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TAXING ENERGY IN THE UNITED STATES: Which Fuels Does the Tax Code Favor?

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At a time of deep national concern about both the adequacy of the U.S. energy supply and how much cleaner it can become, the question of how the U.S. tax code influences investment in energy generation is a crucial one. This report offers a comprehensive overview of the energy-related provisions of the U.S. tax code and their estimated impact on tax revenues. More important, this report indicates where the U.S. tax regime as a whole is likely to direct energy investment.

The term for such an overall measure is the "effective" tax rate—that is, the total effect of the tax code on investors trying to decide into which part of the energy industry to put an additional dollar. This paper builds on other work on effective tax rates by including in its analysis production and investment tax credits appearing in the code as well as depletion allowances reserved for the petroleum and gas sectors. It also considers energy-specific tax provisions that most previous analyses have not taken into account. By providing more detailed disaggregated estimates than its predecessors, it is able to permit clearer and broader comparisons of the tax code's effects on investment in different fuels.

The present analysis has determined that a major shift has occurred since the time, not so long ago, when the tax code encouraged domestic oil and coal investment above all other kinds.

- The subsidy for fossil fuels has dropped from over 60 percent in 1997 to under 50 percent in 2007.

- The subsidy for renewable energy and conservation has risen from just under 40 percent to over 50 percent in the same period.

- The current tax code, especially since enactment of the Energy Policy Act of 2005, strongly encourages investment in nuclear, wind, and solar power, which enjoy tax subsidies ranging from nearly 100 percent, for nuclear, to more than 200 percent, for solar.

In other words, tax subsidies for these forms of energy generation are sufficiently generous that investors may use them to offset tax liabilities for capital gains and income derived from non-energy investments. It is worth noting that wind capacity, a highly tax-favored source of energy, grew by nearly 50 percent in 2007 and accounted for one-third of all new electrical capacity added in that year. Independent oil companies that are able to use percentage depletion to the fullest extent have also received significant tax benefits at the margin.

Still, the positive impact of these tax subsidies is to some extent vitiated by the code's relatively ungenerous treatment of investment in the electric grid, which carries electricity produced by any type of energy source to businesses and households. Given the great distance of the steadiest sources of wind and solar power from the largest energy consumers, the economics of these cleaner sources depend on the further development of high-voltage transmission lines and other features of the grid. Yet the code continues to tax income realized from investments in high-voltage power transmission lines more heavily than capital gains or most ordinary income.

About the Author

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Taxing Energy in the United States: Which Fuels Does the Tax Code Favor?

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I. INTRODUCTION

Federal tax policy has historically played a large role in shaping energy markets in the United States. A recent analysis by the U.S. Energy Information Administration (2008c) shows that the largest subsidies to the energy sector can be found in the tax code. How much do different sectors benefit from these subsidies, and what is their likely impact on investment? This paper explores these questions.

The popular press is full of stories about federal subsidies to nuclear power, to coal, to renewables—in fact, to every energy source employed in the United States. What is not clear from these stories is the extent to which any fuel source is disproportionately favored in the tax code. One difficulty that arises in assessing the tax treatment of any fuel source or energy investment is the necessity of distinguishing between the statutory and the effective tax rate. The statutory tax rate simply measures the tax bracket of a firm or an individual. The effective tax rate, on the other hand, takes into account the various deductions and credits that influence the after-tax cash flow of a project.

A large gap can exist between the statutory tax rate and the effective tax rate. It is the latter that matters in measuring how investment behavior, for example, responds to the tax code. The effective tax rate can help us determine whether a fuel is appropriately taxed in light of various national energy policy goals.

The tax treatment of energy sources is important for a number of reasons. First, a basic precept of efficiency in taxation is that under perfect competition, the tax system should provide a level playing field for investment. One source of efficiency losses in the tax code is the code's favorable treatment of one energy source over another. In order to measure the magnitude of this loss, it is necessary to measure the extent to which the playing field for energy investment is uneven.

It may be desirable, however, to provide an uneven playing field at times. If the use of a particular fuel has environmental impacts that are not captured in the price of the fuel, then government intervention through taxes can enhance efficiency. This is the rationale for environmental taxes to address pollution externalities. It is not enough, however, to compare tax rates across fuels with estimates of the social damages from the use of these fuels, given the complexity of the tax code.

Another reason to focus on the tax code's treatment of energy is the critical energy investment needs that must be addressed in the next few decades. The International Energy Agency (2007) estimates that the world will need to invest over $20 trillion (in year 2006 dollars) between 2006 and 2030 in energy infrastructure. Of that, over $4 trillion is required in North America, with half of that in the power sector (electricity, heat, and heat and power).[1]

The U.S. Energy Information Administration (EIA) estimates that electricity demand will rise by nearly 30 percent between 2006 and 2030 (U.S. Energy Information Administration, 2008a). In addition to investment in new power plants to generate the energy necessary to meet this growing demand (and to replace retiring plants), significant new investment will be needed to upgrade the nation's transmission and distribution network. Doing this is particularly important, given the growing supply of renewable power. Wind power, for example, can most efficiently be produced in areas where the wind is strong and steady. These areas typically are distant from areas of high electricity demand. Already the U.S. power grid is struggling to handle this new electricity (see Wald, 2008); without expensive upgrades to the network, it would be highly inefficient to develop significant amounts of new wind and solar capacity in remote sites optimal for generation.

Demand for liquid fuels is also projected to rise. Much of this demand will be for alternatives to gasoline. Biofuels will require significant investment in new refineries as well as in R&D to develop second-generation biofuel technology. We are also seeing new investment in liquefied natural gas (LNG) facilities to meet a growing demand for this fuel. All of this points to the importance of new capital to meet our growing energy needs.

In this paper, I provide disaggregated estimates of the effective tax rate for energy investments. An effective tax rate compares the before-tax return with the difference between the before- and after-tax return on a marginal investment. It is a comprehensive measure of the effect of the tax code on decisions to make incremental investments in new capital.

My analysis builds on other work in the literature on effective tax rates in a couple of important ways. First, it provides more detailed disaggregated estimates, which allow us to compare and contrast the tax code's treatment of different fuels. Second, it incorporates important tax provisions specific to the energy sector, including production and investment tax credits as well as depletion in the petroleum and gas sectors. None of the other recent measures of effective tax rates that focus in whole or in part on the energy sector takes these detailed provisions into account.

I find that the distribution of tax subsidies across fuel types has shifted over time, with renewables and conservation receiving greater support through the tax code than they have historically. Whether the distribution of subsidies is optimal, given the various externalities associated with energy production and consumption, is not addressed in this paper.

I also find that the effective tax rate on new energy investment varies widely across different fuel sources. Many investments receive large subsidies at the margin, with nuclear power, wind, and solar especially advantaged. Independent oil companies that are able to use percentage-depletion allowances to the fullest extent receive significant benefits at the margin that are greater than those available to firms unable to use percentage depletion.

In addition, the effective-tax-rate analysis suggests that investments in the transmission grid receive among the least favorable treatments of all energy capital. This is particularly worrisome, given the current grid congestion in certain parts of the country and the need for a modern grid infrastructure to handle the challenges of intermittent energy supply from renewables such as wind and solar.

In the next section, I construct detailed summary measures of the tax code's comprehensive impact on energy investment incentives. These are followed by, in section III, a detailed survey of the tax-code provisions enacted to direct capital to particular kinds of energy capital projects. Section IV provides a discussion of the implications of my tax-rate measures for future energy investment. I provide some concluding thoughts in section V.

II. ASSESSING THE IMPACT OF THE TAX CODE ON ENERGY

The tax treatment of energy is extremely complex, with multiple provisions affecting production, distribution, and consumption that have evolved in a somewhat ad hoc fashion over time. Two questions arise when thinking about these subsidies. What is the absolute size of federal subsidies for different fuel sources? What impact do these subsidies have on investment in energy capital and, ultimately, on energy supply? In this section, I present two measures to get at these questions. First, I discuss estimates of energy-related tax expenditures as reported by the federal government. Tax expenditures are estimates of the reduction in federal tax revenue arising from various deductions and credits. As discussed below, tax expenditures are a subjective concept and suffer from a number of measurement problems. Perhaps more important, they provide scant information on how the tax code affects behavior.

Second, I construct effective-tax-rate measures for energy-specific capital, which is the main contribution of this paper. These measures provide information on the degree to which the tax code favors one type of new energy capital over other types. As discussed below, my measures build on an existing literature, including recent papers by the Congressional Budget Office (2005, 2006) and Ernst & Young (2007). My measures improve on these in two ways: I provide finer detail on types of energy capital than do the CBO reports, which look at very broad classes of investment; and my measures include greater detail than does the Ernst & Young report. While Ernst & Young looks at narrower investment classes than do the CBO reports, it does not look at wind or solar, for example. None of these reports takes into account as many energy-related provisions of the tax code as I do.

A. Energy Tax Expenditures

A first measure is the value of tax expenditures associated with energy subsidies in the tax system. The various deductions and credits described above are examples of tax expenditures tracked by the Department of the Treasury. This measure is not entirely comprehensive. While the excess of percentage depletion over cost depletion is treated as a tax expenditure, accelerated depreciation (e.g., the five-year recovery period for renewable electricity property) is only partially accounted for.[2] Nor does the measure register the gains in federal tax revenue that would occur if the preference were eliminated, since behavior is treated as fixed when estimates of tax expenditures are being constructed. Nevertheless, the tax-expenditure budget is a commonly used measure of subsidies provided through the tax code.

A recent analysis by the U.S. Energy Information Administration (2008c) breaks out the subsidies by fuel source (see Table 1).

Several points emerge from Table 1. First, the total tax expenditure for energy is modest, totaling less than $11 billion in 2007. Subsidies for biofuels constitute the single largest tax expenditure (listed under Renewables). Second, the distribution of tax expen-

Table I. Energy Subsidies Through the Federal Tax Code in Fiscal Year 2007	Total	2007 Share	1997 Share	Subsidy per Billion BTUs
Coal	290	3%	2%	113
Refined Coal	2,370	23%	0%	113
Natural-Gas and Petroleum Liquids	2,090	20%	59%	63
Nuclear	199	2%	0%	24
Renewables	3,970	38%	31%	584
Electricity (not fuel-specific)	735	7%	4%	na
End Use and Conservation	790	8%	3%	na
Total	10,444			na

Source: U.S. Energy Information Administration (2008c). Total subsidy is measured in millions of dollars. Subsidy per billion BTUs is measured in dollars.

ditures by fuel source has shifted significantly over the past ten years, with the share that goes to fossil fuels dropping by 15 percentage points. Third, on a BTU basis, renewables receive the largest subsidy.

Measuring subsidies as tax expenditures either in the aggregate or per dollar of production is problematic for a number of reasons. Table 1 measures the average subsidy but provides no information about the subsidy's effect on the production of this fuel. It may be that production of a particular form of energy would occur in the absence of any subsidy directed at that fuel source.[3] Second, the subsidy doesn't take into account differences in the quality of fuels. On an energy-content basis, natural gas is nearly five times the cost of coal. Thus, while the subsidy to regular coal used in the production of electricity is roughly two-thirds that of natural gas on an MWh basis, the coal subsidy is more beneficial per dollar of spending on coal.

Finally, none of these measures is useful for identifying the impact of the tax code on marginal decisions. Do these subsidies affect the choice of energy project investment? Do they influence the flows of capital investment into different forms of energy capital? Effective tax rates are useful for answering these questions. I turn to this measure next.

B. Effective Tax Rates on Capital Investments

An effective tax rate is a summary measure of the various provisions in the tax code that affect investment in new capital. Specifically, it compares the before-tax return with the difference between the before- and after-tax return. The before-tax return is the return that an investment must earn in order to cover its cost, pay the required return to investors, and pay taxes on the project. The after-tax return is the return that savers (the source of funds for investment) expect to receive after taxes are paid on marginal investments. Thus, if savers are prepared to accept 7 percent on an investment after tax and the project must earn 10 percent in order to cover depreciation, taxes, and required payments to investors, the effective tax rate is 30 percent $\left(\frac{10 - 7}{10}\right)$.

Effective tax rates focus on the marginal cost of funding investments rather than on project cost. In particular, they focus on the cost of a break-even investment. Because they summarize the many provisions of the tax code that affect the returns on capital investment, effective tax rates are frequently used to consider how the tax system affects capital investment.[4] This is a particularly salient issue, given the capital investment needs of energy infrastructure in the United States, as noted in the introduction.

I follow the methodology of the Congressional Budget Office (2005, 2006) to construct effective tax rates for energy capital. My measures differ from those reported in the CBO reports in two ways: I analyze assets at a more disaggregated level than is done in those reports; and I take into account more provisions of the tax code than do those reports. In particular, the CBO studies do not account for energy-specific production or investment tax credits or for tax rules specific to the oil and gas industry. An overview of the construction of effective tax rates is provided in the Appendix. Readers seeking a fuller description should read Congressional Budget Office (2006) or any of the references cited therein. I then discuss how I modify the standard effective-tax-rate (ETR) measure for energy-specific tax provisions.

Table 2 below reports my estimates of effective tax rates on new, energy-related capital investments based on the formulas in the Appendix. I provide estimates for different forms of electric generation capital, other electricity-related capital, and capital used in the drilling and refining of oil as well as in the transport of natural gas.

The first part of Table 2 provides estimates of effective tax rates for electric generation capital. Under current law, solar thermal and wind capital are subsidized to the greatest extent, with effective subsidy rates of 245 and 164 percent, respectively.[5] Nuclear power is also heavily subsidized, with a subsidy rate of nearly 100 percent. The effective tax rates for coal and gas are substantially higher than they are for nuclear or renewables. Integrated gasification combined-cycle (IGCC) capital is subsidized, while pulverized coal (PC) capital faces a positive tax. The major difference here is the 20 percent investment tax credit for new IGCC investments. Finally, PC and natural-gas combined-cycle plants face an effective tax rate very close to the statutory tax rate (39.3 percent, accounting for both state and federal taxes).

The next two columns in Table 2 indicate the impact on effective tax rates of removing the production and investment tax credits (column 2) and replacing accelerated depreciation with economic depreciation.[6] The production or investment tax credits are the most significant source of subsidy—as evidenced by the size of the change in the effective tax rate when the credits are removed. The effective tax rate for wind, for example, rises from -164 percent to -14 percent if economic depreciation replaces accelerated depre-

Table 2. Effective Tax Rates

	Current Law (1)	No Tax Credits (2)	Economic Depreciation (3)
1. ***Electric Utilities***			
Generation			
Nuclear	-99.5%	32.4%	-49.4%
Coal (PC)	38.9%	38.9%	39.3%
Coal (IGCC)	-11.6%	38.9%	-10.3%
Gas	34.4%	34.4%	39.3%
Wind	-163.8%	12.8%	-13.7%
Solar Thermal	-244.7%	12.8%	-26.5%
Transmission and Distribution			
Transmission Lines	34.0%	34.0%	39.3%
Distribution Lines	38.5%	38.5%	39.3%
2. ***Petroleum***			
Oil Drilling (nonintegrated firms)	-13.5%	-13.5%	39.3%
Oil Drilling (integrated firms)	15.2%	15.2%	39.3%
Refining	19.1%	19.1%	39.3%
3. ***Natural Gas***			
Gathering Pipelines	15.4%	15.4%	39.3%
Other Pipelines	27.0%	27.0%	39.3%
Source: Author's calculations			

ciation, while it rises to +13 percent if the production tax credit is eliminated. With economic depreciation and no production or investment tax credits, the effective tax rate in all cases equals the statutory tax rate of 39.3 percent.

The effective-tax-rate methodology can be used for other types of energy capital. In the electric-utility section, I also construct effective tax rates for transmission and distribution. Transmission lives are allowed a fifteen-year recovery period, while distribution lines are allowed a twenty-year recovery period. The former face an effective tax rate modestly lower than the statutory rate, while the latter receive very little in the form of a subsidy.

Effective tax rates in the petroleum sector depend in large part on whether the firms taking the credits are integrated or nonintegrated (independent) firms. Independent firms benefit from full expensing of their intangible drilling costs, while the integrated firms can expense only 70 percent of their IDCs and must write off the rest over a five- year period. In addition, the independents are allowed to take percentage depletion, while the integrated firms must use cost depletion.

The effective tax rate on oil-drilling equipment depends importantly on a firm's ability to take percentage rather than cost depletion. For independent firms taking percentage depletion, the effective tax rate is -13 percent, whereas firms taking cost depletion face effective tax rates of 15 percent. The rate for integrated firms is a bit lower than the effective tax rate on refining capital. The effective tax rate for refining capital assumes use of the temporary 50 percent expensing provision for capacity additions. This assumption reflects the fact that most new investment in refineries has been in increasing the capacity of existing refineries rather than in building new refineries.[7] In the absence of the temporary expensing provision, the effective tax rate on refinery capital would rise from 19 to 32 percent. The seven-year recovery period for gathering pipelines, which bring gas from the field to central processing plants or large distribution pipelines, gives them a lower tax rate than other kinds of pipelines, which have a fifteen-year recovery period.

The effective tax rate for independent firms taking percentage depletion is sensitive to the ratio of price to operating profit per barrel. Figure 1 shows how the effective tax rate changes as this ratio changes. Percentage depletion drives the effective tax rate down as the oil price relative to per-barrel operating profits rises. The rising cost of extracting oil in the United States means that the effective tax rate for independent firms able to take percentage depletion is falling, holding other factors constant.

The estimates in this paper are highly disaggregated estimates of effective tax rates for energy capital in-

Fig I. Relation of Effective Tax Rate to Price-Profit Ratio

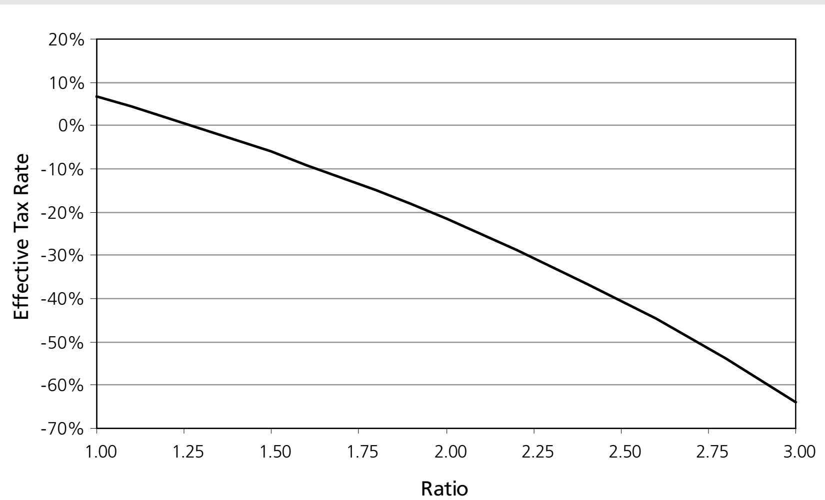

Table 3. CBO Estimates of Effective Tax Rates for Energy Capital Held by Corporations		
Asset Type	ETR	Share of Assets (%)
Electric Structures	18.6%	5.4
Petroleum and Natural-Gas Structures	9.2%	3.2
Electric Transmission and Distribution	24.9%	2.4
Other Power Structures	19.0%	2.1
Mining Structures	9.5%	0.3
Mining and Oil-Field Machinery	21.9%	0.2
Other Electrical Equipment	24.8%	0.1
Source: Congressional Budget Office (2005), table 2		

vestments that take into account important tax benefits specific to the energy sector. My effective-tax-rate estimates in Table 2 can be compared with estimates from the recent Congressional Budget Office (2005) analysis of capital income taxation. The estimates are not directly comparable but are suggestive of the importance of production and investment tax credits as well as the treatment of depletion. While not reported in Table 2, I compute an effective tax rate for nuclear-power structures of -58.9 percent. If I do not account for the production tax credit available to new nuclear-power plants, the tax rate rises to 26.3 percent, an estimate not too far from the CBO estimate for electric structures (Table 3). These calculations indicate the importance of the new nuclear-power production tax credit in lowering the effective tax rate on nuclear power.

Table 4. Ernst & Young Estimates of Effective Tax Rates for Energy Capital		
	Asset Type	ETR
1	Electric Utilities	
	Generation	
	Nuclear	26.7%
	Coal	30.8%
	Gas	26.7%
	Transmission and Distribution	
	Transmission Lines	27.5%
	Distribution Lines	31.7%
2	Petroleum	
	Refining	21.6%
Source: Ernst & Young (2007), table 7		

The estimate for petroleum and natural-gas structures lies between my estimates for integrated and nonintegrated firms. CBO estimates for electric transmission and distribution lines are about 10 percentage points below my estimates. The discrepancy can most likely be explained by the different assumptions that the CBO and I make about rates of returns and other underlying parameters in the tax-rate formulas.

A recent study by Ernst & Young (2007) provides more disaggregated estimates of effective tax rates and so is more comparable with my results. Table 4 below provides some ETR estimates from this study.

The Ernst & Young estimates for coal- and gas-fired generation are similar to my estimates, but its nuclear-power estimate is much higher, reflecting our different treatment of the production tax credit added by the Energy Policy Act of 2005. Our estimates for other assets are quite similar. Ernst & Young did not provide estimates of wind- or solar-powered electric generation.

III. REVIEW OF ENERGY TAX PROVISIONS

In this section, I review the current treatment of energy in the tax code at the federal and state level. Broadly speaking, firms benefit from two types of tax benefits in the federal tax code: rapid tax-depreciation rules; and various production and investment tax credits.

A. Federal Tax Provisions

To begin, income earned in the production or distribution of energy is subject to the U.S. income tax, mostly that on corporate income, which has a top federal marginal rate of 35 percent. Table 5 indicates the share of assets in various energy-related industries subject to the corporate income tax. The vast bulk of assets in the mining, utilities, and petroleum and coal-manufacturing sectors is subject to corporate income tax.

Table 5. Share of Assets Subject to Corporate Income Tax

Industry	Corporate Income-Tax Treatment
Mining	92.3%
Utilities	99.6%
Petroleum and Coal Products, Manufacturing	99.2%
Retail Gasoline Sales	47.6%
Pipeline Transportation	68.5%

Source: Congressional Budget Office (2006), table 3

I analyze energy investments in this paper assuming that firms are subject to federal and state corporate income taxes.[8] Many energy firms are subject to the corporate alternative minimum tax (AMT). While I do not analyze the corporate AMT in detail in this paper, I do note in various places where my analytic results can be affected by the AMT.[9]

1. DEPRECIATION

Under the current tax code, capital assets are depreciated according to the Modified Accelerated Cost Recovery System (MACRS), with recovery periods ranging from three to thirty-nine years. A declining-balance method is used to depreciate most capital, at either 200 percent (three-, five-, seven-, and ten-year property) or 150 percent (fifteen- and twenty-year property), with the option to shift to straight-line depreciation at whichever point it becomes advantageous to do so. Assuming that firms switch to straight-line depreciation at the point where straight-line provides a larger deduction than declining-balance, the two key parameters are the recovery period of the asset and the declining-balance deduction rate. Table 6 illustrates how an asset with a value of $1 would be depreciated under straight-line and double-declining-balance rules, assuming a seven-year recovery period.

Under straight-line depreciation, the taxpayer is allowed to deduct one-seventh of the value of an asset with a recovery period of seven years. The remaining basis in each year is the share of the asset that has not yet been depreciated and that can be depreciated in future years. At the end of seven years, all the asset has been depreciated, and zero basis remains. Under the double-declining-balance method, two-sevenths of the value of the asset may be depreciated in the first year. In subsequent years, two-sevenths of the remaining basis may be taken as a deduction. With these rules, the asset would never be fully depreciated. Thus taxpayers at any point may switch to applying straight-line depreciation to the remaining basis. After year three, it is not advantageous to switch to straight-line, since the deduction allowed in year four would equal 0.364/4 = 0.091, which is less than the amount allowed under double-declining balance (0.104). In the following year, it is advantageous to switch, and the remaining basis is depreciated over the final three years of the asset.[10] Tax depreciation effectively reduces the purchase price of an asset.[11]

Electric generating capital is depreciated over different tax lives, depending on the type of plant. Recovery periods range from five years for renewable energy to twenty years for coal. High-voltage electricity transmission lines received a fifteen-year recovery period in the Energy Policy Act of 2005. That act also clarified the depreciation of natural-gas gathering (seven years) and reduced the recovery period of distribution pipelines from twenty years to fifteen. In addition, the new law contains a provision allowing partial expensing of new refinery capacity placed in service before 2012. The provision allows for 50 percent expensing, with the remainder deducted, as under current law.

New deprecation provisions for "smart grid" technology were included in the Emergency Economic Stabi-

Table 6. Tax Depreciation

	Straight-Line		Double-Declining Balance		Double-Declining Balance with Switch to Straight-Line	
Year	Depreciation	Remaining Basis	Depreciation	Remaining Basis	Depreciation	Remaining Basis
1	0.143	0.857	0.286	0.714	0.286	0.714
2	0.143	0.714	0.204	0.510	0.204	0.510
3	0.143	0.571	0.146	0.364	0.146	0.364
4	0.143	0.429	0.104	0.260	0.104	0.260
5	0.143	0.286	0.074	0.186	0.087	0.174
6	0.143	0.143	0.053	0.133	0.087	0.087
7	0.143	0.000	0.038	0.095	0.087	0.000

Source: Author's calculations

lization Act of 2008, passed last October. The tax lives of smart meters and other demand-response technology were reduced from twenty years to ten.[12]

2. DEPRECIATION AND FOSSIL-FUEL PRODUCTION

Depreciation of assets in the production of fossil fuels (oil and gas drilling and coal mining) requires additional attention. Chief among the depreciation preferences are percentage depletion and the ability to expense intangible drilling costs. As noted in Metcalf (2007), these preferences are less generous than they have been historically, but they continue to be significant. Some background will help explain these tax benefits.

Capital investments in developing oil and gas production sites fall into one of three categories for federal tax purposes. Costs incurred in finding and acquiring the rights to oil or gas are treated as depletable property and are written off over the life of the oil or gas site. These include exploration costs to identify promising sites as well as the cost of upfront (or bonus) bids to acquire sites. Once a site is identified and purchased, its oil or gas enters a firm's proven reserves. As natural resources are extracted from booked reserves, the value of those reserves is diminished. Cost depletion allows a firm to write off depletable costs as the reserve is drawn down.[13]

As an alternative to cost depletion, independent oil, gas, and coal producers are allowed to take percentage depletion.[14] Rather than take a depletion deduction based on actual costs, the firm is allowed to take a certain percentage of revenue as a deduction. The current rate for percentage depletion is 15 percent for oil and gas and 10 percent for coal. Percentage depletion is allowed on production of up to 1,000 barrels of average daily production of oil (or its equivalent for natural gas). In addition, the depletion allowance cannot exceed 100 percent of taxable income from the property (50 percent for coal) and 65 percent of taxable income from all sources.[15] Continuing with the example above, assume that an independent firm owns this oil reserve and sells the 110,000 barrels of oil pumped in the first year for $100 per barrel. Assuming no taxable-income limitations, the firm could take a deduction for 15 percent of the revenue from the sale of the oil, or $1.65 million. If the firm were to sell the entire reserve of oil at $100 per barrel, its cumulative depletion allowance would be $15 million, 50 percent greater than the depletable costs of the field.

Limits on percentage depletion have been added over time, including a reduction in its rate and restriction to independent producers. Despite the curtailed availability of percentage depletion, it continues to be a significant energy tax expenditure, costing $4.4 billion between 2009 and 2013, according to the most recent administration budget submission (Office of Management and Budget, 2008). On the evidence of production data reported in U.S. Energy Information Administration (2007b), roughly two-thirds of domestic crude-oil production in 2006 came from independent producers (Table A6) potentially eligible to take percentage depletion.

Once a property has been identified, the firm incurs significant costs in developing the site. These costs, which might include site improvement, construction costs, wages, drilling mud (used to keep the drill bit cool and to flush out cuttings), fuel, and other expenses, are called intangible drilling costs (or IDCs). Intangible drilling costs are those with no salvage value. Typically, noncapital costs associated with developing a capital asset are depreciated over the life of the asset. In the energy sector, intangible drilling costs may be expensed by independent producers. Integrated producers may expense 70 percent of IDCs and write off the remainder over a five-year period.[16]

The last capital expense category is the drilling equipment itself. This is written off over a seven-year period under double-declining-balance depreciation rules. Drilling equipment constituted in 2006 roughly 5 percent of the total capital costs of new projects, according to U.S. Energy Information Administration (2007a) (table B14). Depletable costs constituted roughly 28 percent of total costs, and IDCs accounted for 67 percent of costs.

Oil and gas drilling receives an additional depreciation benefit from the ability to expense dry holes. One can view dry holes as part of the cost of drilling a successful well. This tax provision raises the effective value of the depreciation deductions for oil rigs. Technology, however, has reduced the percentage of dry holes. In 1960, 40 percent of all wells drilled were dry holes. By 2007, that percentage had fallen to 12 percent, reducing the tax advantage of dry-hole expensing.[17]

3. PRODUCTION AND INVESTMENT TAX CREDITS

The federal tax code includes a number of production and investment tax credits on fossil, alternative, nuclear, and renewable fuels. These are included as part of the general business credit (GBC) and subject to AMT limitations. Carlson and Metcalf (2008) provide evidence that energy firms are restricted in their ability to use all their GBCs. While the AMT plays a role, regular tax limitations play a more significant role in limiting the use of GBCs. The important energy-related production and investment credits include the following:

a. Nonconventional Oil-Production Credit

The Alternative Fuel Production Credit for production of nonconventional oil (e.g., shale oil, synthetic fuel oils from coal) provides for an oil-equivalent production tax credit of $3.00 per barrel (indexed in 1979 dollars and worth $6.79 in 2005). The 2005 energy act adds coke and coke gas to the list of qualified fuels and makes the credit part of the general business credit.[18] The credit phases out for oil prices above $23.50 in 1979 dollars ($53.20 in 2005). With higher crude-oil prices in 2006 and 2007, the credit was partially phased out, with a loss of 32 percent of its value in 2006 and 67 percent in 2007. The credit for coke and coke gas does not phase out and was worth $3.28 last year (in nominal dollars).

b. Production Tax Credits for Electricity Provided from Renewable Sources

Production tax credits are provided at a rate of 1.5¢ per kWh of electricity (indexed in 1992 dollars) generated from wind, biomass, poultry waste, solar, geothermal and other renewable sources.[19] Currently, the rate is 2.0¢ per kWh. Firms may take the credit for ten years. Refined coal is also eligible for a production credit at the current rate of $5.877 per ton.[20] The Energy Policy Act of 2005 added new hydropower and Indian coal, with the latter receiving a credit of $1.50 per ton for the first four years and $2.00 per ton for three additional years (in real dollars).

Production tax credits have historically been authorized by Congress for a two-year period. Considerable uncertainty has arisen a number of times as to whether Congress would reauthorize the credit. The credit actually lapsed in three years (2000, 2002, and 2004), though it was subsequently reauthorized retroactively. Distinct declines in wind investment occurred in each of those periods of uncertainty, as documented in Wiser and Bolinger (2008). The credit for wind and other renewables was renewed in the Emergency Economic Stabilization Act of 2008, passed in October 2008. The credit for solar was extended for eight years, through 2016, while wind received a one-year extension and other renewables a two-year extension.

c. Other Production Tax Credits

The 2005 energy act provided a production tax credit for electricity produced at nuclear-power plants (section 45J). Qualifying plants are eligible for a 1.8¢ per kWh production tax credit for eight years, up to an annual limit of $125 million per 1,000 megawatts of installed capacity. This limit will be binding on a nuclear-power plant with a capacity factor of 80 percent or higher. The law places an aggregate limit of 6,000 megawatts of capacity eligible for this credit.

The American Jobs Creation Act of 2004 (PL 108-357) created a production credit (section 45I) for marginal oil and gas producers of $3.00 per barrel of oil ($0.50 per thousand cubic feet [mcf] of natural gas) in year 2005 dollars. The full credit is available when oil (gas) prices fall below $15 per barrel ($1.67 per mcf) and phases out when prices reach $18 per barrel ($2.00 per mcf).[21] Marginal wells produce, on average, fifteen or fewer barrels of oil (or oil equivalent) per day.

This same law provided for small-refinery expensing of 75 percent of capital costs associated with low-sulfur diesel-fuel production and a 5¢ per gallon small-refiner's credit for the remaining 25 percent of qualified capital costs for the production of low-sulfur diesel fuel. The 2005 Energy Policy Act allowed a pass-through of this credit to owners of cooperatives.

d. Investment Tax Credits

A 30 percent investment tax credit is available for solar installations as well as fuel cells used to produce electricity. A 10 percent credit is available for qualifying microturbine power plants. In addition to credits for renewable energy, the Energy Policy Act of 2005 enacted credits for investments in certain clean-coal facilities. Integrated gasification combined-cycle (IGCC) plants are eligible for a 20 percent credit (up to a maximum of $800 million in credits); other advanced coal-based projects are eligible for a 15 percent credit (up to a maximum of $500 million in credits); and certified gasification projects are also eligible for a 20 percent credit (to a maximum of $350 million in credits).

As it did with respect to the production tax credit for renewable electricity, uncertainty existed last year over the fate of the 30 percent investment tax credit for solar power. Hassett and Metcalf (1999) analyze a model in which government tax policy is randomized (or appears random to investors). Their model predicts that as the probability increases that an investment tax credit will be allowed to expire, firms will speed up investment to take advantage of it in time. This phenomenon appeared to occur last year, when it was unclear whether the tax credits would be renewed. Johnson (2008) notes that a rush to ensure the installation of solar panels before the end of the year occurred, and that it drove up the panels' price. The Omnibus Budget Reconciliation Act of 1990 contained a provision for a 15 percent credit (section 43) for expenditures on enhanced oil-recovery tangible property and intangible drilling and development costs and other related capital expenditures. The credit is phased out when the section 29 reference oil price exceeds $28 in 1990 dollars ($37.44 for 2005). Given the run-up in oil prices over the past five years, producers cannot currently take this credit.

e. Section 40 Alcohol and Biodiesel Fuels Credit

The Energy Policy Act of 1978 included an exemption from the motor fuels excise tax for alcohol and alcohol-blended fuels, generically known as gasohol.[22] The Windfall Profits Tax allowed an immediate tax credit in lieu of the exemption.[23] The credit was set at a rate equivalent to the tax exemption. The alcohol-fuel-mixture credit is currently $0.51 per gallon of ethanol in gasohol and $0.60 for other alcohol-based fuels (excluding petroleum-based alcohol fuels). In addition, small producers may take a credit of $0.10 per gallon. The 2005 Energy Policy Act increased the small-producer production-capacity limit from 30 million to 60 million gallons per year.

The American Jobs Creation Act also added section 40A to the code to provide an income-tax credit for biodiesel fuels at a rate of $0.50 per gallon of biodiesel (other than agri-biodiesel) and $1.00 for agri-biodiesel. Like the alcohol-fuel tax credit, it is first applied to motor-fuel excise tax payments, with the excess added to the general business credit.

B. State Tax Provisions

Most states levy a corporate income tax, with top rates in 2006 that varied from 2 to 12 percent. Thirty-five states impose severance taxes on mineral extraction within their borders, and forty-five states impose public-utilities taxes in some form. Table 7 lists the top ten states in severance-tax and public-utilities-tax collections ranked by amount of collections in fiscal year 2007. Texas, Alaska, and Oklahoma lead the list in severance taxes and account for over half of total U.S. severance-tax collections in that year. These three states were among the top five oil-producing states in 2007 (the other two states are Louisiana and California). Wyoming is a significant oil-and-gas-producing state as well as the largest coal-producing state in the country. While I do not have detailed data breaking out severance-tax collections by fuel, it appears that oil and gas are responsible for the lion's share of revenue. The ten states in Table 7 account for over 90 percent of severance-tax collections in 2006. For many of these states, severance taxes account for a large fraction of total state tax revenues.

Public-utilities taxes are less concentrated. The top three states account for under 40 percent of total public-utilities taxes, and the top ten states account for 82 percent of total collections. In aggregate, severance-tax collections are roughly the same as public-utilities tax collections.

In my analysis below of the impact of taxes on energy investment, I use an average state corporate tax rate of 6.6 percent, which, when combined with the federal corporate tax rate of 35 percent, gives a total corporate tax rate of 39.3 percent.[24] I assume that severance taxes reduce the price paid to owners of land on which the taxed energy sources are found for the right to extract the resource. This assumption follows from the inelasticity of each state's supply of reserves and the ease with which consumers can substitute one state's supply for another's. I also assume that public-utilities taxes (excise taxes on the sale of energy, for the most part) are passed forward to consumers in the form of higher energy prices and so do not affect the return on investment.

Table 7. State Energy Tax Collections in 2007

Severance Tax				Public-Utilities Tax			
State	Amount	Share of Aggregate Severance Taxes	Share of State Taxes	State	Amount	Share of Aggregate Public-Utilities Taxes	Share of State Taxes
Texas	2,763	26%	7%	Illinois	1,834	17%	6%
Alaska	2,216	21%	64%	Pennsylvania	1,299	12%	4%
Oklahoma	942	9%	11%	Florida	1,044	9%	3%
Louisiana	904	8%	8%	Texas	995	9%	2%
New Mexico	844	8%	16%	New Jersey	982	9%	3%
Wyoming	804	7%	40%	New York	774	7%	1%
North Dakota	391	4%	22%	Alabama	745	7%	8%
West Virginia	328	3%	7%	California	601	5%	1%
Kentucky	275	3%	3%	Washington	444	4%	3%
Montana	265	2%	11%	North Carolina	372	3%	2%
United States	10,729		1.4%	United States	10,986		1.5%

Source: U.S. Census Bureau (2008). Amounts in millions of dollars.

IV. IMPLICATIONS FOR INVESTMENT

The effective rate measures help explain several facts about recent trends in energy capital investment. First, the recent boom in wind and solar renewable investment, especially in wind, is consistent with the large negative rates for wind and solar. Wind capacity grew by nearly 50 percent in 2007 and accounted for one-third of all new electrical capacity added in that year (Wiser and Bolinger, 2008). This trend continued in 2008, though it may be partly the result of decisions to move projects up, if possible, and into operation before the end of the year because of uncertainty over the continuation of the production tax credit.

Second, the production tax credit for new nuclear-power plants is driving the large negative effective tax rate on new nuclear-power construction and is likely contributing to the resurgent interest in nuclear construction. Combined construction- and operating-license applications were filed for nine projects totaling fifteen units, with 18.5 GW of capacity, between March 2007 and June 2008. Permits for over half of this additional capacity were filed in this calendar year. Since the Energy Policy Act of 2005 provides the nuclear production tax credit for only the first 6 GW of capacity, firms have a clear incentive to move early, before the available credits are used up. While high natural-gas prices and the possibility of carbon pricing make nuclear power particularly attractive, high hurdles for the construction and operation of any nuclear-power plant remain, making the recent surge in interest even more noteworthy.

Third, domestic oil and gas drilling increased markedly with the run-up in oil prices. The number of crude-oil rotary rigs in operation increased 28 percent between July 2006 and July 2008, while the number of gas rigs increased 12 percent. During this period, the domestic first purchase price of crude oil nearly doubled (U.S. Energy Information Administration, 2008b). The effective-tax-rate estimates in Table 2 suggest that a strong incentive exists for capital to flow to independent firms that can take advantage of the benefits of percentage depletion and the expensing of intangible drilling costs. Note also that rising costs of extraction increase the value of percentage depletion, as illustrated in Figure 1.

Finally, despite the urgent need to upgrade and expand the electricity transmission network, there is a lack of investment incentives that would encourage the flow of financial capital to this asset. This is particularly worrisome given the need to move electricity from remote sites that are well suited to renewable electricity generation to high-demand areas. Generous production and investment tax incentives for renewable energy are undermined to the extent that the domestic electricity transmission network cannot move this new power over the grid.[25]

V. CONCLUSION

This paper provides a number of estimates of the tax subsidies provided to different sources of energy production in the United States. One measure simply adds up estimates of energy-related tax expenditures by fuel source in 2007. A review of these estimates indicates that the distribution of tax subsidies by fuel type has shifted over the past decade. The share of tax expenditures for fossil fuels has dropped from over 60 percent in 1997 to under 50 percent in 2007. The subsidy share for renewable energy and end use/conservation has risen from just under 40 percent to over 50 percent in this same interval.

As for subsidies for electricity generation, refined coal receives a very high subsidy per MWh of generation ($29.94), while renewable electricity receives a subsidy on the order of $2 per MWh. Tax-based subsidies for conventional coal, natural gas and petroleum, and nuclear power are less than $0.25 per MWh.

The main contribution of this paper is the provision of estimates of the effective tax rate on energy-related investment in various types of energy capital. These estimates differ from previous estimates in looking at more disaggregated forms of energy capital than are typically considered in calculations of effective tax rates. In addition, I consider energy-specific tax provisions that most previous analyses have not taken into account. I find that effective tax rates can vary from as high as 39 percent to as low as -245 percent. For electricity generation, production and investment tax credits contribute to large negative effective tax rates. Short recovery periods for depreciation also contribute to low effective tax rates, but to a lesser extent than do tax credits. Percentage-depletion rules produce a negative effective tax rate for independent oil-drilling firms. With other factors held constant, an increase in extraction costs for new oil drives the effective tax rate down for firms taking percentage depletion.

The results of this analysis shed light on the differential tax treatment of energy sources in the United States. An obvious next step is to investigate the extent to which variation in tax subsidies by fuel source affects energy investment. The effective-tax-rate measures constructed here are necessary inputs for such an analysis.

Appendix: Effective Tax Rates for Energy Capital

Following the terminology in Congressional Budget Office (2005), let ρ be the real before-tax return on the marginal investment for a particular capital asset category and *r* the real return paid to investors. The effective tax rate is defined as

(1) $$\frac{\rho - r}{\rho}.$$

The required before-tax return is equal to

(2) $$\rho = \frac{(\tilde{r} + \delta)(1 - \tau z)}{1 - \tau} - \delta.$$

The parameter $\tilde{r}$ in equation (2) is the real corporate discount rate and equals $d(i(1-\tau) - \pi) + (1-d)E$. The discount rate is a weighted average of the real after-tax cost of borrowing, where *i* is the corporate borrowing rate, π is the inflation rate, τ is the corporate tax rate, *d* is the share of investment financed by debt, and *E* is the real return on equity. Assets are assumed to depreciate at an exponential rate, with the rate of decay equal to δ. The present value of tax depreciation is given by *z* and depends on tax rules specific to each asset.

In some cases, I compute effective tax rates for investments that are composed of different types of capital, each of which faces its own effective tax rate. In those cases, I construct before-tax returns for each capital component and compute the before-tax return for the investment weighting by the share of this component in the total investment cost.

A key element in the taxation of capital assets is the tax treatment of depreciation. Let *z* equal the present discounted value of the stream of depreciation deductions, assuming particular tax rules for an asset. If D_t is the amount of depreciation allowed in year *t* for an asset, with initial basis of 1 and a recovery period of *T* years, then *z* equals

(3) $$z = \sum_{t=1}^{T} \frac{D_t}{(1 + \tilde{r})^{t-1}}.$$

The present discounted value of depreciation deductions is equal to the tax rate times *z* (assuming that the tax rate does not change over the life of the asset). Thus, the effective after-tax purchase price of an asset is equal to $1 - \tau \cdot z$ times the cost of the asset. Below, I will show how the effective price is affected by energy-specific tax rules.

Table A1 reports tax depreciation rules and estimates of economic depreciation for various energy-related assets. Capital shares are reported in parentheses after each asset type. Capital shares for nuclear-power plants are taken from table 4.2.2 of Tennessee Valley Authority (2005). This report provides cost estimates for an advanced boiling-water reactor that would be designed and constructed under the new combined construction-permit and operating-license (COL) rules implemented in the Energy Policy Act of 1992. Oil drilling costs vary, depending on the particular characteristics of different sites. I have chosen a representative set of cost shares to construct a composite effective tax rate for drilling. The breakdown of intangible drilling costs for integrated firms reflects tax rules allowing expensing for 70 percent of IDC costs, with the remainder to be deducted over five years.

Table AI. Energy Capital Depreciation			
	Recovery Period	Method	Economic Depreciation Rate
Electric Utilities			
Generation			
Nuclear			
Steam Turbines (25%)	15	150%	5.16%
Other Equipment (54%)	15	150%	5.00%
Structures (21%)	15	150%	2.11%
Coal (PC)	20	150%	5.16%
Coal (IGCC)	20	150%	5.16%
Gas	15	150%	5.16%
Wind	5	200%	3.03%
Solar Thermal	5	200%	3.03%
Transmission and Distribution			
Transmission Lines	15	150%	5.00%
Distribution Lines	20	150%	5.00%
Petroleum			
Oil Drilling (nonintegrated firms)			
Oil Drilling (tangible) (10%)	7	200%	7.51%
IDC (70%)	Expensed		10.00%
Depletable Assets (20%)	percentage depletion		7.51%
Oil Drilling (integrated firms)			
Oil Drilling (tangible) (10%)	7	200%	7.51%
IDC (70%)			
Expensible IDC (49%)	Expensed		7.51%
Deductible IDC (21%)	5	200%	7.51%
Depletable Assets (20%)	cost depletion		7.51%
Refining	10	200%	8.91%
Natural Gas			
Gathering Pipelines	7	200%	2.37%
Other Pipelines	15	150%	2.37%

Economic depreciation rates taken from Bureau of Economic Analysis (2008), available at http://www.bea.gov/national/FA2004/Tablecandtext.pdf. The economic depreciation rate in the case of percentage depletion is set equal to the depletion rate for a representative well. See text for more information.

The formula for the before-tax return in equation 2 needs to be modified to account for production and investment tax credits as well as for percentage depletion for oil and gas drilling. Investment tax credits at rate κ are a straightforward modification. Production tax credits and percentage depletion are slightly more complicated. Let θ be the capacity factor for a renewable electricity investment. This is the fraction of time that the unit is producing electricity. The capacity factor for wind, for example, equals roughly 30 percent. A 1 kW facility produces 8760 θ kWhs of electricity over the year. If ρ is the overnight cost of 1 kW of capacity, a ten-year production tax credit is worth (per dollar of investment)

(4) $$v = \sum_{t=1}^{10} \frac{8760\theta s}{\left(1+\tilde{r}\right)^t p} = \frac{8760\theta s}{p}\left(\frac{1}{\tilde{r}} - \frac{1}{\tilde{r}\left(1+\tilde{r}\right)^{10}}\right)$$

where s is the subsidy rate (dollars per kWh). Since the effective-tax-rate methodology generally uses continuous time analogues, an alternative formula is

$$\nu = \frac{87600\theta s}{p}\left(\frac{1-e^{-10\tilde{r}}}{\tilde{r}}\right).$$

Accounting for production and investment tax credits, the required before-tax rate of return becomes[26]

$$(5) \qquad \rho = \frac{(\tilde{r}+\delta)(1-\kappa-\nu-\tau z)}{1-\tau}-\delta.$$

My treatment of percentage depletion follows that of the Congressional Budget Office (1985) study on oil and gas. The denominator in (5) is adjusted to account for the deduction:

$$(6) \qquad \rho = \frac{(\tilde{r}+\delta)(1-\kappa-\nu-\tau z)}{1-\tau+\mu\psi\tau}-\delta$$

where ψ is the percentage-depletion rate and μ the ratio of price to the before-tax return.[27] The percentage-depletion rate for oil is 15 percent. Where percentage depletion is taken, the firm would have no depletion as part of z.

The ratio of price to before-tax return (or operating profit) will vary, depending on the particular source of oil. While measuring the price of a barrel of oil is straightforward, determining what is the appropriate measure of operating profit per barrel of oil is not. One approach to measuring operating profit might be to take the oil price and subtract production costs (finding and extraction costs). The domestic first purchase price for oil was roughly $60 in 2006. According to U.S. Energy Information Administration (2007a), production costs were roughly $25 per barrel. This suggests a markup of 1.71.

Adelman (1995) cautions that standard measures of finding costs (the sum of exploration and development expenditures divided by oil and gas reserves added [in oil equivalents]) is a flawed measure. As Adelman notes, exploration adds knowledge, while development adds reserves. The knowledge from exploration may not add to reserves for many years. In addition, the conversion rate of gas into oil equivalents is not stable over time, as it depends on how oil and gas are used, as well as their relative prices. The EIA study acknowledges the first problem and addresses it by averaging finding costs over three years.

Alternatively, one could simply measure operating profit from firm balance sheets. U.S. Energy Information Administration (2007a), table 9, reports income and expenses of major energy producers. The ratio of revenue to operating income in 2006 was 1.86. On the basis of these two estimates of the markup ratio (μ), I use a ratio of 1.75 in my calculations below. Table A2 reports the non-technology-specific parameters I use in my effective-tax-rate calculations.

Table A2. Effective-Tax-Rate Parameters

Parameter	Value
Real Required Return to Equity (E)	7%
Inflation Rate (π)	3%
Nominal Bond Rate (i)	8.6%
Federal Tax Rate (τ_F)	35%
Average State Tax Rate (τ_S)	6.6%
Combined Tax Rate (τ)	39.3%

Source: Real required equity return from table 17 in Congressional Budget Office (2006). Nominal bond rate is the fifty-year average of BAA bonds taken from table B-73 in Council of Economic Advisers (2008).

ENDNOTES

1. See table 1.9 in International Energy Agency (2007).

2. The president's budget, for example, includes as a tax expenditure natural-gas distribution pipelines treated as fifteen-year property.

3. Metcalf (2008) argues that the incremental carbon reduced through the ethanol excise tax credit is over $1,700 per ton of CO_2 because of the inframarginal nature of the subsidy.

4. See Congressional Budget Office (2005) for a recent discussion and application of this methodology.

5. I assume throughout that the taxpayer has sufficient taxable income and taxes against which to take all energy-related deductions and credits. To the extent that the firm cannot take all deductions or credits, the effective tax rate on the energy-related investment is higher. Historically, there has been an active market in financing renewable projects benefiting from production tax credits that allow the financing firm to utilize the tax benefits of the investment. This avenue for utilizing the tax benefits from renewable investment appears to have diminished temporarily in the current credit crunch.

6. Here the effective-tax-rate formula uses the exponential economic depreciation rate for tax depreciation rather than approximating it with straight-line depreciation.

7. The number of operable refineries has been steadily declining from its most recent peak of 324 in 1981 to 149 in 2007. Gross inputs to refineries, on the other hand, have increased by over 20 percent over this same period. See table 5.9 in U.S. Energy Information Administration (2008b).

8. Owners of energy firms not subject to the corporate income tax are subject to the personal income tax. All the deductions and credits discussed below apply equally if income is reported on the personal income-tax return. The benefit of any deductions will differ to the extent that the marginal tax rate differs.

9. Carlson and Metcalf (2008) provide results on the AMT's impact on the application of tax credits to the corporate income tax.

10. The IRS adjusts this schedule on the basis of when during the year the asset is purchased. Commonly, firms employ the "half-year" method, in which it is assumed that the asset is purchased halfway through the first year. In that case, the firm would take a deduction equal to 14.3 percent of the asset's value in the first year and apply the double-declining methodology, switching to straight-line subsequently. The asset then is assumed to depreciate fully at the eighth year's midpoint.

11. If z is the present discounted value of the stream of depreciation deductions per dollar for an asset and τ the corporate tax rate, then tax depreciation reduces the price of the asset from one to $1 - \tau z$.

12. Smart meters provide two-way communication between customers and utilities. They can automatically signal utilities when power outages occur, and they can signal customers when power peaks are occurring. Smart meters can be combined with "time of day" pricing to provide greater demand sensitivity to the cost of producing electricity.

13. As an example, imagine a field that contains 1 million barrels of proven reserves of oil, with exploration and purchase costs of $10 million. Under cost depletion, the firm is allowed to write off the $10 million cost as oil is drilled. Thus, if the firm pumps 110,000 barrels of oil from the field in the first year, it would be allowed cost depletion of $1.1 million, since the amount pumped equals 11 percent of the proven reserves. Geological and geophysical costs may be amortized over two years (seven years for the majors).

14. Independent producers are defined as producers that do not engage in refining or retail operations. EPACT increased, from 50,000 to 75,000 barrels per day, the amount of oil a company could refine before it was deemed to engage in refining for this purpose.

15. Amounts in excess of the 65 percent rule can be carried forward to subsequent tax years. The net-income limitation was suspended in years past, but the suspension lapsed as of this year.

16. Intangible drilling costs are not counted as a preference under the Alternative Minimum Tax.

17. Exploratory wells continue to have high failure rates. In 2007, 48 percent of exploratory wells were dry holes, and 8 percent of development wells were dry holes. But only 4,400 exploratory wells were drilled that year; by comparison, more than 49,200 development wells were. Roughly 34,000 development wells were drilled in 1960, with a dry-hole rate of 25 percent. However, 11,700 exploratory wells were drilled then, and over 80 percent of them were dry holes. Data are taken from the Energy Information Administration's website, accessed on July 25, 2008.

18. Coke and coke gas also received a $3 per barrel of oil equivalent credit, but it was indexed to 2004 rather than 1979. Most energy tax credits were part of the GBC. Prior to Energy Policy Act (EPACT) of 2005, the section 29 credits were an exception, so any unused credits were lost. As part of the GBC, excess credits can be carried backward one year and forward up to twenty years.

19. Open-loop biomass is eligible for a 0.75¢ credit in 1992 dollars per kWh.

20. Refined coal is a synthetic fuel produced from coal with lower emissions of certain pollutants.

21. The section 29 reference price is used to determine eligibility for this credit.

22. Originally, the law provided a full exemption from the then $0.04 per gallon tax. But the motor fuels excise tax was raised over time, and the exemption did not keep pace with it. See General Accounting Office (1997) for an early chronology of events related to this tax exemption.

23. The American Jobs Creation Act of 2004 subsequently eliminated the tax exemption in favor of the tax credit.

24. The state corporate tax rate is deductible from federal corporate income taxes. Thus the aggregate rate equals 35% + (1-35%)(6.6%), or 39.3%.

25. Tax incentives for electricity supply do drive up the demand for transmission facilities and so indirectly encourage transmission investment. Although renewable energy sources, which tend to supply energy intermittently, place different demands on the transmission grid from those that traditional sources impose, current pricing structures do not reflect the distinction. As a result, the indirect impact of tax subsidies on grid investment is attenuated.

26. Production tax credits might be viewed as a subsidy to output rather than investment. They subsidize investment to the extent that they increase the return on capital. Since production tax credits are provided for specific energy capital, it is reasonable to assume that they benefit capital owners. As an example, consider a production tax credit that lowers the cost of electricity from a wind project below that of natural gas, the marginal fuel setting the price of electricity. The excess of revenue over the levelized cost of wind goes to capital owners. This is in contrast to state excise taxes on all electricity production. In this latter case, no inframarginal effect leads to impacts on capital owners. The short-run demand elasticities suggest that the amounts paid in excise taxes will be passed forward to consumers.

27. A marginal capital investment earns $(1-\tau)\,\rho-\psi\tau p$, where *p* is the incremental revenue from the investment. Defining $\mu = p/\rho$ gives the desired result. I ignore any net-income limitations in this calculation.

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