
Federal Tax Policy towards Energy

Gilbert E. Metcalf, *Tufts University and NBER*

Executive Summary

On Aug. 8, 2005, President Bush signed the Energy Policy Act of 2005 (PL 109-58). This was the first major piece of energy legislation enacted since 1992 following five years of Congressional efforts to pass energy legislation. Among other things, the law contains tax incentives worth over \$14 billion between 2005 and 2015. These incentives represent both pre-existing initiatives that the law extends as well as new initiatives.

In this paper I survey federal tax energy policy focusing both on programs that affect energy supply and demand. I briefly discuss the distributional and incentive impacts of many of these incentives. In particular, I make a rough calculation of the impact of tax incentives for domestic oil production on world oil supply and prices and find that the incentives for domestic production have negligible impact on world supply or prices despite the United States being the third largest oil producing country in the world.

Finally, I present results from a model of electricity pricing to assess the impact of the federal tax incentives directed at electricity generation. I find that nuclear power and renewable electricity sources benefit substantially from accelerated depreciation and that the production and investment tax credits make clean coal technologies cost competitive with pulverized coal and wind and biomass cost competitive with natural gas.

1. Introduction

On Aug. 8, 2005, President Bush signed the Energy Policy Act of 2005 (PL 109-58). This was the first major piece of energy legislation since 1992 and culminated five years of efforts to pass energy legislation by

the Bush Administration. Among other things, the law contains tax incentives worth over \$14 billion between 2005 and 2015. These incentives represent both pre-existing initiatives that the law extends as well as new initiatives. In this paper I review federal tax energy policy focusing both on programs that affect energy supply and demand.

In the next section, I discuss an economic rationale for energy tax incentives. Next, I review current energy taxes in the third section. In the following section, I summarize the various energy incentives in the tax code.¹ These include accelerated depreciation of various types as well as production and investment tax credits. In addition, special incentives are targeted towards electric utilities and the transportation sector. In the fifth section, I briefly discuss the distributional and incentive impacts of many of these tax incentives. I also conduct a levelized cost analysis of various electricity generation technologies to assess the impact of the production and investment tax incentives directed at electricity generation.

In summary, the energy taxes or tax incentives currently in effect are difficult to justify on the basis of economic theory. Energy taxes totaled \$36.1 billion in fiscal year 2004 with the vast bulk of the revenues coming from motor vehicle fuel taxes. The most pressing case for taxation—externalities—suggests direct pollution or driving charges rather than a gasoline tax. The other motor vehicle related tax, the Gas Guzzler Tax, suffers from the defect of excluding light trucks and Sport Utility Vehicles (SUVs) from the tax. These make up the majority of motor vehicles currently sold.

With the passage of the Energy Policy Act of 2005 (EPACT), energy tax preferences are worth roughly \$6.7 billion in fiscal year 2006. The production and investment tax credits have been effective at making certain renewable energy sources (mainly wind and biomass) competitive with natural gas in electricity generation. I note, however, that tax credits are a socially costly way of making these renewable sources competitive with fossil fuel sources.

Finally, while fossil fuel and nuclear power continue to receive the majority of benefits from tax incentives, the tilt towards these fuels is not as large as it once was. Percentage depletion and expensing of intangible drilling costs, for example, have been scaled back relative to the situation in the 1950s and 1960s. And the investment tax credits for solar generated electricity combined with generous depreciation tax treatment contribute to negative effective tax rates on solar generated electricity.

2. Rationale for Government Energy Tax Incentives

Why should the federal government have an energy policy? More particularly, why should the tax code be used as an instrument of an energy policy? To help evaluate the various provisions of the tax code that affect energy supply and demand, I briefly review four major arguments for government intervention in energy markets: energy externalities, national security, market failures and barriers in energy conservation markets, and rent expropriation. For a more in-depth review, see Newbery (2005) or Lazzari (2005).

A broad array of externalities are associated with our consumption of energy. Burning fossil fuels contributes to air pollution (sulfur dioxides, nitrogen oxides, particulates) and generates greenhouse gases. In addition, our use of petroleum in transportation contributes to roadway congestion, accident externalities, and other traffic related market failures (see Parry and Small 2005 for a fuller discussion of driving related externalities). Economic theory suggests that we should tax externalities directly rather than a proxy for the externality (here, motor vehicle fuels). Road congestion suggests the use of congestion or time-of-day pricing on highways. Tailpipe emissions from vehicles call for emissions pricing if technologically feasible.² Accident externalities call for changes in automobile insurance pricing. None of these externalities suggest a policy of taxing motor vehicle fuels directly. The one externality that might suggest a motor fuels tax is global warming arising from burning fossil fuels given the tight relationship between petroleum consumed and carbon emitted.³ But even here a stronger case could be made for a comprehensive tax on the carbon content of all energy sources rather than a specific tax on motor vehicle fuels.⁴

Positive spill-overs from research and development are frequently cited as an argument for tax incentives for particular technologies. Supporters of production tax credits for renewable fuels, for example, argue that experience in the marketplace and learning by doing will bring about cost savings that support the initial subsidies. The difficulty with such an argument, of course, is that *all* research and development spending has elements of non-appropriability leading to a policy prescription of support for general R&D rather than sector or technology specific R&D support.

A second broad rationale for government intervention in energy markets is national security concerns. Here the argument is that our dependence on imported energy, oil in particular, makes us vulnerable

to economic coercion from foreign owners of energy resources. In 2004, the United States imported over 60 percent of the 20.5 million barrels per day of petroleum that it consumed (Energy Information Administration 2005). The need to protect a stable source of energy imports, it is argued, requires increased spending on defense and national security and has made the country more vulnerable to unstable governments in the Middle East and other oil rich regions. Oil import tariffs are a proposed solution to this problem. By reducing our dependence on foreign oil, it is argued, the United States reduces its vulnerability to political and economic instability elsewhere. The difficulty with this argument is that oil is a commodity priced on world markets. Even if the United States were to produce all the oil it consumes, it would still be vulnerable to oil price fluctuations. A supply reduction in the Middle East would raise prices of domestic oil just as readily as it raises prices of imported oil.⁵

A third argument for government intervention in energy markets is the existence of market barriers to energy efficient capital investment. A long-standing "energy paradox" claims that consumers need very high rates of return on energy efficient capital (appliances, housing improvements, lighting, etc.) and a variety of market barriers have been proposed to explain this paradox and to motivate market interventions. I critique the market barriers literature elsewhere (Metcalf 2006) and simply note two relevant issues here that support possible market interventions. First, many have argued that consumers are poorly informed about the potential for energy savings (as well as the value of the savings) associated with new more expensive technologies. This is a reasonable point given the public good nature of information acquisition and suggests the value of government information programs. Programs such as energy efficiency labeling on new appliances can help overcome information failures at low cost. Second, principal-agent problems may deter energy efficient investments. A good example is the provision of energy efficient appliances and housing in rental housing. Tenants may desire more energy efficient housing and appliances but landlords may be reluctant to make the investments out of concern that they may be unable to recoup their incremental investment through higher rents. In addition, many apartment buildings are not easily converted to allow for tenant control over and payment for energy consumption (especially heating services) in individual units. This removes incentives for tenants to conserve energy. Landlords, meanwhile, may be reluctant to invest in energy conservation capital if the effectiveness of the invest-

ment depends on tenant use characteristics (installing additional insulation is likely not cost-effective if tenants open windows during the winter when apartments become overheated). The appropriate policy response in this situation is to provide a subsidy to tenants (or landlords) for investments in energy conservation capital.

Finally, a number of authors (Newbery 1976; Bergstrom 1982; Karp and Newbery 1991) have noted that an oil import tariff can expropriate some portion of the Hotelling rents associated with oil. The intuition is straightforward if all consuming countries could act in collusion. Since potential oil supply from known oil fields is fixed, a tax that doesn't alter the relative scarcity rents of oil over time will not affect the time profile of extraction. Thus, we can collapse the analysis to that of a tax on an inelastically supplied product. Since the entire burden of such a tax is on the supplier, the result follows.⁶ Newbery (2005) estimates that the optimal oil import tariff for the EU and the United States ranges between \$3.10 and \$15.60 per barrel in 2002.

Summing up, we shall see that the arguments for using the tax code to affect energy supply and demand are poorly related to existing energy tax policy. The most compelling case can be made for energy taxes related to carbon emissions and for an oil import fee to transfer some of the Hotelling rents from oil suppliers to the United States. I turn next to a discussion of current energy tax provisions at the federal level.

3. Federal Energy Taxes

Table 5.1 lists federal taxes that are specifically linked to energy production or consumption. By far the largest are the excise taxes on gasoline and diesel fuels that are dedicated to the Highway Trust Fund accounting for over 95 percent of federal energy excise tax collections in FY 2004. The federal excise tax rate on gasoline is 18.4¢ per gallon. Of that, 0.1¢ is dedicated to the Leaking Underground Storage Tank Trust Fund and the remaining 18.3¢ to the Highway Trust Fund.⁷ Of that 18.3¢ per gallon, 2.86¢ is dedicated to the Mass Transit Account and the remaining 15.44¢ to the Highway Account. In fiscal year 2004, this tax raised \$35.1 billion. In comparison, total outlays for grants to state and local governments from the highway and urban mass transit programs in fiscal year 2004 were \$30.0 billion. Non-trust fund aid to sub-federal governments for highways and urban mass transit totaled an additional \$7.8 billion with nearly all of that designated to urban mass transit.

Table 5.1
Federal Energy Excise Taxes

Tax	Tax Rate	Revenue Projection for FY2004 (\$millions)
Highway trust fund revenues	18.3¢ per gallon of gasoline*	\$34,711
Gas guzzler tax	\$1,000–\$7,700 per vehicle depending on mileage	141
Oil spill liability trust fund	5¢ per barrel	—
Leaking underground storage tank tax	0.1¢ per gallon of motor fuels	189
Coal excise tax	Lower of 4.4 percent of sale price and \$1.10 per ton (\$.55 per ton for surface mined coal)	566
Aquatic resources trust fund tax on motorboat gasoline and other fuels	Motorboat gasoline proceeds from highway trust fund revenues	416
Inland waterway fuels tax	\$.224 per gallon for commercial vessels	91
	Total	\$36,114

*Diesel fuel is taxed at the federal level at 24.3¢ per gallon. State excise taxes on gasoline and diesel fuel averaged 18.1¢ as of April 2006. According to the American Petroleum Institute (2006), taking into account all taxes on gasoline (diesel) including the Leaking Underground Storage Tank Tax, the average tax rate is 46.5¢ (53.02¢) per gallon.

Source: Budget of the United States, Historic Tables, Table 2.4. Gas Guzzler tax revenue from SOI Historic Tables, Table 21.

Because the federal motor fuels gas tax is an excise tax, its ad valorem equivalent rate fluctuates with gas prices. Figure 5.1 shows how the rate has changed between 1978 and 2005. With the decline of gasoline prices in the late 1980s, the tax peaked at 27 percent of the refiner price of finished motor gasoline to end users in 1998 and has fallen since then to 10 percent in 2005.

The United States has the lowest tax rate on unleaded gasoline among all the OECD countries (see figure 5.2). Its tax rate per litre (\$.104) in the fourth quarter of 2005 was less than half that of the next closest country and compares to an OECD average rate of \$.789 per litre. Returning to the importance of motor fuels taxes in total energy tax collections, consider the United Kingdom. Its tax on gasoline is the third highest among OECD countries (see figure 5.2). Yet the UK tax on hydrocarbons is only 90 percent of its total energy tax collections.⁸

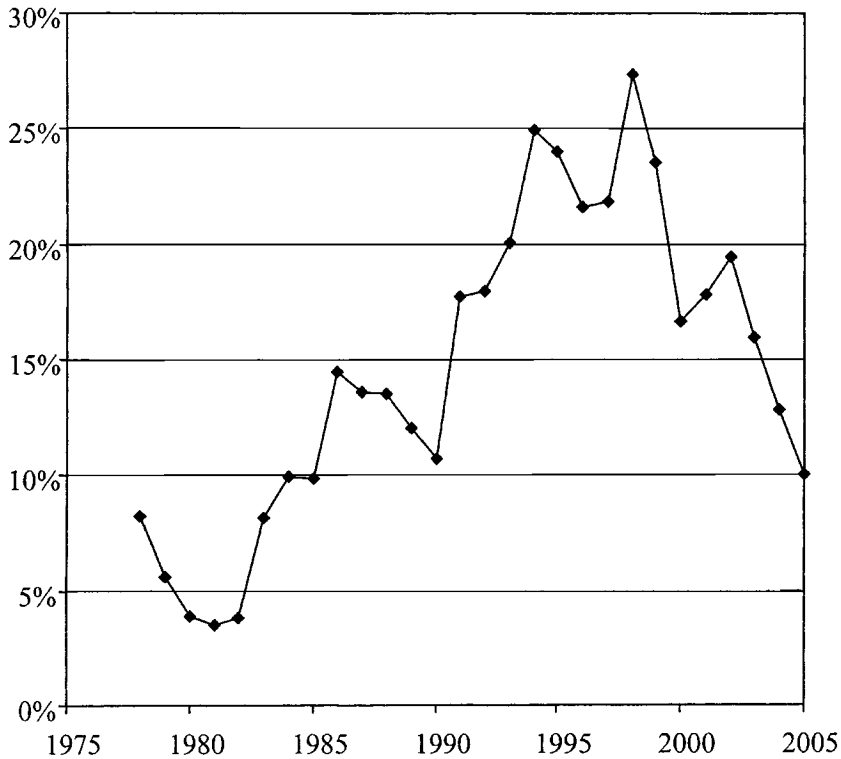


Figure 5.1

Federal Excise Tax Rate as Share of Before-Tax Refiner Price of Gasoline

Sources: EIA Monthly Energy Review and Jackson (2006).

The Gas Guzzler Tax was enacted as part of the Energy Tax Act of 1978. It levies a tax on automobiles that obtain fuel mileage below 22.5 miles per gallon.⁹ Tax rates range from \$1,000 to \$7,700 per vehicle. In 2004 the tax collected \$141 million. The gas guzzler tax explicitly excludes sport utility vehicles, minivans, and pickup trucks, which represent 54 percent of the new vehicle sales in 2004 (U.S. Census Bureau 2006, table 1027). The light truck category (comprising SUVs, minivans, and pickup trucks) is the fastest growing segment of the new vehicle market, growing at an annual rate of 5.5 percent between 1990 and 2004. In contrast, new car sales are falling at an annual rate of 1.6 percent. Unofficial Congressional estimates suggest that phasing out the SUV loophole over four years would raise roughly \$700 million annually once the phase-out was complete.

The Energy Policy Act of 2005 (EPACT) resurrected the Oil Spill Liability Trust Fund tax at the original rate of 5¢ per barrel. This tax had

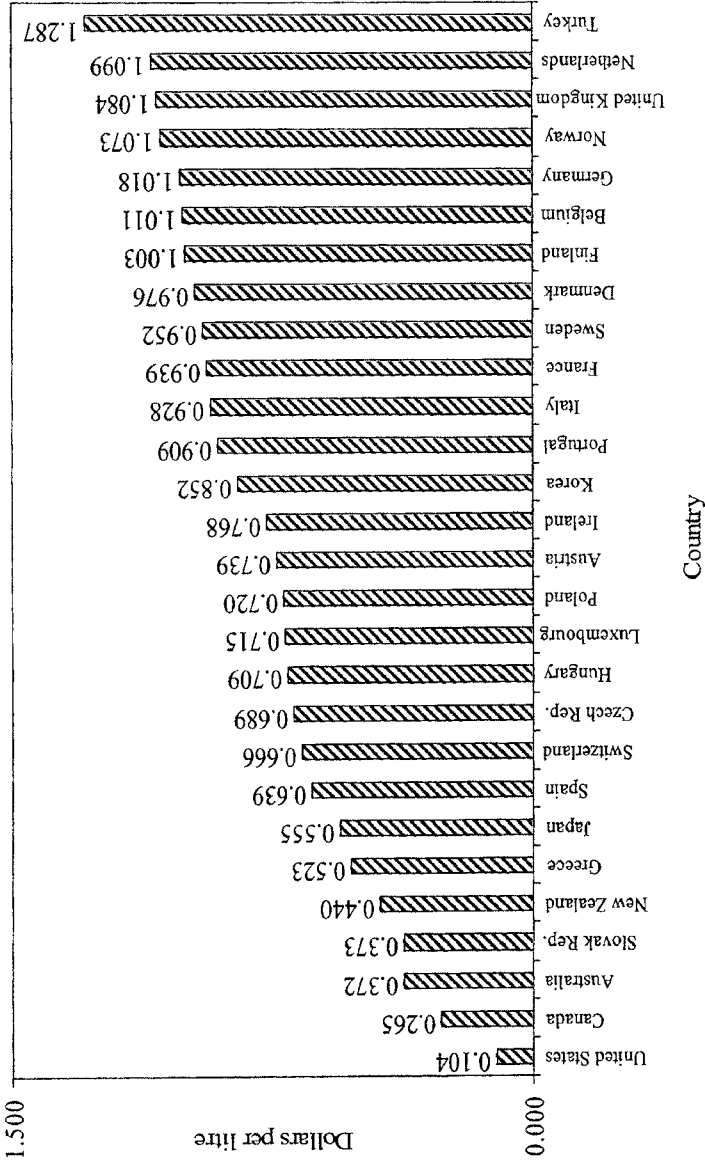


Figure 5.2
Tax Rate on Unleaded Gasoline
(Fourth Quarter 2005)

Sources: IEA, Energy Prices and Taxes, Fourth Quarter 2005.

previously been in effect from 1990 through 1994. The Joint Committee on Taxation estimates that this tax will raise \$1.25 billion between 2005 and 2010. The tax is imposed on crude oil received at U.S. refineries as well as imported petroleum products. Domestic crude oil for export is also subject to the tax if the tax had not been previously paid.

The coal excise tax funds the Black Lung Disability Fund. It is levied on coal mined in the United States at a rate of 4.4 percent of the sales price up to a limit of \$1.10 per ton of underground coal and \$.55 per ton of surface mined coal. This tax raised \$566 million in 2004.

Gasoline sold for sport motorboats is taxed at the same rate as highway gasoline and diesel fuel and the funds allocated to the Aquatic Resources Trust Fund (subject to an annual cap on transfers that effectively reduces the share of tax on motorboat fuels shifted to this trust fund). Finally the Inland Waterways Fuels Tax levies a tax of 22.4¢ per gallon of fuel sold to commercial vessels using the Inland Waterway System (barges for the most part).

4. Energy Incentives in the Corporate and Personal Income Tax

The President's FY2007 Budget Submission lists over \$20 billion of tax expenditures (for the fiscal years 2007–2011) associated with energy.¹⁰ Table 5.2 lists these tax expenditures sorted from highest to lowest cost (over the five year budget window). Both the number of tax provisions and the revenue cost have increased as a result of 2005's energy legislation. The General Accounting Office (2005) listed nine income tax preferences totaling \$4.2 billion in revenue loss in fiscal year 2003.¹¹ In fiscal year 2006, the Administration's budget lists 29 preferences totaling \$6.7 billion for that year.

The single largest tax expenditure is associated with alcohol fuels. Most of this revenue loss arises from the reduction in motor vehicle fuel tax revenues (\$12,500 million) with the remainder arising from the \$.51 per gallon income tax credit for this fuel.¹² After alcohol fuels is the tax expenditure for investment and production tax credits for new energy technologies. Investment tax credits range from 20 to 30 percent depending on the technology and production tax credits exist, primarily for electricity produced from renewable energy sources.

Before turning to a discussion of the current code, it may be useful to provide some historical perspective on the federal tax treatment of energy.¹³ Prior to the first oil embargo in 1973 the federal government's tax policy was designed to encourage fossil fuel exploration and

Table 5.2
Energy Tax Expenditures

Tax Provision	Revenue Cost: FY 2007–2011 (\$millions)
Alcohol fuel credits	12,730
New technology credit (secs. 45 & 48)	4,060
Alternative fuel production credit (sec. 29)	3,450
Expensing of exploration and development costs	3,230
Excess of percentage over cost depletion	3,230
Temporary 50% expensing for equipment used in the refining of liquid fuels	830
Credit for investment in clean coal facilities	780
Amortize all geological and geophysical expenditures over 2 years	630
Natural gas distribution pipelines treated as 15-year property	560
Credit for energy efficiency improvements to existing homes	530
Exclusion of interest on energy facility bonds	510
Tax credit and deduction for clean-fuel burning vehicles	420
Capital gains treatment of royalties on coal	400
Exclusion of utility conservation subsidies	380
Allowance of deduction for certain energy efficient commercial building property	340
Exception from passive loss limitation for working interests in oil and gas properties	200
Credit for holding clean renewable energy bonds	180
Credit for business installation of qualified fuel cells and stationary microturbine power plants	150
Credit for energy efficient appliances	80
Credit for construction of new energy efficient homes	40
Enhanced oil recovery credit	20
30% credit for residential purchases/installations of solar and fuel cells	20
Pass through low sulfur diesel expensing to cooperative owners	–30
Deferral of gain from dispositions of transmission property to implement FERC restructuring policy	–210
Credit for production from advanced nuclear power facilities	—
Alternative fuel and fuel mixture tax credit	—

Source: FY2007 Budget Submission of the President, Analytical Perspectives.

production. Expensing of intangible drilling costs was introduced in 1916 and percentage depletion in 1926. Percentage depletion for oil and gas was particularly generous with a rate of 27.5 percent (relative to the current rate of 15 percent) for oil and gas and was available to all companies, not simply independent producers as at present.

During the 1970s the sharp increase in the price of oil combined with growing environmental concerns associated with oil and gas drilling as well as a rising federal budget deficit led to a curtailment of the preferential treatment for fossil fuels. The percentage depletion rate, for example, was reduced to 15 percent for oil and gas and restricted to independent producers (i.e., producers without refining or retailing operations). The Energy Tax Act of 1978 introduced the Gas Guzzler Tax, tax subsidies for gasohol, and investment tax credits for conservation and renewable energy production. This was followed by the Windfall Profits Tax which, in addition to its efforts to tax profits on old oil, enacted the section 29 production tax credits for non-conventional oil.

The election of Ronald Reagan in 1980 ushered in a new era in the federal government's tax treatment of energy. According to Lazzari (2006), Reagan brought a free-market approach to energy policy. As such, he worked to eliminate the Windfall Profits Tax (largely repealed in 1988) and to end federal tax credits for energy production or investment. By 1988 all that remained of the federal tax credits for energy were the section 48 investment tax credits for solar and geothermal power.

The post-Reagan era saw a number of changes to the tax code with the most significant being the Energy Policy Act of 1992 (PL 102-486). This law enacted the section 45 production tax credits for wind and closed loop biomass generated electricity. As discussed below, this credit was gradually expanded to cover other renewable sources and remains in effect today.¹⁴ Other laws passed during the post-Reagan era generally extended existing production and investment tax credits and raised the gasoline tax.¹⁵

The most recent change is the Energy Policy Act of 2005, which extended and expanded coverage of the section 45 production and section 48 investment tax credits among a variety of other provisions. I discuss the current tax code's various provisions in the next section.¹⁶

4.1 Depreciation

Depreciation is the wearing out of an asset over time and is properly recognized as a cost of doing business. Economic depreciation refers to the actual wearing out of the asset as reflected in changes in the asset's

value over time. A pure income tax would allow a deduction for economic depreciation. Because of the difficulties involved in measuring economic depreciation, the tax code groups assets into broad categories and mandates depreciation schedules for assets in each category. Tax depreciation may bear some resemblance to economic depreciation but it should be stressed that tax depreciation is a policy tool that may be used to encourage or discourage certain types of investment at the expense of other types. Accelerated depreciation refers to a depreciation schedule that allows for more rapid tax depreciation than economic depreciation. The limit of accelerated depreciation is expensing, an immediate deduction for the entire cost of the asset.

Expensing an asset reduces the effective tax rate on this asset to zero. To see this consider an asset worth \$100 that generates additional net profits of \$20 per year. In the absence of taxation, this asset produces a net return of 20 percent. Now impose a 35 percent tax with expensing. In the first year, the firm takes a deduction for the cost of the machine and enjoys a reduction in taxes of \$35 (35 percent times \$100). The after-tax cost of the machine has been reduced to \$65. In subsequent years, the firm obtains additional after-tax profits of \$13. The net return on this investment is still 20 percent ($\$13/\65).

Under the current tax code, capital assets are depreciated according to the Modified Accelerated Cost Recovery System (MACRS) with recovery periods ranging from 3 to 39 years under the General Depreciation System (GDS).¹⁷ Most capital is depreciated using a declining balance method at either 200 percent (3, 5, 7, and 10 year property) or 150 percent (15 and 20 year property). Table 5.3 shows the recovery period for various types of energy related capital. Most electric generating capital is depreciated over 20 years with the major exception being nuclear power plants (15 years) and renewable energy generating capital (five years). High voltage electricity transmission lines received a 15 year recovery period in the Energy Policy Act of 2005. That act also clarified the depreciation of natural gas gathering pipelines (seven years) and reduced the recovery period of distribution pipelines from 20 to 15 years. In addition, the new law also contains a provision allowing partial expensing for new refinery capacity placed in service before 2012. The provision allows for 50 percent expensing with the remainder deducted as under current law.

Below, I provide some analysis of the impact of accelerated depreciation (as well as other tax provisions) on the cost of capital for various types of electricity generating property and show that nuclear power

Table 5.3
Recovery Periods for Energy Capital

Property	Recovery Period (Years)
Electric utility generation and distribution property	20
Electric transmission property (below 69 kV)	20
69 kV and higher electric transmission property	15
Electric utility nuclear power generator	15
Industrial electric generation	15
Liquefied natural gas plant	15
Natural gas distribution pipelines	15
Pipeline transportation (including storage of integrated producers)	15
Coal gasification production property	10
Refineries	10
Natural gas gathering pipelines	7
Natural gas production property	7
Electric utility nuclear fuel assemblies	5
Oil and gas drilling rigs	5
Section 48 alternative energy property	5

Source: U.S. Internal Revenue Service (2006).

and electricity generated from renewable sources receive particularly generous tax treatment from accelerated depreciation.

Oil 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 2004, that percentage had fallen to 12 percent reducing the tax advantage of dry hole expensing.¹⁸

While not energy capital explicitly, motor vehicles have a significant impact on energy consumption and depreciation rules treat different types of motor vehicles very differently. Clean fuel vehicles may be expensed up to limits (ranging from \$50,000 for trucks or vans with gross vehicle weight exceeding 26,000 pounds to \$2,000 for motor vehicles weighing less than 10,000 pounds). Clean fuel vehicles include vehicles that burn natural gas, LNG, LPG, hydrogen, electricity, gasohol (if at least 85 percent alcohol) and certain hybrid electric vehicles.

Passenger cars, SUVs and pickup trucks used in a small business can have very different depreciation treatment. Small businesses are allowed a section 179 deduction of up to \$100,000 per year in capital expenses (subject to phase-out rules). The section 179 deduction is limited for motor vehicles in certain ways. First, passenger vehicles and light trucks with a gross vehicle weight of 6,000 pounds or less are treated as listed property and subject to annual depreciation deduction limits arising from luxury passenger car rules written in the Deficit Reduction Act of 1984 (PL 98–369). These vehicles must be depreciated over a five year period with specified annual depreciation caps.¹⁹ The luxury vehicle limits are such that any passenger car costing more than \$13,860 and any light truck costing more than \$15,360 will have a recovery period longer than the standard five year recovery period for motor vehicles. Second, small businesses purchasing SUVs weighing more than 6,000 pounds (but not more than 14,000 pounds) can expense \$25,000 and depreciate the balance over five years using double-declining balance rules. Table 5.4 illustrates how the various depreciation rules affect the after-tax price for a small business owner in the top personal income tax bracket choosing among three new 2005 vehicles each costing \$30,000. The passenger car must be written off over 21 years as opposed to 19 years for the light SUV and six years for the heavy SUV. The differences in depreciation treatment raise the price of the passenger car and light SUV by 13 and 10 percent respectively relative to the heavy SUV.

4.2 Tax Treatment Specific to Fossil Fuel Production

Traditionally, fossil fuels have received preferential tax treatment. Percentage depletion and the expensing of intangible drilling costs are the

Table 5.4
Depreciation Treatment for Motor Vehicles

	Toyota Avalon	Ford Escape	Ford Expedition
Gross vehicle weight rating	3,490	5,520	7,300
Years to depreciate	21	19	6
PV of tax shield	6,632	7,135	9,308
After-tax vehicle cost	23,368	22,865	20,692
Percentage mark-up over heavy SUV	13%	10%	—

Curb weight reported for Toyota Avalon. Table assumes purchase price of \$30,000 for all vehicles, tax rate of 35 percent and a discount rate of 10 percent.

most well known. While not as generously treated as in the past, the tax preferences for fossil fuel production are still important.

As natural resources are extracted from booked reserves, the value of those reserves is diminished. This is a legitimate cost of business and a Haig-Simons income tax would allow a deduction for the value of the resource extracted. Rather than take deductions for the value of the extracted resource, oil, gas, and coal producers have historically been allowed a deduction based on percentage depletion. Percentage depletion allows the firm to deduct a fraction of the revenue arising from sale of the resource. Historic percentage depletion rates have been as high as 27.5 percent. Currently percentage depletion is allowed for independent producers at a 15 percent rate for oil and gas and 10 percent for coal.²⁰ Percentage depletion is allowed on production 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.²¹ Despite the curtailed availability of percentage depletion, it continues to be a significant energy tax expenditure, costing \$3.2 billion over five years in the federal budget (see table 5.2).

The following example illustrates the tax benefits of percentage depletion over cost depletion. John Doe purchases an interest in a property for \$300,000 that contains reserves of 50,000 barrels of oil. He produces 10,000 barrels of oil in the first year which he sells for \$630,000. Under cost depletion, he would be allowed to deduct \$60,000 for the reduction in reserves

$$\left(\frac{10,000}{50,000} \times \$300,000 \right).$$

Percentage depletion allows him to deduct \$94,500 (.15 × \$630,000). Note that percentage depletion can exceed the basis in the asset. Continuing to assume a first purchase price of \$63 per barrel, the total value of oil extracted would be \$3.15 million and the percentage depletion deduction would be \$472,500.²² Obviously the benefit of percentage depletion would be considerably higher at the historic depletion rate of 27.5 percent.

The second major tax benefit available to oil and gas producers is the ability to expense intangible drilling expenses (labor and material costs associated with drilling wells). Normally the non-capital expenses associated with oil exploration and drilling would be capitalized and the costs allocated as income is earned from the well over its useful

life. Instead firms may deduct these expenses in the first year. Corporations may only deduct 70 percent of the costs and must depreciate the remaining 30 percent over five years. Additionally, geological and geophysical costs associated with exploration can be amortized over a two year period.²³ As noted in table 5.2, this is the third largest energy tax expenditure in the federal budget totaling \$3.2 billion over five years.

In addition to the tax preferences described above, I note two additional significant tax preferences. First, owners of coal mining rights who lease their land for mining receive royalties for coal extracted from their property. Owners who are individuals may elect to treat those royalty payments as capital income in lieu of taking percentage depletion on the property. Second, owners of working interests in oil and gas properties are exempt from passive loss limitations for income from these properties.

4.3 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. Those credits include the following:

1. *Section 29 Non-Conventional Oil Production Credit*²⁴

The 1980 Windfall Profits Tax (PL 96–223) was a failed effort to simultaneously capture profits on old oil as a result of oil price increases in the 1970s and encourage exploration for and production of new oil. The law was repealed in 1988.²⁵ One part of that law that was retained was the section 29 Alternative Fuel Production Credit for production of non-conventional oil (e.g., shale oil, synthetic fuel oils from coal). The section provides for a \$3.00 per barrel of oil-equivalent production tax credit (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.²⁶ The credit phases out for oil prices above \$23.50 in 1979 dollars (\$53.20 in 2005).²⁷

The tax expenditure for this credit is estimated to be \$3.4 billion between FY 2007 and 2011 and is the second largest energy tax expenditure in the federal budget. The main beneficiary of the credit is coalbed methane, natural gas that is extracted from tight seams in coal mines. Traditionally this gas was vented to reduce safety problems in mines. But with higher gas prices, the credit and advances in technology, it has become economic to recover this gas. This is not a non-conventional fuel per se but its extraction method might be viewed as non-conventional.

2. *Section 45 Production Tax Credits*

Section 45 of the IRS code, enacted in the Energy Policy Act of 1992, provided for a production tax credit of 1.5¢ per kWh (indexed) of electricity generated from wind and closed-loop biomass systems.²⁸ The tax credit has been extended and expanded over time and currently is available for wind, closed-loop biomass, poultry waste, solar, geothermal and other renewable sources at a current rate of 1.9¢ per kWh.²⁹ Firms may take the credit for ten years. Refined coal is also eligible for a section 45 production credit at the current rate of \$5.481 per ton.³⁰ EPACT 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. While EPACT extended the section 45 tax credits for two additional years (through 2007), it did not extend the credit for solar generated electricity beyond 2005.

Finally, EPACT allowed for the issuance of \$800 million in Clean Renewable Energy Bonds (CREBs) to finance projects eligible for section 45 production tax credits (with the exception of Indian coal). CREBs do not pay interest. Rather the holder of a CREB on its credit allowance date is entitled to a tax credit to be determined by the Treasury Department so that the bond may be sold at par.³¹

3. *Other Production Tax Credits*

EPACT 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 up to an annual limit of \$125 million per 1,000 megawatts of installed capacity. This limit will be binding for 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 (\$.50 per 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).³² Marginal wells produce on average 15 or less 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.

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 as the section 29 reference oil price exceeds \$28 in 1990 dollars (\$37.44 for 2005). At current prices, producers cannot take this credit.

4. Section 48 Investment Tax Credits

Nonrefundable investment tax credits for alternative energy were initially put in place in the Energy Tax Act of 1978 (PL 95-618) at a rate of 10 percent for solar and geothermal property. That law provided a number of investment tax credits including a credit for residential energy conservation investments. This latter credit expired in 1982. EPACT increased the investment tax credit for solar to 30 percent. In addition the 30 percent tax credit applies to fuel cells used to produce electricity while the 10 percent credit is available for qualifying micro-turbine power plants.

The section 48 investment tax credits for renewable energy production were extended by EPACT to apply to 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 (maximum of \$350 million in credits). The section 45 and 48 credits combined are the single largest energy tax expenditure in the federal budget worth \$4.1 billion over a five year period.

5. 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.³³ The Windfall Profits Tax allowed an immediate tax credit in lieu of the exemption.³⁴ The credit was set at a rate to be equivalent to the tax exemption. The alcohol fuel mixture credit is currently \$.51 per gallon of ethanol in gasohol and \$.60 for other alcohol based fuels (excluding petroleum based alcohol fuels). In addition small producers may take a credit of \$.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 of the code to provide an income tax credit for biodiesel fuels at a rate of \$.50 per gallon of bio-diesel (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.

6. Other Issues Bearing on Production and Investment Tax Credits

Firms or individuals may not receive the full value of the production and investment tax credits (along with other energy related tax incentives) described above depending on the taxpayer's alternative minimum tax (AMT) status. All of these credits are part of the general business credit. Credits included in the general business credit may be used to the extent that they do not reduce the taxpayer's after-credit liability below the tentative minimum tax. Note that this limitation may occur even if the taxpayer pays no alternative minimum tax.³⁵ According to Carlson (2005), 70 percent of firms in the mining industry in 2002 were either in a loss or an AMT status and so unable to avail themselves of many if not all of their tax credits.³⁶ It is unclear how the limitation on the use of credits under the general business credit affects investment.

4.4 Tax Incentives for Electric Utilities

Many of the tax incentives that affect the electric utility industry have to do with accelerated depreciation and are discussed above. EPACT provided for several additional incentives. First, electric utilities are allowed to carry back net operating losses (NOLs) for five years (as opposed to the standard two year carry back) for an NOL occurring in tax years 2003–2005. The NOL must be used before January 1, 2009 and the tax refund arising from the use of the NOL is limited in any year to 20 percent of the utility's prior year investment in electric transmission equipment rated at 69 kV or higher and specified pollution control equipment.³⁷

Second, owners of nuclear power plants are required to make contributions to a decommissioning fund for the plant. The Deficit Reduction Act of 1984 allowed those contributions to be tax deductible at the time of contribution if those contributions were funded as part of the cost of service to ratepayers of regulated utilities. The cost of service rules were repealed in EPACT so that all taxpayers, including unregulated utilities, could deduct their contributions to decommissioning funds.

Finally, EPACT extends a current provision allowing electric utilities who dispose of certain transmission property to implement FERC restructuring policy to recognize the gain over an eight year period

rather than in the current year. Proceeds from the sale must be reinvested in other utility property.

4.5 Transportation

The Energy Policy Act of 1992 allowed a 10 percent credit (up to \$4,000) for the purchase of an electric vehicle. After 2005, the maximum credit falls to \$1,000 and the credit terminates as of the end of 2006. Hybrid clean-fuel vehicles and other clean-fuel vehicles were allowed a \$2,000 deduction. These deductions and credits were replaced by the Alternative Motor Vehicle Credit (sec. 30B) as enacted in EPACT. Section 30B of the tax code provides a credit for fuel cell vehicles, alternate fuel vehicles (natural gas, LNG, LPG, hydrogen, and 85 percent methanol fuel vehicles), and hybrids. The credit depends on different vehicle attributes depending on the type of vehicle. Table 5.5 lists the credit information for different fuel types.

EPACT also replaced a deduction for installing clean-fuel vehicle refueling property with a 30 percent tax credit for property placed in service before Jan. 1, 2008.

4.6 Energy Efficiency

Prior to the passage of last year's energy legislation, the only remaining tax incentive pertaining to energy conservation was section 136 of the tax code enacted in the Energy Policy Act of 1992. Section 136 provides an exclusion from gross income of any subsidies provided by an electric utility for the purchase or installation of any energy conservation measure. EPACT provided a number of new incentives. First, the law allows a 30 percent personal income tax credit not to exceed \$2,000 for photovoltaic and solar water heating property (excluding equipment for heating swimming pools and hot tubs) installed at residential

Table 5.5
Clean Vehicle Tax Credits

Fuel Type	Credit Determining Characteristics	Maximum Credit with Gross Vehicle Rating Less Than 8,500 Pounds
Fuel cell	Gross vehicle weight, fuel economy	\$12,000
Hybrids	Fuel economy, lifetime fuel savings	\$3,400
Alternative fuels	Gross vehicle weight	\$4,000
Advanced lean-burn diesel	Fuel economy, lifetime fuel savings	\$3,400

properties. Fuel cell power plants are also eligible for the 30 percent credit not to exceed \$500 per 0.5 kW of capacity. Second, the law provides a 10 percent personal income tax credit for insulation materials, energy saving windows and doors, and energy conserving metal roofs. In addition, taxpayers may take a credit for specific energy efficiency appliances such as advanced main air circulating fans (\$50), furnace and hot water boilers (\$150), and qualifying energy efficient property (e.g., designated heat pumps and air conditioners) (\$300) with a maximum credit per home of \$500 no more than \$200 of which may be for windows. Third, contractors may take a tax credit of \$1,000 (\$2,000) for new home construction that is certified to obtain a 30 percent (50 percent) reduction in energy usage.

Fourth, commercial property energy conservation expenditures are eligible for a deduction of costs up to \$1.80 per square foot if the spending effects a 50 percent or more reduction in energy usage. For buildings that do not achieve a 50 percent reduction, a partial allowance is allowed based on guidelines for specific technologies to be established by the Secretary of the Treasury. Finally, appliance manufacturers are provided a production credit for energy-efficient dishwashers, clothes washers and refrigerators. The maximum credit is \$100 for dishwashers, \$200 for clothes washers and \$175 for refrigerators.

5. Incentive and Distributional Effects of Energy Tax Incentives

Who benefits from the various taxes and tax incentives described in sections 3 and 4? And what are the impacts on energy demand and supply? In this section, I discuss the incidence and behavioral impacts of various tax provisions.

5.1 Motor Fuels Excise and Gas-Guzzler Taxes

Consider first the incidence impact of the federal excise tax on motor fuels. Doyle and Samphantharak (2006) find that roughly 80 percent of increases in state sales taxes on gasoline are passed forward to consumers. This is consistent with other studies and likely underestimates the shifting of federal excise taxes to consumers given state-level competition.³⁸ Gasoline taxes are generally viewed as regressive. This view is confirmed by Poterba (1991) when households are ranked by annual income. But when ranked by current expenditures as a proxy for lifetime income, Poterba finds that gasoline taxes are much less regressive.

Assessing the gas guzzler tax is more difficult. Surprisingly few studies of the gas guzzler tax have been carried out that take the light truck loophole into account. Greene et al. (2005) undertake simulations of a gas-guzzler tax and find that removing the exemption for light trucks increases mileage for these vehicles as manufacturers cluster vehicles (both passenger cars and light trucks) just above the miles per gallon cutoff for the tax. Their study holds all characteristics other than fuel economy and price constant. Thus, the recent phenomenon of using engine improvements to obtain higher power and performance at the expense of fuel efficiency cannot be modeled in their analysis.

5.2 Oil and Natural Gas Production Incentives

Turning to production and investment tax incentives, consider first oil and natural gas production. The favorable treatment accorded oil producers and refiners lowers the cost of oil and could affect prices of final petroleum products. But since oil is priced in world markets and to a great extent is a homogenous product, it is not clear that the domestic tax incentives would have a large impact on the price of gasoline or other petroleum products.³⁹ In this case, the benefits largely accrue to producers in the form of higher wages for specialized workers in oil production and refining and higher dividends to shareholders.

It may be, however, that the U.S. supply incentives have an impact on worldwide supply and price given the magnitude of U.S. oil production. As noted in endnote 5, the United States is the third largest producer of oil with 8.5 percent of the world's production in 2004. A simple rough calculation suggests however that the U.S. supply incentives are unlikely to have a large impact on world oil prices or supply. Let Q_s^* be the world supply of oil, and Q_s the U.S. supply (with analogous variables defined for oil demand). Also let p_s and \hat{p}_s be the price received by U.S. oil suppliers and oil suppliers in the rest of the world, respectively. Finally, let $p_D = \hat{p}_s = p_s - s$ be the worldwide demand price and s the subsidy arising from tax incentives provided to domestic oil suppliers. Setting world oil supply equal to demand and differentiating, we obtain the relationship between world oil prices and the domestic subsidy:

$$\frac{dp_D}{ds} = \frac{\left(\frac{Q_s}{Q_s^*}\right)\eta_D}{\eta_s - \eta_D} \quad (5.1)$$

where η_D and η_S are the demand and supply elasticities for oil. Long-run estimates of these elasticities are in the neighborhood of -0.5 and 0.5 respectively.⁴⁰ The percentage change in worldwide oil supply is then

$$\frac{dQ_s^*}{Q_s^*} = -\eta_D \frac{\left(\frac{Q_s}{Q_s^*}\right) \eta_D}{\eta_S - \eta_D} \frac{ds}{p}. \quad (5.2)$$

The tax incentives for oil (percentage depletion and expensing of IDCs) are most valuable for small producers. Taking the oil industry as a group, let us say that the value of the subsidies is worth 10 percent of the current price of oil.⁴¹ Table 5.6 shows the impact on world oil production for various demand and supply elasticities:

Table 5.6
Percentage Change in World Oil Supply

		Demand Elasticity			
		-0.1	-0.3	-0.5	-0.7
Supply elasticity	0.1	0.0%	0.1%	0.1%	0.1%
	0.3	0.1%	0.1%	0.2%	0.2%
	0.5	0.1%	0.2%	0.2%	0.2%
	0.7	0.1%	0.2%	0.2%	0.3%

Change arising from a subsidy to domestic production equal to 10 percent of oil price.

The supply response ranges from zero to 0.3 percent with 0.2 percent the response associated with the central parameter value assumptions. Table 5.7 shows that the price response is also small:

Table 5.7
Percentage Change in World Oil Price

		Demand Elasticity			
		-0.1	-0.3	-0.5	-0.7
Supply elasticity	0.1	-0.4%	-0.2%	-0.1%	-0.1%
	0.3	-0.6%	-0.4%	-0.3%	-0.3%
	0.5	-0.7%	-0.5%	-0.4%	-0.4%
	0.7	-0.7%	-0.6%	-0.5%	-0.4%

Change arising from a subsidy to domestic production equal to 10 percent of oil price.

The price decline ranges from 0.1 percent to 0.7 percent with a central parameter response of 0.4 percent.

To some extent, a similar story can be told for natural gas. Natural gas is not as easily transportable as oil and regional price differences can persist over time. Improvements in transportation and the increase in LNG shipping, however, are breaking down these regional barriers.⁴²

This analysis is consistent with a recent analysis of a precursor bill to the Energy Policy Act of 2005 done by the U.S. Energy Information Administration (2004). This report reviewed section 29 and 45 tax credits along with other production incentive tax provisions and concluded that with the exception of the section 29 credits, the provisions did little to increase domestic production of gas or oil. Section 29 credits would increase domestic natural gas from non-conventional sources (coalbed methane for the most part). Ultimately, domestic consumption would be unaffected by these provisions.

Recall the discussion of national security as a rationale for an energy tax policy. The analysis in this section suggests that the production and investment tax credits embodied in current law will have little effect on world production or on efforts to stabilize domestic energy prices. Where a policy to encourage domestic production of energy may be effective is to increase the proportion of energy that is not subject to supply disruptions due to political upheaval. But here the rationale is a bit murky. Many of the tax incentives encourage the production of electricity from nuclear or renewable sources. But currently only 3 percent of oil is used for electricity production. It may well be that concerns about natural gas disruptions motivate these policies (natural gas accounts for 24 percent of electricity production). Natural gas however is more subject to price spikes arising from bottlenecks in production and distribution than from political shocks. A concern with oil supply disruptions would suggest a focus on reducing petroleum use in transportation, currently responsible for two-thirds of all petroleum consumption.

5.3 Electric Generation from Alternative and Renewable Fuels

The production and investment credits for renewable and alternative fuels can have a large impact on whether various electric generation technologies are cost competitive in the marketplace. With the shift from regulated utilities to an environment in which electricity generation is increasingly unregulated, cost considerations become increasingly important for firms contemplating constructing merchant power

plants. In this section, I present estimates of the levelized cost for different sources of electricity under varying assumptions about the availability of federal tax incentives.

The levelized cost analysis is similar in spirit to the Hall-Jorgenson cost of capital framework. It asks what price must be received for electricity sold by a generator to cover fixed and variable costs of providing the electricity including the required return for equity owners.⁴³ This approach has been used in a variety of studies of electric power generation (e.g., Deutch and Moniz 2003; Tolley and Jones 2004; and Sekar et al. 2005). The steps to constructing an estimate of levelized cost are:

- Compute the present discounted value of costs in each year over life of a project. This includes all capital and operating costs net of tax deductions.
- Sum all costs over life of project. This is the present discounted value of the project's overall costs.
- Compute the amount of constant real before-tax revenue required each year that will equal the total present discounted value of costs over the life of the project.
- Divide this required revenue value by total kilowatt-hours produced by plant to obtain a cost per kWh.

I estimate the levelized cost for the following eight electricity generation sources: nuclear, conventional (pulverized) coal, clean coal using an integrated gasification combined cycle (IGCC) process, natural gas combined cycle, biomass, wind, solar thermal and photovoltaics. The first three technologies are generally used as baseload generators and the latter are either shoulder or peaking generators.

Table 5.8 provides key parameter value choices for the eight different technologies.⁴⁴ The capacity factor describes what fraction of the time a plant is operating. Nuclear power plants are designed to operate continuously but are shut down for routine and unexpected maintenance. The capacity factor for nuclear power is taken from Deutch and Moniz (2003). I've chosen capacity factors for coal and natural gas to be comparable to nuclear. The capacity factors for the renewable resources are for the most part taken from the Energy Information Administration's National Energy Modeling System (NEMS).⁴⁵

The overnight cost is the total capital construction cost of the plant in year 2004 dollars. Construction costs are covered with short-term debt financing until the plant goes into service. At that point, ten year

Table 5.8
Selected Parameter Values for Levelized Cost Analysis

Technology	Nuclear	Coal PC	Coal IGCC	Gas-CC	Biomass	Wind	Solar Thermal	PV
Capacity factor	85%	85%	85%	85%	83%	35%*	31%*	21%*
Construction time	6	4	4	3	4	3	3	2
Overnight cost (\$/kW)	2,014	1,249	1,443	584	1,809	1,167	3,047	4,598
% Debt finance	50%	60%	60%	60%	60%	60%	60%	60%
Economic life	40	30	25	25	20	20	20	20
MACRS life	15	15	15	15	5	5	5	5
Production tax credit (\$/kWh)	125	0	0	0	0.019	0.019	0	0
Section 48 ITC	0	0	20%	0	0	0	30%	30%

*I have not assumed any additional costs for capacity to account for the intermittency of these power sources.
Source: See Appendix.

bonds are issued and equity financing raised to cover those costs. I've assumed 60 percent debt financing on all projects except nuclear. I assume a lower debt financing rate of 50 percent to acknowledge the greater perceived risk of nuclear financing in the marketplace. The economic life of these assets varies and they have a MACRS recovery period of five to 15 years. Finally, I assume that the Section 45J production tax credit for nuclear power hits the \$125 million cap per 1,000 MW of capacity. See the Appendix for more details on the computation of levelized costs.

Table 5.9 reports levelized costs of electricity in cents per kWh (year 2004 dollars). I assume that the plant will be placed in service after Jan. 1, 2006 so that solar power is not eligible for a production tax credit but does obtain the more generous 30 percent section 48 investment tax credit.⁴⁶ The first column provides the levelized cost under current law. Coal has the lowest levelized cost with the cost of IGCC comparable to that of a conventional pulverized coal plant given the new investment tax incentive for IGCC enacted in EPACK. Nuclear and natural gas are the next most expensive followed by biomass and wind.⁴⁷ Either of the solar generating plants are considerably more expensive than other electricity sources with photovoltaics (PV) over four times the cost of natural gas. Note that wind and solar are intermittent power sources and so require stand-by generation. A recent study by The Royal Academy of Engineering (2004) found that the requirement for stand-by power raised the cost of onshore wind power by nearly 50 percent. I have not factored such costs into this analysis.

Comparing the first two columns, eliminating the section 45 production tax credit only modestly raises the cost of biomass and wind (4 percent cost increase) but raises the cost of nuclear by nearly 30 percent. Next, eliminating the section 48 investment tax credits raises the cost of the IGCC plant by 15 percent and the cost of solar by over 35 percent.

Column 4 reports levelized costs assuming the various production and investment tax credits but replacing the accelerated depreciation with economic depreciation (modeled as straight-line depreciation) over the asset's life.⁴⁸ Accelerated depreciation is most generous to wind and solar generated electricity. Replacing accelerated depreciation with economic depreciation would raise the cost of wind and solar thermal by 13 percent and PV by 15 percent. For the other fuel sources, replacing accelerated depreciation with economic depreciation would raise the cost of nuclear by 9 percent, biomass by 8 percent, coal by 7 percent and natural gas by 2 percent.

Table 5.9
Real Levelized Costs of Electricity

Technology	Current Law (1)	No PTC (2)	No ITC (3)	Economic Depreciation (4)	Level Playing Field (5)	No Tax (6)
Nuclear	4.31	5.55	4.31	4.70	5.94	4.57
Conventional coal	3.53	3.53	3.53	3.79	3.79	3.10
Clean coal (IGCC)	3.55	3.55	4.06	3.80	4.37	3.53
Natural gas	5.47	5.47	5.47	5.61	5.61	5.29
Biomass	5.34	5.56	5.34	5.74	5.95	4.96
Wind	5.70	5.91	5.70	6.42	6.64	4.95
Solar thermal	12.25	12.25	16.68	13.74	18.82	13.84
PV	22.99	22.99	32.60	26.34	37.39	26.64

Author's calculations. See Appendix for further detail. Cost are reported in cents per kWh at year 2004 prices.

Column 5 reports levelized costs assuming a tax system that provides a level playing field. This scenario assumes economic depreciation and no production or investment tax credits. In terms of the impact on levelized cost, conventional coal and natural gas receive the fewest tax preferences. Leveling the playing field raises the cost of biomass by 11 percent with the bulk of the benefit arising from accelerated depreciation (based on a comparison of columns 2 through 4 with 5). The cost of wind is higher by 16 percent with the majority of the benefit arising from accelerated depreciation. The cost of IGCC is higher by 23 percent with roughly two-thirds of the benefit arising from the investment tax credit. The cost of nuclear is higher by 38 percent with the production tax credit providing the bulk of the benefits. Finally, the cost of solar is over 50 to 60 percent higher with about two-thirds of the benefit arising from the production tax credits.

In the final column, I compute levelized costs assuming zero taxes. While the levelized cost of most technologies falls, the cost of nuclear and solar rises indicating that these technologies face a negative effective average tax rate. Eliminating taxes raises the cost of nuclear by 6 percent and solar by 13 to 16 percent.

From a social welfare perspective, the production and investment tax credits are costly ways to encourage renewable electricity generation since the subsidies must be financed by raising distortionary taxes. An alternative approach to encouraging renewable electricity generation would be to place a tax on traditional fuels.⁴⁹ As a final calculation, I computed the levelized cost of biomass and wind assuming no investment or production tax credits. In this case, the levelized costs of biomass and wind are 5.56¢ and 5.91¢ per kWh respectively. A tax on carbon dioxide of \$12 per metric ton would raise the price of natural gas sufficiently to make biomass and wind cost-competitive with natural gas. Unlike the subsidies, however, the tax would raise revenue which could finance reductions in other distortionary taxes.⁵⁰ In units perhaps more familiar to most readers, a carbon tax of this magnitude would raise the price of gasoline by ten cents if it were fully passed forward to consumers.

Summing up, relative to a world with no taxes the current tax code provides net subsidies to nuclear and solar power. Relative to a tax system with a level playing field, conventional technologies receive very modest subsidies while subsidies for nuclear and clean coal are substantial and the subsidies for solar very substantial. The subsidies are most effective (in the sense of making electricity competitive from this

source) for IGCC plants which become competitive with conventional coal and for biomass and wind which become competitive with natural gas.

5.4 Energy Efficiency

The energy efficiency incentives contained in EPACT are similar in many ways to energy tax credits contained in the Energy Tax Act of 1978, including a 15 percent tax credit (up to \$300) for residential energy conservation improvements. Analyzing a panel of federal tax returns between 1979 and 1985 when the residential conservation credit expired, Hassett and Metcalf (1995) found that the credit significantly raised the probability of a household installing energy conservation capital in their home. Somewhat surprisingly, the authors found that the credit was much more successful at raising investment levels than a comparable energy price increase. They speculated that the credit program may have publicity effects that spur investment that the energy price increase does not have. The study was not able to determine to what extent credit takers were inframarginal investors—that is homeowners who would have made conservation investments in the absence of the tax credit.⁵¹

6. Conclusion

Tax incentives are a major part of the federal government's energy tax policy and increasingly so with the passage of the Energy Policy Act of 2005. A number of points emerge from this analysis. First, the focus of energy incentives contained in the tax code has shifted over the years from focusing almost entirely on traditional fossil fuel production to an increasing emphasis on alternative and renewable technologies. Second, those incentives are difficult to rationalize on the basis of economic efficiency or distributional goals. Production and investment tax credits, in particular, may be very costly ways to encourage the development of renewable energy technology.

Third, incentives for the oil and natural gas industry are unlikely to have an appreciable impact on world energy prices despite the United States being the third largest oil producer in the world (and second largest natural gas producer). Fourth, current tax incentives are making wind and biomass cost competitive with natural gas electricity production. The 20 percent investment tax credit for IGCC in EPACT is likely to make this technology cost competitive with conventional coal

generated electricity. Solar generated electricity continues to be very expensive.

Fifth, the limited evidence suggests that the energy efficiency incentives enacted by EPACT should increase conservation investment activity. It is difficult to say, however, how much of this investment will be new investment as opposed to investment that would have taken place in the absence of the incentive programs. To the extent that inframarginal investment is a significant fraction of total investment, the cost-effectiveness of this incentive is driven down. But of course this is true for all of the energy incentives described in this paper and suggests the importance of further research on the behavioral impacts of energy tax incentives.

Notes

This paper was prepared for the Tax Policy and the Economy conference held on September 14, 2006 in Washington, DC. I thank Tom Barthold, Alex Brill, John Navratil, Nicolas Osouf, John Parsons, Jim Poterba, and participants in the MIT Joint Program on the Science and Policy of Global Change EPPA Seminar for helpful discussions. I am grateful for support from the MIT Joint Program on the Science and Policy of Global Change which I was visiting while writing this paper. Contact information: gmetcalf@tufts.edu.

1. The list is naturally incomplete given the complexity of the tax code. In particular I do not focus on how the tax treatment of foreign income earned by multinational corporations bears on energy production. This is potentially a major issue. For example, prior to the nationalization of oil production in the major oil producing countries, the major U.S. oil producers paid taxes to host countries that were termed income taxes but were in reality excise taxes. Standard tax treatment would provide for a deduction on the U.S. corporate income tax for those foreign tax payments. Instead, the U.S. companies were allowed a foreign tax credit for the "income" taxes paid to host countries, a preference lobbied for by—among others—the State Department. See Adelman (1995), pp. 50–55 for more on this point.
2. See Feng et al. (2005) for a discussion and evaluation of feasible alternatives to direct emission taxes for motor vehicles.
3. Two-thirds of petroleum is used in the transportation sector (U.S. Energy Information Administration 2005).
4. Partial policies can raise the cost of carbon emission reductions considerably. Pizer et al. (2006) present model results showing that focusing climate change policies only on the transportation and electricity sectors doubles the cost of a given carbon emissions reduction. Note too that the motor vehicle fuels tax is sometimes justified as a use charge for highways. To the extent this is true, the motor vehicle fuels tax is even less effective as a proxy tax for externalities.
5. That the source of the oil the United States consumes is irrelevant for oil price stability should be made clear by the fact that the United States is the third largest oil producer in

the world, with production only exceeded by the Russian Federation and Saudi Arabia. The United States produced 8.5 percent of the world's oil in 2004. It is also the second largest producer of natural gas after the Russian Federation with a world production share of 19 percent. See BP (2006) for data.

6. Karp and Newbery (1991) provide a more sophisticated analysis to resolve a dynamic inconsistency problem with simple oil tariff expropriation stories. But the basic result holds.

7. The tax was most recently raised to 18.3¢ per gallon for gasoline on Oct. 1, 1993. See Jackson (2006) for a history of changes to this tax.

8. In fiscal year 2004, the UK collected £832 million in its Climate Change Levy, approximately £1,614 million in VAT on energy related sales, and £22,786 in its hydrocarbons tax. Data are from excise tax sheets published by HM Revenue & Customs and available at <http://www.uktradeinfo.com>.

9. The mileage rating is calculated approximately as 55 percent of the EPA city mileage rating and 45 percent of the highway rating.

10. I have not included tax expenditures associated with transportation (e.g., exclusion from income for employer reimbursed parking). Nor do I consider state or local energy tax incentives in this paper.

11. As GAO points out, one cannot simply add tax expenditures given the interactions among different provisions of the tax code. But the summation indicates the relative importance of the provisions when making comparisons across time.

12. It is unclear whether this tax expenditure has any incentive effect now that ethanol use is mandated in motor fuels by the Energy Policy Act of 2005. I thank John McLelland for pointing this out.

13. This brief description draws on an excellent overview by Lazzari (2006).

14. The American Jobs Creation Act of 2004 (PL 108-357) provided a major expansion of the production tax credits.

15. The production tax credit for wind and biomass briefly expired in 2003. According to the American Wind Energy Association, wind power capacity additions fell from 1,687 MW in 2003 to 389 MW following the temporary lapse of this tax provision.

16. In general I do not discuss energy tax incentives that have expired. See Edwards et al. (1998) for some discussion of energy tax incentives related to global warming that existed prior to 1998. This includes the major incentives that have expired. I also generally do not provide information about sunset provisions for the various incentives since historically sunset dates have been extended for most energy-related tax incentives.

17. The recovery period is the number of years over which an asset may be depreciated for tax purposes. Certain assets must be depreciated under the Alternative Depreciation System (ADS). See U.S. Internal Revenue Service (2006) for more information.

18. Exploratory wells continue to have high failure rates. In 2003, 55 percent of exploratory wells were dry holes and 9 percent of development wells were dry holes. But less than 2,700 exploratory wells were drilled that year compared to over 32,200 development wells. Roughly the same number of development wells were drilled in 1960 but with a dry hole rate of 25 percent. However, 11,700 exploratory wells were drilled with over 80

percent of them being dry holes. See tables 4.5–4.7 in U.S. Energy Information Administration (2005).

19. The caps for 2005 were \$2,960 in the first year, \$4,700 in the second year, \$2,850 in the third year, and \$1,675 in subsequent years for passenger cars. For light trucks weighing less than 6,000 pounds (including minivans, SUVs, and pickup trucks) the limits are \$3,260 in the first year, \$5,200 in the second year, \$3,150 in the third year, and \$1,875 in subsequent years.

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

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

22. This example presumes that the net income from the first year's operation exceeds \$94,500. If not, the deduction would be reduced accordingly. For purposes of computing the net income limitation, costs are computed without any depletion deduction considered.

23. EPACT set the recovery period at two years but the Tax Increase Prevention and Reconciliation Act of 2005 (PL 109–222) extended the period to five years for the major integrated oil companies.

24. Section 29 is relabeled as section 45K by EPACT.

25. For an overview and analysis of the Windfall Profit Tax, see Lazzari (1990).

26. Most energy tax credits were part of the general business credit. Prior to EPACT, the section 29 credits were an exception and so any unused credits were lost. As part of the general business credit, excess credits can be carried backward one year and forward 20 years.

27. The reference price for oil in 2005 was \$50.26 and so the full credit could be taken. The credit amount and reference price are published annually in the Federal Register. With the reference oil price currently at \$62.51 (April 2006 crude oil domestic first purchase price), it is unlikely that firms will be able to take the full section 29 credit in 2006.

28. A closed-loop biomass is plant material grown specifically for use in a biomass generator.

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

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

31. State and local tax exempt financing is also available for qualified energy facilities. These bonds are subject to a state's private-activity volume cap.

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

33. Originally, the law provided a full exemption from the then \$.04 per gallon tax. As the motor fuels excise tax was raised over time, the exemption did not keep pace with the excise tax rate. See General Accounting Office (1997) for an early chronology of events related to this tax exemption.

34. The American Jobs Creation Act of 2004 subsequently eliminated the tax exemption in favor of the tax credit.
35. This would occur if the taxpayer's regular tax liability after foreign tax credits but before other tax credits exceeded the tentative minimum tax but its regular tax liability after tax credits was less than the tentative minimum tax. Foreign tax credits are included in the tentative minimum tax and thus not subject to AMT limitations.
36. In addition to the AMT's impact on tax credits, the AMT treats mining exploration and development costs, depletion including percentage depletion (unless an independent producer) and intangible drilling costs as AMT preferences.
37. The equipment need not be placed in service in that year.
38. Doyle and Samphanthark report other studies showing complete forward shifting of federal motor fuel taxes.
39. Oil differs in its transportation costs as well as product characteristics (sulfur content, viscosity, etc.) In the long run, however, these cost and characteristic differences have little impact on the final product costs.
40. Cooper (2003) reviews estimates of the long run demand elasticity and Greene et al. (1998) reviews long run demand and supply elasticities.
41. This is a high estimate. The GAO estimates for FY2003 tax preferences for the section 29 and enhanced oil recovery credits, the excess of percentage over cost depletion, expensing of IDCs, and the rules on passive loss limitations equal just over 2 percent of the value of domestic crude oil and natural gas production in that year.
42. Natural gas imports as a percentage of total U.S. consumption have risen from 4.7 percent in 1980 to 15.3 percent in 2004 (U.S. Energy Information Administration 2005).
43. The price is a constant real price received over the life of the plant to cover lifetime fixed and variable costs.
44. See Appendix A for a complete listing of parameter values and additional detail about the calculations. These parameter values should be viewed with some caution. A degree of uncertainty underlies many of the values. The overnight cost for nuclear power, for example, is highly uncertain given the limited recent experience with construction in the United States and the uncertainties of the regulatory process.
45. I have not adjusted the wind and solar capacity factors to account for the intermittency of these power sources.
46. I have not assumed any limitations on credits from the Alternative Minimum Tax in table 5.8.
47. Given the cost differential between coal and nuclear, the current interest in nuclear power reflects in part a bet that a U.S. carbon policy will eventually raise the cost of coal power plants.
48. I've also modeled economic depreciation for the assets according to the depreciation rates estimated by Fraumeni (1997) in a modified one-hoss-shay model. I assume geometric depreciation using Fraumeni's rates over the life of the asset with all remaining basis depreciated in the final year. The levelized costs under this approach are very similar to those calculated when economic depreciation is modeled as straight-line.

49. One could also impose renewable portfolio standards as many states have done. Palmer and Burtraw (2005) argue that portfolio standards are more cost effective at achieving given renewable shares in electricity generation than production tax credits given the social cost of raising revenue to finance the subsidies. Note too the different incidence of production tax credits and renewable portfolio standards. The former are borne by taxpayers while the latter are borne by electricity consumers in the form of higher electricity prices.

50. Metcalf (2005) discusses how a carbon tax could be used to finance corporate tax integration. The advantage of taxes over subsidies for clean power extends beyond the distortionary cost of financing the subsidies. The subsidies lower the cost of electricity and so encourage increased consumption.

51. In the energy conservation literature, this is referred to as free-riding. See Metcalf (2006) for a discussion of behavioral responses to energy conservation initiatives and the difficulty in assessing the cost-effectiveness of these programs.

52. Many renewable plants are built at considerably smaller capacity. The cost assumptions used here are based on a plant of optimal size. My approach follows that of Sekar, et al. (2005).

References

- Adelman, M.A. (1995). *The Genie out of the Bottle*. Cambridge, MA: The MIT Press.
- American Petroleum Institute (2006). "Gasoline and Diesel Taxes," <http://api-ec.api.org/filelibrary/2006-gasoline-diesel-taxes-summary.pdf>, Accessed on June 15, 2006.
- Bergstrom, Theodore C. (1982). "On Capturing Oil Rents with a National Excise Tax," *American Economic Review*, 72(2):194–201.
- BP. (2006). "Statistical Review of World Energy 2006," London: BP.
- Carlson, Curtis P. (2005). "The Corporate Alternative Minimum Tax Aggregate Historical Trends," Department of the Treasury Office of Tax Analysis, OTA Paper 93.
- Cooper, John C.B. (2003). "Price Elasticity of Demand for Crude Oil: Estimates for 23 Countries," *OPEC Review*, 27(1):1–8.
- Deutch, John, and Ernest J. Moniz, (eds.) (2003). *The Future of Nuclear Power*. Cambridge, MA: Massachusetts Institute of Technology.
- Doyle, Joseph J., Jr., and Krislert Samphantharak (2006). "\$2.00 Gas! Studying the Effects of a Gas Tax Moratorium," NBER working paper no. 12266.
- Edwards, Chris, Ada Rousso, Peter Merrill, and Elizabeth Wagner (1998). "Cool Code: Federal Tax Incentives to Mitigate Global Warming," *National Tax Journal*, 51(3):465–484.
- Energy Information Administration (2005). "Annual Energy Review 2004," Energy Information Administration.
- Feng, Ye, Don Fullerton, and Li Gan (2005). "Vehicle Choices, Miles Driven, and Pollution Policies," NBER working paper no. 11553.
- Fraumeni, Barbara M. (1997). "The Measurement of Depreciation in the U.S. National Income and Product Accounts," *Survey of Current Business*, 77(7):7–23.

- General Accounting Office (1997). "Effects of the Alcohol Fuels Tax Incentives," U.S. General Accounting Office, GAO/GGD-97-41.
- General Accounting Office (2005). "National Energy Policy: Inventory of Major Federal Energy Programs and Status of Policy Recommendations," U.S. General Accounting Office, GAO-05-379.
- Greene, David L., Donald W. Jones, and Paul N. Leiby (1998). "The Outlook for U.S. Oil Dependence," *Energy Policy*, 26(1): 55-69.
- Greene, David L., Philip D. Patterson, Margaret Singh, and Jia Li (2005). "Feebates, Rebates and Gas-Guzzler Taxes: A Study of Incentives for Increased Fuel Economy," *Energy Policy*, 33:757-775.
- Hassett, Kevin, and Gilbert E. Metcalf (1995). "Energy Tax Credits and Residential Conservation Investment: Evidence from Panel Data," *Journal of Public Economics*, 57:201-217.
- Jackson, Pamela J. (2006). "The Federal Excise Tax on Gasoline and the Highway Trust Fund: A Short History," Congressional Research Service, RL30304.
- Karp, Larry, and David M. Newbery (1991). "Optimal Tariffs on Exhaustible Resources," *Journal of International Economics*, 30(2): 285-299.
- Lazzari, Salvatore (1990). "The Windfall Profit Tax on Crude Oil: Overview of the Issues," Congressional Research Service, 90-442 E.
- Lazzari, Salvatore (2005). "Energy Tax Policy: An Economic Analysis," Congressional Research Service, RL30406.
- Lazzari, Salvatore (2006). "Energy Tax Policy," Congressional Research Service, CRS Issue Brief IB10054.
- Metcalf, Gilbert E. (2005). "Tax Reform and Environmental Taxation," NBER working paper no. 11665.
- Metcalf, Gilbert E. (2006). "Energy Conservation in the United States: Understanding Its Role in Climate Policy," NBER working paper no. 12272.
- Newbery, David M. (1976). "A Paradox in Tax Theory: Optimal Tariffs on Exhaustible Resources," Department of Economics, Stanford University, SEER Technical Paper.
- Newbery, David M. (2005). "Why Tax Energy? Towards a More Rational Policy," *The Energy Journal*, 26(3):1-39.
- Palmer, Karen, and Dallas Burtraw (2005). "Cost-Effectiveness of Renewable Electricity Policies," Resources For The Future, RFF DP05-01.
- Parry, Ian, and Kenneth A. Small (2005). "Does Britain or the United States Have the Right Gasoline Tax?" *American Economic Review*, 95:1276-1289.
- Pizer, William, Dallas Burtraw, Winston Harrington, Richard Newell, and James Sanchirico (2006). "Modeling Economy-Wide Vs Sectoral Climate Policies Using Combined Aggregate-Sectoral Models," *The Energy Journal*, 27(3):135-168.
- Poterba, James M. (1991). "Is the Gasoline Tax Regressive?" *Tax Policy and the Economy*, 5: 145-164.
- The Royal Academy of Engineering (2004). "The Costs of Generating Electricity," The Royal Academy of Engineering.

Sekar, Ram C., John E. Parsons, Howard J. Herzog, and Henry D. Jacoby (2005). "Future Carbon Regulations and Current Investments in Alternative Coal-Fired Power Plant Designs," MIT Joint Program on the Science and Policy of Global Change, No. 129.

Tolley, George, and Donald Jones (2004). "The Economic Future of Nuclear Power," University of Chicago.

U.S. Census Bureau (2006). *Statistical Abstract of the United States*. Washington, DC: Government Printing Office.

U.S. Energy Information Administration (2004). "Analysis of Five Selected Tax Provisions of the Conference Energy Bill of 2003," Office of Integrated Analysis and Forecasting.

U.S. Energy Information Administration (2005). "Annual Energy Review 2004," Energy Information Administration.

U.S. Energy Information Administration (2006). "Assumptions to the Annual Energy Outlook 2006," Energy Information Administration, DOE/EIA-0445(2006).

U.S. Internal Revenue Service (2006). "How to Depreciate Property," Internal Revenue Service, Publication 946.

Appendix. Calculating the Levelized Cost of Electric Power Generating Plants

The levelized cost of an electricity generating power plant is the price per kWh that the plant must receive for electricity sold that will cover all costs of production including a return to equity holders. I construct levelized costs for various technologies for a hypothetical power plant with a 1,000 MW capacity.⁵² Table 5.A1 provides a full list of the plant-specific parameters used in the analysis.

In addition, I assumed an inflation rate of 3 percent, a combined federal and state tax rate of 40 percent, a nominal bond return of 8 percent and a nominal return to equity of 15 percent.

Most plant-specific parameter values are taken from the U.S. Energy Information Administration (2006) Annual Energy Outlook (AEO). Fuel costs are based on projected fuel costs from the AEO which assumes real growth in fuel prices over the 40 year expected life of all power plants. The debt-equity ratio for nuclear and coal is based on assumptions in Deutch and Moniz (2003) and I assume the same ratio for renewables as for coal. Periodic capital spending is required for all technologies for capital additions and upgrades. AEO assumes increased capital upgrade spending in the last ten years of the plant's life. For simplicity I treat these expenditures as operating expenditures rather than capitalize them over the remaining life of the plant. The economic life of the various plants is taken from The Royal Academy of Engineering (2004). I also use this source for the capacity factor for wind based on its analysis of wind production in Europe.

Table 5.A1
Plant Specific Parameters for Levelized Cost Analysis

	Nuclear	Coal PC	Coal IGCC	Gas-CC	Biomass	Wind	Solar Thermal	PV
Capacity factor	85%	85%	85%	85%	83%	35%	31%	21%
Construction time	6	4	4	3	4	3	3	2
Fuel cost (\$/MMBtu)	0.47	0.994	0.994	5.94	2.15	0	0	0
Heat rate (BTU/kWh)	10,400	8,844	8,309	7,196	8,911	10,280	10,280	10,280
fixed O&M (\$/kW/yr)	61.82	25.07	35.21	11.37	48.56	27.59	51.70	10.64
variable O&M (\$/kWh)	0.00045	0.00418	0.00265	0.00188	0.00313	0	0	0
Decommissioning (\$million)	350	na	na	na	na	na	na	na
Capital increment (\$/kW)	18	15	15	6	0	0	0	0
K Increment (yrs 30+)	44	21	21	12	0	0	0	0
% Debt finance	50%	60%	60%	60%	60%	60%	60%	60%
% Equity finance	50%	40%	40%	40%	40%	40%	40%	40%
Discount rate	11.5%	10.8%	10.8%	10.8%	10.8%	10.8%	10.8%	10.8%
Overnight cost (\$/kW)	2,014	1,249	1,443	584	1,809	1,167	3,047	4,598
Economic life	40	30	25	25	20	20	20	20
MACRS life	15	15	15	15	5	5	5	5

The steps required for this calculation are:

1. Compute the present discounted value of costs in each year over life of a project. This includes all capital and operating costs net of tax deductions.
2. Sum all costs over life of project. This is the present discounted value of the project's costs.
3. Compute the amount of constant real before-tax revenue required each year that will equal the total present discounted value of costs over the life of the project.
4. Divide this required revenue value by total kilowatt-hours produced by plant to obtain a cost per kWh.

Construction time differs across the technologies. I assume construction costs follow a sinusoidal pattern (increasing, peaking and then declining) over the time period with plant construction beginning in 2005. To illustrate how construction costs are handled, consider a nuclear power plant built over six years. Table 5.A2 provides the data for an overnight cost of \$2,014 per kW.

The overnight cost for the plant is distributed over the six year construction period with construction costs peaking mid-way through the construction period. Spending is converted to nominal dollars using the last year of construction as the base year. Nominal cash flows are discounted using the firm's discount rate (column 3). These discounted numbers enter the summation in step 2. Once the plant begins operation fixed and operating costs (including fuel costs, maintenance, nuclear decommissioning costs, capital increments, bond interest payments and taxes) are summed and then discounted to year zero values. Depreciation and bond interest costs are allowed as a tax deduction and so reduce the costs by the value of the tax shield (tax rate times deduction).

The sum of the present discounted costs is converted to a real levelized cost that is a constant real annual payment by the firm to cover all costs. For the nuclear power plant, the constant real annual before-tax revenue required to

Table 5.A2
Construction Costs for Nuclear Power Plant

Year	Real	Nominal	Discounted
1	135	116	203
2	369	327	511
3	503	461	643
4	503	475	593
5	369	358	400
6	135	135	135
Total	2014	1872	2484

match the sum of the present discounted costs (including the value of the tax shields) over the life of the plant is \$321 million per year.

Finally in step 4 this is converted to a cost per kWh. Total annual production for the plant is the number of hours in the year times its capacity factor. Dividing this into the annual levelized cost yields a cost per kWh. Based on a capacity factor of 85 percent, the annual \$321 million cost translates to a real levelized cost of 4.31¢ per kWh.