This paper presents a novel methodology for estimating impacts on domestic supply of oil and natural gas arising from changes in the tax treatment of oil and gas production. It corrects a downward bias when the ratio of aggregate tax expenditures to domestic production is used to measure the subsidy value of tax preferences. That latter approach underestimates the value of the tax preferences to firms by ignoring the time value of money.

The paper introduces the concept of the equivalent price impact, the change in price that has the same impact on aggregate drilling decisions as a change in the tax provisions for oil and gas drilling and production. Using this approach I find that removing the three largest tax preferences for the oil and gas industry would likely have very modest impacts on global oil production, consumption or prices. Domestic oil and gas production is estimated to decline by 4 to 5 percent over the long run. Global oil prices would rise by less than one percent. Domestic natural gas prices are estimated to rise by 7 to 10 percent. Changes to these tax provisions would have modest to negligible impacts on greenhouse gas emissions or energy security.

Gilbert E. Metcalf
Department of Economics
Tufts University
Medford, MA 02155
and NBER
gilbert.metcalf@tufts.edu

1. Introduction

The tax treatment of oil and gas investment in the United States has been a contentious policy issue for decades. Reform advocates argue that eliminating tax preferences for producers of oil and gas could increase government revenues by billions of dollars each year and advance global efforts to phase out fossil fuel subsidies, improving international energy security and mitigating climate change. Defenders of the existing tax regime contend that changing it would lead to large declines in domestic oil and gas production and to significant job destruction, imperiling America's energy security and its economic strength. Tax treatment for oil and gas production has also been featured prominently as a politically polarizing linchpin in debates over how to overhaul the U.S. tax code. Because reform perennially features in congressional budget battles and has previously attracted support from presidential candidates from both political parties, it will likely continue to feature in U.S. politics in the future.

Although debates over tax preferences are long-standing, recent changes in the energy landscape are generating new arguments for and against reform. On one hand, U.S. oil and gas production has surged past that of any other country, raising doubts about the continued need for tax preferences to stimulate domestic production. On the other hand, the recent plunge in global oil prices—from over $100 in 2014 to below $30 at points in early 2016—has endangered the viability of some producers and deepened concerns that eliminating tax preferences would further undermine the industry.

Policymakers considering this issue need a thorough understanding of the potential consequences of tax reform in the new energy context. Unfortunately, existing studies either fail to seriously analyze the economic effects of removing tax preferences or are not transparent or publicly available.

To fill the gap, this study models firm behavior in response to the potential loss of each of the three major tax preferences, which collectively cost the government roughly $4 billion annually (Congressional Budget Office, 2013). It finds that domestic oil drilling activity could initially decline by roughly 9 percent, and domestic gas drilling activity could decline initially by roughly 11 percent. These declines in drilling would in turn lead to a long-run decline in domestic oil and gas production. As a result, the global price of oil could rise by 1 percent by 2030 and domestic production could drop 5 percent; over the long run, global consumption could fall by less than 1 percent. Domestic natural gas prices, meanwhile, could rise between 7 and 10 percent, and both domestic production and consumption of natural gas could fall between 3 and 4 percent.

I close with some observations on the role these tax preferences play in achieving important policy objectives. The results from the empirical analysis make it possible to assess each tax preference against three policy objectives: improving U.S. energy security, mitigating climate change, and saving taxpayer dollars.

2. Background

A. Major Tax Deductions for domestic oil and gas production

Tax preferences (or tax expenditures) are departures from a standard income tax and tracked both in the annual Budget Submission by each president as well as by the Joint Committee on Taxation. With respect to oil and gas production, three provisions account for over 90 percent of the fiscal cost of tax preferences for the oil and gas sector. These preferences are diverse in age—the oldest dates back a century and the newest is just twelve years old—but they have in common the effect of reducing a firm's tax burden, compared with the standard tax treatment of U.S. firms. As a result, the industry argues, firms can invest in finding and developing wells to sustain production. The three deductions are *percentage depletion*, *expensing of intangible drilling* *costs*, and the *domestic manufacturing deduction* for oil and gas production. I begin with a brief description of each.

Percentage Depletion: When a firm incurs "leasehold costs," or costs related to purchasing a lease to drill a site expected to contain natural resources, it capitalizes those costs. That is, it records those costs on its balance sheet as the value of the asset—proven reserves—that it now owns. Because the value of the reserves diminishes as the firm extracts natural resources, the firm records a depletion expense on its income statement equal to the reduction in value of the asset.

Standard tax accounting would stipulate cost depletion, under which the asset's value would fall in proportion to the quantity of natural resources extracted. Suppose an oil company were to spend $10,000 to lease a tract of land with an underground reservoir estimated to hold 2,000 barrels (bbls) of oil. The firm would then capitalize the $10,000 cost as an asset in the form of proven reserves of oil. Over the next year, if the firm proceeded to extract 10 percent of the reserves—200 bbl—then it would record an expense of $1,000 on its income statement, reducing its taxable income by $1,000. The cost depletion deduction is analogous to deductions that firms in other industries can take for drawing down inventory.

By contrast, percentage depletion allows the firm to deduct a fixed percentage of the revenue from each site as the depletion expense. When Congress originally enacted percentage depletion in 1926, all oil and gas firms could deduct 27.5 percent of annual revenue—regardless of what their costs had been to develop the reserves and what proportion of the reserves they had extracted (Lazzari, 2008). As a result, the percentage depletion deduction could actually exceed the total cost to acquire the reserves. Today, percentage depletion has been reduced to allow a deduction of 15 percent of revenue covering up to 1,000 bbl of oil or 6,000 million cubic feet (mcf) of natural gas. Moreover, only independent firms—firms that participate in "upstream" exploration and production but not in petroleum refining or other "downstream" activities—are eligible for the deduction; integrated firms—firms that vertically integrate production with refining or retailing—have to use cost depletion. Although its size and scope has been curtailed, the percentage depletion deduction is still a substantial tax preference, costing the federal government $1.7 billion annually.[1]

Intangible Drilling Costs: When extracting natural resources, firms can avail themselves of another tax preference by immediately expensing intangible drilling costs (IDCs). These costs relate to site improvement, construction costs, wages, drilling mud, fuel, and other expenses but exclude the cost of all drilling equipment that would retain salvage, or resale, value after use. According to Wood Mackenzie Consulting (2013), IDCs account for a large majority—between 70 and 85 percent—of the costs of extracting oil and gas.

Under standard tax accounting, IDCs would be capitalized as assets and then amortized in one of two ways. Under the cost depletion protocol discussed above, IDCs could be written off in proportion to the quantity of resources extracted from a well. Alternatively, IDCs could be depreciated over seven years.

Current tax treatment of IDCs instead permits immediate expensing—that is, the entire value of the IDCs can be written off as an expense to offset taxable income in the year that the costs are incurred. This provision dates back to 1916, making it the oldest oil and gas industry tax preference. Today, the provision covers 100 percent of IDCs incurred by independent producers of oil and gas but only 70 percent of IDCs incurred by integrated producers. The remaining 30 percent of an integrated producer's IDCs can be depreciated over five years. Given that firms can immediately expense either all or the large majority of their IDCs, which are the largest compo-

[1] These and subsequent revenue losses are for fiscal year 2017 and are taken from U.S. Department of the Treasury (2016), otherwise known as the "Greenbook." Revenue estimates from the Greenbook differ from the value of tax expenditures reported in the Administration's annual budget documents because the former assumes repeal (or scaling back) of a tax preference, whereas the tax expenditure document assumes a baseline in which the preference had never been in place.

nent of production costs, the IDC tax preference is the most expensive, costing the federal government $3.2 billion annually.

Domestic Manufacturing Deduction: After applying the depletion and IDC deductions, firms can apply the third major tax preference—the domestic production manufacturing deduction—to further reduce their taxable income. The most recent preference, enacted in 2004, allows oil and gas firms to reduce their taxable income by up to 6 percent, limited to 50 percent of the firm's wages that it pays employees. This is lower than the deduction allowed other domestic manufacturing who receive a 9 percent deduction. This deduction will cost the federal government roughly $1.1 billion in fiscal year 2017.

B. Tax Policy Debate and the Energy Landscape

Over the last half-century, administrations and members of Congress from both political parties have proposed scaling back tax preferences for oil and gas firms. In some cases, they have succeeded in enacting partial changes, notably the curtailment of the percentage depletion and IDC deductions. But in other cases, like the domestic production manufacturing deduction, Congress has added new tax preferences for the industry. Intense debate continues over further changes to the tax treatment of oil and gas firms.

From 1916, when the IDC deduction was enacted, through 1970, the federal government aimed to promote increased oil and gas production through tax preferences. In the 1970s and 1980s, the federal government scaled back preferences for the industry to reduce dependence on oil, address public environmental concerns, and limit tax policy interventions in the market. Since then, the federal government has swung between expanding and restricting tax preferences for the oil and gas industry. Throughout the 1990s and 2000s, highly contentious debates over oil and gas tax treatment delayed or derailed passage of federal budget and energy bills.

In 2009, world leaders at the Group of Twenty (G20) summit in Pittsburgh signed on to a pledge committing to phase out fossil fuel subsidies to improve global energy security and mitigate climate change. This added an international dimension to the heretofore domestic debate over oil and gas tax preferences. In particular, Aldy (2013) has argued that ongoing tax preferences to oil and gas producers erode the ability of the United States to persuade developing countries to reduce fossil fuel consumption subsidies that engender wasteful energy use. Although the Treasury Department estimates that eliminating most oil and gas tax preferences could raise an estimated $34.5 billion over ten years in public revenue, Congress remains deadlocked on the issue.

Meanwhile, the energy landscape has shifted sharply. Rising oil and gas production has decreased U.S. imports. Domestic oil production in 2015 was 75 percent greater than production in 2005; by 2014 according to data in BP (2015), the United States had become the global leader in oil production (Figure 1a). A similar pattern holds for natural gas (Figure 1b). As a result, over the last decade, U.S. net imports of crude oil, petroleum products, and natural gas have collectively fallen by roughly two-thirds.

A revolution in drilling technology has driven this remarkable rise in production. The combination of hydraulic fracturing technology and advances in horizontal and directional drilling enabled firms to access large pools of oil and natural gas—known as shale or unconventional oil and gas—that were once economically unrecoverable.[2] The changing distribution of rig types used to drill wells reveals this shift in technology (Figure 2). Vertical drilling rigs, which in the early 1990s accounted for over 80 percent of rigs, now account for less than 15 percent of the total. Meanwhile, horizontal drilling rigs have risen from less than 10 percent in the early 1990s to three-quarters of the share of rigs today. Much of the growth in unconventional production has been driven by independent firms using horizontal drilling techniques combined with fracking (Curtis, 2015).

[2] Mason, Muehlenbachs and Olmstead (2015) provide a useful survey of the shale gas industry.

For most of the last decade, rising energy prices have accompanied rising U.S. production. Then, in June 2014, the price of oil began to plunge, falling from more than $100/bbl to less than $30/bbl in early 2016. Over the same period, natural gas prices have also fallen by over half. Yet, production did not fall commensurately. Domestic oil production continued to rise through April 2015 and remains within 10 percent of its peak; domestic natural gas production has continued to rise though appears to be flattening out as of mid-2016. Part of the explanation for the resilience of domestic production in the face of falling prices is that firms have ruthlessly slashed costs, especially by squeezing suppliers of oil services, and focused only on drilling the most productive wells.

Production declines lag price declines. This is because wells, once drilled, continue to produce oil and gas as a result of underground pressure, an insight noted by, among others, Adelman (1990) and Anderson, Kellogg and Salant (2014). Capping wells is costly, which means that firms that had already drilled wells when prices were higher have had little economic choice but to keep producing. Whereas production may not be responsive to prices in the short run, drilling rates for both oil and natural gas wells are (Figures 3a, 3b). As a result, the number of rigs drilling for oil has declined by more than half, tracking the plunge in oil prices. As existing wells are depleted, the scarcity of new wells may lead to declining production in the long run.

Following the price collapse in 2014, firms initially bolstered sagging cash flows from sales with income from derivative hedges purchased when oil prices were much higher. This accounted for roughly one-third of cash flow in early 2015, but the hedges have or will soon be exhausted. Moreover, before the oil price collapse, many large independent firms had paid for their rapid expansion through debt financing, often issuing junk bonds. Now, as cash flows continue to fall, highly leveraged firms are increasingly at risk of default and bankruptcy.[3]

Interviews conducted for this study with executives at independent firms highlighted the importance of cash flows in funding future drilling investments. Crooks and Platt (2016) emphasize that as debt finance becomes scarcer, cash flows from existing projects will be crucial to finance new ones. Therefore, when deciding whether to invest in a new project, firms will not only consider the rate of return—a generic metric to evaluate a project's profitability over many years—but also the time profile of the cash flows from the project. Because tax preferences can accelerate project cash flows, understanding how firms would change their investment decisions without the preferences is essential to assessing the benefits and costs of the preferences.

C. Previous Approaches to Measuring the Impact of Tax Preferences on Production

Reports sponsored by the industry forecast drastic cuts to domestic production and resultant spikes in energy prices should tax preferences be eliminated. A study undertaken by Wood Mackenzie Consulting (2013) for the American Petroleum Institute, for example, estimates a 14 percent reduction in long-run oil and gas production if expensing of IDCs is eliminated. Such reports may carefully project the reduction in near-term cash flows from eliminating tax preferences and more accurately describe the consequent reductions in drilling from cash-strapped firms. But these studies are much less transparent about their assumptions and methodologies, for example, relying on proprietary databases of U.S. oil and gas fields and models of the economic effects of tax reform.

Academic analyses generally measure the impact of tax preferences on production by modeling the tax preferences as an output subsidy. Specifically, Allaire and Brown (2009) meas-

[3] See The Economist (2015) and Helman (2015) for a survey of the financial struggles of the oil and gas industry due to low prices.

ured the value of tax preferences by dividing the government's annual tax expenditure by the amount of domestic oil produced.[4] They then concluded that eliminating most preferences, equivalent to eliminating an annual subsidy payment, would raise world oil prices by 6.3 cents per barrel in 2011 and 10.4 cents per barrel in 2030. Assistant Secretary of the Treasury Alan Krueger used a similar methodology in his 2009 Congressional testimony advocating repeal of the preferences.[5]

Measuring the subsidy value of tax expenditures as the ratio of tax expenditures to domestic production underestimates the value of the tax preferences to firms. This is because firms value near-term cash flows more than long-term cash flows, and tax preferences reduce or defer a firm's immediate tax burden. To see why this underestimates the value of these tax expenditures, consider the following thought experiment applied to expensing of intangible drilling costs. Imagine we are in a long-run equilibrium where identical wells are drilled each year, decline in productivity at the same rate, and last for the same number of years. Assuming stable aggregate production, each year old wells are retired and replaced by an equal number of equivalent new wells. Now imagine that we move from a world with expensing to one in which intangible drilling costs are treated as a depletable expense and so written off over the life of the well. From an aggregate perspective, the subsidy value of IDC expensing is zero. All we have done is shift the time profile of tax deductions so that newer wells receive fewer deductions while older wells receive larger deductions. With a zero value subsidy, we'd expect no change in well drilling.

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[4] Their methodology is presented in detail in Allaire and Brown (2012). Metcalf (2007) used a similar approach for a back of the envelope calculation in his survey of federal tax policy towards energy.
[5] Alan B. Krueger, "Statement of Alan B. Krueger Assistant Secretary for Economic Policy and Chief Economist, US Department of Treasury Subcommittee on Energy, Natural Resources, and Infrastructure," U.S. Department of Treasury, September 10, 2009, https://www.treasury.gov/press-center/press-releases/Pages/tg284.aspx.

Clearly this is incorrect since from the driller's point of view the aggregate analysis has ignored the time value of money. Expensing is valuable precisely because it moves tax deductions towards the present and tax payments to the future.

A simple example in the appendix quantifies the bias. Eliminating preferences in 2017 would raise an estimated \$0.74 in government revenue per barrel of oil produced that year, but that figure is between three and seven times lower than the present value of the foregone tax benefits that matters to firms making marginal investment decisions.[6] As a result, the most commonly used methodology for estimating the effect of tax preferences likely underestimates the reduction in oil production and resultant price increase.

How then should we measure the impact of removing tax preferences on drilling and long-run production? In the next section, I answer this question by introducing the concept of the *Equivalent Price Impact (EPI)*, a price change equal in value to the loss in tax preferences from the driller's point of view.

3. The Equivalent Price Impact Approach

Evaluating the implications of tax reform requires understanding how firms and markets would behave if oil and gas tax preferences were eliminated. Specifically, changes in prices, production, and consumption of oil and gas, both at home and abroad, could affect U.S. energy security and global climate change. Although previous studies fall short in forecasting these effects of tax reform, many researchers have studied how firms react to changes in oil and gas prices and how markets adjust as a consequence. This insight suggests a potential strategy: if producers react to tax reform in the same ways as they do to a drop in the price of oil or gas, then recasting tax reform as a price change unlocks existing research to forecast how firms and markets respond.

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[6] The Treasury FY2016 Greenbook estimate for revenue losses from the proposed elimination of oil and gas tax preferences is \$6.455 billion in 2017. EIA's 2014 *Annual Energy Outlook* estimates domestic oil and gas production for that period at 50.5 quads. This is equivalent to 8.78 billion barrels, so the average subsidy rate is \$0.74 per barrel.

This study does just that. It forecasts the effects of repealing the three major tax preferences in the following three step process:

- *Translating tax reform into an equivalent drop in the price of oil or gas that firms receive.* This answers the question, "If preferences had not been repealed, what price drop of oil or gas would have reduced the profitability of drilling the next well as much as the loss of tax preferences?"

- *Estimating the drop in drilling rates.* Because losing tax preferences makes firms behave *as if* the price of oil or gas has fallen, firms will no longer drill marginally profitable wells that become unprofitable with the loss in tax preferences.

- *Projecting where the market will settle in the long run.* If firms drill fewer wells in the short run, then they will produce less oil or gas in the long run. This will increase prices and decrease demand, driving the market toward a new equilibrium.

Figure 4 shows a simple model of domestic oil supply and demand. Domestic oil production (and consumption) is measured along the horizontal axis (*Q*) and its price (*p*) is measured on the vertical axis. The upward sloping curve S_0 shows how domestic supply responds to changes in price. This is a long-run supply curve reflecting responses to price changes through changes in drilling and site selection, among other factors. The downward sloping curve labeled *D* is the long-run demand curve for domestic oil. Demand for domestic oil equals global demand for oil less supply from other suppliers (OPEC and other non-U.S. oil producers). Demand for domestic oil is more price responsive than demand for oil in general given the opportunities for changes in non-U.S. supply as prices rise.

Point A in the diagram shows the equilibrium price (p_0) and domestic supply (Q_0) given existing tax preferences for oil production. Removing the tax preferences leads to a leftward shift in domestic oil production (moving from supply curve S_0 to S_1). This study measures this leftward shift of the supply curve by 1) computing the EPI of repealing tax preferences; 2) multiplying the EPI by the elasticity of drilling with respect to price; and 3) adjusting for changes in initial well productivity as price changes.

The EPI is a measure of the price decline that is comparable to the loss of tax preferences. In the figure, the EPI is represented as a fall in price from p_0 to p'_0. Were the price to fall to p_0', domestic supply would fall from Q_0 to Q_1. But the oil price has not in fact changed; what has changed is the tax treatment of oil. So the supply curve shifts left to S_1, where supply equals Q_1 at price p_0. It is important to stress that this is not an equilibrium outcome but simply a shift in the supply curve arising from the change in tax treatment of domestic oil production. This long-run leftward shift in the supply curve is a combination of decreased drilling activity and changes in site selection.

With the supply curve shift, the market is no longer in equilibrium at the old price. Price rise to bring the market back into equilibrium. As price rises from p_0 to the new equilibrium price p_1, two things happen: demand for domestic oil falls as consumers reduce oil consumption, and foreign suppliers increase oil production. This is represented by the amount $(Q_0 - Q_2)$. In addition, domestic supply rises as the price goes up $(Q_2 - Q_1)$ so that the net reduction in domestic supply is given by $(Q_0 - Q_2)$. The market is now at the new equilibrium at point B. This makes it possible to compute the changes in price, demand, domestic supply, and nondomestic supply, reported in Table 8. A similar analysis is done for natural gas markets.

To translate tax reform into EPIs in the case of oil wells (the approach is the same for natural gas), consider the driller's problem. He seeks to drill wells with a positive net present value (NPV). Given that the bulk of costs are in the form of intangible drilling costs, most of which can be expensed, one can approximate the NPV in the case where IDCs can be expensed as

$$NPV = (1-\tau)\left(\int_0^T pQ_0 e^{-(\delta+r)t}dt - C\right) \tag{1}$$

where τ is the tax rate; p, the current oil price; Q_0, the initial production rate; δ, an exponential decline rate; r, the discount rate; and C, the up-front cost of the project. (This approach assumes that today's oil or gas price is the best estimate of future oil and gas prices.) For terminal time large enough, the net present value can be approximated as

(2) $$NPV(p,1) = (1-\tau)\left(\frac{pQ_0}{\delta + r} - C\right)$$

where the notation $NPV(p,1)$ indicates the NPV at current price *p* when expensing of IDCs is allowed.

For a given cumulative distribution function (CDF) for initial production from new wells conditional on cost, $F(Q)$, wells will be drilled for initial production levels such that $NPV(p,1) \geq 0$ or

(3) $$Q_0 \geq \frac{C(r+\delta)}{p}.$$

At a given price *p* the number of wells drilled, D, is[7]

(4) $$D = 1 - F\left(\frac{C(r+\delta)}{p}\right)$$

and the change in the number of wells drilled as price changes is

(5) $$\frac{\partial D}{\partial p} = f\left(\frac{C(r+\delta)}{p}\right)\left(\frac{C(r+\delta)}{p^2}\right) = f(\hat{Q})\left(\frac{\hat{Q}}{p}\right)$$

where $\hat{Q}$ is the breakeven (i.e. zero NPV) initial production level for a project at price *p*.

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[7] Without loss of generality, I can normalize the maximal number of wells that are drilled as Q_0 goes to its lower bound to equal 1.

For future reference, the elasticity of drilling with respect to price is

(5) $$\frac{\partial lnD}{\partial lnp} = \frac{\partial D}{\partial p}\frac{p}{D} = \frac{\hat{Q}f(\hat{Q})}{1 - F(\hat{Q})}$$

where $f(Q)$ is the density function associated with $F(Q)$ and both are evaluated at the breakeven initial production level $\hat{Q}$.

Next, I turn to the question of how to assess changes to the taxation of oil and gas. A critical question is the correct tax treatment of IDCs if expensing is disallowed. Although there is no certain answer to the question in the absence of explicit language in any law that eliminated expensing of IDCs, Treasury regulation 1.612-4(b) suggests that IDCs would either be subject to depletion or depreciation. Conversation with oil executives and tax experts suggest that the vast majority of IDC costs would be depletable rather than depreciable in the absence of expensing.

Continuing to assume all costs are treated as IDCs, the shift from expensing to depletion yields a new NPV equation:

(6) $$NPV(p,0) = (1-\tau)\int_0^T pQ_0 e^{-(\delta+r)t}dt - \left(1 - \tau A\int_0^T e^{-(\delta+r)t}dt\right)C$$

where A is a constant chosen to ensure that the sum of undiscounted depletion deductions per dollar of cost sums to one. The notation $NPV(p,0)$ denotes a net present value calculation at price *p* in the absence of expensing of IDCs. Assuming *T* large enough, I can approximate this equation as

(7) $$NPV(p,0) = \frac{(1-\tau)pQ_0}{r+\delta} - \left(1 - \frac{\tau\delta}{r+\delta}\right)C.$$

Drilling occurs in all cases where $NPV(p,0) \geq 0$ or

(8)
$$Q_0 \geq \frac{r + (1-\tau)\delta}{(1-\tau)p} C$$

or

(9)
$$D = 1 - F\left(\frac{r + (1-\tau)\delta}{(1-\tau)p} C\right)$$

The change in drilling resulting from the loss of expensing equals

(10)
$$1 - F\left(\frac{r + (1-\tau)\delta}{(1-\tau)p} C\right) - \left(1 - F\left(\frac{C(r+\delta)}{p}\right)\right)$$
$$= F\left(\frac{C(r+\delta)}{p}\right) - F\left(\frac{r + (1-\tau)\delta}{(1-\tau)p} C\right)$$

and the percentage change in drilling is given by

(11)
$$\%\Delta D = \frac{F\left(\frac{C(r+\delta)}{p}\right) - F\left(\frac{r + (1-\tau)\delta}{(1-\tau)p} C\right)}{1 - F\left(\frac{C(r+\delta)}{p}\right)}$$

To say anything more we need to assume a specific density function (or CDF) for the distribution of initial production. For simplicity, I will assume a Type I Pareto distribution with minimum size 1:[8]

(12)
$$f(Q) = \begin{cases} \varepsilon Q^{-\varepsilon-1}, & Q \geq 1 \\ 0, & Q < 1 \end{cases}$$

This density function has a CDF function given by $F(Q) = 1 - Q^{-\varepsilon}$. This is a valid CDF for $\varepsilon > 0$ and $Q > 1$. Straightforward substitution shows that the elasticity of drilling for this density function

[8] Mandelbrot (1995) was an early proponent of the Pareto Distribution as a useful model of undiscovered play sizes. Attanasi and Charpentier (2002) compare truncated lognormal and Pareto distributions and find that the latter better represents the left-hand part of an observed distribution of play sizes.

is constant and equal to ε. Thus the drilling function is $D(p) = Bp^{\varepsilon}$ where *B* is some arbitrary constant.

For this density function, the percentage change in drilling equals

(13) $$\%\Delta D = \left(\frac{r + (1-\tau)\delta}{(r+\delta)(1-\tau)}\right)^{\varepsilon} - 1.$$

The equivalent price impact is defined as the percentage change in price (assuming IDC expensing) that gives rise to the same percentage change in drilling as occurs from the loss of expensing. Given a price elasticity of drilling equal to ε, the EPI is implicitly defined by

(14) $$\frac{D(p') - D(p)}{D(p)} = \frac{Bp'^{\varepsilon} - Bp^{\varepsilon}}{Bp^{\varepsilon}} = \left(\frac{r + (1-\tau)\delta}{(r+\delta)(1-\tau)}\right)^{\varepsilon} - 1$$

or

(15) $$\frac{p'}{p} = \frac{r + (1-\tau)\delta}{(r+\delta)(1-\tau)}$$

and so

(16) $$EPI = \frac{p' - p}{p} = \frac{r + (1-\tau)\delta}{(r+\delta)(1-\tau)} - 1 = -\left(\frac{\tau}{1-\tau}\right)\left(\frac{r}{r+\delta}\right).$$

The EPI depends on three parameters. It increases with the tax rate given the higher value of tax deductions at higher tax rates; it also increases with the firm's discount rate since moving tax deductions forward in time is more valuable for more impatient firms; and the EPI is higher at lower decline rates since more of the well's revenue occurs in the future at lower decline rates.

Note that the EPI does not depend on the current price of oil. At higher oil prices, more wells will be in the money (positive NPV) and the breakeven initial production level will be lower for a well to be marginally profitable. If expensing of IDCs is eliminated, the wells that will now not be drilled will be wells that are just marginal at the current price – whatever that price is. The constant elasticity of drilling with respect to price has the implication that the percentage change in price that leads to the same change in drilling as the loss of tax preferences is independent of price. The constant elasticity assumption is reasonable for small changes in price. Larger inframarginal changes could lead to different drilling responses. Below, I use an estimate of the price elasticity of drilling from previous research that considers data over a wide price range (between $20 and 90 a barrel for oil and between less than $3 and more than $15 per mcf for gas).

As a final step, I show that the EPI can be calculated in an alternative fashion that is more intuitive and can be more readily calculated for more general assumptions about well characteristics or tax provisions. Consider a breakeven project with a zero NPV when IDC expensing is available $(NPV(p,1) = 0)$. If expensing is disallowed the NPV of this project (as well as the change in NPV) equals

$$NPV(p,0) = \frac{-\tau r}{r+\delta}C. \tag{17}$$

Next consider what percentage change in price leads to the same loss in NPV assuming expensing is still available. Let p' be the price that leads to the same NPV for a project that can expense IDC's as the breakeven project that may no longer expense IDC's:

$$NPV(p', IDC) = (1-\tau)\left(\frac{p'Q}{r+\delta} - C\right) = \frac{-\tau r}{r+\delta}C. \tag{18}$$

The EPI is defined as the percentage change in price:

$$EPI = \frac{p' - p}{p} = -\left(\frac{\tau}{1-\tau}\right)\left(\frac{r}{r+\delta}\right). \tag{19}$$

This is equal to the EPI calculated in equation (16) which is the theoretically correct form focusing on the percentage change in drilling assuming the Type I Pareto distribution. It turns out to be more convenient to calculate the EPI using this net present value approach as I can calculate the EPI for more general assumptions about well characteristics and tax provisions than assumed in this theory section. In particular I can allow for finite lived wells, non-exponential well decline, and can model the loss of percentage depletion and the domestic manufacturing deduction in addition to the expensing of IDC's.

This insight—that tax reform and the corresponding decline in the price of oil or gas are indistinguishable with respect to the effect on the profitability of marginal wells—underpins the "equivalent price impact" (EPI) that this paper introduces. The EPI is the percentage drop in the price of oil or gas that would reduce the profitability of drilling a well as much as tax reform would. To calculate the EPI for a given tax preference or combination of preferences, first compute the NPV of a new project after tax reform. Then, find the hypothetical price of oil or gas that would yield the same NPV, but with the tax preferences reinstated. I can then use price elasticity estimates from the literature to measure the impact of tax reform on drilling and production. Before turning to the empirical analysis, let me illustrate how the EPI is used to predict changes in drilling.

Based on equation 19, I report the EPI for different exponential decline rates ranging from 20 to 70 percent. The former is a depletion rate typically associated with offshore drilling while the latter is more consistent with fracked on-shore wells. I assume a combined federal and state tax rate of 40 percent and a discount rate of 15 percent.[9]

[9] A hurdle rate of 15 percent is typical for the industry as noted by Wood Mackenzie Consulting (2013) and industry experts.

I move from an estimate of the EPI to drilling and production impacts by applying the theory developed in Anderson, et al. (2014). This paper posits a Hotelling style model applied to drilling. The authors estimate an elasticity of drilling with respect to price of 0.6 for oil wells. A related paper by Hausman and Kellogg (2015) reports an elasticity of natural gas well drilling with respect to price of 0.8. Consider onshore oil wells with an exponential decline rate of 70 percent. It's EPI is 11.8 percent. Based on Anderson et al.'s estimate of the elasticity of drilling, we would expect a 7 percent reduction in drilling of wells of this type. For off-shore wells with a 20 percent decline rate, we would expect a 17.2 percent reduction in drilling of off-shore wells. With a lower decline rate, the loss of IDC expensing is more painful and so leads to greater cutbacks in drilling.

Following the logic of Anderson et al (2014), the change in the tax treatment of oil and gas drilling would have an immediate impact on drilling but no immediate impact on production. As older wells are taken out of service, however, production will eventually decline. Assuming no change in initial well productivity, we would eventually observe a long run decline in production equal to the percentage drop in drilling activity. So the 7 percent reduction in drilling of on-shore wells described above would eventually translate into a 7 percent reduction in production (ignoring price changes to equilibrate the market – the supply curve shift from Q_0 to Q_1 in Figure 1 above).

The numbers in Table 1 are illustrative given the model's stylized drilling project. I turn in the next section to a more realistic parameterization of oil and gas wells to compute more accurate EPI's. I also account for potential changes in initial well productivity in response to changes in the tax law.

4. Empirical Analysis

A. Assumptions on Wells

The EPI depends on the characteristics of the wells in question as well as their producer. For oil, this study considers two types of wells—onshore and offshore—each drilled by one of two kinds of producer—independent and integrated firms. As Table 2 illustrates, three-quarters of U.S. production comes from independent producers operating onshore wells.[10] Because 95 percent of natural gas production is onshore (90 percent produced by independent producers and 5 percent by integrated producers), this study only considers onshore gas wells.

EPIs differ between independent and integrated producers because of differences in tax treatment—integrated firms can only expense 70 percent of IDCs in the first year of a project, whereas independent firms can expense 100 percent. EPIs also differ by well type based on the assumed cost and production profiles of each. For onshore wells, I assume six months of initial well development. Based on the work of Mason and Roberts (2015), I assume a decline rate of 70 percent in the first twelve months of operation, and a 30 percent annual decline rate for the remainder of the 21-year project lifetime.

For onshore projects, 85 percent of costs are assumed to be intangible drilling costs based on Wood Mackenzie Consulting (2013), 10 percent depreciable costs, and 5 percent depletable costs, all of which are borne in the first year. For offshore wells, I assume four years of well drilling and development costs before production begins; at that point, the wells decline at a 12 percent annual rate based on data from U.S. Department of the Interior (2007). For offshore projects, 70 percent of costs are assumed to be intangible, 10 percent depletable, and 20 percent depreciable.[11] I assume that all firms use a 15 percent discount rate (an assumption which is later tested in the sensitivity analysis) based on Wood Mackenzie Consulting (2013). In addition, the ratio of a

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[10] The breakdown in oil and gas production between integrated and independent producers in 2014 comes from Ernst and Young Global (2015). Onshore and offshore production data come from Mason (2015).

[11] The most critical costs are intangible drilling costs. My share of total costs attributed to IDCs are based on data reported in Wood Mackenzie Consulting (2013). For firms operating in the Gulf of Mexico, the Wood Mackenzie report indicates that roughly 70 percent of total project costs are IDCs.

marginal well's initial production to its total cost is such that the NPV is zero when firms take advantage of the IDC and domestic manufacturing deductions given the focus on marginal producers in the analysis.[12]

B. Equivalent Price Impact

Table 3 reports the equivalent price impact (EPI) for oil production. The EPI depends on the type of producer—independent or integrated—as well as whether the site is onshore or offshore. Because there is a relatively low ceiling on how much of a firm's production qualifies for the percentage depletion deduction, I report an EPI for all three tax preferences as well as for IDC expensing and the domestic manufacturing deduction combined under the assumption that the marginal well is not eligible for percentage depletion. This would be the case for producers who already have operating wells exceeding the production ceiling of 1,000 barrels per day below, which the percentage depletion deduction applies. The EPI also depends on how long it takes to start production after investing in a project, as well as how high the decline rate from the well is. The shorter the delay or the higher the decline rate, the sooner the project will produce revenue, reducing the value of tax preferences that accelerate cash flows (see section 2 of the appendix for a sensitivity analysis of the EPI).

The EPI from repealing all three tax preferences ranges from -9 to -24 percent (assuming percentage depletion is inframarginal for oil drilling). Onshore wells with independent producers represent three-quarters of domestic oil production and face an EPI of -14 percent. Table 3 also breaks out the effect that repealing each one of the tax preferences would have on the EPI for wells produced by independent and integrated firms. The EPI of repealing the IDC deduction is substantially larger than that of repealing either of the other two preferences.

[12] Percentage depletion is valuable to marginal small producers but is unlikely to appreciably affect aggregate oil or gas production.

Table 4 reports EPIs for onshore natural gas wells, which also vary by producer type and eligibility for percentage depletion. The EPI of repealing all three tax preferences ranges from -9 to -18 percent in the price of gas. I don't report the breakdown for the individual preferences as they are very similar to the breakdowns for oil wells.

C. Changes in Drilling Rates

The next step is to consider how changes in the tax treatment of oil and gas translate into changes in drilling (holding all else equal). Production tax preferences increase the breakeven initial well productivity for a set of potential wells and so leads to increased drilling activity. The EPI calculation above has translated those preferences into price changes that lead to the same increase in drilling. Thus, I multiply the EPI by a price elasticity of drilling to model the leftward shift in the drilling supply curve, following the change in tax treatment of oil and gas. Anderson et al. estimated the price elasticity for drilling oil wells to be 0.6, and Hausman and Kellogg estimated the price elasticity for drilling gas wells to be 0.8. Therefore, the change in drilling rate is simply the product of the relevant elasticity and the EPI and is reported in Table 5.

For oil projects, removing all three tax preferences would lead to an immediate decline in drilling ranging from 5 percent (onshore projects by integrated producers) to 16 percent (offshore projects by independent producers) as reported in Table 5. Weighting by current production, I project an 8.8 percent overall decline in drilling holding all else constant. For natural gas, I project a 10.5 percent decline in overall drilling.

D. Changes in Long Run Production

The next step is to move from expected changes in drilling activity to expected changes in long-run production. Anderson et al. (2014) find no relation between current oil prices (including various lags) and current production. Over the long-run, however, the decline in drilling should lead to a reduction in domestic production (holding other factors constant). If there were no correlation between expected project IRR and initial production (Q_0), then any leftward shift in the drilling supply curve would translate to an equal leftward shift in the domestic oil supply curve. If, however, smaller plays (lower values of Q_0, the initial production level) are associated with lower internal rates of return, then the change in tax treatment of oil and gas would lead to smaller plays being canceled first, and the shift in the oil supply curve would be less than the shift in the drilling supply curve. Assuming average play sizes may change as energy prices change, I can model the long-run supply curve impact of changes in tax treatment of oil and gas as follows:

$$Q^{LR} = \left(\frac{Q^{LR}}{D}\right) D \tag{20}$$

where Q^{LR} is long-run supply of oil or gas at a given price and *D* is the number of wells drilled. Taking logs yields:

$$lnQ^{LR} = ln\left(\frac{Q^{LR}}{D}\right) + lnD \tag{21}$$

and

$$\frac{dlnQ^{LR}}{dlnP^E} = \frac{dln\left(\frac{Q^{LR}}{D}\right)}{dlnP^E} + \frac{dlnD}{dlnP^E}. \tag{22}$$

The percentage change in long-run production (supply curve shift) due to a change in the EPI ($dlnP^E$) for eliminating fossil fuel tax preferences is the sum of the elasticity of new well productivity and the elasticity of drilling rates both with respect to price changes. I compute the first elasticity and use estimates of the latter from the literature.

Presumably, marginal oil and gas projects would be the first to be canceled with the loss of these tax preferences. Whether these projects are smaller or larger than the average sized oil project is not clear. Given the fixed costs of drilling (relative to output), one might expect the marginal projects to be smaller than average. To test this, I regressed monthly oil and gas new rig average initial production levels against oil and gas prices. Specifically, I ran regressions of the form

$$lnQ_{it} = \alpha + \beta lnP_{it} + \gamma t + \sum_j \theta_j I_{it}^j + v_i + \varepsilon_{it}$$

where the log of new well productivity in region *i* and month t (Q_{it}) is regressed on the log of price (the WTI benchmark for oil and the Henry Hub price for natural gas), γ measures the trend over time in new well productivity, the θs measure monthly seasonality effects, and v_i controls for region specific differences in well productivity. Data on new well productivity are taken from the October 2015 release of EIA's *Drilling Productivity Report*. Table 6 presents results from several regressions on oil and gas well productivity for monthly data between January 2007 and August 2015.[13]

The top row of Table 6 reports results for new oil wells, and the second row reports results for new gas wells. Although not reported, the coefficient on the monthly trend variable is positive in all regressions as expected and is on the order of .02 for oil and .01 for natural gas. A trend growth of 1 or 2 percent per month is quite high and reflects the dramatic supply boom from fracking that emerged during this period. The first reported coefficient is from a simple regression of well productivity on price (and trend). Neither the gas nor oil price coefficient is statistically significant at reasonable levels. Once region dummies (column 2) and monthly seasonality dummies (column 3) are included, the oil price coefficient becomes statistically significant at the 10 percent level and, in fact, has a p-value of 5.1 to 5.2 percent. The price coefficient in the gas regression is small and statistically indistinguishable from zero in all cases.

Based on these regressions, I compute the long-run percentage change in oil and gas production following the elimination of fossil fuel tax preferences as

(23) $$\%\Delta Q^{LR} = (\varepsilon^{WP} + \varepsilon^{D})(\%\Delta P^{E})$$

[13] I also ran regressions using various lags of prices. The results are not substantively different.

where ε^{WP} is the elasticity of well productivity with respect to price (assumed to equal -0.24 for oil and zero for natural gas), ε^{D} is the elasticity of drilling with respect to price, and $\%\Delta P^{E}$ is the EPI from Tables 3 and 4. Note that this is not an equilibrium supply change but rather a measure of the shift in the long-run supply curve following the loss of the tax preferences for oil and gas production.

Table 7 reports results. I focus on the final column showing the shift in the aggregate oil and gas supply curves. The long run supply curve for domestic oil shifts to the left by 5.3 percent while the curve for natural gas shifts by 10.5 percent. This is not the observed decline in long-run production since the market is not in equilibrium once the supply curves shift. I next turn to a market model to assess how long run prices and quantities change in response to the loss of the tax preferences.

E. Market Equilibrium - Oil

I construct a simple model of oil markets to assess the effect of the removal of the various oil and gas tax preferences. Given that this is a long-run change in production, I calibrate this model so that it reproduces the global oil price and production in 2030 that the Energy Information Agency (EIA) forecasts in its 2014 *International Energy Outlook (IEO).* Given that the EIA projects multiple future cases for how the oil market might develop, I calibrate the model to two of those cases: the reference case, in which the oil price rises to \$119/bbl by 2030, and the Low Price Case, in which the oil price rises to \$72/bbl by 2030. I focus on supply from three major oil supply sectors and global demand:

$$Q^{D}(p) = Q^{US}(p,\theta) + Q^{OPEC}(p,\omega) + Q^{ROW}(p) \tag{24}$$

where global oil demand (Q^{D}) is a function of the world price (p). Oil is supplied by the United States (Q^{US}), whose supply is a function of world price and various tax preferences (θ). OPEC's supply of oil is a function either of world price or a desired world oil supply share (ω). Other global suppliers supply oil according to an upward sloping supply function Q^{ROW}.

I assume functional forms with constant elasticities, though for OPEC I model two variants: one with constant price elasticity of supply and one with a target supply share[14].

(25a)
$$Q^D(p) = Ap^{\varepsilon_D}$$

(25b)
$$Q^{US}(p,\theta) = B(\theta)p^{\varepsilon_S}$$

(25c)
$$Q^{OPEC}(p,\omega) = Cp^{\varepsilon_S} \; or \; Q^{OPEC}(p,\theta) = \omega Q^D(p)$$

(25d)
$$Q^{ROW}(p) = Dp^{\varepsilon_S}$$

Drawing on the literature review of supply and demand elasticities in Allaire and Brown (2012), I assume $\varepsilon_D = -0.5 \text{ and } \varepsilon_S = 0.5$.[15] The values of $A, B, C, \text{and } D$ are set to values that match supply and demand estimates for 2030 from the 2014 IEO. For the United States, the value of B is reduced by 5 percent, based on estimates from Table 7, when the tax preferences for IDCs, percentage depletion, and domestic manufacturing are removed. The value of ω is set to the value from the reference scenario for 2030 from the 2014 IEO.

Table 8 presents the modeled equilibrium values of global oil price, supply, and demand in 2030. The first column lays out four ways that the global market could develop: two future oil price possibilities considered by the Energy Information Agency (EIA), and within each of those cases, the two scenarios for OPEC to be price-responsive or exhibit cartel behavior to maintain its market share. Within each of these four alternatives for how global markets might behave, the second column presents two scenarios for domestic policy: the United States maintains existing tax preferences (baseline), or it repeals the three major preferences. The tax reform is assumed to

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[14] At the OPEC meeting in June 2015, OPEC maintained its current quotas despite oil prices in the $40 a barrel amid widespread speculation that it was committed to maintaining its market share. See, for example, Reed (2015).

[15] For the United States, I use a price elasticity of 0.36 based on the elasticities of drilling and initial well productivity with respect to price detailed in equation 23.

shift the domestic oil supply curve by 5 percent. The remaining columns in Table 8 report the equilibrium Brent oil price—the benchmark for most of the world's oil—in 2012 dollars; supply, in million barrels of oil per day (mbd) from the United States, OPEC, and the rest of the world (ROW); and global demand.

Table 8 shows that the long-run effects of U.S. tax reform are minimal under a wide range of input assumptions for how the future oil market behaves. The loss of the tax prerferences drives up global prices between one-half and one percent; global demand falls on the order of one-half of one percent. The modest increase in price dampens the domestic supply response a bit so that domestic production falls by less than 5 percent, regardless of the assumptions of future oil prices and how OPEC will respond. An oil price increase of up to 1 percent would be over three hundred times smaller than price spikes in the 1970s and ten times smaller than the average annual increase in oil prices from 2009 to 2014. It would raise domestic gasoline prices by at most two pennies per gallon at the pump.[16]

F. Market Equilibrium – Natural Gas

I use a similar market structure for domestic natural gas supply and demand, slightly modified to reflect the smaller role of global trade in natural gas. I calibrate the model so it reproduces the domestic gas price, production, and consumption in 2030 that the International Energy Agency forecasts in the 2015 *International Energy Outlook* (IEA). There are two IEA cases that the model considers: the reference case, in which the Henry Hub gas price is $5.69/MMBTU in 2030, domestic production is 33 trillion cubic feet (tcf) per year, and net exports are roughly 15 percent of domestic production; and the high gas supply case, in which the gas price is $3.67/MMBTU, domestic production is 43 tcf per year, and net exports are roughly 25 percent of domestic production. I cal-

[16] About half of a price increase in gasoline is passed through to gasoline prices according to U.S. Energy Information Administration (2014b).

ibrate the model to the 2030 prices and quantities from EIA's *Annual Energy Outlook 2015* reference and high gas supply scenarios. Natural gas production can either be consumed domestically or exported. (The AEO reference scenario posits that roughly 15 percent of domestic production will be exported in 2030.) The market model is given by:

(26) $$Q^D(p) = Q^{US}(p,\theta) - NX(p)$$

where Q^D is domestic demand, Q^{US} is domestic production, and NX is net exports. As with the oil market above, I assume constant elasticity of demand and production, where the long-run elasticity of supply is based on the elasticity of drilling of 0.8 as discussed above. In the case where the United States repeals all three tax preferences, I assume a supply curve shift of 10 percent (see Table 7).

For the demand elasticity, I construct an aggregate demand elasticity based on the sectoral demand elasticities estimated by Hausman and Kellogg. The aggregate elasticity, a weighted average of the elasticities of demand by residential, commercial, industrial, and electric power consumers with weights equal to each sector's market share of natural gas, equals -0.42. (More precisely, $\varepsilon = \sum_i \omega_i \varepsilon_i \rho_i$, where ε is the elasticity of demand for total natural gas, ε_i is the elasticity of demand for gas in sector *i*, ω_i is the share of gas consumption in sector *i*, and ρ_i is the percentage change in the price of natural gas in sector *i* due to a one percent change in the Henry Hub price of natural gas. I assume ρ_i equals one for purposes of this analysis.) Other model parameters are calibrated to match supply and demand for 2030 in the 2015 *Annual Energy Outlook*.

Modeling net exports is more difficult. Presumably, a significant decline in domestic production would lead to a decline in net exports and, potentially, a shift from exporting to importing. I model net exports in two ways. First, exports might vary based on the domestic gas price; in this scenario, the model assumes that exports would fall by the same percentage as the percentage increase in the gas price (an export elasticity of -1). Second, net exports might be unaffected by changes in domestic prices. This second scenario, though unlikely, provides a helpful limit on the market response to U.S. tax reform.[17]

Table 9 presents the modeled equilibrium values for price, supply, and demand for the domestic natural gas market in 2030. The first column lays out two alternatives for how the domestic market might evolve, based on possible future gas prices considered by the International Energy Agency (IEA). The second column compares a baseline case, in which U.S. tax policy is unchanged, to a case in which the three major tax preferences are eliminated. The tax reform is assumed to shift the domestic gas supply curve by 10 percent. The remaining columns report the 2030 North American, or "Henry Hub," price, domestic production and net exports, and domestic demand.

The effects of tax reform are more significant for gas markets than they are for oil markets. How net exports respond to tax reform is also important to predict the size and direction of market shifts. In the reference case, and under the assumption that net exports respond to price, the gas price rises by $0.48 per MMBTU (8 percent) and domestic production falls by 4 percent. Overall demand falls by 3 percent. If net exports do not change in response to the price change, domestic supply falls by 3 percent and the Henry Hub price rises by 10 percent. Domestic gas consumption falls by 4 percent. Under the IEA's high gas supply scenario, these results are similar. Still, across all input assumptions, tax reform should increase domestic prices by less than 10 percent. Given that natural gas is one of the inputs in the production of electricity, the price increase in natural gas from tax reform would raise an average household's monthly electricity bill by, at most, seven dollars.[18]

[17] An alternative assumption is that exports fall to zero, perhaps in response to policy changes limiting liquefied natural gas (LNG) exports. In that case, the fall in domestic supply would be more than offset by a decline in exports, leading to a drop in the price of domestic gas.

[18] The average U.S. household's monthly electricity bill is $114 , according to the U.S. Energy Administration (available at http://www.eia.gov/electricity/sales_revenue_price/xls/table5_a.xls and accessed on

5. Assessment of Policy Reforms

Participants in the debate over U.S. tax treatment of oil and gas firms tend to invoke three policy objectives—improving U.S. energy security, mitigating climate change, and saving taxpayer dollars—to justify their position for or against reform. The results reported above make it possible to assess tax reform against these three objectives.

The estimated effects of tax reform on both domestic consumption and imports of oil and gas suggest that U.S. energy security would neither increase nor decrease substantially if the three major preferences were repealed. Some, including the American Petroleum Institute (2011), have argued that without tax preferences, domestic production would fall, damaging U.S. energy security by exposing the economy to foreign supply shocks, especially given geopolitical turmoil in the Middle East. But this study's results project at most a 5 percent drop in domestic oil production, which would not substantially increase U.S. imports. Moreover, because oil is a globally traded commodity, a more important lever to reduce an economy's vulnerability to sudden price movements is how much oil an economy consumes relative to its size.[19] Tax reform would barely alter domestic petroleum consumption—consumers will not reduce their use of gasoline when it is one or two pennies per gallon more expensive—and so it should not materially affect energy security when it comes to oil. In the case of natural gas, the United States has historically imported the vast majority of natural gas demand in excess of U.S. supply from Canada, limiting geopolitically driven energy insecurity. And given that tax reform would reduce domestic consumption of natural gas by no more than four percent, it would not materially change the exposure of the U.S. economy to natural gas price shocks.

April 24, 2016); an increase in the price of natural gas by 10 percent can at most increase the price of retail electricity by 6.5 percent, because generation accounts for 65 percent of the price of electricity, according to the U.S. Energy Information Administration (available at https://www.eia.gov/energyexplained/index.cfm?page=electricity_factors_affecting_prices and accessed on April 26, 2016).

[19] Deutch and Schlesinger (2006) and Metcalf (2014), among others, elaborate this argument.

The even smaller impacts of domestic tax reform on global consumption imply that emissions of greenhouse gases that cause climate change would not change substantially. Previously, Allaire and Brown (2012) estimated that eliminating the IDC and percentage depletion deductions would have reduced domestic carbon dioxide emissions by 21.1 million metric tons between 2005 and 2009, or less than a 1 percent reduction in U.S. emissions. Indeed, their result, small as it is, overstates the emissions reduction potential of tax reform by failing to account for emissions "leakage," or increased emissions elsewhere in the world. If OPEC member countries were to respond to rising oil prices by increasing production, the results in Table 8 suggest that roughly half of the fall in U.S. production would be offset by increased global production. Even if OPEC targeted a fixed market share, neutralizing any leakage effect, global consumption of oil would fall by less than 1 percent as a result of tax reform, negligibly mitigating climate change. Similarly, emissions from natural gas are unlikely to change materially. Table 9 shows that domestic gas consumption would fall by, at the most, 4 percent as a result of tax reform. Given that burning natural gas accounts for roughly one-fifth of U.S. greenhouse gas emissions, domestic emissions might fall by 1 percent or less, with trivial effects on global emissions. Any decrease in domestic natural gas consumption may well be offset by increased coal power generation, which is twice as carbon intensive as natural-gas fueled power (though fugitive methane emissions from natural gas production narrow the emissions gap between coal and natural gas).

Tax reform could, however, strengthen U.S. climate leadership and therefore help mitigate climate change. Although the United States has backed the G20 initiative to phase out fossil fuel subsidies in the world's largest economies, its own subsidies to fossil fuel producers impair its ability to coax major developing economies to roll back fossil fuel consumption subsidies. Because they encourage wasteful energy consumption, such subsidies do in fact contribute substantially to global emissions (see Aldy (2013) for an elaboration of this argument). If the United States were to repeal its oil and gas tax preferences, these countries would no longer be able to deflect international pressure to roll back their subsidies by pointing to U.S. fossil fuel subsidies. Still, there is no guarantee in those countries that international pressure for reform would overcome domestic barriers against it.

The most important benefit of tax reform for the oil and gas sector may be to save taxpayer dollars: directly, by reducing subsidies to fossil fuel producers, and indirectly, by jumpstarting broader tax reform. Repealing the three major tax preferences would generate fiscal savings of roughly $4 billion annually. Although the direct savings would reduce the federal budget deficit by less than 1 percent, indirect benefits could also accrue. Successful reform of these preferences—protected by formidable interest groups—may embolden policymakers to tackle other preferences in the tax code. Ultimately, a simpler tax code may save taxpayers money and more efficiently allocate economic resources.

In addition to the three policy objectives above, it is important to ask whether tax reform could have substantial domestic macroeconomic effects. Defenders of the existing tax regime often invoke the number of jobs or contribution to gross domestic product (GDP) that result from domestic oil and gas production; reform, some argue, would cost the U.S. economy dearly. But the results in Tables 5, which estimate the short run reduction in domestic drilling rates from tax reform, suggest otherwise. If oil and gas drilling were to fall 10 percent, the oil and gas industry might proportionally shed 19,000 jobs from its overall workforce of 190,000.[20] Some, if not all, of these losses would be offset elsewhere in the economy because of the fiscal savings from tax reform. With respect to overall economic effects, tax reform is unlikely to substantially affect GDP growth. The Council of Economic Advisors (2014) estimated that the growth in oil and gas production in 2012 and 2013—when oil production rose roughly 15 percent annually—added 0.2 per-

[20] Bureau of Labor Statistics, "May 2015 National Industry-Specific Occupational Employment and Wage Estimates – Oil and Gas Extraction," U.S. Department of Labor, http://www.bls.gov/oes/current/naics3_211000.htm#00-0000 accessed Aug. 8, 2016.

centage points to the growth rate of GDP in those years. Given that this study forecasts production falling roughly 4 to 5 percent, one might expect a one-time reduction in the GDP growth rate on the order of 0.06 percentage points. Reductions in employment and activity in the oil and gas sector would occur over time, because the reduction in drilling would only gradually lead to lower production. Although further study is needed to refine an estimate of the macroeconomic consequences of tax reform, prima facie estimates suggest that any effects would be minimal.

6. Conclusion

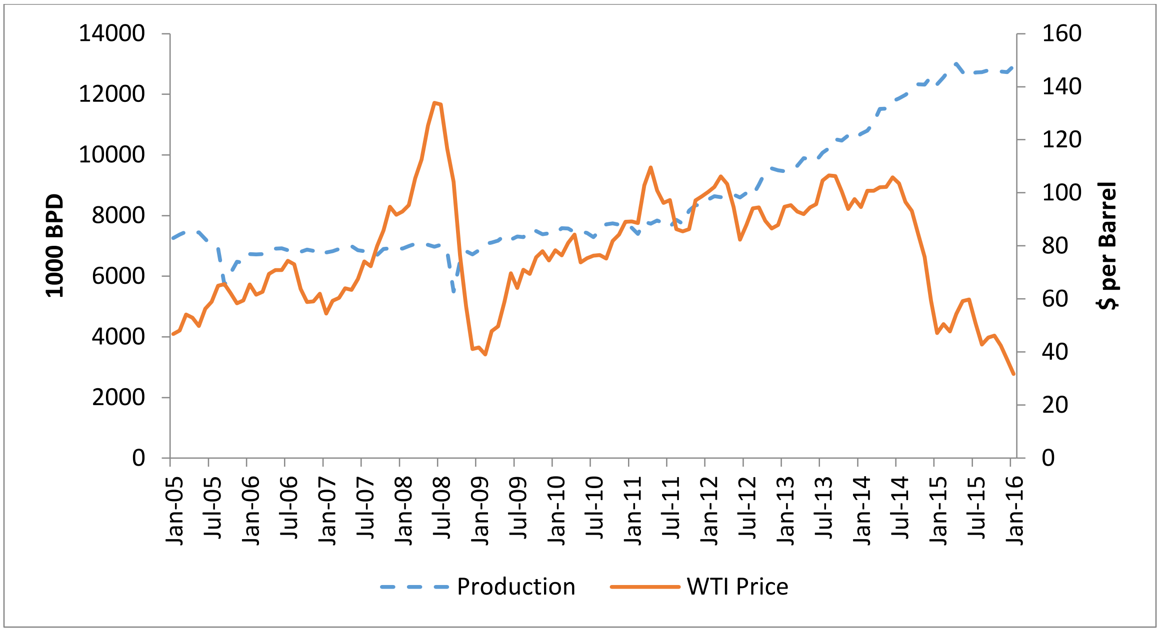
This paper presents a new methodology for estimating the impacts on domestic oil and gas production if the tax treatment of oil and gas were reformed. The three preferences analyzed here – expensing of intangible drilling costs, percentage depletion, and the domestic manufacturing deduction – account for 90 percent of the tax benefits accruing to domestic producers.

I find that reforming these tax preferences is equivalent to a drop in oil price of 9 to 24 percent depending on the type of well (onshore or offshore) and the type of firm (integrated or independent). For the bulk of production, the loss of tax preferences is equivalent to a 14 percent drop in price. For natural gas, the loss of tax preferences is comparable to a 14 percent decline in price for independent producers and 9 percent for integrated producers.

The loss of these preferences would lead to short run declines in drilling on the order of 5 to 16 percent for oil and would average about 9 percent. For gas, the decline in drilling is on the order of 11 percent. Market responses would dampen these impacts with domestic oil and gas production estimated to decline by 4 to 5 percent over the long run. Global oil prices would rise by less than one percent. Domestic natural gas prices are estimated to rise by 7 to 10 percent. Changes to these tax provisions would likely have modest to negligible impacts on greenhouse gas emissions or energy security.

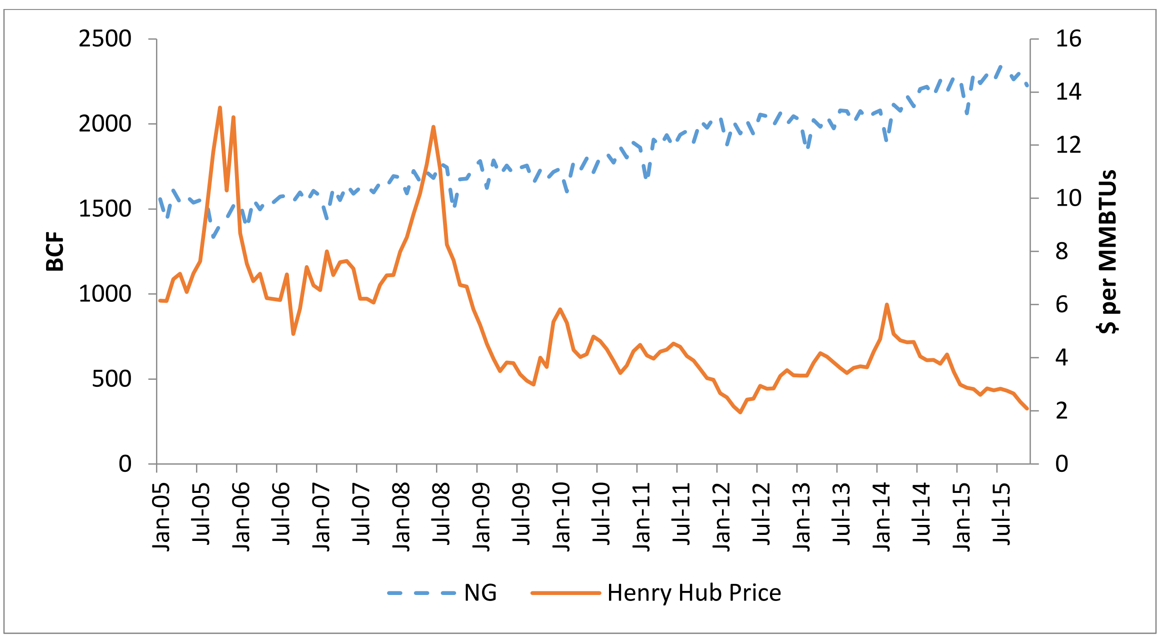
When Congress is ready to take up fundamental tax reform, it will have to grapple with many challenging issues as it attempts to lower overall income tax rates. Having a clear sense of the costs and benefits of proposals to raise revenue from the oil and gas sector will be essential to those discussions.

Figure 1a. Domestic Oil Prices and Production



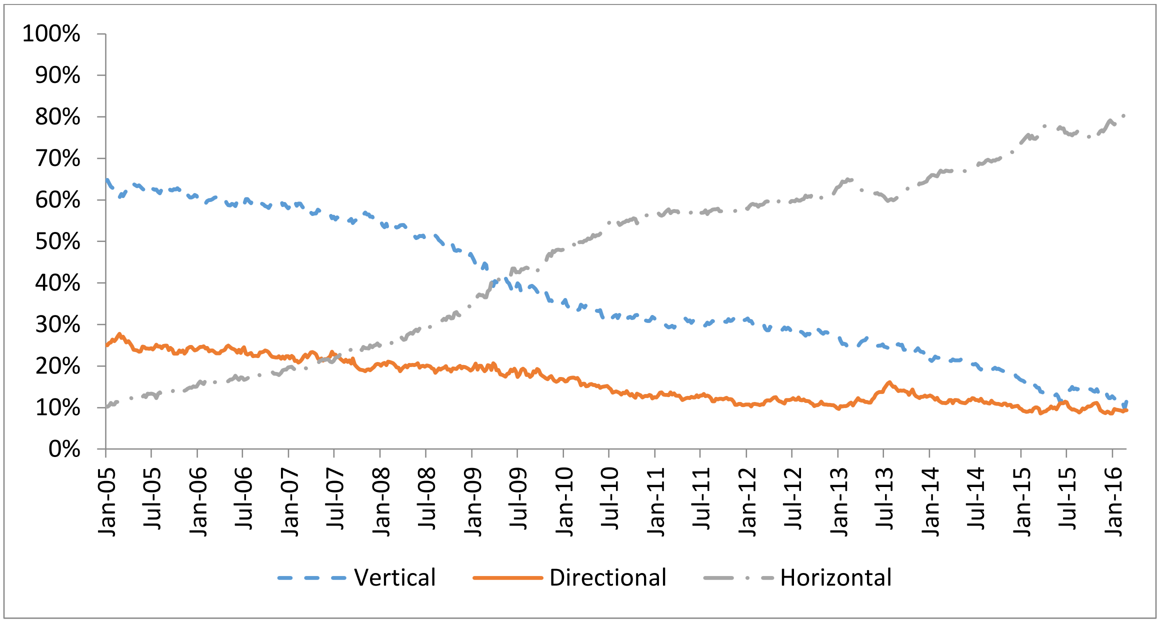
Source: EIA, *Monthly Energy Review.*

Figure 1b. Domestic Natural Gas Prices and Production



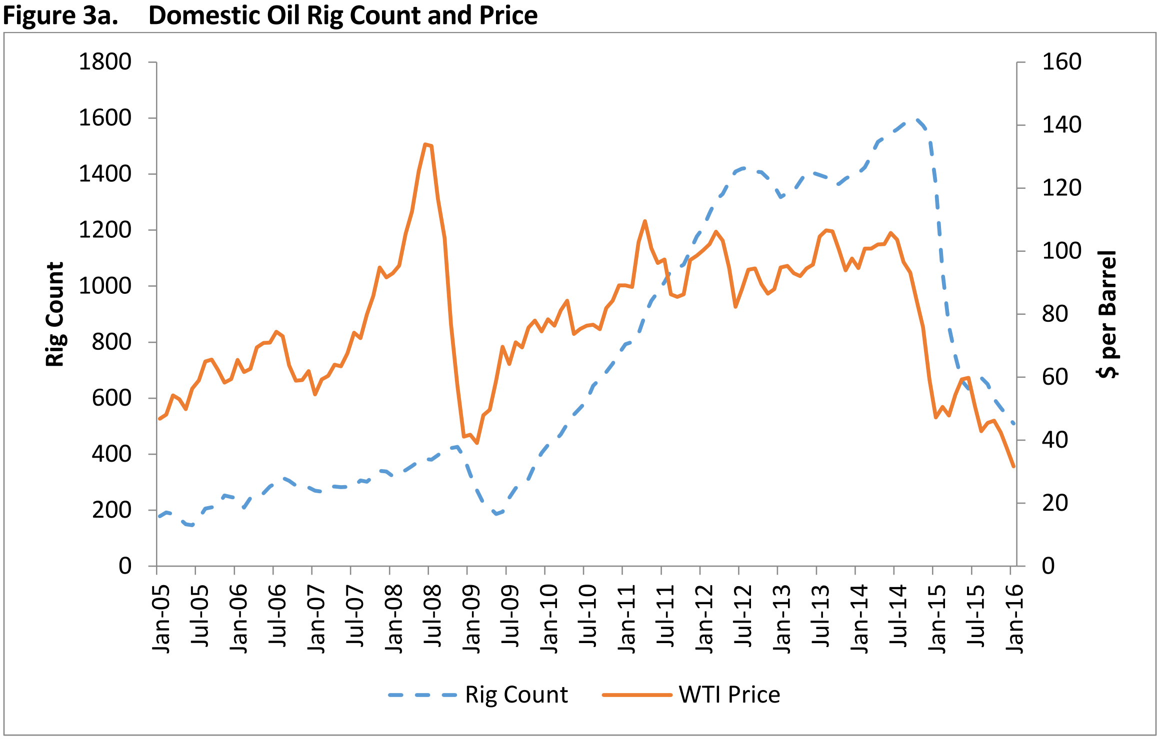
Source: EIA, *Monthly Energy Review.*

Figure 2. The Rise of Horizontal Drilling in the U.S. Natural Gas Industry



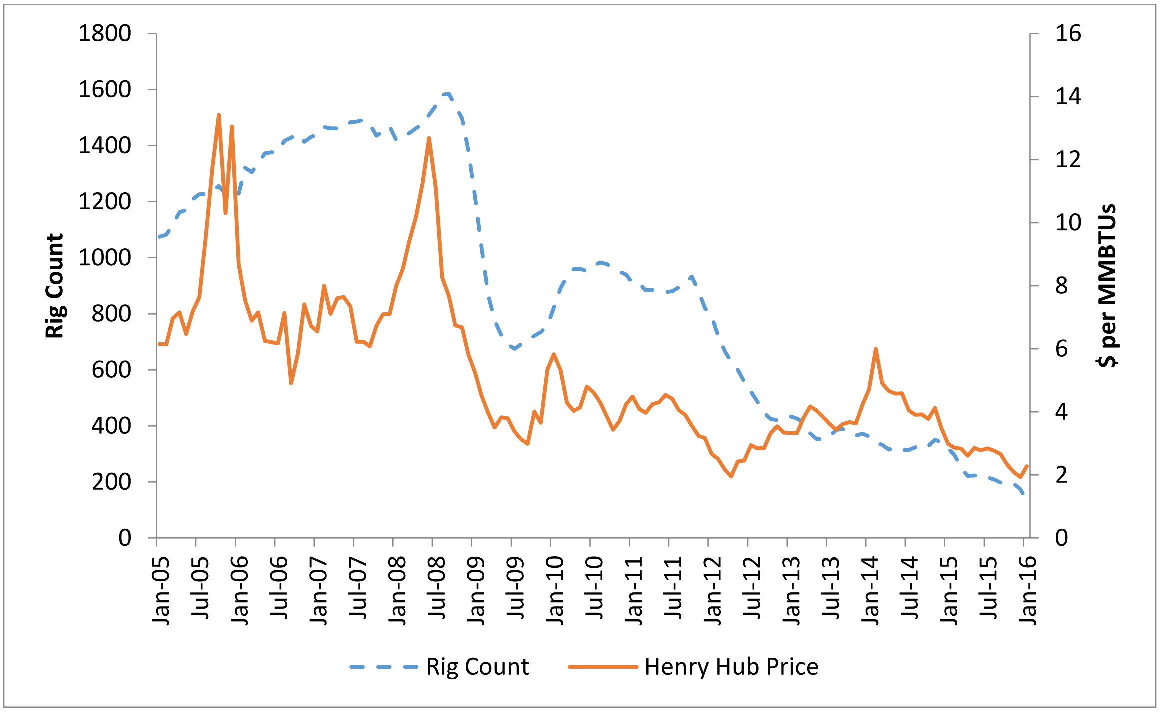
Source: Baker Hughes.

Figure 3a. Domestic Oil Rig Count and Price



Source: EIA, *Monthly Energy Review*

Figure 3b. Domestic Natural Gas Rig Count and Price



Source: EIA, *Monthly Energy Review*.

Figure 4. Ending Tax Preferences: Market Impacts

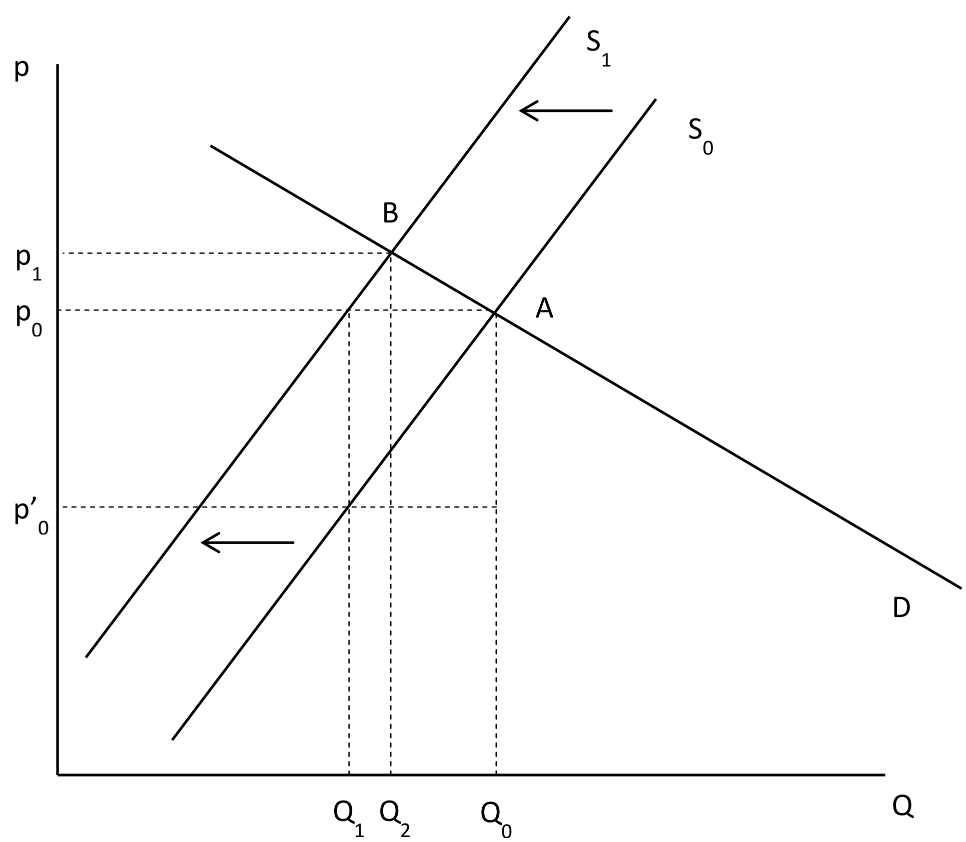


Table 1. Equivalent Price Impacts: Model Prediction	
Exponential Decline	***EPI***
20%	28.6%
30%	22.2%
40%	18.2%
50%	15.4%
60%	13.3%
70%	11.8%
Author calculations assuming a tax rate of 40 percent and a discount rate of 15 percent.	

Table 2. Distribution of Domestic Oil Production			
	Onshore	***Offshore***	***Total***
Independents	76%	8%	84%
Integrated	9%	7%	16%
Total	85%	15%	100%
Source: Author's calculations based on data in Ernst and Young Global (2015) and Mason (2015).			

Table 3. Equivalent Price Impact for Oil Production							
Independent Producers Onshore Wells					***Integrated Producers Onshore Wells***		
Percentage Depletion	*IDC Expensing*	*Domestic Mfg Deduction*	*All*	*All But Percentage Depletion*	*IDC Expensing*	*Domestic Mfg Deduc-tion*	*All But Percentage Depletion*
-5.3%	-12.2%	-1.6%	-18.0%	-13.6%	-8.0%	-1.5%	-8.6%
Independent Producers Offshore Wells					***Integrated Producers Offshore Wells***		
-5.2%	-20.5%	-2.2%	-27.5%	-24.0%	-16.2%	-2.4%	-18.1%
Author's calculations. Each column reports EPI for the tax preference indicated. See text for details.							

Table 4. Equivalent Price Impact for Natural Gas Production		
Independent Producers		***Integrated Producers***
All	*No Percentage Depletion*	
-18.0%	-13.6%	-8.6%
Author's calculations. Each column reports EPI for the tax preference indicated. See text for details.		

Table 5. Changes in Drilling Rates				
Panel A. Oil Drilling				
Independent Producers		Integrated Producers		All Wells
On Shore	Off Shore	On Shore	Off Shore	
-8.2%	-16.5%	-5.2%	-10.9%	-8.8%
Panel B. Natural Gas Drilling				
On Shore	Off Shore	On Shore	Off Shore	All Wells
-10.9%	NA	-6.9%	NA	-10.5%

This table reports the change in drilling assuming price impacts from Tables 3 and 4, an elasticity of drilling with respect to the price of oil of 0.6, and an elasticity of drilling with respect to natural gas of 0.8. Percentage depletion is assumed to be non-marginal. The last column reports a production weighted percentage change in drilling.

Table 6. Well Initial Productivity Regressions			
	(1)	(2)	(3)
Oil Production	-0.135 (0.149)	-0.234* (0.096)	-0.243* (0.100)
Gas Production	-0.079 (0.289)	0.030 (0.236)	0.031 (0.242)
Region Variables	No	Yes	Yes
Month Variables	No	No	Yes

Each cell reports the coefficient estimate (and standard error) on the oil or gas price variable in a regression of monthly new well productivity in the drilling regions as reported in EIA's Drilling Productivity Report. Data from January 2007 through August 2015 are used in the regression. All regressions also include a trend variable. Regions are Bakken, Eagle Ford, Haynesville, Marcellus, Niobrara, Permian, and Utica. Regressions are weighted by region production levels and standard errors clustered by region.

* - p value of .10 or less

Table 7. Shift in Long Run Supply Curves				
Panel A. Oil				
Independent Producers		Integrated Producers		All Wells
On Shore	Off Shore	On Shore	Off Shore	
-4.9%	-9.9%	-3.1%	-6.5%	-5.3%
Panel B. Natural Gas				
On Shore	Off Shore	On Shore	Off Shore	All Wells
-10.9%	NA	-6.9%	NA	-10.5%

This table reports the change in long-run production assuming price impacts from Tables 3 and 4, an elasticity of oil drilling with respect to price of 0.6 and an elasticity of gas drilling with respect to price of 0.8. Elasticity of oil well productivity with respect to price equals -0.24 while initial natural gas productivity is assumed to be unaffected by price. Percentage depletion is assumed to be non-marginal in all cases. The last column reports a weighted average percentage change in production based on production shares.

Table 8. Long Run Oil Market Impacts

Global Oil Price Scenarios	U.S. Tax Policy Options	How OPEC Responds to Lower U.S. Production	Global Price, $2012/ bbl (% change)	Global Supply, mbd (% change)			Global Demand, mbd (% change)
				U.S.	OPEC	ROW	
EIA Reference Case: $119/bbl in 2030	**Baseline**	N/A	**$ 119.00**	**13.2**	**44.4**	**49.8**	**107.4**
	Repeal Major Preferences	OPEC Supply Responds to Price	$ 119.75 (0.6%)	12.6 (-4.8%)	44.5 (0.3%)	50.0 (+0.3%)	107.1 (-0.3%)
		OPEC Maintains Constant Market Share	$ 120.30 (1.1%)	12.6 (-4.6%)	44.1 (-0.5%)	50.1 (+0.5%)	106.9 (-0.5%)
EIA Low Price Case: $72/bbl in 2030	**Baseline**	N/A	**$ 72.00**	**11.7**	**54.6**	**44.2**	**110.6**
	Repeal Major Preferences	OPEC Supply Responds to Price	$ 72.39 (0.5%)	11.2 (-4.8%)	54.8 (0.3%)	44.3 (+0.3%)	110.3 (-0.3%)
		OPEC Maintains Constant Market Share	$ 72.79 (1.1%)	11.2 (-4.6%)	54.3 (-0.5%)	44.5 (+0.5%)	110.0 (-0.5%)

Source: Author's calculations. 5% domestic supply shift

Table 9. Long Run Natural Gas Market Impacts

Natural Gas Price Scenarios	U.S. Tax Policy Options	How U.S. Net Exports Respond to Lower U.S. Production	U.S. Price, $2012/ MMBTU (% change)	U.S. Supply, tcf/ Year (% change)		U.S. Demand, tcf/ Year (% change)
				Production	Exports	
IEA Reference Case: $5.69/MMBTU in 2030	**Baseline**	N/A	**$ 5.69**	**33.07**	**4.80**	**28.27**
	Repeal Major Preferences	Unitary Export Price Elasticity	$ 6.17 (+8.4%)	31.75 (-4.0%)	4.43 (-7.8%)	27.33 (-3.3%)
		Zero Export Price Elasticity	$ 6.23 (+9.5%)	32.01 (-3.2%)	4.80 (NC)	27.21 (-3.7%)
IEA High Gas Supply Case: $3.67/MMBTU in 2030	**Baseline**	N/A	**$ 3.67**	**42.72**	**9.03**	**33.69**
	Repeal Major Preferences	Unitary Export Price Elasticity	$ 3.94 (+7.3%)	41.13 (-3.7%)	8.42 (-6.8%)	32.71 (-2.9%)
		Zero Export Price Elasticity	$ 4.03 (+9.8%)	41.43 (-3.0%)	9.03 (NC)	32.40 (-3.8%)

Source: Author's calculations. 10% domestic supply shift

Appendix

I. Measuring Tax Preferences: Accounting for the Time Value of Money

A number of studies value fossil fuel tax preferences either explicitly or implicitly as the ratio of the tax expenditures in a given year associated with the preferences to oil production in that year. Such an approach ignores the time value of money as tax preferences are generally most valuable in the early stages of a project, but oil or gas revenues occur long after the tax preferences are received.

To use a concrete example, Table A1 shows the revenue, production, and value of tax benefits across time for an illustrative oil project, given a current oil price of $50 per barrel, which remains constant in real terms in future years. It also assumes a 35 percent corporate tax rate. The last column reports the undiscounted savings in taxes from percentage depletion, IDC expensing, and the section 199 domestic manufacturing deduction relative to cost depletion, IDC depletion, and the loss of the domestic manufacturing deduction. This assumes that this project is eligible for percentage depletion, IDC expensing, and the domestic manufacturing credit.

We can view Table A1 as a snapshot of revenue, production, and tax benefits across projects at a given point in time. This is the approach taken by the studies mentioned above. If one new project came online each year and one old project was ended after twenty years of production, then each row in the table could be viewed as an oil well at a different stage of production. Adding up the savings in taxes from the tax preferences and dividing by production gives a value per barrel of $2.76 which equates to a 5.5 percent subsidy rate per barrel of oil.

But this approach to valuing tax preferences ignores the time value of money. For a firm assessing the value of the tax benefits of percentage depletion, IDC expensing, and the domestic manufacturing deduction, what matters is the net present value of the tax savings relative to the net present value of revenue from the project. For the well in this example, the net present value of revenue is $1,252, discounted at 15 percent. The net present value of tax savings, also discounted at 15 percent, is \$145. This approach discounts future production when valuing tax benefits per barrel of oil to reflect the fact that a barrel of oil in the future is worth less than a barrel today, controlling for price. Now, after accounting for time value, the tax preferences are worth 11.6 percent of revenue, and the new per-barrel value of the tax benefits is \$5.80, more than double the value when discounting is ignored. When assessing the effect of tax incentives on well profitability, this latter approach, which incorporates the time value of money, is the relevant metric.

Table A2 reports per-barrel values of the tax preferences at different oil prices. The values under the heading “All” describe the tax benefits for small independent producers who can take advantage of all three major preferences. The values under the heading “All But Percentage Depletion” describe the tax benefits for large independents and integrated firms, whose production substantially exceeds the cap on the percentage depletion deduction and therefore do not derive substantial value from the deduction. The “No Discounting” columns describe the undiscounted, per-barrel value of tax preferences derived by dividing annual revenues by annual tax benefits, assuming the firm’s wells are all identical to the well in Table A1 and uniformly distributed in age. The “Discounting” columns describe the discounted per-barrel value of tax preferences by dividing the net present values of tax benefits and production by a project’s lifetime. After discounting, the per-barrel benefits are worth nearly seven times the undiscounted value at an oil price of \$40 a barrel, the assumed break-even price for projects in this analysis.

Ignoring the time value of money in most cases will lead to an underestimate of the effect of the tax preferences on drilling and production. One implication is that removing the tax preferences will lead to larger drilling and long-run production effects than the previous literature has estimated, especially in the current low oil price environment.

2. Sensitivity Analysis

Table A3 reports some sensitivity results for how the EPI varies based on different decline rates and discount rates for independent producers undertaking onshore projects. I focus on this set of producers since this is the source of most domestic oil production. The columns labeled "Base Case" report the benchmark results for the EPI from Table 3. Increasing the decline rate to 70 percent throughout the well's life cuts the EPI roughly in half. To the extent that I have underestimated well decline rates, I am overestimating the effect of the loss of these tax preferences on drilling and long-run production. Reducing the first year decline rate from 70 to 30 percent raises (in absolute value) the EPI by a small amount. Lowering the discount rate from 15 to 7 percent reduces the magnitude of the EPI by between one-third and one-half. To the extent that exploration and production (E&P) firms are using lower discount rates than my base rate of 15 percent, I will overstate the effect of changing the tax treatment of oil and gas production. I discuss below how my drilling and production results, as well as market equilibrium results, are changed if a lower discount rate is assumed. Results in the last column show that the EPI is not materially affected by lengthening the life of the project.

The only way to significantly increase the magnitude of the EPI is to lower the decline rate substantially or raise the discount rate substantially—neither of which is plausible. Note that I have not taken into account any limitations on the ability to use tax deductions from oil and gas drilling. Despite this caveat, this approach of constructing an EPI to gauge the value of tax incentives captures the focus of E&P companies on choosing projects based on the expected return from the project and the use of threshold IRR measures to choose projects.

Next, I report the sensitivity of the long-run supply shifts given the sensitivity analysis in Table A4. The baseline values for the shifts in long-run supply of oil is given in the first column of Table A4**Error! Reference source not found.**. A higher well decline rate lowers the long-run production decline to between 1 and 2 percent. Only when the decline rate of wells is substantially lower and/or a higher discount rate than 15 percent is used does long-run production decline appreciably more than in the base case.

Table A1. Valuing Tax Preferences

Year/Project	Revenue	Production	Value of Tax Preferences
1	365	7.29	248.9
2	399	7.99	-46.6
3	280	5.59	-32.7
4	196	3.91	-22.9
5	137	2.74	-16.0
6	96	1.92	-11.3
7	67	1.34	-7.9
8	47	0.94	-5.5
9	33	0.66	-3.8
10	23	0.46	-2.7
11	16	0.32	-1.9
12	11	0.23	-1.3
13	8	0.16	-0.9
14	6	0.11	-0.6
15	4	0.08	-0.4
16	3	0.05	-0.3
17	2	0.04	-0.2
18	1	0.03	-0.2
19	1	0.02	-0.1
20	1	0.01	-0.1
21	0	0.01	-0.1

Table A2. Value of Tax Preferences per Barrel			
All		**No Percentage Depletion**	
No Discounting	**Discounting**	**No Dicounting**	**Discounting**
$2.10	$5.14	$0.58	$3.62

Table A3. Sensitivity Analysis on EPI				
Base Case	***Exponential Decline Rate (70%)***	***Exponential Decline Rate (30%)***	***Lower Discount Rate (7%)***	***Shorter Well Life (10 Years)***
-13.6%	-6.4%	-14.8%	-7.8%	-13.1%
This table reports EPI's for different constant decline rates, well lifetimes, and discount rates.				

Table A4. Sensitivity Analysis on Long Run Supply Shift				
Base Case	***Exponential Decline Rate (70%)***	***Exponential Decline Rate (30%)***	***Lower Discount Rate (7%)***	***Shorter Well Life (10 Years)***
-4.9%	-2.3%	-5.3%	-2.8%	-4.7%
Shifts in long run domestic supply based on EPI's reported in Table A3. Results assume a drilling price elasticity of 0.6 and a well productivity elasticity of -0.24.				

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