U.S. Energy Information
Administration

Direct Federal Financial Interventions and Subsidies in Energy in Fiscal Year 2010

JULY 2011

Contacts

This report, Direct Federal Financial Interventions and Subsidies in Energy in Fiscal Year 2010, was prepared under the general guidance of John Conti, Assistance Administrator for Energy Analysis, J. Alan Beamon at 202/586-2025 (email, joseph.beamon@eia.gov), Director, Office of Electricity, Coal, Nuclear, and Renewables Analysis, and Jim Diefenderfer at 202/586-2432 (email, jim.diefenderfer@eia.gov).

Technical information concerning the content of the report may be obtained from Kevin Lillis at 202/586-3704 (email, kevin.lillis@eia.gov), Executive Summary, Chapters 1, 2 and 4; William Watson at 202/586-1707 (email, william.watson@eia.gov), Chapter 2; coal tax expenditures; Scott McKee at 202/287-6049 (email, scott.mckee@eia.gov), Chapter 2; Robert Eynon at 202/586-239 (email, robert.eynon@eia.gov), Chapter 3; and James Hewlett at 202/586-9536 (email, james.hewlett@eia.gov), Chapters 4 and 5.

Other contributors to the report include: Margie Daymude, Marie LaRiviere, Louise Guey-Lee, Robert Schmitz, and Peggy Wells.

Preface

This report responds to a November 2010 request to the U.S. Energy Information Administration (EIA) from U.S. Representatives Roscoe G. Bartlett, Marsha Blackburn, and Jason Chaffetz for an update to a 2008 report prepared by EIA that provided a snapshot of direct federal financial interventions and subsidies in energy markets in fiscal year (FY) 2007, focusing on subsidies to electricity production. As requested, this report updates the previous report using FY 2010 data and is limited to subsidies that are provided by the federal government, provide a financial benefit with an identifiable federal budget impact, and are specifically targeted at energy markets. Subsidies to federal electric utilities, in the way of financial support, are also included as requested.

Contents

Tables

Figures

Executive Summary

Background

This report responds to a November 2010 request to the U.S. Energy Information Administration (EIA) from U.S. Representatives Roscoe G. Bartlett, Marsha Blackburn, and Jason Chaffetz for an update to a 2008 report prepared by EIA that provided a snapshot of direct federal financial interventions and subsidies in energy markets in fiscal year (FY) 2007, focusing on subsidies to electricity production (Appendix A). As requested, this report updates the previous report using FY 2010 data and is limited to subsidies that are provided by the federal government, provide a financial benefit with an identifiable federal budget impact, and are specifically targeted at energy markets. Subsidies to federal electric utilities, in the way of financial support, are also included, as requested. These criteria do exclude some subsidies beneficial to energy sector activities (see box entitled "Not All Subsidies Impacting the Energy Sector Are Included in this Report") and this should be kept in mind when comparing this report to other studies that may use narrower or more expansive inclusion criteria.

Energy subsidies and interventions discussed in this report are divided into five separate program categories:

Direct Expenditures to Producers or Consumers. These are federal programs that involve direct cash outlays which provide a financial benefit to producers or consumers of energy.

Tax Expenditures. These are provisions in the federal tax code that reduce the tax liability of firms or individuals who take specified actions that affect energy production, consumption, or conservation.

Research and Development (R&D). These are federal expenditures aimed at a variety of goals, such as increasing U.S. energy supplies or improving the efficiency of various energy consumption, production, transformation, and end-use technologies. R&D expenditures generally do not directly affect current energy consumption, production, and prices, but, if successful, they could affect future consumption, production, and prices.

Loans and Loan Guarantees. These involve federal financial support for certain energy technologies. The U.S. Department of Energy (DOE) is authorized to provide financial support for "innovative clean energy technologies that are typically unable to obtain conventional private financing due to their 'high technology risks.' In addition, eligible technologies must avoid, reduce, or sequester air pollutants or anthropogenic emissions of greenhouse gases."[1]

Electricity programs serving targeted categories of electricity consumers in several geographic regions of the country. Through the Tennessee Valley Authority (TVA) and the Power Marketing Administrations (PMAs), which include the Bonneville Power Administration (BPA) and three smaller PMAs, the federal government brings to market large amounts of electricity, stipulating that "preference in the sale of such power and energy shall be given to public bodies and cooperatives."[2] The federal government also indirectly supports portions of the electricity industry through loans and loan guarantees made by the U.S. Department of Agriculture's Rural Utilities Service (RUS) at interest rates generally below those available to investor-owned utilities.

1 Section 1703 of Title XVII of the Energy Policy Act of 2005 authorizes the U.S. Department of Energy to support innovative clean energy technologies that are typically unable to obtain conventional private financing due to high technology risks. In addition, the technologies must avoid, reduce, or sequester air pollutants or anthropogenic emissions of greenhouse gases. See: United States Department of Energy, Loan Programs Office at https://lpo.energy.gov/?page_id=39.

2 Flood Control Act of 1944 (58 Stat. 890; 16 U.S.C. 825s).

With the exception of the federal electricity programs and loan guarantee programs, this report measures subsidies and support on the basis of the cost of the programs to the federal budget as provided in budget documents from.[3] This report measures support provided by federal electricity programs by comparing the actual cost of funds made available to these entities to the cost of funds that they might otherwise have incurred. Similarly, the value of the support provided by DOE's loan guarantee program is estimated by analyzing what the costs of financing eligible projects might be without the guarantees and the cost of the credit subsidy required for the guarantee. Uncertainties in the estimation of subsidy and support costs for federally-guaranteed loans, federal utilities, and participants in Rural Utilities Service loan programs are reflected by providing a range of subsidy estimates for selected programs in the body of the report. To facilitate exposition, the Executive Summary presents only midpoint value estimates for these programs.

Not All Subsidies Impacting the Energy Sector Are Included in this Report

This report only includes subsidies meeting the following criteria: they are provided by the federal government, they provide a financial benefit with an identifiable FY 2010 federal budget impact, and, they are specifically targeted at energy. These criteria, particularly the energy-specific requirement, exclude some subsidies that benefit the energy sector. Some of the subsidies excluded from this analysis are discussed below.

For example, Section 199 of the American Jobs Creation Act of 2004, referred to as the domestic manufacturing deduction, provides reductions in taxable income for American manufacturers, including domestic oil and gas producers and refiners. The value of the Section 199 deduction in FY 2010 is estimated at $13 billion and approximately 25 percent is energy-related. While domestic oil and natural gas companies utilized this provision to reduce their 2010 tax liability, other industries, including traditional manufacturing sectors and other activities such as engineering and architectural services, sound recordings, and qualified film production, also took advantage of it.

Accelerated depreciation schedules arise from many provisions of the tax code and are widely available to energy and non-energy industries. Because the Internal Revenue Service (IRS) allows firms and individuals to deduct depreciation as an expense when computing their tax liability, accelerated depreciation front-loads deductible expenses, thereby reducing the present value of that liability. Accelerated depreciation provides a subsidy only to the extent that the amount of depreciation specified by the IRS exceeds the true economic "wear and tear" costs. Most empirical studies of economic depreciation have found evidence of some type of accelerated economic depreciation affecting various industries, though the exact pattern varied from study to study. This report includes the impacts of accelerated depreciation schedules identified as specific to the energy sector, but excludes schedules with applicability beyond the energy sector.

Subsidized credit for energy infrastructure projects is frequently provided by export credit agencies and multilateral development banks. However, entities such as the Export-Import Bank of the United States also provide support to non-energy industries including aerospace, medical equipment, non-energy mining, and agribusiness.

Tax-exempt municipal bonds allow publicly-owned utilities to obtain lower interest rates than those available from either private borrowers or the U.S. Treasury. However, while they are used by energy industries such as electric

[3] Office of Management and Budget, *Analytical Perspectives of the Budget of the United States*, Editions 2009 and 2012. Data for 2007 appeared in Table 19-1; data for 2010-1016 appeared in Table 17-1. Joint Committee on Taxation, *Estimates of Federal Tax Expenditures for Fiscal Years 2010-2014*, JCS-3-10, Table 1.

utilities, the group of eligible borrowers also includes water utilities, telecommunication facilities, waste treatment plants, and other publicly-owned entities.

The tax code allows a foreign tax credit for income taxes paid to foreign countries. If a multinational company is subject to a foreign country's levy, and it also receives a specific economic benefit from that foreign country, it is classified as a "dual-capacity taxpayer." Dual-capacity taxpayers cannot claim a credit for any part of the foreign levy unless it is established that the amount paid under a distinct element of the foreign levy is a tax, rather than a compulsory payment for some direct or indirect economic benefit. Major oil companies are significant beneficiaries of this provision. However, this tax provision is also available to non-energy industries.

The tax code also provides special treatment for some publicly-traded partnerships (PTP). Section 7704 of the Code generally treats a publicly-traded partnership as a corporation for federal income tax purposes. For this purpose, a PTP is any partnership that is traded on an established securities market or secondary market. However, a notable exception to Section 7704 occurs if 90 percent of the gross income of a PTP is passive-type income, such as interest, dividends, real property rents, gains from the disposition of real property, and similar income or gains. This would include gains from natural resource sales. In these cases, the PTP is exempt from corporate level taxation, thus allowing it to claim pass-through status for tax purposes.[4] As with many other tax provisions, the tax treatment of PTPs is not exclusive to the energy sector.

Another potential subsidy source not addressed in this report is associated with energy-related trust funds financed by taxes and fees. Examples include the Black Lung Disability Trust Fund, the Leaking Underground Storage Tank Trust Fund, the Oil Spill Liability Trust Fund, the Pipeline Safety Fund, the Aquatic Resources Trust Fund, the Abandoned Mine Reclamation Fund, the Nuclear Waste Fund, and the Uranium Enrichment Decontamination and Decommissioning Fund. By tying trust fund collections to products and activities responsible for the damages they address, the cost of programs for remediation and prevention of those damages can be reflected in the market price of energy use and production. If the fees or taxes collected by trust funds have been set appropriately, the funds will have sufficient resources to meet their obligations with the result that no subsidy is involved. However, if the fees or taxes are set too low, energy companies are receiving an implicit subsidy. These potential subsidies are not addressed in this report because of the difficulty in determining the sufficiency of the funds to meet potential liabilities and the fact that there is no direct federal budgetary impact in FY 2010.

This report also does not attempt to quantify the potential subsidy resulting from limits to liability in case of a nuclear accident provided by Section 170 of the Atomic Energy Act of 1954, the Price-Anderson Act. The Price-Anderson Act requires each operator of a nuclear power plant to obtain the maximum amount of primary coverage of liability insurance. Currently, the amount is about $400 million. Damages exceeding that amount would be funded with a retroactive assessment on all other firms owning commercial reactors based upon the number of reactors they own. However, Price-Anderson places a limit on the total liability to all owners of commercial reactors at about $12 billion.

[4] The Pew Charitable Trusts, Subsidy Scope, http://subsidyscope.org/tax_expenditures/db/group/31/?estimate=1&year=2001.

Key Findings

The value of direct federal financial interventions and subsidies in energy markets doubled between 2007 and 2010, growing from $17.9 billion to $37.2 billion. In broad categories, the largest increase was for conservation and end-use subsidies, followed to a lesser degree by increases in electricity-related subsidies and subsidies for fuels used outside the electricity sector (Table ES1).

Table ES1. Value of energy subsidies by major use, FY 2007 and FY 2010 (million 2010 dollars)

Subsidy and Support Category	FY 2007	FY 2010
Electricity-Related	7,663	11,873
Fuels and Technologies Used for Electricity Production	6,582	10,902
Transmission and Distribution	1,081	971
Fuels Used Outside the Electricity Sector	6,246	10,448
Conservation, End Use and LIHEAP	3,987	14,838
Conservation	369	6,597
End-Use/Other	1,342	3,241
LIHEAP	2,276	5,000
Total	**17,895**	**37,160**

Notes: Totals may not equal sum of components due to independent rounding.
Note that the 2007 values reported here are inflated to 2010 dollars and reflect final 2007 data estimates. The values provided in this table also represent the average of the low and high values of more detailed estimates provided in the body of the report.
Sources: Office of Management and Budget, *Analytical Perspectives*, Budget of the United States Government, Fiscal Year s 2012 and 2009. Joint Committee on Taxation, Estimates of Federal Tax Expenditures for Fiscal Years 2010-2014, JCS-3-10 (Washington, DC, December 2010), Table 1, and budget documents from the Departments of Energy, Agriculture, Transportation, Treasury, Health and Human Services, Housing and Urban Development, the Environmental Protection Agency and the General Services Administration.

A key factor in the increased support for conservation programs, end-use technologies and renewables was the passage of several pieces of legislation responding to the recent financial crisis and subsequent economic downturn, particularly the American Recovery and Reinvestment Act of 2009 (ARRA) and the Energy Improvement and Extension Act (EIEA). Some of the ARRA-related programs that account for a large portion of the growth in subsidies and support between FY 2007 and FY 2010 (Table ES2) are temporary and the subsidies associated with them are scheduled to phase out over the next few years (see box "Energy Provisions Included in Legislation Responding to the Recent Financial Crisis"). Other recent legislation impacting energy subsidies included the Food, Conservation, and Energy Act of 2008, which provided significant new subsidies to biofuels (primarily ethanol and biodiesel) producers, and the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010, which extended the sunset dates for several tax expenditure programs, as well as the grant program for qualifying renewables.

Conservation and end-use subsidies experienced rapid growth in both absolute and percentage terms, more than tripling in real terms between FY 2007 and FY 2010. The increase in subsidies and support was led by growth in direct expenditures and tax expenditures (Table ES2). The home energy efficiency improvement tax expenditure accounts for most of the increase in conservation-related subsidies between FY 2007 and FY 2010. Conservation subsidies were almost equally divided between direct expenditures and tax expenditures, with estimated tax credits for energy efficiency improvements to existing homes totaling $3.2 billion. These tax credits funded investments in energy-efficient windows, furnaces, boilers, boiler fans, and building envelope components. End-use subsidies, nearly all of which were provided through direct expenditures of appropriated funds, were boosted by a doubling of expenditures in the Low Income Home Energy Assistance Program (LIHEAP) spending between FY 2007 and FY 2010.[5]

The composition of subsidies to specific fuels and technologies in FY 2010 is significantly different than in FY 2007, reflecting the elimination of subsidies to refined coal and increases in subsidies to renewable energy due to a change in the incentive structure. The growth in subsidies for renewable fuels is primarily driven by the $4.2 billion in expenditures for grants under Section 1603 of ARRA, which went mainly to wind facilities, and by growth in federal support for biofuels. The ARRA grant program allowed investors in new qualifying facilities to choose an upfront grant in lieu of the longstanding 10-year production tax credit that was also available, but which became less attractive to developers as the market for financial instruments based on tax credit streams withered following the financial crisis. Though the two options have roughly similar value to investors and cost to the government over the life of the projects, the grant program front loads the government's support for covered projects in the year that the grant is awarded. If the wind and solar plants that took advantage of the grant program during the financial crisis had instead utilized the production tax credit program, the subsidy value reported in FY 2010 would have been much smaller, reflecting only the credit for up to one year of generation.[6] Tax expenditures associated with ethanol tax credits also increased significantly between FY 2007 and FY 2010 with the growth in ethanol blending activity under the Renewable Fuel Standard.

The DOE loan program, designed to support nuclear power, energy efficiency and renewable energy projects, advanced fossil fuels, electric power transmission systems, advanced technology vehicles, and leading-edge biofuels, was only in its early stages in FY 2010. The midpoint estimate of the loan subsidies was $1.6 billion in 2010. As more projects are approved, the loan subsidies associated with this program are expected to rise over time.

[5] LIHEAP provides funds to states, the District of Columbia, U.S. territories and commonwealths, and Indian tribal organizations (collectively referred to as grantees) primarily to help low-income households pay home energy expenses.
[6] The amount of the subsidy for the Production Tax Credit (PTC) reflects the dollar amount for production from all qualifying generators in that year. Qualifying generators receive the credit for 10 years from the initial in-service date. For 2010, the total dollar amount reflects the annual PTC for all qualifying generators and the grant amount for those new generators qualifying under the Section 1603 program under ARRA.

Table ES2. Quantified energy-specific subsidies and support by type, FY 2010 and FY 2007 (million 2010 dollars)

Beneficiary	Direct Ex-penditures	Tax Ex-penditures	Research & Develop-ment	DOE Loan Guarantee Program	Federal & RUS Electricity[1]	Total	ARRA Related
2010							
Coal	42	561	663	0	91	1,358	97
Refined Coal	0	0	0	0	0	0	0
Natural Gas and Petroleum Liquids	4	2,690	70	0	56	2,820	0
Nuclear	0	908	1,169	265	157	2,499	147
Renewables	4,696	8,168	1,409	269	133	14,674	6,193
Biomass	57	523	537	0	0	1,117	10
Geothermal	160	1	100	12	0	273	228
Hydro	17	17	52	0	130	216	16
Solar	496	120	348	173	0	1,134	788
Wind	3,556	1,178	166	85	1	4,986	4,852
Other	95	0	205	0	1	302	130
Biofuels	314	6,330	0	0	0	6,644	169
Electricity -Smart Grid & Transmission	461	58	222	20	211	971	495
Conservation	3,387	3,206	0	4	0	6,597	6,305
End-Use	5,705	693	832	1,011	0	8,241	1,549
LIHEAP	5,000	0	0	0	0	5,000	0
Other	705	693	832	1,011	0	3,241	1,549
Total	**14,295**	**16,284**	**4,365**	**1,570**	**648**	**37,160**	**14,786**

Table ES2. Quantified energy-specific subsidies and support by type, FY 2010 and FY 2007 (cont.) (million 2010 dollars)

Beneficiary	Direct Ex-penditures	Tax Ex-penditures	Research & Develop-ment	DOE Loan Guarantee Program	Federal & RUS Electricity[1]	Total	ARRA Related
2007							
Coal	0	291	582	NA	70	1943	NA
Refined Coal	0	3,038	0	NA	0	3,038	NA
Natural Gas and Petroleum Liquids	0	1,914	43	NA	53	2,010	NA
Nuclear	0	600	1,017	NA	96	1,714	NA
Renewables	110	4,130	717	NA	167	5,124	NA
Biomass	16	5	40	NA	0	61	NA
Geothermal	0	5	9	NA	0	14	NA
Hydro	0	6	0	NA	165	170	NA
Solar	0	8	171	NA	0	179	NA
Wind	0	418	58	NA	1	476	NA
Other	5	6	211	NA	1	224	NA
Biofuels	89	3,682	228	NA	0	3,999	NA
Electricity -Smart Grid & Transmission	0	696	142	NA	243	1,081	NA
Conservation	369	0	0	NA	0	369	NA
End-Use	2,276	832	509	NA	0	3,618	NA
LIHEAP	2,276	0	0	0	0	2,276	NA
Other	0	832	509	NA	0	1,342	NA
Total	2,755	11,501	3,010	NA	629	17,895	NA

[1]Total will not match Table 24 midpoint of "Estimated Interest Subsidy at Benchmark Interest Rate" because some data can not be allocated by fuel or activity.

Notes: Totals may not equal sum of components due to independent rounding.

Renewable other includes landfill gas, municipal solid waste and hydrogen.

The values provided in this table represent the average of the low and high values of more detailed estimates provided in the body of this report. Due to data availability issues, not all federal utility data was allocated by fuel or activity.

Sources: Office of Management and Budget, *Analytical Perspectives*, Budget of the United States Government, Fiscal Year s 2012 and 2009. Joint Committee on Taxation, Estimates of Federal Tax Expenditures for Fiscal Years 2010-2014, JCS-3-10 (Washington, DC, December 2010), Table 1, and budget documents from the Departments of Energy, Agriculture, Transportation, Treasury, Health and Human Services, Housing and Urban Development, the Environmental Protection Agency and the General Services Administration.

Energy Provisions Included in Legislation Responding to the Recent Financial Crisis

Two laws enacted in response to the financial crisis of late 2008 and early 2009, the American Recovery and Reinvestment Act of 2009 (ARRA) and the Energy Improvement and Extension Act (EIEA), include significant energy-related provisions.

Both bills emphasize particular segments of the energy market such as use of renewable fuels in electricity production, alternative transportation fuels, clean energy facilities, upgrading the Nation's high voltage transmission system, energy efficiency, and conservation.

Both laws extended sunset provisions for some existing tax expenditures in addition to introducing new ones. These laws also featured provisions expanding the use of tax exempt bonds to publicly-owned energy providers. The energy-related provisions of EIEA were focused on tax expenditures. The energy-related provisions of ARRA included additional funding of existing direct expenditure, tax expenditure, and R&D programs, as well as funding for new direct expenditure, tax expenditure, and R&D programs; a new grant program available in lieu of production tax credits; and, expansion of DOE's loan guarantee program, first established in 2005. Finally, ARRA provided the Western Area Power Administration and the Bonneville Power Administration each with $3.25 billion in new borrowing authority to expand their transmission systems to better accommodate renewable sources of electricity supply.

ARRA created, expanded, or extended programs to increase the use of clean energy and improve energy efficiency. ARRA coupled an emphasis on promoting economic recovery and job creation with investments in energy programs. While only energy-related funds expended in FY 2010 are included in this report, ARRA included appropriations of more than $35.2 billion to the Department of Energy and provided more than $21 billion in energy tax incentives. This funding focused on energy efficiency, renewable energy, and smart grid investments. ARRA also provided $6 billion, of which $3.5 billion was subsequently rescinded, to fund a loan guarantee program administered by the U.S. DOE for eligible energy projects.

ARRA's Section 1603 energy grant program, which was designed as a supplement to existing energy production and investment tax credit programs directed at renewables, paid out $4.2 billion in FY 2010, targeted at wind (84 percent) and solar (11 percent) projects. ARRA also included additional spending on several existing direct expenditure programs. ARRA-related direct expenditures in FY 2010 totaled $8.5 billion.[7] This included $1.5 billion to the Weatherization Assistance program, $682 million to the State Energy program, $409 million to smart grid investments, and $317 million to fund a program supporting advanced battery manufacturing. ARRA also provided $473 million in initial funding to the Conservation Block program (authorized by the Energy Independence and Security Act of 2007 (EISA)), to deploy economical, clean, and reliable conservation technologies.

At $3.2 billion, the Credit for Energy Efficiency Improvements to Existing Homes was the largest energy-specific tax expenditure in FY 2010 after the ethanol tax credit. Although established under the Energy Policy Act of 2005 (EPAct 2005), it was expanded under Section 302 of EIEA and amended under Section 1121 of ARRA. This credit is available to offset funds used for the installation of energy-efficient windows, furnaces, boilers, boiler fans, and building envelope components, such as exterior doors and any metal roof that has appropriate pigmented coatings.

[7] The $8.5 billion includes non-DOE-related energy expenditures.

ARRA included $0.6 billion in new R&D funding. The largest target of this funding included basic science, at $159 million, followed by non-defense uranium enrichment decontamination and decommissioning, at $139 million.

ARRA also expanded DOE's loan guarantee authority that was first established under Section 1703 of EPAct 2005 by authorizing loan guarantees to electric power transmission systems and biofuels projects.

EIEA and ARRA both contained provisions providing significant tax benefits to issuers and holders of certain energy-related tax-exempt bonds.[8] EIEA provided $800 million in additional financing for Clean Renewable Energy Bonds (CREBs) and provided a one-year extension to existing CREBs. EIEA also created two new categories of CREB-like financing: New Clean Renewable Energy Bonds (New CREBs) and Qualified Energy Conservation Bonds (QECBs). Section 1111 of ARRA increased the amount of funds available to issue New CREBS from $800 million to $2.4 billion. Section 1112 of ARRA increased the amount of funds available to finance QECBs from $800 million to $2.4 billion.

The growth in energy-specific subsidies and support between FY 2007 and FY 2010 does not closely correspond to changes in energy consumption and production over the same time period. In fact, overall energy consumption actually fell from 101 quadrillion Btu to 98 quadrillion Btu between 2007 and 2010, reflecting economic conditions, while domestic energy production rose from 71 quadrillion Btu to 75 quadrillion Btu due to increasing domestic production of shale gas, crude oil, and renewable energy (Table ES3). While the overall amount of federal subsidies and support provided per unit of overall energy consumption or production has clearly grown, simply dividing the current value of subsidies by current consumption or production does not reflect either the long-run impact of imbedded subsidies and or the future impacts of current subsidies and support that may only be starting to impact energy markets. For example, increases in R&D expenditures are not reflected in the Nation's energy mix unless and until the research leads to successful innovations that penetrate the market, a process that can take many years.

Table ES3. Energy subsidies and support, selected indicators, 2007 and 2010

Item	2007	2010
Total Energy Subsidies and Support (million 2010 dollars)	17,895	37,160
U.S. Energy Consumption (quadrillion Btu)	101.4	98.0
U.S Energy Production (quadrillion Btu)	71.4	75.0

Notes: Totals may not equal sum of components due to independent rounding.
The subsidy and support values provided in this table represent the average of the low and high values of more detailed estimates provided in the body of the report.
The energy consumption and production values shown in this table represent 2007 and 2010 calendar year data rather than the fiscal year data reported for the estimated subsidies.
Sources: U.S. Energy Information Administration, Monthly Energy Review May 2011, DOE/EIA-0035(2011/05) (Washington, DC, May, 2011), Office of Management and Budget, *Analytical Perspectives*, Budget of the United States Government, Fiscal Year s 2012 and 2009. Joint Committee on Taxation, Estimates of Federal Tax Expenditures for Fiscal Years 2010-2014, JCS-3-10 (Washington, DC, December 2010), Table 1, and budget documents from the Departments of Energy, Agriculture, Transportation, Treasury, Health and Human Services, Housing and Urban Development, the Environmental Protection Agency and the General Services Administration.

[8] These bonds are classified by the U.S. Treasury as tax expenditures although they are targeted at public power providers, which do not have any federal profit tax liabilities. They are, in some sense, the equivalent of the Production Tax Credit or Investment Tax Credit provided to investor-owned utilities. In essence, they amount to interest free loans, with the Treasury providing the interest payments rather than the public power provider.

Findings Regarding Electricity-Related Subsidies and Support

Electricity-related subsidies and support are estimated at $11.9 billion in FY 2010, up from $7.7 billion in FY 2007 (Table ES1). While fuel- and technology-related electricity subsidies grew 66 percent between FY 2007 and FY 2010, transmission and distribution system-related subsidies actually declined.

Direct expenditures accounted for 39 percent of total electricity-related subsidies in FY 2010 (Table ES4). These expenditures were mostly the result of the ARRA Section 1603 grant program, 84-percent of which went to wind generation. As noted, the relatively high value for this program stems from the fact that the grant program places all of the costs in the year that a project is initiated, while the existing production tax credit that the grant substituted for spread the costs of the tax credit over the first 10 years of a project's operation. If developers return to using the production tax credit in the future, the first-year costs for each project will be much lower.

Tax expenditures comprise over 28 percent of the total subsidies and support related to electricity production. Renewables accounted for 40 percent of all electricity-related tax expenditures in FY 2010, mostly due to the Sections 45 and 48 production and investment tax credits which predominantly went to wind facilities. A nuclear decommissioning–related tax credit accounted for $908 million in tax expenditures.

Research and development accounted for 22 percent of the total subsidies and support to the electric power sector. Nuclear accounted for the highest level of R&D expenditures at $1,169 million, followed by renewables at $632 million, and coal at $575 million.

Federal electricity support to federal utilities and participants in the Rural Utilities Service loan programs in the form of explicit and implicit loan guarantees are estimated at approximately $648 million in FY 2010. The level of this support is largely a function of the value of outstanding debt and prevailing interest rates.

Relative to their share of total electricity generation, renewables received a large share of direct federal subsidies and support in FY 2010. For example, renewable fuels accounted for 10.3 percent of total generation, while they received 55.3 percent of federal subsidies and support (Tables ES4 and ES5). However, caution should be used when making such calculations because many factors can drive the results. For example, many of the programs that showed the largest increases in subsidies between FY 2007 and FY 2010 are supporting facilities that are still under construction, including energy equipment manufacturing facilities that may not affect energy consumption or production for several years. Furthermore, the ARRA 1603 grant program, that allows investors to choose an upfront grant instead of a 10-year production tax credit, tended to lead to much higher overall electricity subsidy estimates for renewables in FY 2010 than would have occurred had they continued to rely on the existing production tax credit program, which does not front-load subsidy costs. Focusing on a single year's data also does not capture the imbedded effects of subsidies that may have occurred over many years across all energy fuels and technologies.

Table ES4. Fiscal year 2010 electricity production subsidies and support (million 2010 dollars)

	Direct Expenditures	Tax Expenditures	Research & Development	Federal & RUS Electricity Support	Loan Guarantee	Total	Share of Total Subsidies and Support
Coal	37	486	575	91	0	1,189	10.0%
Natural Gas and Petroleum Liquids	1	583	15	56	0	654	5.5%
Nuclear	0	908	1,169	157	265	2,499	21.0%
Renewables	4,178	1,347	632	133	269	6,560	55.3%
Biomass	6	54	55	0	0	114	1.0%
Geothermal	115	1	72	0	12	200	1.7%
Hydropower	17	17	51	130	0	215	1.8%
Solar	409	99	287	0	173	968	8.2%
Wind	3,556	1,178	166	1	85	4,986	42.0%
Unallocated Renewables	75	0	0	0	0	75	0.6%
Transmission and Distribution	461	58	222	211	20	971	8.2%
Total	**4,677**	**3,382**	**2,613**	**648**	**555**	**11,873**	**100%**

Notes: Estimates of federal electricity program support are based on the most recent audited annual reports for federally-owned utilities which conform to federal fiscal year convention.
Totals may not equal sum of components due to independent rounding.
The values provided in this table represent the average of the low and high values of more detailed estimates provided in the body of the report.
Sources: Office of Management and Budget, *Analytical Perspectives*, Budget of the United States Government, Fiscal Year s 2012 and 2009. Joint Committee on Taxation, Estimates of Federal Tax Expenditures for Fiscal Years 2010-2014, JCS-3-10 (Washington, DC, December 2010), Table 1, and budget documents from the Departments of Energy, Agriculture, Transportation, Treasury, Health and Human Services, Housing and Urban Development, the Environmental Protection Agency and the General Services Administration.

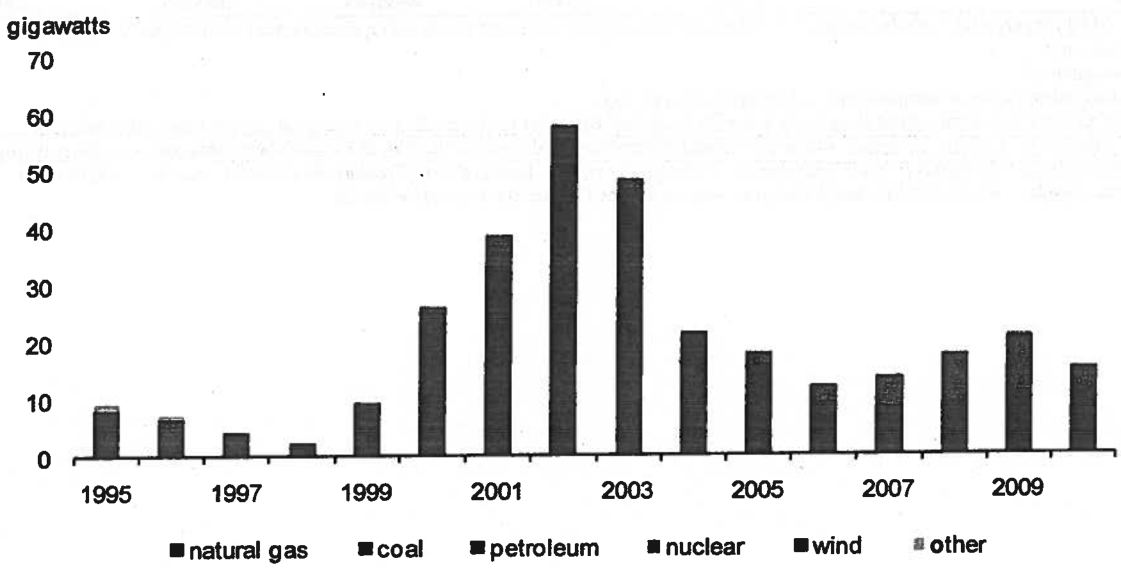
Among the specific fuels and technologies, wind plants received the largest share of direct federal subsidies and support in FY 2010, accounting for 42 percent of total electricity-related subsidies. While the share of electricity-related subsidies and support received by wind and solar technologies is disproportionate to their generation share, their generation has increased dramatically in the last decade. Wind generation in 2010 is nearly 16 times the level achieved in 2000 (Table ES5). While natural gas-fired capacity additions have dominated for most of the last 15 years, wind generating capacity additions have also ramped up substantially in recent years (Figure ES1).

Findings Regarding Subsidies and Support For Fuels Used Outside of the Electricity Sector

Biofuels receive most of the subsidies and support for fuels used outside the electricity sector. Based on the subsidy categories used in this report, subsidies and support for fuels used outside the electricity sector, at $10.4 billion, accounted for 28 percent of total energy subsidies. In this category, biomass and biofuels received the largest subsidy in FY 2010, at $7.6 billion (Table ES6). Under the Volumetric Ethanol Excise Tax Credit (VEETC), blenders receive a $0.45-per gallon credit for each gallon of ethanol that is blended with gasoline for use as a motor fuel.[9] Internal Revenue Service regulations require that blenders apply for VEETC refunds to offset gasoline excise tax payments, but they may submit a claim for payment or take a credit against other taxes if their VEETC credits exceed their gasoline excise tax liability. Based on its implementation rules, the Treasury reports VEETC as a $5.7-billion reduction in excise tax revenues for FY 2010. For purposes of this report, VEETC is classified as tax expenditure.

Natural gas and petroleum liquids also received significant subsidies and support for fuels used outside the electricity sector. They accounted for 20.7 percent of the fuel specific subsidies and support and, together with biofuels, accounted for nearly 94 percent of the subsidies and support going to fuels not supporting electricity

Figure ES 1. Electricity generating capacity additions by year



production.

Source: U.S. Energy Information Administration, Form EIA-860 Annual Electric Generator Report, and Form EIA-860M (see Table ES3 in the March 2011 Electric Power Monthly).

[9] The credits for mixtures other than ethanol are $0.60–per-gallon for alcohol fuel mixtures (other than ethanol), $0.50-per-gallon of biodiesel, and $1.00-per-gallon for agri-biodiesel.

Table ES5. Measures of electricity production and production growth

	2000 Net Generation (billion kilowatt-hours)	2010 Net Generation (billion kilowatt-hours)	Share of 2000 Generation (percent)	Share of 2010 Generation (percent)	Annual Growth from 2000 to 2010 (percent)
Coal	1,966	1,851	51.7%	44.9%	-0.6%
Natural Gas and Petroleum Liquids	726	1,030	19.1%	25.0%	3.6%
Nuclear	754	807	19.8%	19.6%	0.7%
Renewables	356	425	9.4%	10.3%	1.8%
Biomass Power	61	57	1.6%	1.4%	-0.7%
Geothermal	14	16	0.4%	0.4%	1.3%
Hydroelectric	276	257	7.3%	6.2%	-0.7%
Solar	0	1	0.0%	0.0%	NA
Wind	6	95	0.2%	2.3%	31.8%
Total	**3,802**	**4,120**	**100.0%**	**100.0%**	**0.8%**

Notes: Total net generation includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, miscellaneous technologies not included in individual rows.
NA=Not applicable.
Totals may not equal sum of components due to independent rounding.
Sources: Office of Management and Budget, *Analytical Perspectives*, Budget of the United States Government, Fiscal Year s 2012 and 2009. Joint Committee on Taxation, Estimates of Federal Tax Expenditures for Fiscal Years 2010-2014, JCS-3-10 (Washington, DC, December 2010), Table 1, and budget documents from the Departments of Energy, Agriculture, Transportation, Treasury, Health and Human Services, Housing and Urban Development, the Environmental Protection Agency and the General Services Administration.

Table ES6. Subsidies and support to fuels used outside of the electricity sector

	2000 Fuel Production Excluding That Used for Electricity Generation (quadrillion btu)	2010 Fuel Production Excluding That Used for Electricity Generation (quadrillion btu)	FY 2010 Subsidy and Support (million 2010 dollars)	Share of 2010 Non-Electricity-Related Fuel Production (percent)	Share of 2010 Fuel-Specific Non-Electricity-Related Subsidies (percent)
Coal	2.52	2.94	169	8.3%	1.6%
Natural Gas Petroleum Liquids	28.20	28.55	2,165	80.3%	20.7%
Biomass and Biofuels	2.55	3.87	7,646	10.9%	73.2%
Geothermal	0.02	0.06	73	0.2%	0.7%
Solar	0.06	0.10	169	0.3%	1.6%
Other Renewables	0.04	0.02	226	0.0%	2.2%
Total	**33.39**	**35.54**	**10,448**	**100.0%**	**100.0%**

Notes: Totals may not equal sum of components due to independent rounding.
The fuel production values in this table represent domestic fuel production for each fuel minus the amount consumed in the electricity sector.
The values provided in this table represent the average of the low and high values of more detailed estimates provided in the body of the report.
Other Renewables includes hydroelectricity, wind, and hydrogen.
Sources: Office of Management and Budget, *Analytical Perspectives*, Budget of the United States Government, Fiscal Year s 2012 and 2009. Joint Committee on Taxation, Estimates of Federal Tax Expenditures for Fiscal Years 2010-2014, JCS-3-10 (Washington, DC, December 2010), Table 1, and budget documents from the Departments of Energy, Agriculture, Transportation, Treasury, Health and Human Services, Housing and Urban Development, the Environmental Protection Agency and the General Services Administration.

1. Introduction

Background

This report responds to a November 2010 request to the Energy Information Administration (EIA) from U.S. Representatives Roscoe G. Bartlett, Marsha Blackburn, and Jason Chaffetz for an update to a 2008 report prepared by EIA that provided a snapshot of direct federal financial interventions and subsidies in energy markets in fiscal year (FY) 2007, focusing on subsidies to electricity production (Appendix A). As requested, this report updates the previous report using FY 2010 data and is limited to subsidies that are provided by the federal government, provide a financial benefit with an identifiable federal budget impact, and are specifically targeted at energy markets. Subsidies to federal electric utilities, in the way of financial support, are also included as requested. These criteria do exclude some subsidies beneficial to energy sector activities (see box Not All Subsidies Impacting the Energy Sector Are Included in this Report) and this should be kept in mind when comparing this report to other studies that may use narrower or more expansive inclusion criteria.

Energy subsidies and interventions discussed in this report are divided into five separate program categories:

Direct Expenditures to Producers or Consumers. These are federal programs that involve direct cash outlays which provide a financial benefit to producers or consumers of energy.

Tax Expenditures. These are provisions in the federal tax code that reduce the tax liability of firms or individuals who take specified actions that affect energy production, consumption, or conservation.

Research and Development (R&D). These are federal expenditures aimed at a variety of goals, such as increasing U.S. energy supplies or improving the efficiency of various energy consumption, production, transformation, and end-use technologies. R&D expenditures generally do not directly affect current energy consumption, production, and prices, but, if successful, they could affect future consumption, production, and prices.

Loans and Loan Guarantees. These involve federal financial support for certain energy technologies. The U.S. Department of Energy (DOE) is authorized to provide financial support for "innovative clean energy technologies that are typically unable to obtain conventional private financing due to their 'high technology risks.' In addition, eligible technologies must avoid, reduce, or sequester air pollutants or anthropogenic emissions of greenhouse gases."[10]

Electricity programs serving targeted categories of electricity consumers in several geographic regions of the country. Through the Tennessee Valley Authority (TVA) and the Power Marketing Administrations (PMAs), which include the Bonneville Power Administration (BPA) and three smaller PMAs, the federal government brings to market large amounts of electricity, stipulating that "preference in the sale of such power and energy shall be given to public bodies and cooperatives."[11] The federal government also indirectly supports portions of the electricity industry through loans and loan guarantees made by the U.S. Department of Agriculture's Rural Utilities Service (RUS).

[10] Section 1703 of Title XVII of the Energy Policy Act of 2005 authorizes the U.S. Department of Energy to support innovative clean energy technologies that are typically unable to obtain conventional private financing due to high technology risks. In addition, the technologies must avoid, reduce, or sequester air pollutants or anthropogenic emissions of greenhouse gases. See United States Department of Energy, Loan Programs Office at:https://lpo.energy.gov/?page_id=39.

[11] Flood Control Act of December 2, 1944 (58 Stat. 890; 16 U.S.C. 825s).

With the exception of the federal electricity programs and loan guarantee programs, this report measures subsidies and support on the basis of the cost of the programs to the federal budget as provided in budget documents from the Office of Management and Budget, and the Joint Committee on Taxation.[12] This report measures support provided by federal electricity programs by comparing the actual cost of funds made available to these entities to the cost of funds that they might otherwise have incurred in the absence of federal support. Similarly, the value of the support provided by DOE's loan guarantee program is estimated by analyzing what the costs of financing eligible projects might be without the guarantees and the cost of the credit subsidy required for the guarantee. In contrast to the Executive Summary where midpoint estimates are used to provide measures of finance-related subsidies, subsequent chapters present a range of subsidy estimates, to reflect uncertainty in the estimation of the costs of federally-guaranteed loans and the borrowing costs of the federal utilities and participants in Rural Utilities Service loan programs. This report estimates these costs based upon the savings realized from borrowing at preferential rates compared to market rates. Rather than choosing a single benchmark interest rate to estimate the cost of these programs, a range of borrowing costs starting with the 30-year Treasury rate through the Baa investor- owned- utility interest rate were used.

Not All Subsidies Impacting the Energy Sector Are Included in this Report

This report only includes subsidies meeting the following criteria: they are provided by the federal government, they provide a financial benefit with an identifiable FY 2010 federal budget impact, and, they are specifically targeted at energy. These criteria, particularly the energy-specific requirement, exclude some subsidies that benefit the energy sector. Some of the subsidies excluded from this analysis are discussed below.

For example, Section 199 of the American Jobs Creation Act of 2004, referred to as the domestic manufacturing deduction, provides reductions in taxable income for American manufacturers, including domestic oil and gas producers and refiners. The value of the Section 199 deduction in FY 2010 is estimated at $13 billion and approximately 25 percent is energy-related. While domestic oil and natural gas companies utilized this provision to reduce their 2010 tax liability, other industries, including traditional manufacturing sectors and other activities such as engineering and architectural services, sound recordings, and qualified film production, also took advantage of it.

Accelerated depreciation schedules arise from many provisions of the tax code and are widely available to energy and non-energy industries. Because the Internal Revenue Service (IRS) allows firms and individuals to deduct depreciation as an expense when computing their tax liability, accelerated depreciation front-loads deductible expenses, thereby reducing the present value of that liability. Accelerated depreciation provides a subsidy only to the extent that the amount of depreciation specified by the IRS exceeds the true economic "wear and tear" costs. Most empirical studies of economic depreciation have found evidence of some type of accelerated economic depreciation affecting various industries, though the exact pattern varied from study to study. This report includes the impacts of accelerated depreciation schedules identified as specific to the energy sector, but excludes schedules with applicability beyond the energy sector.

Subsidized credit for energy infrastructure projects is frequently provided by export credit agencies and multilateral development banks. However, entities such as the Export-Import Bank of the United States also

[12] Office of Management and Budget, *Analytical Perspectives of the Budget of the United States*, Editions 2009 and 2012. Data for 2007 appeared in Table 19-1; data for 2010-1016 appeared in Table 17-1. Joint Committee on Taxation, *Estimates of Federal Tax Expenditures for Fiscal Years 2010-2014*, JCS-3-10, Table 1.

provide support to non-energy industries including aerospace, medical equipment, non-energy mining, and agribusiness.

Tax-exempt municipal bonds allow publicly-owned utilities to obtain lower interest rates than those available from either private borrowers or the U.S. Treasury. However, while they are used by energy industries such as electric utilities, the group of eligible borrowers also includes water utilities, telecommunication facilities, waste treatment plants, and other publicly-owned entities.

The tax code allows a foreign tax credit for income taxes paid to foreign countries. If a multinational company is subject to a foreign country's levy, and it also receives a specific economic benefit from that foreign country, it is classified as a "dual-capacity taxpayer." Dual-capacity taxpayers cannot claim a credit for any part of the foreign levy unless it is established that the amount paid under a distinct element of the foreign levy is a tax, rather than a compulsory payment for some direct or indirect economic benefit. Major oil companies are significant beneficiaries of this provision. However, this tax provision is also available to non-energy industries.

The tax code also provides special treatment for some publicly-traded partnerships. Section 7704 of the Code generally treats a publicly-traded partnership (PTP) as a corporation for federal income tax purposes. For this purpose, a PTP is any partnership that is traded on an established securities market or secondary market. However, a notable exception to Section 7704 occurs if 90 percent of the gross income of a PTP is passive-type income, such as interest, dividends, real property rents, gains from the disposition of real property, and similar income or gains. This would include gains from natural resource sales. In these cases, the PTP is exempt from corporate level taxation, thus allowing it to claim pass-through status for tax purposes.[13] As with many other tax provisions, the tax treatment of PTPs is not exclusive to the energy sector.

Another potential subsidy source not addressed in this report is associated with energy-related trust funds financed by taxes and fees. Examples include the Black Lung Trust Fund, the Leaking Underground Storage Tank Trust Fund, the Oil Spill Liability Trust Fund, the Pipeline Safety Fund, the Aquatic Resources Trust Fund, the Abandoned Mine Reclamation Fund, the Nuclear Waste Fund, and the Uranium Enrichment Decontamination and Decommissioning Fund. By tying trust fund collections to products and activities responsible for the damages they address, the cost of programs for remediation and prevention of those damages can be reflected in the market price of energy use and production. If the fees or taxes collected by trust funds have been set appropriately, the funds will have sufficient resources to meet their obligations with the result that no subsidy is involved. However, if the fees or taxes are set too low, energy companies are receiving an implicit subsidy. These potential subsidies are not addressed in this report because of the difficulty in determining the sufficiency of the funds to meet potential liabilities and the fact that there is no direct federal budgetary impact in FY 2010.

This report also does not attempt to quantify the potential subsidy resulting from limits to liability in case of a nuclear accident provided by Section 170 of the Atomic Energy Act of 1954, the Price-Anderson Act. The Price-Anderson Act requires each operator of a nuclear power plant to obtain the maximum amount of primary coverage of liability insurance. Currently, the amount is about $400 million. Damages exceeding that amount would be funded with a retroactive assessment on all other firms owning commercial reactors based upon the number of reactors they own. However, Price-Anderson places a limit on the total liability to all owners of commercial reactors of about $12 billion.

[13] The Pew Charitable Trusts, Subsidy Scope, http://subsidyscope.org/tax_expenditures/db/group/31/?estimate=1&year=2001.

Organization of Report

In addition to this introductory chapter, this report contains five chapters. Chapter 2 reports on energy-related tax expenditures and direct expenditures. Chapter 3 discusses subsidies which are listed in the federal budget as R&D expenditures. Chapter 4 evaluates support associated with federal electricity programs. Chapter 5 analyzes loan guarantee subsidies associated with recent legislation. Since this report is essentially an update of the report prepared in 2008, it focuses on providing revised tabular information and generally limits discussion to areas where changes were made or new methodologies were used. Readers are referred to the earlier report and other supporting documents for more information.[14]

[14] Energy Information Administration, *Federal Financial Interventions and Subsidies in Energy Markets 2007*, Washington, DC, 20585, April 2008, available at http://www.eia.gov/oiaf/servicerpt/subsidy2/index.html.

2. Tax Expenditure and Direct Expenditures

Overview

This chapter focuses on energy-specific federal tax expenditures and direct expenditures that subsidize activities of energy producers and consumers.

In FY 2010, energy-related tax expenditures are estimated at $16.3 billion (2010 dollars) (Table 1). This represents an increase of $4.8 billion (42 percent) from the estimated $11.5 billion in energy-related tax expenditures in EIA's 2007 report. Most of this increase is accounted for by changes in a small number of tax expenditure programs, notably the tax credit for alcohol fuels, up $2.2 billion between FY 2007 and FY 2010, and credits for energy efficiency improvements to existing homes, which increased by $2.8 billion over the same period. As discussed below, increases and decreases in other energy-specific tax expenditures between FY 2007 and FY 2010 came close to no net change, with the sharp drop in tax credits for coal-based synfuels nearly balancing increases in other tax expenditures..

For several decades, policies in the federal budget affecting energy production have largely been exercised through the Internal Revenue Code (Tax Code or IRC). Recently, in order to inject funds more quickly into a weak economy, ARRA made more prominent use of direct spending. This was done with the intention of providing capital to investors with little or no taxable income to offset during the financial crisis. The most significant of these new grants arose from Section 1603 of ARRA. As with the pre-existing PTC and ITC for eligible renewable electricity technologies, this grant has been used primarily to fund wind power investments. Eligible investors have elected to take the cash grant over the ITC or PTC by a wide margin. Direct expenditure programs to support biofuels saw funding rise to $300 million by FY 2010 with the addition of several new programs after FY 2007. Turning from production to consumption, a sizable gain in LIHEAP funding, which increased by $2.7billion between FY 2007 and FY 2010 also lifted direct expenditures, which in total were up $11.5 billion from FY 2007.

Tax Expenditures

Energy tax expenditures are broadly defined as provisions in the IRC that provide beneficial tax treatment to taxpayers who produce, consume, or economize on energy in ways that are deemed to be in the public interest. Tax expenditures are not treated in budgetary terms as federal spending even though they have a similar impact on the budget. Energy-specific tax expenditures for FY 2007 together with FY 2010 estimates are reported in Table 1.

The federal budget lists tax expenditures, pursuant to the Congressional Budget Act of 1974 (Public Law 93-344), which defines them as "revenue losses attributable to provisions of Federal tax laws, which allow a special exclusion, exemption, or deduction from gross income or provide a special credit, preferential rate of tax, or deferral liability."

Tax expenditures arise from provisions in federal tax laws including credits, deductions, deferrals, preferential rates, and exemptions (exclusions), as briefly described below.

Tax Credit. A tax credit is an amount deducted directly from income tax otherwise payable. For instance, the HOPE credit can lower an eligible party's tax bill by a fixed amount per child for the first two years of their college education.

Tax Deduction. A tax deduction is an amount deducted from taxable income to arrive at adjusted taxable income. An example is the mortgage interest deduction available to homeowners.

Tax Deferral. A tax deferral allows for payment of a tax in a later year, providing in essence an interest free loan. The Office of Management and Budget (OMB) reports the annual value of tax expenditures for tax deferrals on a cash basis. The OMB notes that "although such estimates are useful as a measure of cash flow into the government, they do not accurately reflect the true economic cost of the provisions. For example, for a provision where activity levels have changed, so that incoming tax receipts from past deferrals are greater than deferred receipts from new activity, the cash-basis tax expenditure estimate can be negative, despite the fact that in present value terms current deferrals have a real cost to Government."

Preferential Tax Rate. A preferential tax rate treats certain forms of taxable income more favorably than other income. One example is the lower tax rate applied to capital gains.

Tax Exclusion. A tax exclusion exempts a portion of income from taxation. For example, employee provided health insurance can often be excluded from income.

Table 1. Estimates of energy-specific tax expenditures
(million 2010 dollars)

Tax Expenditures	FY 2007	FY 2010
Expensing of Exploration and Development Costs	551	400
Exception from Passive Loss Limitation for Working Interests in Oil and Gas Properties	31	30
Excess of Percentage over Cost Depletion	822	980
Capital Gains Treatment of Royalties on Coal	187	50
Alcohol Fuel Credits	42	70
Qualified Energy Conservation Bonds	-	-
Alternative Fuel Production Credit	3,038	170
Energy Investment Credit	-	130
Energy Production Credit	426	1,540
Tax Credit and Deduction for Clean-Burning Vehicles	270	250
Biodiesel land Small Agri-Biodiesel Producer Tax Credits	187	20
Alcohol Fuel Exemption[a]	3,454	5,680
Biodiesel Producer Tax Credit[a]		490
Exclusion from Income of Conservation Subsidies Provided by Public Utilities	125	220
Credit for Holding Clean Renewable Energy Bonds[b]	21	70

Table 1. Estimates of energy-specific tax expenditures (cont)
(million 2010 dollars)

Tax Expenditures	FY 2007	FY 2010
Deferral of Gain from Disposition of Transmission Property to Implement FERC Restructuring Policy	635	(50)
Credit for Investment in Clean Coal Facilities	31	240
Credit for Production from Advanced Nuclear Power Facilities	-	-
Temporary 50-Percent Expensing for Equipment used in the Refining of Liquid Fuels	31	760
Natural Gas Distribution Pipelines being Treated as 15-Year Property	62	120
Amortize all Geological and Geophysical Expenditures over 2 Years	52	150
Allowance for the Deduction of Certain Energy Efficient Commercial Building Property	198	60
Credit for Construction of New Energy Efficient Homes	21	20
Credit for Energy Efficiency Improvements to Existing Homes	395	3,190
Credit for Energy Efficient Appliances	83	150
Credit for Residential Energy Efficient Property	10	220
Credit for Business Installation of Qualified Fuel Cells and Stationary Microturbine Power Plants	83	-
Partial Expensing for Advanced Mine Safety Equipment	10	3
Expensing of Capital Goods with Respect to Complying with EPA Sulfur Regulations	10	-
Exclusion of Special Benefits for Disabled Coal Miners	31	40
Transmission Property Treated as Fifteen-Year Property	19	100
5-Year Net Operating Loss Carryover for Electric Transmission Equipment	43	-
Amortization of Certain Pollution Control Facilities	31	100
Nuclear Decommissioning	600	900
Advanced Energy Manufacturing Facility Investment Tax Credit	-	180
Total	**11,501**	**16,284**

Note; Total may not equal sum due to independent rounding.
Sources: Office of Management and Budget, *Analytical Perspectives*, Budget of the United States Government, Fiscal Year s 2012 and 2009. Joint Committee on Taxation, Estimates of Federal Tax Expenditures for Fiscal Years 2010-2014, JCS-3-10 (Washington, DC, December 2010), Table 1, and budget documents from the Departments of Energy, Agriculture, Transportation, Treasury, Health and Human Services, Housing and Urban Development, the Environmental Protection Agency and the General Services Administration.
[a]The alcohol fuel exemption (VEETC) is essentially the excise tax exemption equivalent to the Alcohol Fuel Credits. The Biodiesel Producer Tax Credit is the excise tax exemption to the Biodiesel and Small Agri-biodiesel Producer Tax Credits. These are both listed as footnotes to an OMB table which includes energy tax expenditures.
[b]In addition, the provision has an outlay effectof $10 million in 2010.

The determination of what exactly is a preferential provision is subject to interpretation. Items in the budget identified as tax expenditures by the U.S. Treasury Department on occasion differ from those determined to be tax expenditures by the Joint Committee on Taxation (JCT)—the two bodies which produce these estimates. Historical tax expenditure data used in this report are taken from a number of government sources. For FY 2010, the Treasury Department is the primary provider of estimates for tax expenditures, supplemented by data provided by the JCT.

Tax Expenditure Caveats

Each year the U.S. Treasury Department estimates tax expenditures for the upcoming fiscal year budget. This data appears in the Office of Management and Budget document, Analytical Perspectives of the United States Budget. It is important to recognize that tax expenditure data are estimates and forecasts. Furthermore, prior year tax expenditure estimates may be substantially revised. However, a particular year's revision will not necessarily affect all past estimates. Additionally, the methodology used to estimate tax expenditures is subject to periodic modification and these changes are not always applied to revisions of all historical tax expenditure data.

This report uses tax expenditure estimates for FYs 2007 and 2010. Sizable changes in the dollar value of particular expenditures over time often reflect changes in their utilization due to changes in the IRC, key interpretations of the IRC, or in other key market and policy drivers. The historical data also reveal when particular energy programs were implemented and terminated. Although there are gaps in the data for some years, generalized trends in tax expenditures are still apparent. Readers of this report are cautioned that some of the tax expenditure data presented in this report will be revised in the future and that some of the historical data presented here have not been fully revised. This report sums annual tax expenditures across various programs. These summations should be treated with care as the Treasury Department cautions that the estimates would be different if tax expenditures were changed simultaneously because of potential interactions among provisions.

In many cases, the level of energy production or investment determines the potential value of the tax expenditure for qualified taxpayers. However, the value of the tax expenditure received by eligible taxpayers may not equal the potential value of the expenditure based upon production or investment. One factor mitigating against the eligible party receiving the full value of the tax expenditure is the alternative minimum tax (AMT), a separately calculated tax that eliminates many deductions and credits for which many tax expenditures are not exempt. Another mitigating factor is that a tax expenditure, in many cases, may not be received in the year in which the investment or production took place, but may, by law, be carried back or forward a number of years.

The Treasury Department does not provide estimates of de minimis tax expenditures, i.e., $5 million or less. Therefore, the impact of these tax expenditures is not reported in either OMB budget documents or this report.

Also, this report does not address in a quantitative manner energy legislation that has recently been passed and for which the budgetary impact has not yet been assessed by the OMB for FY 2010 or for future years. A case in point is Section 1306 of EPAct2005 which provides a production tax credit for eligible nuclear power sales. This credit does not have a value until such time as an eligible plant is producing electricity, which is not anticipated to occur until after FY 2015.

Energy-Specifc Tax Expenditure Programs

Coal-Related Tax Expenditures

Over 90 percent of coal is consumed by the electricity sector. Coal-fired generation accounted for 45 percent of total electricity generation in 2010. However, coal was estimated to be a relatively small recipient of tax expenditures in FY 2010, with an estimated value of $561 million in FY 2010, down from $3.3 billion in FY 2007 (Table 2). The alternative fuel production tax credit for refined coal was the largest tax expenditure related to coal use during FY 2007, but the relevant provisions of the IRC were not available for production beyond 2007. The credit for clean coal facilities, in contrast, showed a marked gain over FY 2007 spending. While coal is also eligible for percentage depletion and expensing of exploration and development costs, there are no data to break these out by fuel type and they are not included in the estimate of coal-related tax expenditures for FY 2010.

Table 2. Coal-related tax expenditures
(million 2010 dollars)

Tax Expenditure	Type	FY 2007	FY 2010
Exclusion of Special Benefits for Disabled Coal Miners	Exemption	31	40
Partial Expensing for Advanced Mine Safety Equipment	Expense Deduction	10	3
Credit for Investment in Clean Coal Facilities	Credit	31	240
Capital Gain Treatment of Royalties in Coal	Preferential Tax Rate	187	50
Amortization of Pollution Control Equipment	Expense Deduction	31	100
Advanced Energy Property Credit	Credit	0	1
Energy Production Credit (Refined coal and Indian coal credits)	Credit	0	27
Subtotal Coal Tax Expenditures		290	461
Alternative Fuel Production Credit (Synthetic coal, Coke and coke gas credit, and Steel industry fuel)	Credit	3,038	100
Total Coal and Refined Coal Tax Expenditures		**3,329**	**561**

Notes: Totals may not equal sum of components due to independent rounding. The advanced energy property credit was allocated by fuel using data appearing in: http://www.whitehouse.gov/the-press-office/president-obama-awards-23-billion-new-clean-tech-manufacturing-jobs. EIA estimated that $12 million of the new technology credit is directed at refined coal. This credit appeared under the alternative fuel production credit in 2007.

Sources: Office of Management and Budget, *Analytical Perspectives*, Budget of the United States Government, Fiscal Year s 2012 and 2009. Joint Committee on Taxation, Estimates of Federal Tax Expenditures for Fiscal Years 2010-2014, JCS-3-10 (Washington, DC, December 2010), Table 1, and budget documents from the Departments of Energy, Agriculture, Transportation, Treasury, Health and Human Services, Housing and Urban Development, the Environmental Protection Agency and the General Services Administration.

Exclusion of Special Benefits for Disabled Coal Miners. Disability payments to former coal miners out of the Black Lung Trust Fund are generally excluded from taxable income. This provision is categorized by the Treasury Department as an income security tax expenditure. The value of this expenditure is estimated at $40 million in FY 2010 versus $31 million in FY 2007.

Partial Expensing of Mine Safety Equipment. Section 404 of the Tax Relief and Welfare Act of 2006 (Public Law 109-432) allowed qualified mine safety equipment to be expensed rather than capitalized. Its value for FY 2007 is estimated at $10 million. This tax expenditure expired on December 31, 2008. However, in 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Public Law 111-312) extended this credit through the end of 2011. The value of this tax expenditure was $3 million in 2010.

Credit for Investment in Clean Coal Facilities. This credit has an estimated value of $31 million in FY 2007 and $240 million in FY 2010. Section 1307 of the EPAct 2005 provided for a 20-percent credit to coal gasification projects using integrated gasification combined-cycle (IGCC) technology and a 15-percent credit to other advanced coal technologies. It allocated $800 million tax credits towards electricity-related IGCC projects and $500 million towards other advanced coal technologies. An additional $350 million was applied to coal gasification technologies for industrial use. Eligible plants are expected to achieve a 90-percent reduction in SO2 and a 90-percent reduction in mercury. The Energy Improvement and Extension Act of 2008 authorized an additional $1.5 billion in tax credits for clean coal, $1.5 billion for advanced coal-based generation technologies that sequester at least 65 percent of CO2, and $250 million for projects that sequester 75 percent of CO2. Section 112 of the Energy Improvement and Extension Act included an income tax credit for coal gasification investments. In July 2010, the U.S. government awarded a $417-million investment tax credit to builders of the 602-megawatt Taylorville "clean coal" power plant with carbon capture and storage in south central Illinois. The Taylorville plant is designed to capture at least 65 percent of its CO2 emissions. Construction of the Taylorville plant has encountered delays as the Illinois state senate has yet to approve construction.

Capital Gains Treatment of Royalties on Coal. The estimated value of this credit in FY 2010 was $50 million down from $187 million in 2007. Owners of coal mining rights who lease their property usually receive royalties on mined coal. If the owners are individuals, these royalties can be taxed at a lower individual capital gains tax rate rather than at the higher individual top tax rate.

Amortization of Pollution Control Equipment. This provision was added by EPAct2005, under Section 1309. In general, a taxpayer may elect to recover the cost of any certified pollution control facility over a period of 60 months. A certified pollution control facility is defined as a new, identifiable treatment facility which (1) is used in connection with a plant in operation before January 1, 1976, to abate or control water or atmospheric pollution or contamination. A certified air pollution control facility (but not a water pollution control facility) used in connection with an electric generation plant which is primarily coal fired is eligible for 84-month amortization if the associated plant or other property was not in operation prior to January 1, 1976. The 60-month amortization period remains in effect for any certified air pollution control facility used in connection with an electric generation plant which is primarily coal fired and which was in operation prior to January 1, 1976. The JCT estimated the value of this expenditure to be $31 million for FY 2007 and $100 million for FY 2010.

Advanced Energy Property Credit. This credit, whose impact is largest on renewable fuels, is discussed later in this chapter. However, an estimated $1 million of this credit was directed at two Carbon Capture and Storage (CCS) projects in 2010.

Energy Production Credit (Refined coal and Indian coal). In total, these credits are estimated to be $27 million in 2010.

Refined Coal. This tax credit was created in the American Jobs Creation Act of 2004. Section 45 of the Internal Revenue Code, dealing with the refined coal production credit, provides guidance for this tax credit. In 2009, the section 45 tax credit was about $6.20 per ton of refined coal. To qualify for the credit, facilities had to meet two tests: (1) the facility must be placed in service after October 22, 2004 and before January 1, 2012; and, (2) facilities placed in service after Dec. 31, 2008 must produce refined coal that reduces emissions of nitrogen oxide by at least 20 percent and at least 40 percent of either sulfur dioxide or mercury compared to the emissions released when burning the original feedstock coal or comparable coal. The 40-percent reduction for sulfur dioxide or mercury is relaxed to a 20-percent reduction for facilities placed in service before Dec. 31, 2008. The lower tax credit per ton and the emission reduction requirements provided a much reduced set of opportunities compared to the prior coal synthetic fuel credit program. In 2009, only one refined coal facility operated in the U.S. and it produced only about 100,000 tons of refined coal. Two additional refined coal plants are scheduled to begin operating in 2010. The value of the refined coal tax credit is expected to be about $12 million in FY2010.

Indian Coal. The credit in 2010 for coal produced from reserves owned by an Indian tribe or held in trust by the U.S. for an Indian tribe was $2.20 per ton. The qualifying Kayenta mine in Arizona, produced about 7.7 million short tons in 2010 and earned a credit of about $15 million.

Alternative Fuel Production Credit (Synthetic coal, Coke and coke gas credit, and Steel Industry fuel). In total, these credits are estimated to be $100 million in FY 2010, all attributable to the coke and coke gas tax credit.

Synthetic coal. In FY 2007, the value of this credit for synthetic fuel produced from coal, and biomass, at $3.0 billion, made it the second largest tax expenditure. However under the Code, the credit was available only for synthetic fuel produced from coal and biomass sold up through 2007. Absent the tax credit, none of the 59 coal synthetic plants producing about 140 million tons of coal synfuel in 2007 remained profitable and all ceased production at the end of 2007.

Coke and coke gas. Currently the alternative fuel section 45 K credit (formerly section 29) is still available for coke and coke gas. The tax credit is about $30/ton of coke produced. Credit-eligible coke at any one facility many not exceed an average barrel-of-oil equivalent of 4,000 barrels per day, which is approximately 1,000 tons of coke per day, 360,000 tons of coke per year, and about $11 million in tax credit per plant. The original owner of the coke plant must still be its owner. There are 20 coke plants in the U.S. Some have been resold. The cumulative value of the tax credit is estimated to be $100 million in 2010. Some of this credit may be carried forward, depending upon profit prospects at specific coke plants.

Steel Industry Fuel. Steel industry fuel, which is included as a type of refined coal under the American Jobs Creation Act of 2004, is produced through a process of liquefying coal waste sludge, distributing the liquefied product on coal, and using the resulting mixture as a feedstock for the manufacture of coke. The credit in 2010 is $2.87 per ton of barrel-of-oil equivalent produced and sold. Coke plants can claim either the coke and coke gas credit or the steel industry fuel credit, but not both within a given year. Because the coke and coke gas credit is much larger per ton and usually covers more tons than the steel industry fuel credit, coke plants are choosing to take the coke and coke gas credit for now. The time period for the steel industry fuel credit is 1 year from the placed-in-service date, which can be as late as Dec. 31, 2011. Unless there is an extension to the credit period, there probably will be very little or no tax credit claimed for producing steel industry fuel.

Renewable-Related Tax Expenditures

At $8.2 billion, renewable-related tax expenditures in FY 2010 were more than double their FY 2007 $4.1 billion (Table 3) largely due to the expanding U.S. ethanol industry and expanded renewable production of electricity (Table 4). The Volumetric Ethanol Excise Tax Credit (VEETC) continued to be the largest renewable-related tax credit in FY 2010 as was the case in FY 2007.[15] This credit accounted for nearly 70 percent of tax expenditures directed at renewable sources of energy. Renewables accounted for 10 percent of total electricity production in 2010, primarily due to conventional hydroelectricity, which does not receive significant support from renewable-related tax expenditures. However, wind power has shown considerable growth in recent years, and in 2010 provided 2.3 percent of total U.S. electricity generation. Wind power has received significant support from The New Technology credit and the investment tax credit, as well as from the ARRA Section 1603 grant program that is discussed in the Direct Expenditures section of this chapter.

The Alcohol Fuel Credit is the sum of some smaller credits for which tax revenue losses have not been estimated. They include the Alcohol Mixture credit, the Alcohol Credit, and the Cellulosic Biofuel Credit. The Alcohol Fuel Credit also contains a Small Ethanol Producer Credit, which provides qualified producers with tax credit worth 10 cent per gallon of ethanol. To be eligible, the ethanol producer must have productive capacity less than 60 million gallons per year with the credit being applied to the first 15 million gallons.

In recent years this credit has seen dramatic swings in value. This occurred because tax specialists working for the pulp and paper industry realized that this credit could be applied to the mixture of black liquor with conventional fuels and the paper industry began claiming this credit in 2008. An estimated $4 billion went to the pulp and paper industry in 2009 due to this credit.[16] Subsequently, the eligibility of black liquor was removed and the value of the credits fell to $70 million in 2010.

The Volumetric Ethanol Excise Tax Credit (VEETC) is related to the Alcohol Fuel Credit. VEETC is not directed at ethanol producers but rather to facilities that blend ethanol with gasoline. At $5.7 billion, it is estimated to be the largest energy-related tax provision in FY 2010. In FY 2007, VEETC's had a value estimated at $3.5 billion and was also the largest energy-related revenue reduction in that year. Historically, alcohol fuels have received the greatest amount of federal financial support in the way of energy tax expenditures. In 2004 Section 301 of the American

[16] As a footnote to the alcohol fuels credit in the table which lists energy tax expenditures.
[17] Congressional Budget Office, http://www.cbo.gov/ftpdocs/108xx/doc10871/Chapter4.shtml.

Table 3. Renewable-related tax expenditures (million 2010 dollars)

Tax Expenditures	Type	FY 2007	FY 2010
Alcohol Fuel Credit	Credit	42	70
Excise Taxes/VEETC (ethanol fuel)	Credit	3,454	5,680
Alternative Fuel Production Credita	Credit	0	70
New Technology Credit (Energy Production Credit)	Credit	426	1,513
Energy Investment Credit	Credit	0	130
BioDiesel Producer Credit	Credit	0	490
BioDiesel and Small Agri-Biodiesel Producer Tax Credit	Credit	187	20
Credit for Holding Clean Renewable Energy Bondsb	Credit	21	70
Advanced Energy Property Credit	Credit	0	125
Total		**4,130**	**8,168**

Note: Totals may not equal sum of individual components due to independent rounding. The credit for business installation of qualified fuel cells and microturbine power plants is part of the investment tax credit (Section 48 of the code). The new technology credit included both the investment tax credit and the production tax credit in 2007. These were broken out in 2010 Similar to the alcohol fuel credit, the credit can be taken as an income tax credit or an excise tax credit. The small producer credit is only available as income tax credit. a The Alternative Fuel Production credit in 2007 went primarily to coal.
b In addition, the provision has outlay effects of (in millions of dollars): 2010; $10; 2011 $20; 2012 $30; 2013 $30; 2014 $30; 2015 $30; 2016 $30.
Sources: Office of Management and Budget, *Analytical Perspectives*, Budget of the United States Government, Fiscal Year s 2012 and 2009. Joint Committee on Taxation, Estimates of Federal Tax Expenditures for Fiscal Years 2010-2014, JCS-3-10 (Washington, DC, December 2010), Table 1, and budget documents from the Departments of Energy, Agriculture, Transportation, Treasury, Health and Human Services, Housing and Urban Development, the Environmental Protection Agency and the General Services Administration.

Table 4. U.S. renewable net generation (billion kilowatthours)

Fuel	1970	1980	1990	2000	2010
Conventional Hydroelectric	251.96	279.18	292.87	275.51	257.05
Wood	0.14	0.28	32.52	37.9	37.97
Waste	0.22	0.16	13.26	23.13	18.56
Geothermal	0.53	5.07	15.43	14.09	15.67
Solar/PV	NA	NA	0.37	0.49	1.30
Wind	NA	NA	2.79	5.59	94.65
Total	**251.84**	**284.69**	**357.24**	**356.48**	**425.20**

Source: U.S. Energy Information Administration, *Annual Energy Review, 2009*, DOE/EIA-0384 (2009) (Washington, DC, August 2010), Table 8.2a, and *Monthly Energy Review*, DOE/EIA-0035(2011/04) (Washington, DC, April 2011), Table 7.2a.

Jobs Creation Act (AJCA) (Public Law 108-357) instituted the VEETC as a replacement for the excise tax exemption for alcohol fuels. Initially, VEETC provided ethanol blenders/retailers with 51 cents per gallon of ethanol or $.0051 per percentage point of ethanol blended in motor gasoline. VEETC was extended by the Food, Conservation, and Energy Act of 2008 in Section 15331 of Public Law 110-234, although the rate was lowered to 45 cents per gallon. Public Law 110-246 also extended ethanol import duties and established new loan and grant programs. The Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Public Law 111-312) extended this credit (under IRC § 6426 and 6427) through the December 31, 2011. Ethanol production reached a record level of over 860,000 barrels per day in 2010.

Production Tax Credit In 2007, this credit, along with the energy Investment Tax Credit discussed below, were combined to form the New Technology Credit. This credit is frequently referred to as the as the Section 45 credit for its applicable provision in the Code. Section 242 of EPAct2005 expanded the tax credit to include incremental hydroelectric generation for a 10- year period at 1.8 cents per kilowatthour. EPAct2005 also extended the in-service date to qualify for the credit by 2 years for closed-loop biomass, geothermal, landfill gas, irrigation-produced power, landfill gas, municipal solid waste, open-loop biomass, and wind facilities. For qualifying open-loop biomass, geothermal, solar, and small irrigation power facilities, the credit period was expanded from 5 to 10 years. The production tax credit is estimated at $1.5 billion in FY 2010 versus $426 million in FY 2007. The Treasury Department forecasts that the production tax new technology credit will exceed $1.5 billion per year between 2011 and 2016. Wind power is estimated to be the primary beneficiary of the credit in FY 2010. Section 1603 of ARRA offered a cash grant in lieu of the production tax credit. This cash grant is discussed in the direct expenditure section later in this chapter.

Section 101 of the Energy Improvement and Extension Act of 2008 (Public Law 110-343) extended the placed-in-service date for the Production Tax Credit through December 31, 2009 (1 year) for wind and refined coal, and through December 31, 2010 (2 years) for other eligible sources (geothermal, some biomass, landfill gas, hydroelectric facilities) by amending Section 45 of the Code. EIEA added several new sources of energy to become eligible for the tax credit through December 31, 2016. Section 102 extended the credit to include marine and hydrokinetic energy; Section 103 extended the credit for solar energy, fuel cells, and microturbine properties through December 31, 2016; and, Section 108 included steel industry fuel as a renewable resource. Section 1101 of ARRA extended the eligibility dates for the credit for wind till January 1, 2013 and for other eligible facilities to January 1, 2014.

The Energy Investment Tax Credit is the alternative to the Production Tax Credit discussed above. Section 1102 of ARRA allowed for the election of an Investment Tax Credit in lieu of the production credit for businesses property placed in service facilities that produce electricity from solar and geothermal energy property, qualified fuel cell power plants, stationary microturbine power plants, geothermal heat pumps, small wind property and combined heat and power property after December 31, 2008. Investors can either chose the energy Investment Tax Credit, which generally provides for a 30-percent tax credit, or a 1.2-cent-per-kilowatt hour electricity Production Tax Credit.

The energy Investment Tax Credit offers a 30-percent energy tax credit for the purchase of qualified fuel cells with a maximum of $1,500 per 0.5 kilowatt of capacity, with a cap of $500 for each 0.5 kilowatt of capacity placed in service before October 24, 2008. A 10-percent credit is applied to qualifying stationary mircroturbine power plants. For qualified microturbine property, the nameplate capacity must be less than 2,000 kilowatts and the electricity-only efficiency must exceed 26 percent of International Standard Organization conditions. For qualified fuel cells, in order to qualify for the credit, the plant must have an electricity-only efficiency of 30 percent or more and capacity of at least 0.5 kilowatts of power generation. This provision is included in Section 48 of the Code.

Section 201 of the Tax Relief and Health Care Act (109-432) extended the credit through December 31, 2008. Section 103 of EIEA (Public Law 110-343) increased the credit limit for fuel cells from $500 to $1,500 per half kilowatt of capacity. EIEA extended the 30-percent investment tax credit (ITC) for solar power, previously set to expire on December 31, 2008, to December 31, 2016, and also eliminated the $2,000 cap on the tax credit. Solar power capacity has grown from 1,350 MWs in 2008 to 2,950 MWs in 2010.[17] EIA expects penetration of 10,420 MWs of solar capacity, including residential capacity, to be in place by 2016. Due to the desirability of the "grant" in lieu of the production tax credit and investment tax credit, $444 million, or 11 percent of the Section 1603 grant will be used to fund solar power projects in 2010. Section 104 of EIEA allowed for the energy investment credit to be applied to small wind property with a nameplate capacity of under 100 KW, with a termination date of December 31, 2016. Section 1103 of ARRA removed the cap on the ITC for small wind property that was established in EIEA and provided a tax credit for investments in generating, storing, conserving and distributing renewable energy, advanced battery technology, carbon capture and sequestration, and next-generation" technologies. Section 1122 of American Recovery and Reinvestment Act (Public Law 111-5) reinstated the $500-cap on fuel cell property expenditures per kilowatt of capacity.

The BioDiesel and Small Agri-Biodiesel Producer Tax Credit This credit has an expected value of $20 million in FY 2010. Section 313 of the AJCA created a $1-per-gallon credit for the sale of agri-biodiesel fuel. The credit applied to "virgin" agricultural feedstock such as soybeans or cotton-seed. A 50-cent credit is provided to biodiesel produced from recycled grease. Initially, the credit was due to expire at the end of 2006. Section 1344 of EPAct2005 extended the credit though the end of 2008. Section 202 of EIEA further extended the tax credit for biodiesel and renewable diesel to December 31, 2009. EIEA also increased the amount of the tax credit for biodiesel and renewable diesel produced from recycled feedstock from 50 cents to one dollar. ARRA also increased the amount of the tax credit for biodiesel and renewable diesel produced from recycled feedstock. Section 202 of ARRA amended Section 40A of the Code to extend the $1 per gallon production credit for biodiesel and the 10 cent per gallon credit for small biodiesel producers through December 31, 2009. Section 202 also extended the credit to biomass diesel. Section 701 of the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Public Law 111-312) retroactively extended the credit for biodiesel and renewable diesel for two years, through December 31, 2011. The Small Agri-Biodiesel Producer Tax Credit is purely an income tax credit and is worth 10-cents-per-gallon credit for up to 15 million gallons of agri-biodiesel produced by small producers.

Similar to the Alcohol Fuel Credit, the Biodiesel Credit can be taken as an income tax (under Code 40A) or as an excise tax credit (under Code 6426). The Biodiesel Tax Credit is limited to biodiesel not mixed with conventional diesel fuel. In lieu of the Biodiesel Tax Credit, there is an excise tax exemption. The value of this exemption was estimated at $490 million in 2010. The Biodiesel Fuel provisions include: (1) A Biodiesel Mixture Credit, which is $1.00 for each gallon of biodiesel and agri-diesel used by the taxpayer in the production of a qualified biodiesel mixture. This can be taken as a fuel which is a blend of biodiesel and diesel, as either an income tax credit or an excise tax credit.

[17] Energy Information Administration, *Annual Energy Outlook, 2011* DOE/EIA-0383(2011) (Washington, DC, April, 2011). http://www.eia.gov/forecasts/aeo/source_renewable.cfm,Table 6.

The Credit for Holding Clean Renewable Energy Bonds This credit was established under Section 1303 of EPAct2005, which provided for the issuance of Clean Renewable Energy Bonds (CREBs) through December 31, 2007. Purchases of CREBs bonds are to be provided with a tax credit in an amount intended to provide an after-tax return equal to that of a comparable taxable investment. In 2006, amendments added $400 million to CREBS and extended the deadline to December 31, 2007. New CREBs (NCREBs) were added in 2008 with an $800 million cap by Section 107 of EIEA. ARRA authorized an additional $1.6 billion from qualifying facilities. Whereas CREBS receive an exemption on interest, NCREBs are tax credit bonds.

Eligible participants in CREBs and NCREBS include: State and local governments, U.S. territories and possessions, the District of Columbia, Indian tribal governments, the National Rural Utilities Cooperative Finance Corporation, and mutual or cooperative electric entities. Prior to passage of EPAct2005, only investor-owned utilities (IOUs) qualified to receive tax incentives for producing electricity from renewable energy resources. In essence, CREBS allowed non-IOU electricity providers to issue interest free bonds to finance qualified energy projects. CREBS applied to the following sources of energy: wind, closed-loop biomass, open-loop biomass, geothermal, solar, small irrigation hydro, land fill gas, municipal solid waste, refined coal, and qualifying hydro. The value of the CREB tax credit is estimated at $21 million in FY 2007 and $70 million in 2010 in NCREB revenue losses in 2010. Section 202 of the Tax Relief and Health Care Act of 2006 (Public Law 109-432) increased the allocation of CREBs to $1.2 billion and extended the deadline to December 31, 2008. NCREBs effectively replaced CREBs in 2008, NCREBS do not have a defined expiration date. However, NCREBS allocations are valid for 3 years after which any unused authority reverts to the Treasury for reallocation.

Under NCREBS, the bond purchaser can claim a 70-percent tax credit versus the 100 percent tax credit claimable under CREBS. The initial allocation of NCREBs was capped at $800 million. Section 1111 of Public Law 111-5 increased the amount of funds available for NCREBs to $2.4 billion. Section 301 of the Hiring Incentives to Restore Employment Act 2010 (Public Law 111-147) offered issuers the option of converting NCREBs from tax credits to direct subsidy bonds similar to the Build America Bonds (BABs) whereby the NCREB issuer pays investors a taxable coupon and receives a direct payment from the U.S. Treasury. The U.S. Treasury estimated that the value of NCREBs was $70 million in 2010. There is, however, an associated outlay, which appears as a direct expenditure. NCREBS have an outlay equivalent effect of $10 million in 2010.

Advanced Energy Property Investment Tax Credit (Renewables) Section 1302 of ARRA established a credit providing a 30-percent credit for investment in eligible property used in a qualified advanced energy manufacturing project. This credit had a $125-million estimated value in FY 2010 directed at renewables. Renewables accounted for 69 percent of the recipients of this credit in 2010. Manufacturers of solar PV units, and wind towers, turbines, and blades were the largest recipients of this credit. A qualified advanced energy manufacturing project re-equips, expands, or establishes a manufacturing facility for the production of: (1) property designed to be used to produce energy from the sun, wind, geothermal deposits, or other renewable resources; (2) fuel cells, microturbines, or an energy storage system for use with electric or hybrid-electric motor vehicles; (3) electric grids to support the transmission of intermittent sources of renewable energy, including the storage of such energy; (4) property designed to capture and sequester carbon dioxide; (5) property designed to refine or blend renewable fuels (excluding fossil fuels) or to produce energy conservation technologies; (6) new qualified plug-in electric drive motor vehicles or components that are designed specifically for use with such vehicles; or, (7) other advanced energy property designed to reduce greenhouse gas emissions as may be determined by the Department of the Treasury. Eligible property must be depreciable (or amortizable) property used in a qualified advanced energy project and does not include property designed to manufacture equipment for use in the refining or blending of any transportation fuel other than renewable fuels. The credit is available only for projects certified by the Department of the Treasury (in consultation with the Department of Energy).

Table 5. NCREBs allocations by project type and issuer, 2009
(million 2010 dollars)

Approved Projects	Municipal Utilities # of projects	Municipal Utilities $	Co-ops # of projects	Co-ops $	Governments # of projects	Governments $	Total # of projects	Total $
Solar	13	55	4	70	694	714	711	839
Wind	9	395	8	161	30	63	47	619
Landfill Gas	0	0	0	0	0	0	0	0
Biomass	1	6	11	204	3	8	15	218
Hydropower	12	345	8	175	6	11	26	531
Geothermal	0	0	0	0	3	4	3	4
Total	**35**	**800**	**31**	**609**	**736**	**800**	**802**	**2,209**

Note: The above data are estimates of the value of NCREB supported projects, not the value of the subsidy. Totals may not equal sum of components due to independent rounding.
Source: National Renewable Energy Laboratory. These estimates are incomplete as they lack some private placements.

The Credit for Holding Qualified Energy Conservation Bonds EIEA provided for $800 million in funding for a new category of tax credit bonds to finance state, local, and tribal governments initiatives designed to reduce greenhouse gases. Qualified Energy Conservation Bonds (QECBs) do not have a termination date and are directed at qualified conservation purposes, such as projects which reduce energy consumption in publicly-owned buildings, green community programs, and rural development involving renewable energy production. Wind, biomass, geothermal, landfill gas, municipal solid waste, qualified hydroelectric power facilities were also made eligible for this credit as were certain energy research activities. A minimum of 70 percent of a state's allocation must be used for governmental purposes, which the remainder may be used to finance private activity projects. Section 1112 of ARRA increased the amount of funds available to finance QECBs by $2.4 billion to $3.2 billion. Section 301 of the Hiring Incentives to Restore Employment (HIRE) Act 2010, (Public Law 111-147) gave issuers the option of converging QECBs from tax credit bonds to direct subsidy bonds similar to BABs whereby the QECB issuer pays investors a taxable coupon and receives a direct payment from the U.S. Treasury. The U.S. Treasury estimates the income tax effect of QECBs will be $10 million in FY 2011, having had no value in prior years. There is, however, an associated outlay, which appears as a direct expenditure.

Natural Gas and Petroleum-Related Tax Expenditures

Natural gas and petroleum-related tax expenditures grew from $1.9 billion in FY 2007 to $2.7 billion in FY 2010 (Table 6). Natural gas-fired generation accounted for an estimated 24 percent of total electricity production in 2010, while oil provided less than one percent of electricity generation.

The Expensing of Exploration and Development Costs Deferral Federal tax law allows energy producers, principally oil and natural gas producers, to expense exploration and development (E&D) expenditures rather than capitalize and depreciate them over time. In FY 2010, this tax expenditure estimate, at $400 million, was down from the $551 million estimated for FY 2007.

Table 6. Natural gas and petroleum related tax expenditures (million 2010 dollars)

Tax Expenditures	Type	FY 2007	FY 2010
Expensing of Exploration and Development Costs	Deferral	551	400
Credit for Business Installation of Qualified Fuel Cells and Stationary Microturbine Power Plants	Credit	83	0
Excess of Percentage over Cost Depletion	Deferral	822	980
Amortize All Geological and Geophysical Expenditures over 2 Years	Deferral	52	150
Tax Credit and Deduction for Clean-Burning Vehicles	Credit	270	250
Natural Gas Distribution Pipelines Treated as 15-year Property	Deferral	62	120
Exception from Passive Loss Limitation for Working Interests in Oil and Gas Properties	Deferral	31	30
Temporary 50 Percentage Expensing for Equipment Used in the Refining of Liquid Fuels	Deferral	31	760
Expensing of Capital Costs with Respect to Complying with EPA Sulfur Regulations	Deferral	10	0
Total		**1,914**	**2,690**

Note: Totals may not equal sum of components due to independent rounding. A portion of the tax expenditures, but indeterminate amount, of the Excess of Percentage over Cost Depletion and the Expensing of exploration and Development Costs goes to coal.
Sources: Office of Management and Budget, *Analytical Perspectives*, Budget of the United States Government, Fiscal Year s 2012 and 2009. Joint Committee on Taxation, Estimates of Federal Tax Expenditures for Fiscal Years 2010-2014, JCS-3-10 (Washington, DC, December 2010), Table 1, and budget documents from the Departments of Energy, Agriculture, Transportation, Treasury, Health and Human Services, Housing and Urban Development, the Environmental Protection Agency and the General Services Administration.

The Excess of Percentage over Cost Depletion Deferral Percentage depletion for oil and gas properties became law with the passage of the 1926 Revenue Act Under cost depletion, the annual deduction is equal to the non-recovered cost of acquisition and development of the resource times the proportion of the resource removed during that year. Under percentage depletion, taxpayers deduct a percentage of gross income from resource production. In FY 2010 this deferral had a value of $980 versus $822 million in FY 2007. The Tax Relief and Health Care Act of 2006 (Public Law 109-342) extended for two years the present-law taxable income limitation on the provision for marginal production (through taxable years beginning on or before December 31, 2007). Section 706, of Public Law 111-312 extended the use of the limitation on percentage depletion for oil and gas from marginal wells through December 31, 2011.

The Amortization of all Geological and Geophysical Expenditures Over 2 Years This provision provides that geological and geophysical (G&G) expenditures for domestic exploration of oil and natural gas be amortized over 2 years. This tax expenditure was enacted in EPAct2005, Section 1329. This tax expenditure is estimated to be worth $150 million in 2010 versus $52 million in FY 2007. Section 503 of the Tax Increase Prevention and Reconciliation Act of 2005 (Public Law 109-222) scaled back this benefit by lengthening the amortization period for integrated petroleum companies to 5 years. A major integrated oil company is defined as a producer of crude oil which has an average daily worldwide production of crude oil of at least 500,000 barrels for the taxable year, which has gross receipts in excess of $1 billion for its last taxable year ending during calendar year 2005, and has an ownership interest of 15 percent or more in a refiner. The geological and geophysical deduction for major integrated oil companies was further amended by the Tax Increase Prevention and Reconciliation Act (Public Law 109-222) signed on May 17, 2006. Major integrated oil companies are required to substitute 5 years for the 24-month amortization period.

The Tax Credit and Deduction for Clean-Fuel, Alternative Fuel, and Electric Vehicles was initiated under Section 1913 of the Energy Policy Act of 1992 (EPACT1992, Public Law 108-486) The value of the tax credit is estimated at $250 million in FY 2010 and $270 million in FY 2007. Subsequent legislation has further expanded this credit. Title II Section 205 of EIEA provided a tax credit for the purchase of new, qualified plug-in electric drive motor vehicles. Section 1141 of ARRA modified the law for PHEVs purchased after December 31, 2009. Section 1143 of ARRA provided a tax credit for PHEV conversion kits equal to 10 percent of converting the vehicle if placed in service after February 17, 2009 and before December 31, 2011. Section 1144, of ARRA, allowed for the treatment of alternative motor vehicle as a personal credit against the alternative minimum tax. Section 1123 of ARRA increased the credit for refueling properties. Section 711 of the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010, (Public Law 111-312) extended this credit for two years.

The Natural Gas Distribution Pipelines Treated as 15-Year Property Deferral This deferral was established by EPAct2005 (Section 1308) and is estimated to have a value of $120 million in FY 2010 and a value of $62 million in FY 2007. Section 1308 accelerated the recovery period for natural gas distribution lines from 20 years to 15 years. This provision, which began in 2005, ended in 2010.

The Exception from Passive Loss Limitation for Working Interest in Oil and Natural Gas Properties Deferral The value of this tax credit in FY 2010 is $30 million versus an estimated at $31 million in FY 2007. The exception allows owners of working interests to offset their losses from passive activities against active income. Under normal rules, passive losses that remain after being netted against passive income can only be carried forward to apply against passive income in future years. The exception from passive loss limitation provision on oil and natural gas properties applies principally to partnerships and individuals rather than corporations.

The Temporary 50-Percent Expensing of Equipment Used in the Refining of Liquid Fuels Deferral This provision was established under Section 1323 of EPAct2005 and expires on December 31, 2011. This provision is available for property, which is placed in service before January 1, 2014, which a binding construction contract has been entered into before January 1, 2010. It allows for an accelerated recovery of the cost of certain refinery investment under Section 179 C of the Code by allowing a partial expensing of the cost. It is estimated to have grown considerably from $31 million in FY 2007 to an estimated $760 million in 2010. EIEA extended this provision through December 31, 2013.

The Expensing of Capital Costs with Respect to Complying with Environmental Protection Agency Sulfur Regulations Deferral This provision was provided for in Section 1324 of EPAct2005. It allows small refiners (defined to employ less than 1,500 employees and have less than 205,000 barrels per day of total refining capacity) to deduct 75 percent of qualified capital costs related to complying with EPA sulfur regulations. "Qualified costs include expenditures for the construction of new process units or the dismantling and reconstruction of existing process units to be used in the production of low sulfur diesel fuel, associated adjacent or offsite equipment (including tankage, catalyst, and power supply), engineering, construction period interest, and site work." The percentage of costs allowed is reduced for amounts in excess of 155,000 barrels a day of total refinery capacity. The estimated value of this tax expenditure is $10 million in FY 2007 and no value in FY 2010 as this credit expired December 31, 2009.

The Enhanced Oil Recovery Credit This credit enables taxpayers to claim a general business credit for enhanced oil recovery (EOR) investment. The EOR credit applies to 15 percent of the cost of one or more tertiary recovery methods. EOR involves the extraction of oil from a petroleum reservoir greater than that which can be economically recovered by conventional primary and secondary methods. The credit also applies to the construction of a natural gas treatment plant in Alaska to process Alaskan natural gas for pipeline transportation. The credit phases out when the inflation-adjusted price of oil exceeds $28 per barrel (in 1991 dollars) in the preceding year. Due to the average price of oil in 2010 being above the cap, the value of this credit was zero in FY 2010.

Nuclear-Related Tax Expenditures

EPAct 2005 extended the Production Tax Credit to approved new nuclear facilities. The credit for the production from advanced nuclear power facilities had no value in 2010 as this credit does not go into effect until qualifying new nuclear power plants produce electricity (Table 7). The Code was also modified to eliminate impediments to the transfer of ownership of nuclear plants arising from the tax treatment of qualified and nonqualified nuclear decommissioning trust funds. Because these particular revisions to the Code were not itemized by OMB, EIA relied on the estimates of the value of these tax expenditures prepared by the JCT. A small portion of the advanced energy property tax credit was also directed to nuclear facilities.

The Credit for the Production of Advanced Nuclear This credit was established under EPAct2005 (Section 1306). Over the Treasury Department's 2010 through 2015 tax expenditure forecast horizon, the value of this credit remains at zero as no eligible nuclear power plants are expected to come on line during that time frame. The credit is worth 1.8 cents per kilowatthour of electricity produced during the first 8 years of operation from plants having a Nuclear Regulatory Commission (NRC) approved design. The legislation limits the capacity for this production tax credit (PTC) to 6,000 megawatts. The Secretary of Energy is responsible for the allocation of this credit by capacity. The provision has an additional limitation of $125 million per thousand megawatts of capacity per taxable year.

The Modification to Special Rules for Nuclear Decommissioning Costs Section 1310 of EPAct2005 changed the IRS rules for qualified nuclear decommissioning trust funds by repealing the cost of service requirement for contributions to a qualified decommissioning trust fund created under IRC Section 468A. This change permitted full present value funding of a qualified nuclear decommissioning fund and the transfer of pre-1984 decommissioning funds held in nonqualified trusts. The provision also required that nuclear plant owners obtain a new schedule of ruling amounts from the IRS upon renewal of a plant's operating license by the NRC. In FY 2010, the estimated value of this tax expenditure is $900 million versus $600 in FY 2007. Modification of section 468A of the Code was done to eliminate an impediment to nuclear plant sales arising from the structural change in the electric utility industry.

Advanced Energy Property Credit (Nuclear) By early 2010, there were two nuclear recipients of this credit. Alstom will establish a new turbine manufacturing facility designed to manufacture the world's largest steam turbines, with unit output up to 1700 MW. The new facility will focus on turbines used in advanced nuclear power plants, nd retrofitting existing turbines in nuclear power plants with higher efficiency technologies. The other recipient, Shaw Modular Solutions LLC, will fabricate modules used in advanced, passively-safe, nuclear stations. This credit had an estimated $8 million value in 2010 (Table 9).

Table 7. Nuclear transformation-related tax expenditures (million 2010 dollars)

Tax Expenditures	Type	FY 2007	FY 2010
Credit for Production from Advanced Nuclear Power Facilities	Credit	0	0
Nuclear Decommissioning		600	900
Advanced Energy Property Credit	Credit	0	8
Total		**600**	**908**

Notes: Totals may not equal sum of components due to independent rounding. The Advanced Energy Property Credit was allocated by fuel using data appearing at: http://www.whitehouse.gov/the-press-office/president-obama-awards-23-billion-new-clean-tech-manufacturing-jobs.
Sources: Office of Management and Budget, *Analytical Perspectives*, Budget of the United States Government, Fiscal Year s 2012 and 2009. Joint Committee on Taxation, Estimates of Federal Tax Expenditures for Fiscal Years 2010-2014, JCS-3-10 (Washington, DC, December 2010), Table 1, and budget documents from the Departments of Energy, Agriculture, Transportation, Treasury, Health and Human Services, Housing and Urban Development, the Environmental Protection Agency and the General Services Administration.

Energy Efficiency and Conservation-Related Tax Expenditures

Recently, efficiency and conservation-related tax expenditures have become more prominent tools in shaping energy policy. These tax provisions are primarily directed at individuals (residential) and commercial taxpayers in the form of tax expense deductions, tax credits, or exclusion of certain receipts from gross income. Conservation-related tax expenditures are estimated to have increased by nearly 400 percent since FY 2007, having grown from $832 million to $3.9 billion in FY 2010 (Table 8). The credit for energy efficiency improvements of existing homes is the most prominent conservation tax provision, having grown from $395 million in 2007 to $3.2 billion in 2010. In 2010, it accounted for 82 percent of total conservation-related tax expenditures.

Table 8. Conservation, efficiency, and end-use tax expenditures (million 2010 dollars)

Tax Expenditures	Type	FY 2007	FY 2010
Credit for Energy Efficiency Improvements of Existing Homes	Credit	395	3,190
Allowance of Deduction for Certain Energy Efficient Commercial Building Property	Deduction	198	60
Exclusion for Utility-Sponsored Conservation Measures	Exemption	125	220
Credit for Energy Efficient Appliances	Credit	83	150
Qualified Energy Conservation Bonds	Credit	0	0
Credit for Construction of New Energy-Efficient Homes	Credit	21	20
30-Percent Credit for Residential Purchases/Installations of Solar and Fuel Cells	Credit	10	220
Advanced Energy Property Credit	Credit	0	39
Total		832	3,899

Notes: Totals may not equal sum of components due to independent rounding. The advanced energy property credit was allocated by fuel using data appearing in: http://www.whitehouse.gov/the-press-office/president-obama-awards-23-billion-new-clean-tech-manufacturing-jobs
Sources: Office of Management and Budget, Analytical Perspectives, Budget of the United States Government, Fiscal Year s 2012 and 2009. Joint Committee on Taxation, Estimates of Federal Tax Expenditures for Fiscal Years 2010-2014, JCS-3-10 (Washington, DC, December 2010), Table 1, and budget documents from the Departments of Energy, Agriculture, Transportation, Treasury, Health and Human Services, Housing and Urban Development, the Environmental Protection Agency and the General Services Administration.

The Credit for Energy-Efficiency Improvements of Existing Homes Established in EPAct2005, Section 1333, this credit had an estimated value of $3.2 billion in FY 2010 up sharply from an estimated $395 million in FY 2007, with most of this growth traceable to the higher credit amounts made available due to ARRA. This credit applies to windows, furnaces, boilers, furnace fans, and building envelope components, such as exterior doors and any metal roof that has appropriated pigmented coatings. Initially, the credit was available to houses constructed before December 31, 2007 (the credit expires on December 31, 2011).

Sections 103 through 106 reinstated the credits for efficient water heaters, boilers, furnaces, heat pumps, air conditioners, and building shell equipment, such as windows, doors, weather stripping, and insulation. Section 1121 of ARRA (Public Law 111-5) increased the tax credit to 30 percent (from 10 percent) of the cost of all qualifying improvements and raised the maximum credit limit to $1,500 for improvements placed in service in 2009 and 2010. ARRA also extended the tax credits for improvements to existing homes through December 31, 2010. Section 710 of the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Public Law 111-312) extended the credit one year, although reestablishing pre-ARRA limitations and Standards. Currently, the credit is equal to 10 percent of the costs of qualified property up to $500 per taxpayer for all taxable years. No more than $200 may be attributable to expenditures on windows.

The Allowance of Deduction for Certain Energy-Efficient Commercial Building Property This deduction was established under EPAct2005 (Section 1331). Taxpayers are permitted to take a deduction of $1.80 per square foot on new construction built after December 31, 2005, and before December 31, 2007, if annual energy and power costs of interior lighting systems, heating, cooling, ventilation, and hot water systems are 50 percent or more below the standards set by the American Society of Heating, Refrigerating (ASHRAE). The value of this credit is estimated at $60 million for FY 2010, a marked decline from the estimated $198 million for FY 2007. Section 201 of The Tax Relief and Health Care Act of 2006 (Public Law 109-432) extended the credit to December 31, 2008. Section 303 of EIEA extended this tax deduction through December 31, 2013.

The Exclusion for Utility-Sponsored Conservation Measures This exclusion was established by Section 136 of EPAct1992. Section 136 amended the Code to provide tax benefits to individual consumers for participating in utility-sponsored energy conservation programs. Payments to individual consumers from utilities for investing in energy conversation measures may be excluded from gross income for purposes of calculating taxable income. For example, utilities engaged in demand-side management activities often pay rebates to consumers who purchase more efficient heating or cooling equipment in order to reduce the consumption of natural gas and electricity. The value of this credit is estimated at $125 million for FY 2007 and $220 million for FY 2010.

The Credit for Efficient Appliances Established by Section 1334 of EPAct2005, this credit has an estimated value of $150 million in FY 2010 versus an estimated $83 million for FY 2007. Appliance manufacturers receive a tax credit for manufacturing energy-efficient dishwashers, clothes washers, and refrigerators. The tax credit is limited to 2 percent of the gross revenue for the 3 taxable years prior to the taxable year in which the credit occurs. Initially, the credits applied to appliances manufactured between December 31, 2005, and January 1, 2008. Section 305 of EIEA extended the credit for energy efficient appliances that are a certain percent more efficient than the prevailing federal standard. The duration and value of the credit vary by appliance and the level of efficiency achieved. Section 709 of the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Public Law 111-312) extended this credit (under IRC § 45M) through the end of 2011. Public Law 111-312 raised the credit level to 4 percent of the average annual gross receipts.

The Credit for Construction of New Energy-Efficient Homes This credit was established under Section 1332 of EPAct2005. It provides home builders a tax credit of $2,000 for the construction of a new energy-efficient home. To qualify, the home must achieve energy savings of 50 percent over a comparable unit constructed in conformance with the International Energy Conservation Code. The value of this credit is estimated at $21 million for FY 2007 and $20 million in FY 2010. Initially, the credit was available to houses constructed before December 31, 2007. However, Section 304 of EIEA extended the $2,000 credit for new homes through 2009 that are 50 percent more efficient than specified in the International Conservation Code. Section 703 of the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Public Law 111-312) extended this credit (under IRC § 45L) through the end of 2011.

The 30-Percent Credit for Residential Purchases/Installations of Solar and Fuel Cells has an estimated value of $220 million in 2010 and $10 million in FY 2007. Section 1335 of EPAct2005 established a 30-percent personal tax credit, not to exceed $2,000, for the purchase of solar electric and solar water heating property. A 30-percent tax credit up to $500 per 0.5 kilowatt (kW) of capacity is also available for fuel cells. The fuel cell provision of EPAct2005 was due to expire at the end of 2007. It was extended through the end of calendar year 2008 by Section 206 of the Tax Relief and Health Care Act of 2006 (Public Law 109-432). Section 106 of EIEA removed the cap on the tax credit for purchase of residential solar photovoltaic installations and extended the credit out to December 31, 2016. Section 104 of EIEA extended the credit to include small wind properties (under 100 kilowatts) through December 31, 2016; and, Section 105 extended the tax credit to include geothermal heat pumps through December 31, 2016. Section 1122 of ARRA removed some of the previous maximum amounts and allowed a credit equal to 30 percent of the cost of qualified property.

Advanced Energy Property Credit (Conservation) This credit had an estimated value of $39 million in 2010. The largest investment in conservation involved Texas Instruments re-equipping a facility and purchasing equipment to produce 300mm wafers for advanced power management semiconductors. Another significant investment involved GE, which is using the credit to re-equip a facility to manufacture new Energy Star compliant appliances – specifically, Ultra-high Efficient Dishwashers. This new dishwasher line is expected to exceed the future, anticipated ENERGY STAR standards for residential dishwashers.

Electricity Transmission-Related Tax Expenditures

Overall, it is estimated that the electric power industry tax expenditures in FY 2010 have a value of a $58 million, down considerably from the estimated value of $696 million in 2007 (Table 9). This decline is largely due to a $685-million reversal in the value of the deferred gain from the disposition of transmission property to implement FERC restructuring policy.

Table 9. Electricity transmission-related tax expenditures (million 2010 dollars)

Tax Expenditures	Type	FY 2007	FY 2010
Deferral of Gain from Disposal of Transmission Property to Implement FERC Restructuring Policy	Deferral	635	(50)
Transmission Property Treated as a 15-Year Property	Expense Deduction	19	100
5-Year Net Operating Loss Carryover for Transmission Investment	Enhanced Tax Attribute	43	0
Advanced Energy Property Credit	Credit	0	8
Total		**696**	**58**

Note: Totals may not equal sum of individual components due to independent rounding. For 2010, the Credit for Business Installation of Qualified Fuel Cells and Microturbine Power Plants is part of the investment tax credit (Section 48 of the code).
Sources: Office of Management and Budget, *Analytical Perspectives*, Budget of the United States Government, Fiscal Year s 2012 and 2009. Joint Committee on Taxation, Estimates of Federal Tax Expenditures for Fiscal Years 2010-2014, JCS-3-10 (Washington, DC, December 2010), Table 1, and budget documents from the Departments of Energy, Agriculture, Transportation, Treasury, Health and Human Services, Housing and Urban Development, the Environmental Protection Agency and the General Services Administration.

The Deferral of Gain from Disposition of Transmission Property to Implement Federal Energy Regulatory Commission (FERC) Restructuring Policy This provision has in previous years been the largest tax credit directly affecting the provision of electricity, as opposed to an electricity-related fuel. However, the value of this expenditure was a negative $50-million in 2010, as previously deferred taxes came due. The FY 2007 value of this tax expenditure was estimated at $635 million. This tax expenditure was provided for in Section 1305 of EPAct2005. The Treasury Department projects a negative $2.5 billion cumulative deferral between 2010 and 2015. Section 109 of Public Law 110-343 extended the credit to December 31, 2009. Section 705 of the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Public Law 111-312) extended this credit through the end of 2011.

The Transmission Property Treated as 15-year Property This provision was set forth in Section 1308 of EPAct2005 and modified Section 168 of the Code by shortening the recovery period from 20 to 15 years for eligible assets used in the transmission of electricity following sale of the property or related land improvements. Specifically, this applies to Section 1245 property, (i.e., personal property and real property subject to depreciation or amortization) used in the transmission of electricity that is energized at 69 kilovolts or more. The provision applies to transmission facilities placed in service by the taxpayer after April 11, 2005, but excludes any transmission facilities for which the taxpayer or related party had entered into a binding construction contract for or initiated self-construction on or before April 11, 2005. This provision expired on December 31, 2009.

The 5-Year Net Operating Loss Carryover for Electric Transmission Equipment Section 1311 of EPAct 2005 implemented this provision that has allowed taxpayers the option to carry back a net operating loss (NOL) for each of the 5 years prior to the tax year in which the loss was incurred. The amount of NOL that may be carried back may not exceed 20 percent of the value of investment made in qualified transmission and pollution control facilities in the preceding year. There was no estimated value of this tax benefit for FY 2010 as it expired at the end of 2008. The value of this carryover was estimated at $43 million for FY 2007.

Direct Expenditures

Until recently energy-related direct expenditures were dominated by funding for LIHEAP and weatherization programs. Expenditures for these programs have increased in recent years reflecting increased spending to assist low income consumers with rising energy costs. In the wake of the credit crisis and a sharp economic downturn, the federal government launched several new energy-specific direct expenditure programs that are largely directed at renewables and energy conservation. Section 1603 of ARRA, which provides a grant option in lieu of long-standing PTC and ITCs for qualifying sources of renewable energy, is the most prominent of these new programs. Energy specific direct expenditures in FY 2007 and FY 2010 by federal agencies are summarized in Table 10. Descriptions of each direct expenditure program are provided below.

Table 10. Direct expenditures in energy (million 2010 dollars)

Department	FY2007	FY2010
Department of Energy	273	4,239
Office of Energy Efficiency and Renewable Energy	273	3,722
Office of Fossil Energy	0	42
Office of Electricity and Energy Reliability	0	448
Other DOE Offices	0	27
Department of Labor	0	46
Department of Transportation	0	121
Environmental Protection Agency	0	144
General Services Administration	0	50
Department of Housing and Urban Development	0	65
Department of Health and Human Services	2,276	5,000
Department of Agriculture	206	385
Department of Treasury	0	4,250
Total	**2,755**	**14,295**

Note: Totals may not equal sum of components due to independent rounding.
Source: Department of Energy, Department of Agriculture, and Department of Health and Human Services Budgetary documents.

Energy-Specific Direct Expenditure Program Descriptions

Department of Energy

The Department of Energy spent $4.2 billion in FY 2010 on energy-related direct expenditures, nearly $4 billion of which was from ARRA-appropriated funds. The direct expenditures were spread among various programs under the offices of Energy Efficiency and Renewable Energy, Fossil Energy, and Electricity and Energy Reliability. The Office of Energy Efficiency and Renewable Energy spent $3.7 billion in FY 2010 on direct expenditures related to energy – the largest of program offices' expenditures. Approximately $3 billion was spent on conservation and efficiency programs, with the remainder spent on programs related to various energy technologies.

Weatherization and Intergovernmental Activities (WIA): The Department of Energy's Office of Energy Efficiency and Renewable Energy (EERE) funds and supports programs fall under the umbrella of Weatherization and Intergovernmental Activities. Within this group are three budget-funded subprograms: Weatherization Assistance Grants, the State Energy program, Tribal Energy Activities, and the Energy Efficiency Conservation Block Grant program. Total appropriation for the Weatherization and Intergovernmental Activities programs (WIP) in FY2010 were $270 million, with $210 million allocated to WIA, $50 million to State Energy programs and $10 million to Tribal Energy Activities. In FY 2010, WIP had $258 million in actual expenditures from the budget appropriated funds. The original FY2009 appropriation for the entire program was $516 million, but ARRA appropriated an additional $11.6 billion to this program, with $5 billion for Weatherization Assistance Grants, $3.1 billion for State Energy programs, and $3.2 billion for Energy Conservation Block grants. Of the ARRA-appropriated funds, $2.6 billion was spent in FY 2010.

Subprogram: Weatherization Assistance Grants are offered by DOE to assist low-income households in weatherizing their homes. Both single and multi-family residences are eligible for the program. This program involves implementing efficiency measures that range from sealing and caulking to the installation of energy efficient appliances. By increasing home energy efficiency, this program helps eligible recipients to reduce their energy usage thereby lowering heating and cooling costs. DOE administers this program by funneling funding to state-based weatherization programs.

The weatherization program received $450 million in FY 2009 and an additional $5 billion from ARRA for the weatherization of 590,000 residences. In 2009, $4.73 billion was awarded in the form of grants at the State, territory or Tribe level, but both spending levels and weatherization progress fell far short of DOE goals. A significant impediment to the program's implementation involved a dispute which arose between the federal government and States over language in ARRA that related to wage rates of laborers paid by weatherization funds. ARRA set forth a requirement that Davis-Bacon wage rates apply to ARRA funded projects. In implementing the weatherization program, the Department of Labor began conducting surveys to determine appropriate wage rates for weatherization work. DOL later joined with DOE to issues a memorandum recommending that State and local agencies move the program forward prior to the completion of the wage survey in order to expedite weatherization projects. Upon completion of the survey, worker payments could be adjusted retroactively, if necessary. However, many state agencies decided not to undertake weatherization projects until after the rate issue was resolved for fear of possible legal complications and burdens that might arise with any retroactive wage adjustment. Due to these delays, most recipients of ARRA weatherization funds did not begin to draw upon funds until the end of 2009 and into the beginning on 2010.

Subprogram: The State Energy poffers grants to States for energy efficiency, renewable energy, and new technology programs and usage. The States administer these programs and match the DOE grant at a level of 20 percent. Formula grants are also offered for energy priority and goal-setting at the State level. DOE's stated goals for these programs are to reduce energy costs, to increase energy efficiency, to improve reliability, to increase the usage of renewable and alternative energy sources, and to promote economic growth.

Subprogram: The Tribal Energy program, in existence since 2002, funds a competitive grant program for Indian tribes to research, develop and deploy renewable energy resources on tribal lands. Additionally, grants offered by the program fund energy efficiency improvements and education as well as training opportunities. Past projects include feasibility studies for the development of wind and solar resources.

Subprogram: The Energy Efficiency and Conservation Block Grant (EECBG) program was a new program under ARRA in 2009. The program invests in the cheapest, cleanest, most reliable energy technologies available—efficiency and conservation—which can be deployed immediately. Through $3.2 billion in formula and competitive grants to over 2,300 U.S. cities, counties, states, territories, and Indian tribes, EECBG empowers communities to make strategic investments to meet the nation's long-term goals for energy independence and leadership climate change.

Renewable Energy Production Incentive: The Renewable Energy Production Incentive (REPI) was part of an integrated strategy to promote the generation of electricity from renewable energy sources and to advance renewable energy technologies. It provided financial incentive payments for electricity produced and sold by qualifying renewable energy generation facilities. Qualifying facilities included: State and local government entities (such as municipal utilities and Tribal governments) and not-for-profit electric cooperatives. The REPI provided not-for-profit entities with a financial incentive to invest in renewable generation technologies much like the incentive provided to for-profit entities eligible for Section 45 PTC. Qualifying facilities were to use solar, wind, geothermal (with certain restrictions as contained in the rulemaking), or closed-loop biomass (except for municipal solid waste combustion) generation technologies. In FY 2007, the value of REPI was estimated to be $5 million. However, REPI received no funds under the FY 2010 budget.

Department of Labor

Training and Employment Services: Under ARRA, the Department of Labor was appropriated $500 million to the Training and Employment Services program for research, labor exchange, and job training projects that prepare workers for careers in energy efficiency and renewable energy. The program spent approximately $46 million of the total appropriation in FY 2010.

Department of Transportation

Transit Investments for Greenhouse Gas and Energy Reduction (TIGGER) program: In FY 2010, the Department of Transportation spent approximately $121 million on the Transit Investments for Greenhouse Gas and Energy Reduction (TIGGER) program, with approximately a third of the spending from ARRA funds. The TIGGER program works directly with public transit agencies to implement new strategies for reducing greenhouse gas emissions or reduce energy usage from their operations. These strategies can be implemented through operational or technological enhancements or innovations.

Environmental Protection Agency

Diesel Emissions Reduction Program: In FY 2010, the Environmental Protection Agency (EPA) spent a total of $144 million on the Diesel Emissions Reduction program, with less than $0.1 million coming from ARRA funds. As part of the Energy Policy Act of 2005, the Diesel Emissions Reduction Act (DERA) authorizes funding of up to $200 million annually for FY 2007 through FY 2011 to help fleet owners reduce diesel emissions. Under this act, EPA has developed four programs.

Subprogram: The National Clean Diesel Funding Assistance program awards competitive grants to fund projects that implement EPA or California Air Resources Board (CARB) verified and certified diesel emission reduction technologies.

Subprogram: The National Clean Diesel Emerging Technologies program awards competitive grants for projects that spur innovation in reducing diesel emissions through the use, development and commercialization of emerging technologies. Up to 10 percent of the national funds may be spent on emerging technologies.

Subprogram: SmartWay Clean Diesel Finance program issues competitive grants to establish national low-cost revolving loans or other innovative financing programs that help vehicle fleets reduce diesel emissions.

Subprogram: State Clean Diesel Grant program allocates funds to participating states to implement grant and loan programs for clean diesel projects. Base funding is distributed to states using a specific formula based on participation, and incentive funding is available for any states that match their base funding. Currently all 50 States and the District of Columbia are participating in this program.

General Services Administration

Fuel-efficient vehicles: Under ARRA, the General Services Administration (GSA) was appropriated $300 million for the procurement of energy-efficiency motor vehicles for use in federal agency fleets. Eligible vehicles include hybrids, plug-in hybrids, and pure electric vehicles. The GSA spent approximately $50 million of the total appropriation in FY 2010.

Department of Housing and Urban Development

Green Retrofits for Multifamily Housing (also known as the Energy Efficiency Assisted Housing Retrofits).This program, created under ARRA, is administered by the Housing and Urban Development agency's (HUD) office of Affordable Housing Preservation. Funding for FY2009 was $250 million and was to be disbursed in a multi-year schedule. Funding is provided up to $15,000 per residential unit and the total amount of appropriations is expected to be used to retrofit upwards of 25,000 units. Retrofit and efficiency projects that are eligible under this program include the installation of efficient heating and cooling systems and appliances, and the upgrade of units to reduce water usage, increase indoor air quality and provide other various environmental benefits. Funds were be dispersed via a competitive loan and grant program, and have ranged from small amounts up to almost $4 million for a single property. Approximate expenditures for FY 2010 totaled $65 million.

Department of Health and Human Services

Low Income Home Energy Assistance Program: For FY 2010, the Department of Health and Human Services (DHHS) LIHEAP spent of $5 billion dollars (Table 10). Of this $5 billion, $4.5 billion was directed at formula grants while $590 million was set aside in a contingency fund to be used in the case of extreme energy price swings or other unprecedented event that affects LIHEAP recipients. This level of funding is the same as the original FY 2009 appropriations, and LIHEAP received no additional funding under ARRA.

LIHEAP was established as a block grant program in 1981 for the purpose of subsidizing heating and cooling costs for low-income households. Because LIHEAP is a block grant, LIHEAP grants are provided to States, territories and Tribes who are then free to administer the program within the requirements of federal law. Federal LIHEAP requirements set eligibility at 150 percent of the federal poverty level or 60 percent of the State's median income, but do have some flexibility and allow "maximum policy discretion to grantees." Other federal rules include coordination with DOE's Weatherization Assistance program, annual audits, and outreach activities. Heating and/or cooling assistance funds may be paid directly to eligible households or to retail energy suppliers in the form of cash or vouchers but in practice the majority of funds are paid directly to the energy providers. In addition to funds used for heating and/or cooling assistance, money must be set aside by recipients for energy crisis intervention and has been released for natural disasters, such as Hurricane Katrina in 2005.

Department of Agriculture

Rural Business Service Programs and Rural Utility Services High Energy Cost Grant Program: These programs fall under the USDA's Rural Business-Cooperative Service (RBS) and Rural Utility Service (RUS), and are intended to promote clean energy in rural business environments and subsidize energy consumption in high-cost rural areas. FY 2010 expenditures were $105 million for Rural Business Services and $18 million for the High Energy Cost Grant program.

Subprogram: The Rural Energy for America joint program between USDA and DOE promotes energy efficiency and renewable energy usage by rural agricultural producers and small rural businesses. The program is broken into two parts, the first of which provides grants for renewable energy development and energy audits. Under this part of the program, eligible rural entities include units of government (such as local or Tribal governments), rural electric cooperatives, public power entities, land grant colleges, universities or other institutions of higher learning or any other similar entity to be defined by the USDA Secretary. The recipients use the grant funds to assist rural agricultural producers and small businesses with conducting energy audits, improving the efficiency of their operations while also incorporating renewable energy technologies and resources. The second half of the program provides loan guarantees directly to rural small businesses and agricultural producers to make energy efficiency improvements, and purchase and employ renewable energy systems.

Subprogram: The Repowering Assistance program both encourages biorefineries that are currently using fossil fuels for heat inputs to switch to renewable biomass sources. The Secretary of USDA is authorized to make direct payments to any biorefinery that meets the particular specifications. These payments are to be calculated based on two factors: the amount of fossil fuels usage that will be avoided and the efficiency and cost of the newly-installed biomass system.

Subprogram: The Bioenergy for Advanced Biofuels program functions via direct payments to producers of advanced biofuels, based on the volume of fuels produced and the amount of renewable energy content contained therein. Eligible Fuels include: Biofuels derived from cellulose, hemicelluloses, or lignin; biofuel derived from sugar and starch (other than Ethanol derived from corn kernel starch); biofuel derived from waste material, including crop residue, other vegetative waste material, animal waste, food waste and yard waste; diesel-equivalent fuel derived from Renewable Biomass, including vegetable oil and animal fat; biogas (including landfill gas and sewage waste treatment gas) produced through the conversion of organic matter from Renewable Biomass; butanol or other alcohols produced through the conversion of organic matter from Renewable Biomass; and, other fuel derived from cellulosic biomass.

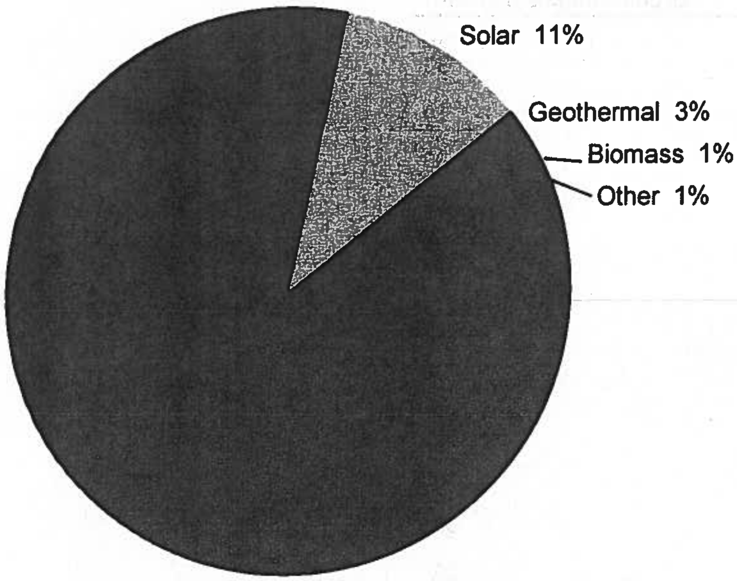
Subprogram: The High Energy Costs Grants under the Rural Utilities Service (RUS) are available for improving and providing energy generation, transmission, and distribution facilities serving communities with average home energy costs exceeding 275 percent of the national average. Grant funds may be used for on-grid and off-grid renewable energy projects, energy efficiency, and energy conservation projects serving eligible communities.

Biomass Crop Assistance Program: This program provides financial assistance to owners and operators of agricultural and non-industrial private forest land who wish to establish, produce, and deliver biomass feedstocks. The program spent $246 million in FY 2010.

Department of the Treasury

Grant in Lieu of Production or Investment Tax Credit Section 1603 provision in ARRA provided for the tax-free grant program. Eligible beneficiaries (including solar, fuel cells, geothermal, wind, hydro, and biomass, in particular), can apply for a grant in lieu of the 30 percent Investment Tax Credit. Eligible funding is fuel dependent with coverage ranging from 10 percent to 30 percent of a projects cost (Table 11). Section 1603 has become an enormously popular program. The Office of Management and Budget shows this value to have grown to $1.1 billion in 2009 during the first year of eligibility. In 2010, the value of the grant, at $4.2 billion, was the second largest "tax expenditure" for that year. Between 2009 and 2015, the value of the grant is forecasted to approach $19 billion. In 2010, 84 percent of 1603 grants went to wind projects, 11 percent to solar projects, 3 percent to geothermal projects, and 1 percent to biomass (Figure 1).

Figure 1. Percentage share of the section 1603 investment grant by energy category, 2010



Note: Data depicts only dollar amounts allocated by energy source.
Source: U.S. Department of the Treasury, http://www.treasury.gov/initiatives/recovery/Documents/Web%20Posting.xls

Grants can cover between 10 percent and 30 percent of the cost of an eligible project depending upon the nature of the project (Table 11). Eligible properties are described in Sections 45 and 48 of the Code. Section 1603 applied to eligible properties placed in service between January 1, 2009 and January 1, 2011. Section 707 of the Tax Relief, Unemployment Reauthorization, and Job Creation Act of 2011 extended the placed in service date to run through December 31, 2011.

Table 11. Section 1603 facility property eligibility amounts

Energy Property	Eligible Funding (Percent)
Closed-Loop Biomass Facility	30
Combined Heat & Power	10
Fuel Cells	30
Geothermal Heat Pumps	10
Geothermal under IRC sec. 45	30
Geothermal under IRC sec. 48	10
Landfill Gas Facility	30
Large Wind	30
Marine & Hydrokinetic	30
Microturbines	10
Open-Loop Biomass Facility	30
Qualified Hydropower Facility	30
Small Wind	30
Solar	30
Trash Facility	30

Source: American Recovery and Reinvestment Act of 2009, Section 1603 (Public Law 111-5).

3. Federal Energy Research and Development

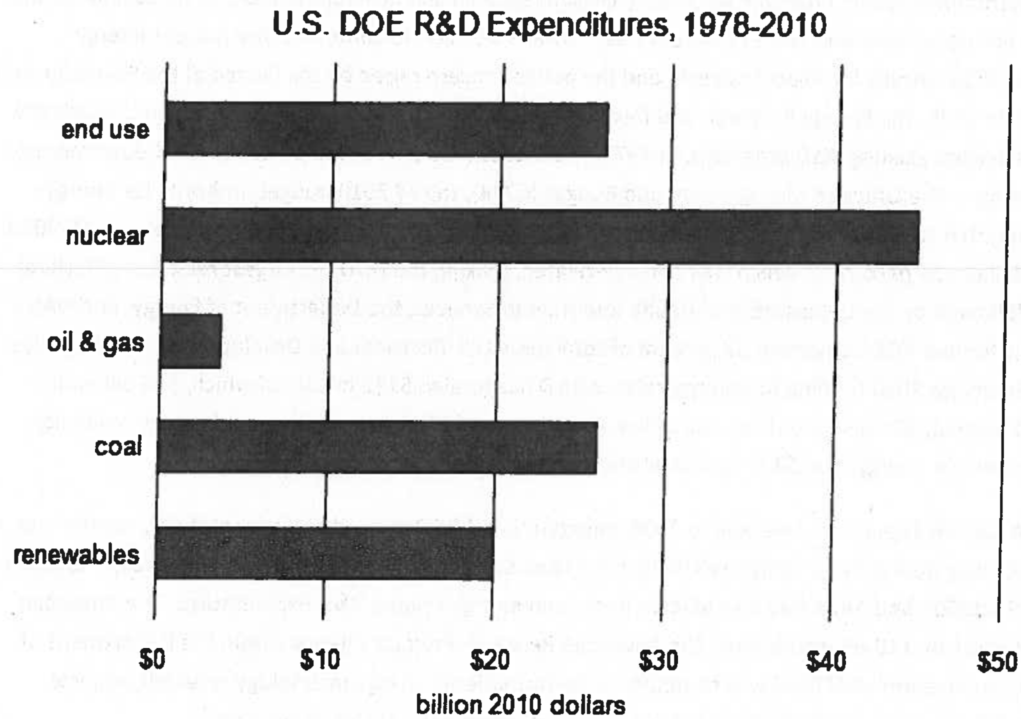
The federal government's role in financing large-scale civilian research and development (R&D) dates back to the late 1940s. The principal landmarks were President Eisenhower's decision to commercialize nuclear energy articulated in his 1953 "Atoms for Peace" speech, and the public concern raised by the launch of the Soviet Sputnik satellite in 1957. In 1975, the Energy Research and Development Administration (ERDA) was created through the consolidation of several existing R&D programs. In 1977, ERDA became a part of the United States Department of Energy.[18] According to the Office of Management and Budget (OMB), the FY 2010 budget authority for energy-related R&D amounted to about 7 percent of all federally-funded R&D.[19] Total federal R&D for fiscal year FY 2010 exceeded $147 billion, 55 percent of which was defense-related, making the DOD the largest recipient of federal R&D spending, followed by the Department of Health and Human Services, the Department of Energy, and NASA. In 2008, federally funded R&D comprised 57 percent of total basic U.S. Research and Development spending. Over the period 1978 through 2010 funding for energy-related R&D has totaled $121 billion, of which, $45 billion has been devoted to nuclear, $26 billion to coal, $26 billion to end use and electricity delivery and energy reliability, $20 billion to renewable energy, and $4 billion to oil and gas (Figure 2).

Since the last EIA subsidy report was released in 2008, energy-related R&D expenditures for biofuels, renewables, end use, and electricity delivery and energy reliability have risen substantially. Like the growth in tax expenditures, the passage of EPAct2005 and ARRA had a significant impact on energy-related R&D expenditures. The American Competes Act (Public Law 110-69) established the Advanced Research Projects Agency within the Department of Energy (ARPA-E). The mission of ARPA-E was to support transformational energy technology research projects. Under ARRA, the Advanced Research Projects Agency-Energy received $387 million in funding.

Since EIA produced its last subsidy report in 2008 (which used primarily 2007 R&D data), applied R&D funding authorizations for renewable technologies, end use and electricity delivery and energy reliability (EDER) energy has grown considerably. Funding for renewable R&D rose 97 percent between 2007 and 2010, while expenditures on end use and EDER rose 62 percent (Table 12 and Figure 3). Renewables have seen their share rise from 24 percent of total spending in 2007 to 32 percent of total spending in 2010. In 2010, nuclear, at 27 percent of total spending declined from 2007 when nuclear's share equaled 34 percent. Over the same period, coal related R&D declined—from 19 percent of total spending to 15 percent. End use and EDER expenditures accounted for 24 percent of total spending in 2010 versus 22 percent in 2007.

[18] See, http://www.whitehouse.gov/omb/budget/fy2008/pdf/hist.pdf.
[19] Perspectives of the U.S. Budget 2012, pp. 367 and 368.

Figure 2. U.S. DOE cumulative R&D expenditures, 1978-2010 (billion dollars)



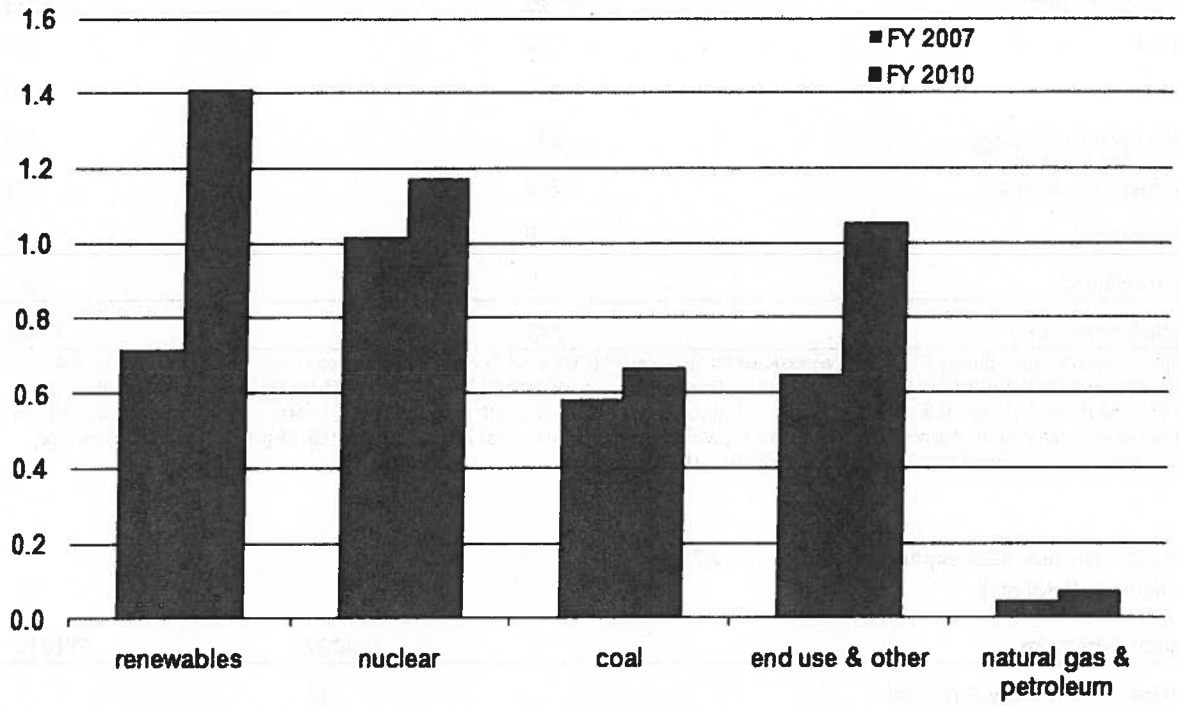
Sources: DOE Historical Budget Authorizations by Organization 1978-2011, M Leonard 08-18-10 v2 and DOE ARRA 753 Recovery Act - Historical Monthly Payments and Obligations.
Notes: The expenditures for FY 2009 and FY 2010 also include ARRA expenditures and obligations. Energy R & D Expenditures by other federal agencies such as DOD are not included.

Table 12. Applied Federal energy R&D expenditures by type and function, 2007 and 2010 (million 2010 dollars)

Applied R & D	FY 2007	FY2010
Coal	582	663
Natural Gas and Petroleum Liquids	43	70
Nuclear Power	1,017	1,169
Renewable Technologies	717	1,409
End Use and Electricity Delivery and Energy Reliability	652	1,053
Total	**3,010**	**4,365**

Note: Totals may not equal sum of components due to independent rounding.
Sources: Department of Energy FY 2009 Congressional Budget Request (DOE/CF-031) and Department of Energy FY 2012 Congressional Budget Request (DOE/CF-0064).

Figure 3. Research and development expenditures by energy category, 2007 and 2010 (billion dollars)



Sources: Department of Energy FY 2009 Congressional Budget Request (DOE/CF-031) and Department of Energy FY 2012 Congressional Budget Request (DOE/CF-0064)
Notes: Other is the Electricity Delivery and Energy Reliability Program.

Tables 13 through 18 breakout R&D spending for 2007 and 2010 by fuel / program type. For detailed information on Department of Energy R&D expenditures see the Department of Energy's fiscal year 2009 Congressional Budget Request (DOE/CF-031) and the Department of Energy fiscal year 2012 Congressional Budget Request (DOE/CF-0064) which can be found at http://www.ne.doe.gov/budget/budgetpdfs/Highlight2009.pdf and http://www.cfo.doe.gov/budget/12budget/Content/FY2012Highlights.pdf, respectively.[20]

[20] While most of the information in this chapter comes from DOE documents, additional information from the Department of the Interior (see http://www.doi.gov/budget/2011/data/greenbook/FY2011_USGS_Greenbook.pdf), the U.S. Geological Survey (see http://www.usgs.gov/budget/2009/green_book/FY2009_USGS_Greenbook.pdf), the National Institute of Standards and Technology (see http://www.nist.gov/public_affairs/budget/2010_budget_inits_portal.cfm), the Defense Advanced Research Projects Agency (see www.darpa.mil/WorkArea/DownloadAsset.aspx?id=2400) and U.S. Department of Agriculture (see http://www.obpa.usda.gov/budsum/FY10budsum.pdf and http://www.obpa.usda.gov/budsum/FY07budsum.pdf.

Table 13. Renewable R&D expenditures, 2007 and 2010 (million 2010 dollars)

Source / Program	FY2007	FY2010
Wind	58	166
Solar	171	348
Hydrogen Technology	211	205
Biofuels and Biomass	268	537
Geothermal	9	100
Hydroelectric	0	52
Total Renewables	**717**	**1,409**

Sources: Department of Energy FY 2009 Congressional Budget Request (DOE/CF-031) and Department of Energy FY 2012 Congressional Budget Request (DOE/CF-0064), U.S. Geological Survey (see http://www.usgs.gov/budget/2009/green_book/FY2009_USGS_Greenbook.pdf), the National Institute of Standards and Technology (see http://www.nist.gov/public_affairs/budget/2010_budget_inits_portal.cfm), the Defense Advanced Research Projects Agency (see www.darpa.mil/WorkArea/DownloadAsset.aspx?id=2400) and U.S. Department of Agriculture (see http://www.doi.gov/budget/2011/data/greenbook/FY2011_USGS_Greenbook.pdf.

Table 14. Nuclear R&D expenditures, 2007 and 2010 (million 2010 dollars)

Source / Program	FY2007	FY2010
Integrated University Program	17	5
Research & Development	312	-
Infrastructure	246	-
Nuclear Power 2010	-	102
Generation IV Nuclear Energy Systems	-	213
Fuel Cycle Research & Development	-	132
Radiological Facilities Management	-	72
Idaho Facilities Management	-	173
Program Direction	-	73
Congressionally Directed	65	3
Transfer from State Department	13	3
Non-defense environmental cleanup	364	393
Total	**1,017**	**1,169**

Note: Totals may not equal sum of components due to independent rounding.
Sources: Department of Energy FY 2009 Congressional Budget Request (DOE/CF-031) and Department of Energy FY 2012 Congressional Budget Request (DOE/CF-0064),and the National Institute of Standards and Technology (see http://www.nist.gov/public_affairs/budget/2010_budget_inits_portal.cfm).

Table 15. Coal R&D expenditures, 2007 and 2010 (million 2010 dollars)

Source / Program	FY2007	FY2010
Coal	555	582
Plant & Capital Equipment	12	27
Fossil Energy Environmental Restoration	10	13
Cooperative R & D	1	7
Special Recruitment Programs	0	1
Congressional Directed Projects	0	32
National Coal Resources (USGS)	3	1
Total	**582**	**663**

Note: Totals may not equal sum of components due to independent rounding.
Sources: Department of Energy FY 2009 Congressional Budget Request (DOE/CF-031) and Department of Energy FY 2012 Congressional Budget Request (DOE/CF-0064), the U.S. Geological Survey (see http://www.usgs.gov/budget/2009/green_book/FY2009_USGS_Greenbook.pdf), and the National Institute of Standards and Technology (see http://www.nist.gov/public_affairs/budget/2010_budget_inits_portal.cfm), and http://www.doi.gov/budget/2011/data/greenbook/FY2011_USGS_Greenbook.pdf.

Table 16. Natural gas and petroleum R&D expenditures, 2007 and 2010 (million 2010 dollars)

Source / Program	FY2007	FY2010
Natural Gas Technologies	17	24
Unconventional Fossil Energy Technologies	0	26
Petroleum- Oil Technologies	8	1
Oil Shale	1	2
National Oil & Gas Resources	15	15
World Oil & Gas Resources	2	2
Total	**43**	**70**

Note: Totals may not equal sum of components due to independent rounding.
Sources: Department of Energy FY 2009 Congressional Budget Request (DOE/CF-031) and Department of Energy FY 2012 Congressional Budget Request (DOE/CF-0064), the U.S. Geological Survey (see http://www.usgs.gov/budget/2009/green_book/FY2009_USGS_Greenbook.pdf), and the National Institute of Standards and Technology (see http://www.nist.gov/public_affairs/budget/2010_budget_inits_portal.cfm), and http://www.doi.gov/budget/2011/data/greenbook/FY2011_USGS_Greenbook.pdf.

Table 17. End-Use and Electricity Delivery and Energy Reliability R&D Expenditures, 2007 and 2010 (million 2010 dollars)

Source / Program	FY2007	FY2010
Vehicle Technologies	204	352
Building Technologies	129	315
Industrial Technologies	65	139
Congressionally Directed	0	6
Facilities & Infrastructure	111	19
Total End Use	**509**	**832**
Electricity Delivery and Energy Reliability	142	222
Total	**652**	**1,053**

Note: Totals may not equal sum of components due to independent rounding.
Sources: Department of Energy FY 2009 Congressional Budget Request (DOE/CF-031) and Department of Energy FY 2012 Congressional Budget Request (DOE/CF-0064) and National Institute of Standards and Technology (see http://www.nist.gov/public_affairs/budget/2010_budget_inits_portal.cfm), and the Defense Advanced Research Projects Agency (see www.darpa.mil/WorkArea/DownloadAsset.aspx?id=2400).

Table 18. Basic federal energy R&D expenditures by type and function, 2007 and 2010 (million 2010 dollars)

Source / Program	FY2007	FY2010
Basic Energy Sciences	1,270	1,797
Advanced Scientific Computing	287	383
Biological & Environmental Research	499	629
High Energy Physics	762	791
Nuclear Physics	429	522
Fusion Energy Systems	324	418
Other Allocated	419	736
Total	**3,990**	**5,277**

Note: Totals may not equal sum of components due to independent rounding.
Sources: Department of Energy FY 2009 Congressional Budget Request (DOE/CF-031) and Department of Energy FY 2012 Congressional Budget Request (DOE/CF-0064).

4. Federal Electricity Programs

Introduction

The federal government provides federal utilities and electric utilities participating in the RUS electric program access to capital at reduced interest rates. federal utilities also receive support by pricing power with rates of return that are lower than possible for a competitive company. The federally-owned utilities include the Tennessee Valley Authority (TVA) and the four Power Marketing Administrations (PMAs), the Bonneville Power Administration (BPA), the Western Area Power Administration (WAPA), the Southeastern Power Administration (SEPA), and the Southwestern Power Administration (SWPA).[21] Lending subsidies provided through the RUS loan programs are included due to the advantages that these programs provide to eligible borrowers.[22]

This chapter examines support provided by the federal government to certain electric power customers. This support differs significantly from the support provided to other energy sectors described in this report. First, the federal support outlined in the following discussion does not include any direct expenditures provided to federal utilities by the federal government, as is the case for other federal programs. The market value of the interest subsidies provided to TVA, the PMAs, and RUS borrowers is not measured by the Treasury Department, and it is not reported in federal budget documents. The measures of support described in this chapter are values estimated by the EIA.

Measuring the Support

In this report, the federal subsidies to TVA, the PMAs, and RUS borrowers are quantified by estimating the benefits they receive because of their ability to borrow directly from the Treasury and access low cost federal loans and loan guarantees. In additions, TVA and BPA, have access to lower cost private financing due to the financial markets' perception of an implied federal guarantee for their non-federal obligations. This measure of support represents a snapshot of the difference between the interest expense paid by TVA, the PMAs, and RUS borrowers at their embedded cost of debt relative to what they would have paid at a range of market interest rates. Unlike the previous report, a range of interest rates is used here because of the uncertainty about selecting the appropriate market.

[21] The United States Department of Interior, Bureau of Indian Affairs owns or has interests in projects primarily engaged in irrigation that also provide electric service on Indian Reservations. See NEOS Corporation," Draft Final Report: Tribal Authority Case Studies: The Conversion of on-Reservation Electric Utilities to Tribal Ownership and Operation," prepared for the Western Area Power Administration, Contract No. DE-AC65-91WA07849, January 1996. Any support that may exist with respect to these government-owned projects are excluded from the analysis because their primary purpose is agricultural irrigation, not electricity production.

[22] For more information on the history of the federal utilities role in electricity markets and the issues involved with assessing whether subsidies are provided to them see Energy Information Administration, *Federal Financial Interventions and Subsidies in Energy Markets 2007*, Washington, DC, 20585, April 2008, available at http://www.eia.gov/oiaf/servicerpt/subsidy2/index.html.

These interest rates include the Treasury's cost of money on 30-year debt instruments and interest rates that reflect the variations in credit quality within the general category of investment grade debt (i.e., Aaa to Baa) for IOU bonds rated by nationally-recognized rating agencies.[23]

It should be pointed out that there are other approaches for measuring federal support to these utilities. These include a comparison of the prices charged for electricity under federal programs versus an estimate of relevant "market" prices and a comparison of rates of return on assets between the federal utilities and IOUs. The price measure looks at the benefit received by preference customers based on the difference between the cost-based rates charged for federal power versus the rate charged in competitive wholesale markets. These other methods are not addressed in this report, but were discussed in the previous report.

This analysis uses both public-sector and private-sector interest rates as benchmarks against which to measure the value of interest rate support. The public-sector benchmark is the Treasury's 30-year constant yield to maturity debt obligation. For the private-sector rates, the benchmarks used are the Moody's utility bond ratings ranging from Aaa down to Baa. These ratings indicate two different measures of support. When debt carried on the balance sheets of federal utilities has lower average borrowing costs than the U.S. Treasury itself, the underlying advantage can be viewed as support provided directly to the borrower by the U.S. Treasury or by the public at large. The second measure of support assumes that federal utilities are advantaged to the extent that the associated average interest costs of their outstanding borrowing costs are at rates less than they would be if they were private entities. This measure of support compares the borrowing costs of the federal utilities with the cost of funds paid out by risk-adjusted groups of IOUs that raise debt in the market place. The comparable IOU rating may or may not be appropriate, depending on the presumed creditworthiness a federal utility would command were it to lose the borrowing benefits derived from federal ownership or its implicit financial backing by the U.S. Treasury.

The measure used to estimate the federal interest rate support for federally-owned utilities is highly dependent on the risk differential reflected by the spread between the interest rates for the various categories of investment grade bonds described above. In 2010, interest rates were close to record lows (Table 19).[24] However, in measuring interest support for a single year, what matters is the interest rate spread, which reflects the risk premium. Table 20 illustrates that the level of estimated support varies directly with the benchmark interest rate chosen. The spread between these rates could remain relatively stable or could change over time. In 2010, the

[23] An alternative measure of Federal support would employ a comparison of a weighted average of the various maturities of all Federal debt at the time of issuance against Treasury and IOU debt being issued contemporaneously to the Federal debt with the same maturities. There are several shortcomings with this alternative measure. First there is a lack of relevant interest data. The source of constant-maturity U.S. Treasury interest rates used in this report is the Federal Reserve Bank's Form H-15. In 2001, due to expectations of future budgetary surpluses, the United States Treasury announced that it would suspend issuance of its 30-year bond, the long-bond. Hence, Form H-125 lacks historical data on constant-maturity 30-year Treasuries for the years 2003 through 2005, making a comparison for those years subject to estimating 30-year Treasury surrogates. A second issue also concerns data availability. While the Federal utilities reported historical debt issuances of 50 years or more, corresponding data are unavailable for U.S. Treasuries and IOUs. For instance, Form H-15 reports long-bond Treasury rates going back no earlier than 1977. In 2010, TVA reported debt with a maturity of 50 years (Source: *TVA 2010 Annual Report*, p. 52). Another issue concerns standardized maturities. While the Treasury issues bonds with standardized maturities of 10, 20, and 30 years, Federal utilities issue debt with various maturities. For instance, a Federal utility issuing debt having a maturity of 15 years would have no U.S. Treasury counterpart with the same maturity. Furthermore, a portion of BPA's ENW debt has variable interest rates (See: *BPA 2010 Annual Report*, p. 36. Any attempt to estimate interest rates based upon "hypothetical" comparative Treasuries involves extrapolations for debt with maturity dates greater than 30 years, which would have to surmount a number of issues, such as how to deal with periodic yield curve inversions. Finally, bond-by-bond comparisons would overlook an advantage available to the PMAs in that they are allowed by the Department of Energy to pay off their high cost debt prior to maturity. While IOUs may issue callable debt, which also may be retired prior to maturity, this debt would be priced at rates higher than those associated with debt, which could not be retired prior to maturity.

[24] Changes over time in the spread between interest rates of Federal utilities and the benchmark rates they are being measured against in no way reflect intended changes in Federal support for these electricity programs. Rather, they reflect supply and demand conditions in credit markets prevailing in 2007 and in 2010.

average yield on 30-year Treasury bonds was 4.24 percent while the average yield on Aaa-rated utility bonds was 4.96 percent, producing a spread of 72 basis points; in contrast, the spread between the 4.84 percent 30-year Treasury and the 5.67 percent investor- owned Aaa rate in 2007 equaled 83 basis points. The estimated interest support will be higher when the IOU Aa rate is compared to the Treasury rate, and higher still when the comparison is graduated downward to the IOU Baa rate. For the year 2010, the difference in yield between a 30-year Treasury and a Baa IOU-rated bond was 173 basis points versus 149 basis points in 2007. The difference in yield between an Aaa utility rating and Baa utility was 101 basis points in 2010 versus 66 basis points in 2007. The level of support rises and falls depending on: (1) changes in the yield spread between different debt instruments (e.g., Treasuries and utilities); (2) changes in the level of outstanding debt; (3) and, the federal utilities and RUS borrowers embedded cost of debt versus the Treasury's and utilities' current cost of money.

Selection of a Market Interest Rate

This analysis is a snapshot that compares the current interest expense based on the average cost of outstanding debt to a hypothetical interest expense that applies a contemporaneous market interest rate to the outstanding debt. In effect this implies the debt is being refinanced. A more accurate measure would have been to estimate the value based on the sum of the difference between the face amount of each original loan or bond and the present value of each loan or bond issue at the market rate of interest at the time the obligation was incurred. However, the data required to perform this alternative analysis was not readily available.

Table 19. Interest Rates used to Estimate Federal Utilities and RUS Interest Subsidies, 2007 and 2010 (percent)

Comparison Debt	2007	2010
30-Year Treasury	4.84	4.24
Investor-Owned Aaa	5.67	4.96
Investor-Owned Aa	5.94	5.23
Investor-Owned A	6.07	5.46
Investor-Owned Baa	6.33	5.97

Sources: Source: Moody's Investor Services and Federal Reserve Bank Form H-15.

Since the financial accounts of the four PMAs, TVA, and RUS borrowers differ considerably and due to reasons cited below, a single federal interest rate support estimate was used in this analysis. A more complicated method would be to measure the interest paid by federally-supported power entities against the interest paid on similar debt (i.e., same maturity) issued by the Treasury or by IOUs at the same time the debt was issued. However, several difficulties arise with the latter methodology. In essence the yield curve for the federal utilities is fundamentally different from the yield curve for the IOUs. One problem is that the debt maturities cannot always be matched. For instance, TVA has issued debt with maturities as long as 50 years, for which there are no similar Treasury or IOU debt instruments. Another difficulty is that some debt is callable, which means it may never be held to maturity. There is an interest rate differential between callable and non-callable debt. Callable debt, all other factors being equal, has a higher interest rate. Another problem is the lack of available data. Although some of the debt on the books of the PMAs dates back to the 1940s, there is little in the way of comparable IOU and Treasury interest rate data available. For instance, the U.S. Treasury did not start to issue 30-year debt until 1978

Table 20. Estimate of federal electricity interest rate support to TVA, 2007 and 2010 (million 2010 dollars)

	Treasury Rate	Aaa IOU Rate	Aa IOU Rate	A IOU Rate	Baa IOU Rate
2007					
1) Benchmark Interest Rate (%)	4.84	5.67	5.94	6.07	6.33
2) Outstanding Debt ($)	25, 834	25,834	25, 834	25,834	25,834
3) Average Cost of Outstanding Debt (%)	5.67	5.67	5.67	5.67	5.67
4) Actual Interest Expense ($)	1,466	1, 466	1,466	1,466	1,466
5) Interest Expense Computed at Benchmark Rate ($) [(1)*(2)]	1,250	1,466	1,535	1,569	1,636
6) Estimated Interest Support at Benchmark Rate ($) [(5)-(4)]	NA	NA	70	103	170
2010					
1) Benchmark Interest Rate (%)	4.24	4.96	5.23	5.46	5.97
2) Outstanding Debt ($)	24,591	24, 591	24,591	24,591	24,591
3) Average Cost of Outstanding Debt (%)	4.96	4.96	4.96	4.96	4.96
4) Actual Interest Expense ($)	1,220	1,220	1,220	1, 220	1,220
5) Interest Expense Computed at Benchmark Rate ($) [(1)*(2)]	1,043	1,220	1,286	1,342	1,467
6) Estimated Interest Support at Benchmark Rate ($) [(5)-(4)]	NA	NA	66	123	247

Notes: The above table represents the historic value of TVA's debt in 2010 dollars for purposes of illustrating how support values for 2007 and 2010 were calculated. The nominal value of debt reported on TVA's balance sheet for the year 2007 was: $24,925,000,000.
A negative estimate of interest support indicates the weighted average cost of outstanding debt exceeds the benchmark interest rate.
Source: Tennessee Valley Authority Annual Report, 2007 and 2010. Moody's Investors Service, Federal Reserve Bank Form H-15.

and in the years 2003, 2004 and 2005, no 30-year Treasury bonds were in circulation. Finally, the PMAs also have two other advantages over IOUs that tend to make an IOU/PMA bond-to-bond comparison problematic. First, the PMAs have the right to pay off high-interest debt first and, second, the PMAs can defer payments of debt during revenue shortfalls up to the point of the maturity of the loan. These deferrals can be as long as 50 years.[25]

[25] General Accounting Office, Power Marketing Administrations, Their Ratesetting Practices Compared with those of NonFederal Utilities, GAO/AIMD-00-114, (Washington, DC, March 2000), p.14.

In making comparisons between the interest costs faced by the federal utilities and the IOUs, two other complications arise. The first began in FY 2000, when TVA initiated lease/lease back arrangements.[26] In lease/lease back arrangements, the TVA "leases" TVA generation assets to investors for a one-time cash payment used to retire debt. In turn, the TVA leases back the plants and makes periodic lease payments.[27] The other complication relates to TVA's prepayment plan. In 2003, the TVA initiated a pre-payment plan, which allowed TVA customers to pay for their power in advance in return for discounted, wholesale rates. Again, TVA used the transactions proceeds to retire long-term debt. Due to both of these transactions, the TVA significantly reduced its long-term debt. Both of these obligations are recorded as liabilities on TVA's balance sheet although TVA does not define these liabilities as debt. However, due to their strong resemblance to debt, this report defines them as such. Both lease/lease back arrangements and prepayments are discussed later in the TVA section of this chapter.

TVA's debt in 2010 received an Aaa bond rating from Moody's Rating Service and AAA from Standard and Poor's and Fitch Ratings.[28] The imputed interest expense for the TVA lease payments and the prepayment discount were not treated as interest expense in TVA's financial documents. Therefore, TVA's interest costs were estimated by applying an Aaa interest expense to TVA's long-term debt which includes both the values of its lease payment obligations, as well as, the unamortized balance of the prepayments which represents TVA's power supply obligation to those who prepaid. The Aaa interest rate expense was then compared to what TVA would pay in interest payments if its debt was priced at a lower bond rating.

For the PMAs, the debt values and interest expenses were obtained from their 2008-2010 annual reports. Having actual data on both PMAs' long-term debt and the interest on the long-term debt allows for a comparison of what that interest would be if the PMA's rates available to IOUs. In 2007, the three smaller PMAs had an embedded cost of debt below the current 30-year Treasury rate. By 2010, the embedded cost of PMA debt slightly exceeded the Treasury rate. Furthermore, unlike TVA, the three smaller PMAs have an advantage unavailable to the Treasury itself in that DOE requires the retirement of high-interest debt first whenever possible. Borrowing costs for the 3 smaller PMAs were also measured against borrowing costs at the Treasury rate, as well as, the interest rates for investment grade IOU bonds rated Aaa, Aa, A, and Baa.

---

[26] In general, Lease Lease-Back arrangements appeared in the 1980s. These leases often involved the transfer of tax benefits to third parties when the utility cannot use them (i.e., publicly-owned utilities do not benefit from accelerated depreciation). Source: Public Utilities Report Guide, Chapter 5 Financial Issues for Utilities 1999, p. 5-28, Public Utilities Reports Inc., Vienna, Virginia.

[27] One of the benefits of this arrangement is the transfer of the tax benefit of depreciation to the equity investors participating in the lease lease/back transaction that is not available to TVA. Under this type of transaction, the parties typically share in the benefit of the tax benefit being transferred. In this case, TVA realizes a portion of the benefit in lease payments that are passed on to its customers. The equity investors realize the benefits of the deductibility of deprecation as an operating expense and the deferral associated with the timing difference between book and tax depreciation. The value of the portion of the transaction transferred to the counterparty may be viewed as a form of Federal government support, although insufficient information prevents estimating the value of this subsidy in this report.

[28] Tennessee Valley Authority, TVA's News Release, "TVA Issues 50-Year Bonds at Record Low Interest," September 17, 2010.

Tennessee Valley Authority

Prior to the TVA Act of 1959, TVA was financed through federal appropriations. The 1959 TVA Act authorized the TVA to raise capital on its own—to be "self-financing," allowing TVA considerably more latitude in making its investment decisions. Congress initially imposed a $750 million debt cap on TVA. This debt cap was later raised to $1.75 billion in 1966, $5 billion in 1970, $15 billion in 1975, and $30 billion in 1979. In 2010, TVA's long-term debt stood at $26 billion.[29] Since 2000, TVA has not relied on federal appropriations to fund its non-power operations, such as multipurpose activities and recreational programs, when other sources of revenues, such as user's fees, were insufficient to fund those operations. Funding for these operations has been derived from user fees, other revenues, and electricity sales.

A number of explicit and implicit benefits are conferred upon TVA by the federal government. For example, TVA receives implicit interest rate support via a favorable debt rating since it is owned by the federal government. The rating does not reflect TVA's underlying business or financial condition. In general, TVA borrows at rates comparable to those of federal government agencies. TVA also benefits from having a captive market and certain other regulatory advantages, which fall outside the scope of this study. Its customers are required to provide up to 10-years notice before they are allowed to switch their service to another utility.[30] This provides for stability in TVA's revenue from electricity generation, a competitive advantage not enjoyed by competing IOUs. It is also exempt from antitrust laws, an exemption IOUs and the other federal utilities also do not enjoy. EPAct 1992 provided an exemption for TVA from amendments to the federal Power Act that enhanced the federal Energy Regulatory Commission's authority to order utilities to provide transmission service. This exemption is referred to as the "anti-cherry picking" advantage.[31,32] The anti-cherry picking provision, although regulatory, and not included as a subsidy in this report, reinforces the financial community's perception that TVA bonds are virtually a risk-free investment. However, the TVA Act of 1959 places strict limits on how much power TVA can sell outside of its jurisdiction. The TVA Act of 1959 established a "fence" based upon the geographic area of the distributors served by the TVA in 1957.

TVA rates are not regulated by the FERC, nor are its rates subject to State regulation. TVA's Board has complete discretion in setting rates. Over the last decade, TVA's rates have been generally higher than those of surrounding utilities. Until recently, TVA was exempt from the reporting requirements required of publicly-held companies. However, in February 2003, the TVA Board adopted the TVA Corporate Accountability and Disclosure Plan which required TVA to develop corporate practices that reflect the reforms of the Sarbanes-Oxley Act of 2002 (Public Law 107-204), including certification of financial statements and related disclosures by the TVA Board of Directors and the Chief Financial Officer.[33]

Based on these factors, EIA adjusted TVA's outstanding debt to reflect two obligations that pursuant to Generally Accepted Accounting Practices (GAAP) are not reflected as long-term debt on its balance sheet, but as "other liabilities." These liabilities included TVA's obligations pursuant to two lease/lease back transactions and future

[29] General Accounting Office, Tennessee Valley Authority: *Bond Ratings Based on Ties to the Federal Government and Other Nonfinancial Factors*, GAO-01-540 (Washington, DC, April 2001), p. 3.
[30] This restriction is not absolute, as customers are allowed to expand outside TVA's territory or to self-generate.
[31] General Accounting Office, *Tennessee Valley Authority, Debt Reduction Efforts and Potential Stranded Costs*, GAO-01-327, (Washington, DC, February 2001), p. 6.
[32] General Accounting Office, *Tennessee Valley Authority, Assessment of 10-year Business Plan*, GAO/T-AIMD-99-295, (Washington, DC, September 1999), p. 2.
[33] Tennessee Valley Authority: http://www.tva.gov/foia/readroom/policy/prinprac/bun24.htm, accessed October 11, 2007.

obligations to supply power to its largest customer, Memphis Light, Gas, and Water Division (MLGW). MLGW issued tax-exempt debt, the proceeds of which were used to prepay future power supply costs at a discount.[34]

In 2010, the TVA carried over $1.4 billion (2010 dollars) in lease/lease back liabilities on its balance and energy prepayment obligations totaling $822 million (2010 dollars) on its balance sheet. These obligations have an effect on TVA's cash flow and therefore, its ability to meet debt service obligations. The Office of Management and Budget (OMB) treats TVA's lease/lease back arrangements as debt and has advised that this should be included in the TVA's $30 billion debt ceiling.[35] More recently, TVA's office of the Inspector General treated these obligations as debt to be applied to TVA's $30 billion debt ceiling.[36] In the FY 2012 budget, the OMB determined "that each of these methods (lease/lease back obligations and prepayment financing methods) is a means of financing the acquisition of assets owned and used by the federal government, or refinancing debt previously incurred to finance such assets. They are equivalent in concept to other forms of borrowing from the public, although at different terms and conditions."[37] The GAO also concluded that "while the lease/lease back arrangements are not considered debt for purposes of financial reporting and debt cap compliances, they have substantially the same economic impact on TVA's financial condition and future competitiveness as traditional debt financing...Thus while the lease/lease back arrangements are not treated as debt for financial reporting purposes, they are in essence debt because they have substantially the same economic impact on TVA as traditional debt financing."[38] GAO also noted that GAAP does not require that the lease/lease back arrangements be classified as debt.

For its part, TVA has expressed concerns that applying the $30-billion debt ceiling to lease/lease back arrangements may result in a capital shortfall: "If Congress decides to broaden the type of financial instruments that are covered by the debt ceiling or to lower the debt ceiling, TVA might not be able to raise enough capital to, among other things, service its then-existing financial obligations, properly operate and maintain its power assets, and provide for reinvestment in its power program."[39] TVA records lease/lease back transactions and power prepayment obligations—along with more traditional forms of debt—as Total Financial Obligations (TFOs).

In 2010, TVA had outstanding long-and short-term debt of $25 billion (Table 20), which compares to the $26 billion in debt it reported in 2007 (2010 dollars). One method of calculating the value underlying TVA's high credit rating would be to compare TVA's total interest costs against what TVA would pay if it had a lower credit rating. To determine the different levels of borrowing costs under various credit ratings, an estimate of the spread between different interest rates was calculated. The spread between TVA's borrowing costs and alternative borrowing costs

---

[34] In 2003 TVA initiated a pre-payment plan, which allowed TVA customers to pay for their power in advance but in return receive discounted rates, again resulting in a reduction in long-term debt. In 2004, TVA and MLGW, entered into an energy prepayment agreement under which MLGW prepaid TVA $1.5 billion for the future costs of electricity to be delivered by TVA to MLGW over a period of 180 months. TVA reported the prepayment as unearned revenue, and booked future energy sales obligations to MLGW as a long-term liability on its balance sheet. In 2010, TVA reported $822 billion (2010 dollars) liability in energy prepayment obligations.

[35] Office of Management and Budget: http://www.whitehouse.gov/omb/budget/fy2004/pma/tvapower.pdf and http://www.whitehouse.gov/omb/budget/fy2004/agencies.html.

[36] TVA, Office of the Inspector General, "Final Report—Inspection 2007-11399—Review of TVA's Financial Performance," June, 2009.

[37] Office of Management and Budget, Analytical Perspectives of the United States Budget Fiscal Year 2012, (Washington, 2011), p. 67.

[38] General Accounting Office, *Information on Lease-Leaseback and Other Financing Arrangements*, "GAO-03-784, (Washington, DC, June 2003).

[39] Tennessee Valley Authority, SEC 10-K, 2006, p. 42. In TVA's 2010, in summing the potential risk factors the TVA faced outlined in their forward looking statement, TVA stated: "Also, Congress may lower TVA's debt ceiling or broaden the types of financial instruments that are covered by the ceiling." Source: TVA 2010 10-K, p. 38.

presents a measure of the value of TVA's interest rate support. This report benchmarks TVA's support to its Aaa bond rating. In other words, if TVA borrowed money at the Aa rate rather than the Aaa rate, its borrowing costs in 2010 would increase 27 basis points, or result in $66 million (2010 dollars) in additional interest expense. This is one measure of federal support. An A bond rating would raise TVA's 2010 borrowing costs by $123 million (2010 dollars), and the Baa rating by $247 million (2010 dollars). In 2007, an Aa rating would have raised TVA's borrowing costs by $70 million (2010 dollars), an A rating by $103 million (2010 dollars) and a Baa rating by $170 million (2010 dollars). The significantly larger Baa subsidy value in 2010 was largely driven by the broadening of the basis point spread between the Aaa rate and the Baa rate since 2007. Despite the decline in interest rates between 2007 and 2010, the increased point spread between the Aaa and A, and the Aaa and Baa resulted in a larger subsidy in 2010 than in 2007 when TVA's debt is priced at the single A and Baa rates.

Power Marketing Authorities

The Bonneville Project Act of 1937 (Public Law 75-329) resulted in the creation of the Bonneville Power Administration. The Act required BPA to market hydropower produced from the Columbia River and to promote regional economic development. BPA is the largest of the federal PMAs and the second largest federal utility in terms of assets after TVA. The second largest PMA, the Western Area Power Administration (WAPA), was created in 1977 with the Department of Energy Organization Act of 1977 (Public Law 95-91). WAPA was charged with marketing hydropower facilities in the western United States including the power from the Hoover Dam, which was built in 1935. Both the Southwestern Power Administration and the Southeastern Power Administration owe their existence to the Flood Control Act of 1944 (Public Law 78-534) although the Southeastern Power Administration was not actually created until 1950. The Flood Control Act required: "Electric power and energy generated at reservoir projects under the control of the Department of the Army and in the opinion of the Secretary of the Army not required in the operation of such projects shall be delivered to the Secretary of the Interior, who shall transmit and dispose of such power and energy in such manner as to encourage the most widespread use thereof at the lowest possible rate to consumers consistent with sound business principles...Rate schedules shall be drawn having regard to the recovery (upon the basis of the application of such rate schedules to the capacity of the electric facilities of the projects) of the cost of producing and transmitting such electric energy, including the amortization of the capital investment allocated to power over a reasonable period of years. Preference in the sale of such power and energy shall be given to public bodies and cooperatives. The PMAs operate within the Department of Energy and the Secretary of Energy selects the PMA administrators.

BPA's Borrowing Costs

BPA receives no direct payment from the Treasury. Rather, the support it receives from the Treasury involves the interest it pays on its debt. As with all other federal utilities, BPA is a not-for-profit enterprise and prices its power to recover its operating and capital costs.

Although in large measure BPA's lower prices are the result of its access to low-cost generation from federal hydropower facilities, below-market borrowing costs also add to its price advantage. BPA has, since its inception, benefited from substantial federal intervention in the form of interest rate support. The size of BPA's estimated federal interest rate support is a function of the interest rate chosen to reflect the appropriate "market" interest rate. Table 21 illustrates a computation of federal utility interest support, making alternative assumptions about the appropriate market interest rate. The estimated interest cost of BPA's total debt lies somewhere between where it would be if it were priced between the 30-year Treasury and a Baa utility bond rating. BPA carries three forms of debt on its books.

Appropriated Debt. BPA appropriated debt refers to the unpaid portion of pre-1992 appropriations by Congress to fund the construction and replacement of U.S. Army Corps of Engineer's generation facilities.[40] Since passage of the EPAct1992, BPA has been required to fund these operations directly. BPA's appropriated debt was restructured in 1996. Under the BPA Appropriations Refinancing Act of 1996[41] (The Refinancing Act), BPA reduced its principal obligation of the debt by $2.5 billion based on the present value of its debt service payment. It was then required to pay interest on the restated principal balance based on prevailing Treasury rates as of October 1996.[42] The $2.5 billion reflects the difference between BPA's original principal balance and restated principal. It appears on BPA's financial statements as a Capitalization Adjustment. Because BPA sets its own rates, it is able to record the Capitalization Adjustment on its balance sheet as a regulatory liability and amortize it through its income statement under Financial Accounting Standards Board Announcement No. 71 (FAS No. 71). In the absence of meeting the requirements of FAS No. 71, BPA would be required to write-off the Capitalization Adjustment. In other words, the Refinancing Act obligated BPA to pay a higher interest rate on a lower amount of debt. After the refinancing, the total cash flow to the Treasury, including a $100 million up-front cash payment, yields the same present value as BPA's pre-refinancing obligation.

In 2010, BPA's appropriated debt plus the Capitalization Adjustment equaled $5.9 billion in (2010 dollars) versus $6.4 billion in 2007 (2010 dollars). The nominal value of BPA's appropriated debt was $6.2 billion in 2007.

Long-Term Debt. BPA's long-term debt primarily funds its transmission system. In 1974, the Congress, as a part of the Columbia River Transmission Act (Public Law 93-454), allowed BPA an amount limited to a nominal $4.5 billion in direct borrowing authority from the Treasury with $3.2 billion earmarked to fund the utility's transmission and other investment capital program and $1.3 billion for conservation and renewable energy investments. The appropriations are to be repaid to the Treasury by BPA. This long-term debt is actually a combination of medium and long-term maturities. The debt is held by the Treasury at interest rates set by the Treasury, which approximate the interest rates paid by government agencies. The rates are adjusted to reflect the cost of specific features of BPA's bonds. In 2010, BPA's long-term debt equaled approximately $2.2 billion versus $1.9 billion in 2007 (2010 dollars). ARRA provided BPA with an additional $3.25 billion in Treasury borrowing authority. This additional sum was earmarked for transmission planning operation and construction. Thus far, BPA has used this authority to begin construction on the $343 million McNary-John Day transmission project, which is intended to support the integration of wind development in the Northwest

Non-Federal Projects Debt. Non-Federal projects debt stems from BPA's assumption of the payment obligation on the debt of three Washington State Public Power Supply System (WPPSS) nuclear projects and several smaller generation and conservation investments. In 2000, BPA's one commercially-operating reactor, WNP-2 was renamed the Columbia Generating Station. During the 1980's, WPPSS defaulted on nuclear units 4 and 5.[43] WPPSS is now known as Energy Northwest.[44] Energy Northwest is responsible for the financing of Nuclear Projects 1, 2,

[40] This includes some funding for fish and wildlife recovery.
[41] 16 U.S.C. 838l.
[42] The Act also required the BPA to pay the Treasury an additional $100 million, prorated over the course of the appropriations. This value was incorporated by BPA into its interest payment on appropriated debt and was captured in the interest support estimated in this chapter. In 2010, BPA's appropriated debt stood at $5.9 billion. This includes a capitalization adjustment of $1.7 billion, which was included under appropriated debt prior to 1997. In 1997, the principal on BPA's appropriated debt was reduced by $2.5 billion while interest on the debt was raised to 7.1 percent from 3.5 percent. BPA realized a $100-million dollar transaction cost as a result of this principal and interest adjustment.
[43] Myers, Elaine and David, *Lessons from WPPSS*, "In Context," Volume No. 7, p. 28 August 1984. See, http://www.context.org/ICLIB/IC07/Myers.htm.
[44] Unit 4 is located at Richland, Washington while unit 5 is located at Satsop, Washington.

and 3.[45] As a result of its net billing arrangements, BPA passes on the cost of its non-Federal project debt to its customers. Net billing agreements are contractual arrangements under which the BPA bills participants in its inoperable Trojan nuclear plant[46,47] and the Columbia Generating Station. Each participant assigns its share of output to the BPA and in return BPA credits the participant's wholesale bill up to the monetary value of the participant's share of the generation output.[48] Thus, non-Federal project debt is not actually issued by BPA, but rather it is issued by Energy Northwest with BPA as the obligor pursuant to a net billing power supply arrangement.[49]

In 2010, approximately $3.4 billion of BPA's $6.0 billion (2010 dollars) in non-Federal project debt was devoted to cancelled nuclear power plants. Although the federal government does not explicitly guarantee BPA's non-Federal debt, the financial community treats the debt as though it was guaranteed. BPA is a federally-owned utility, and for its latest debt financing in 2010, Standard and Poor's and Fitch Ratings assigned newly issued Energy Northwest revenue and refinancing bonds an AA rating.[50] Moody's rated the bonds as Aaa.[51] In Moody's Investor Services High Profile New Issue dated December 2010, Moody's states: "BPA's Status as a U.S. Energy Department Line Agency and Its Relationship to the federal Government Are Important to the Credit Rating. While BPA's obligations do not benefit from the full faith and credit of the United States Government, BPA benefits from significant support from the US government and strong interrelationships as shown below. In a major stress scenario, Moody's expects any US government support to BPA is likely to be provided through the established US Treasury credit lines or deferral of payments to the US Treasury."[52]

In the estimate of BPA's federal interest rate support presented below, the interest cost of BPA's non-Federal power debt is compared to the cost of similar debt issued by IOUs. This estimate is not without controversy. On the one hand, although much of BPA's Energy Northwest debt is exempt from federal taxation, BPA is obligated to pay the debt service on Energy Northwest bonds and this debt appears on the balance sheet of the federally-owned utility.[53] As obligor of this debt, whatever tax-free status this debt enjoys due to it "municipal" status, is deemed not relevant to the calculation of interest support provided through implicit federal ownership and backing. However, an alternative view might be to compare the cost of this debt to the cost of debt on tax-free municipal bonds.

[45] The only operating unit among these is Project 2, the Columbia Generating Station.
[46] The Trojan project is among Bonneville's terminated nuclear plants along with Energy Northwest Nuclear Projects 1 and 3.
[47] BPA charges preference customers' entitlement shares of output from the abandoned Trojan project. BPA became responsible for Trojan's debt service and decommissioning costs.
[48] Bonneville Power Administration http://www.bpa.gov/Power/PSR/pbl_billing_procedures.pdf, accessed October 11, 2007.
[49] Standard and Poor's notes that "Debt service on the $7.17 billion of outstanding ENW debt as of March 1, 2007 is legally an operating expense of Bonneville." Source: Standard and Poor's Public Finance:
http://www.bpa.gov/corporate/Finance/Debt_Management/reports_articles/docs/SP_2_17_04.pdf, accessed October 11, 2007.
[50] Standard and Poor's Global Credit Portal, "Summary: Energy Northwest, Washington Bonneville Power Administration,: Wholesale Electric," February 25, 2011, http://www.bpa.gov/corporate/Finance/Debt_Management/reports_articles/docs/2011/S_P_Rating_Report-feb-2011. Fitch Ratings, Fitch Rates Energy Northwest, WA's Columbia Generating Station 'AA' & Bonneville Power Implied 'AA' Ratings, December 2010, http://www.bpa.gov/corporate/Finance/Debt_Management/reports_articles/docs/2010/Fitch_Rates_ENW__AA__Stable_Outlook_12-9-10.pdf.
[51] Moody's Investors Service, High Profile New Issue, Energy Northwest, Bonneville Power Administration, December, 2010, http://www.bpa.gov/corporate/Finance/Debt_Management/reports_articles/docs/2010/BPA-ENW_high_profile_report_dec_2010.pdf
[52] http://www.bpa.gov/corporate/Finance/Debt_Management/reports_articles/docs/2010/BPA-ENW_high_profile_report_dec_2010.pdf.
[53] Certain Energy Northwest bond issues are also enhanced with bond insurance.

Table 21. Estimate of federal electricity interest rate support to BPA, 2007 and 2010 (million 2010 dollars)

	Treasury Rate	Aaa IOU Rate	Aa IOU Rate	A IOU Rate	Baa IOU Rate
2007					
1) Benchmark Interest Rate (%)	4.84	5.67	5.94	6.07	6.33
2) Outstanding Debt ($)	18,378	18,378	18,378	18,378	18,378
3) Average Cost of Outstanding Debt ($)	4.90	4.90	4.90	4.90	4.90
4) Actual Interest Expense (%)	901	901	901	901	901
5) Interest Expense Computed at Benchmark Rate ($) [(1)*(2)]	899	1,043	1,092	1,116	1,164
6) Estimated Interest Support at Benchmark Rate ($) [(5)-(4)]		142	191	215	263
2010					
1) Benchmark Interest Rate (%)	4.24	4.96	5.23	5.46	5.97
2) Outstanding Debt ($)	18,246	18,246	18,246	18,246	18,246
3) Average Cost of Outstanding Debt (%)	4.28	4.28	4.28	4.28	4.28
4) Actual Interest Expense ($)	782	782	782	782	782
5) Interest Expense Computed at Benchmark Rate ($) [(1)*(2)]	774	905	954	996	1,088
6) Estimated Interest Support at Benchmark Rate ($) [(5)-(4)]		123	172	214	307

Notes: The above table represents the historic value of BPA's debt in 2010 dollars for purposes of illustrating how support values for 2007 and 2010 were calculated. The nominal value of debt reported on BPA's balance sheet for the year 2007 was: $14,531,190,000.
A negative estimate of interest support indicates the weighted average cost of outstanding debt exceeds the benchmark interest rate.
Source: Bonneville Power Administration, 2007 and 2010. Moody's Investors Service, Federal Reserve Bank Form H-15.

New Financial Arrangement

In April 2008, BPA and the U.S. Treasury formalized a new arrangement that provided what BPA calls "a more flexible banking financial relationship that better meets the Agency's business needs. As part of this arrangement, BPA gained the ability to use part of its, then, $4.45 billion line of credit with the U.S. Treasury to borrow for expenses. Formerly, BPA had no arrangement with Treasury to borrow for such costs. BPA can now borrow up to $750 million for Northwest Power Act-related operating expenses, with funds available the same day as the request is made. The repayment period for these borrowings can range from three months to two years. When drawn on, this facility would be a use of Treasury borrowing authority."

BPA's Federal Interest Support

EIA has estimated BPA's cost of funds as being based upon its three sources of debt (Appropriated debt, long term debt, and non-Federal power debt) multiplied by the appropriate interest rates. In the case of appropriated debt a 30-year Treasury rate was applied. In the case of long term debt, the weighted average of BPA's long term debt was used. In the case of non-Federal power debt, the average interest rate for municipal utilities was used. BPA's current total cost of funds compared to what it would have spent had it borrowed at the U.S. Treasury rate and various IOU rates varies by the alternative interest rate selected for purposes of estimating the support (Table 21). This report estimates BPA's borrowing costs based upon its three forms of debt. Estimates of the cost of this debt were done as follows: BPA's appropriated debt is benchmarked to the BPA's embedded borrowing costs, which are assumed to reflect long-term Treasury rates in both 2007 and 2010. Long-term debt is benchmarked to a weighted average of BPA's reported long term borrowing costs as a percent of associated long-term debt issuances, as reported in BPA financial documents. BPA's non-federal power interest payments are benchmarked to municipal bond rates as found in the Federal Reserve Bank's Form H-15. In 2010, borrowing at a public utility rating of Aaa would have cost BPA an additional $123 million (2010 dollars); an Aa rating would have cost BPA an additional $172 million (2010 dollars); an A rate would have cost BPA an additional $214 million (2010 dollars); and, a Baa rating an additional $307 million (2010 dollars). In contrast, in 2007, an Aaa rating would have raised BPA's borrowing costs by $142 million (2010 dollars); an Aa rate would have increased BPA's borrowing costs by $191 million (2010 dollars); an A rate by $215 million dollars; and, a Baa rate by $263 million dollars (2010 dollars).

The Smaller Power Marketing Administrations

The three smaller PMAs are the SEPA, the SWPA, and the WAPA. Each is headed by an administrator appointed by the Secretary of Energy. More so than either BPA or TVA, the three smaller PMAs benefit from low-cost hydropower dams that were built as long as 60 years ago. The PMAs receive appropriations from the Treasury for most of their operations and maintenance expenses, as well as for capital expenditures. The former is expected to be paid off in the year it is received; the latter can be paid back with interest over the service life of the investment, for a period not to exceed 50 years. In 2007, the PMAs' embedded cost of debt was more than 100 basis points below the Treasury's own borrowing costs, while in 2010, PMA's embedded cost of debt was 24 basis points higher the Treasury benchmark rate.

The largest of the 3 smaller Power Marketing Administrations, the Western Area Power Administration, received additional borrowing authority under the ARRA. The Act grants the Western Area Power Administration the

Table 22. Estimate of federal electricity interest rate support to the three smaller PMAs, 2007 and 2010 (million 2010 dollars)

	Treasury Rate	Aaa IOU Rate	Aa IOU Rate	A IOU Rate	Baa IOU Rate
2007					
1) Benchmark Interest Rate (%)	4.84	5.67	5.94	6.07	6.33
2) Outstanding Debt ($)	7,310	7,310	7,310	7,310	7,310
3) Average Cost of Outstanding Debt ($)	3.80	3.80	3.80	3.80	3.80
4) Actual Interest Expense (%)	278	278	278	278	278
5) Interest Expense Computed at Benchmark Rate ($) [(1)*(2)]	354	415	434	444	463
6) Estimated Interest Support at Benchmark Rate ($) [(5)-(4)]	76	137	156	166	185
2010					
1) Benchmark Interest Rate (%)	4.24	4.96	5.23	5.46	5.97
2) Outstanding Debt ($)	7,405	7,405	7,405	7,404	7,405
3) Average Cost of Outstanding Debt ($)	4.47	4.47	4.47	4.47	4.47
4) Actual Interest Expense (%) Computed at Benchmark Rate ($) [(1)x(2)]	331	331	331	331	331
5) Interest Expense Computed at Benchmark Rate ($) [(1)*(2)]	314	367	387	404	442
6) Estimated Interest Support at Benchmark Rate ($) [(5)-(4)]	NA	37	56	74	111

Notes: The above table represents the historic value of three smaller PMAs debt in 2010 dollars for purposes of illustrating how support values for 2007 and 2010 were calculated. The nominal value of debt reported on their balance sheet for the year 2007 was $7,261,961,000.
A negative estimate of interest support indicates the weighted average cost of outstanding debt exceeds the benchmark interest rate.
Sources: Southeastern Power Administration 2007 and 2010 Annual Reports, Southwestern Power Administration 2007 and 2009 Annual Reports, Western Area Power Administration 2009 Annual Report, Moody's, and Federal Reserve Bank Form H-15.

authority to borrow up to $3.25 billion from the U.S. Treasury.[54] Section 402 of ARRA states: "The rate of interest to be charged in connection with any loan made pursuant to this subsection shall be fixed by the Secretary of the Treasury taking into consideration market yields on outstanding marketable obligations of the United States of comparable maturities as of the date of the loan."[55] Section 402 also promotes construction of additional transmission to move renewable energy across the grid in the West. Thus far, Western is using the grant to help build a $213 million Montana-Alberta Tie Limited transmission project between Great Falls, Mont., and Lethbridge, Alberta, Canada with the purpose of bringing additional wind power to the grid. The project is the first to use our new borrowing authority.[56]

[54] Ibid, http://www.wapa.gov/newsroom/sec402.htm.
[55] American Recovery and Reinvestment Act of 2009, Public Law 111-5, Section 402.
[56] Western Area Power Marketing Administration, http://www.wapa.gov/recovery/default.htm.

Before 1983, the interest rate on the debt for the three smaller PMAs debt was set below prevailing Treasury rates. In 1983, DOE required the PMAs to pay a rate equal to the average Treasury yield during the previous fiscal year for new projects. According to an OMB study on PMA debt repayment, the Treasury has made a practice of borrowing money for the PMAs at 6 to 12 percent and accepting repayments on that debt at 2 to 4 percent. The PMAs are required to retire their high-cost debt first whenever possible, an advantage unavailable to the Treasury itself.[57] This is another reason that the PMAs can realize an effective borrowing rate lower than the Treasury.[58]

Southwestern Power Administration: (SWPA) Southwestern markets hydroelectric power in Arkansas, Kansas, Louisiana, Missouri, Oklahoma, and Texas from 24 U.S. Army Corps of Engineers multipurpose dams. Preferential power is offered, by law, to public bodies such as rural electric cooperatives and municipal utilities.

Western Area Power Administration: WAPA's marketing region includes five different regions, the Great Plains Region covers Montana, North and South Dakota, eastern Nebraska, and extreme western Minnesota and Iowa. The Rocky Mountain Region covers Wyoming, western Nebraska, western and northern Kansas and Colorado. The Desert Southwest Region covers the southern tip of Nevada, all but the northeast corner of Arizona, and southern California. The Sierra Nevada Region covers northern California and northern Nevada. The Colorado River Storage Project Management Center covers northeastern Nevada, Utah, New Mexico, west Texas, and the northeastern corner of Arizona.

Southeastern Power Administration: SEPA is headquartered in Elberton, Georgia, has the responsibility to market the electric power and energy generated at reservoirs operated by the U.S. Army Corps of Engineers in the states of Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee, Virginia, West Virginia, and a small portion of southern Illinois.

PMA Borrowing Costs

The three PMAs' current interest expense was compared to what they would have paid had they borrowed at long-term Treasury rates, Aaa, Aa, A, or Baa IOU rates. The federal interest rate support is estimated as the difference between a hypothetical interest payment based on Treasury and market interest rates and the actual interest expense reported by each PMA. Depending on the comparative interest rate benchmarks, the three smaller PMAs received federal support ranging from $37 million (2010 dollars) if their debt were priced at an Aaa rate to $111 million (2010 dollars) at the Baa rate in 2010 (Table 22). This compares with estimated support at the Treasury rate of $76 million in 2007 (2010 dollars) and $185 million at the Baa rate. In 2010, the smaller PMA's borrowing costs exceeded those of the Treasury's by 60 basis points.

[57] IOUs have the ability to issue callable bonds which allows them the same advantage. However, when a bond is called, typically the issuer of the bond pays the bondholder a premium above the par value of the bond.
[58] General Accounting Office, Federal Power: Options for Selected Power Marketing Administrations' Role in a Changing Electricity Industry, GAO/RCED-98-43, (Washington, DC, March 1998), p. 7.

Rural Utilities Service Electric Loans, Guarantees, and Grants

The Rural Utilities Service (RUS), a part of the U.S. Department of Agriculture, makes direct loans and loan guarantees used to finance the construction of electric distribution, transmission, and generating facilities that serve customers in rural areas. By law, a RUS borrower must be a publicly-owned cooperative utility. RUS is the successor to the Rural Electrification Administration (REA), which was authorized by the Rural Electrification Act of 1936. As the name, REA, suggests, RUS's initial focus was solely on electricity. Over the years, REA's authority expanded to include making loans for water, sewage disposal, and telecommunication facilities.[59] Additionally, unlike the Department of Energy's loan program, discussed in the next chapter, RUS has a long history in providing government-sponsored loan support. In fact, RUS's loan program is one of the oldest in the federal government.

In total, RUS's borrowers service about 12 million customers and the total generation of these firms represents about 7 percent of the nation's total. Also, more than 50 percent of the total sales of RUS borrowers go to residential customers, indicating that the borrowers' retail share of electricity sales is relatively high when compared to other providers of electricity. This is not surprising since by law the customers of RUS borrowers must be in rural areas which, in a relative sense, tend to have a lower concentration of industrial and commercial electricity consumers. Lastly, the average size of RUS's loans is about $30 million which is very small when compared to the average DOE loan programs office loan of more than $1 billion, as described in Chapter 5. The typical RUS borrower therefore tends to be a relatively small cooperative utility that services residential customers.

RUS can make three general types of loans and loan guarantees.[60] First, hardship loans are available to electric distribution borrowers that have experienced an unavoidable natural disaster. The interest rate on these loans is 5 percent. Hardship loans are also available to electric distribution borrowers that meet a rate disparity and consumer income test. This test compares the borrower's retail rates and its customers' per capita or household income to statewide averages.[61] Second, RUS can also make direct loans that are tied to municipal bond or Treasury rates. These loans can be used to fund the construction of distribution, and renewable generating facilities, as well as their operational costs. After 2008, none of these loans can be used to construct fossil fuel-fired power plants. Borrowers receiving loans, that are tied to municipal bond rates, which are typically lower than Treasury yields, must obtain supplemental financing from other lenders for generally 30 percent of the total loan amount. Third, RUS can also guarantee loans made by the federal Financing Bank (FFB), the funding arm of the Department of the Treasury through which government agencies obtain capital or by accessing financing from

[59] Recently, Federal legislation has been enacted that mandates the RUS to promote broadband. See; Congressional Research Service, "Broadband loan and Grant Programs in the USDA's Rural Utilities Service," RL33816 (Washington, DC, March 17, 2009).
[60] See the 2007 report for a more detailed description of the types of RUS loans and guarantees. U.S. Energy Information Administration, *Federal Financial Interventions and Subsidies in Energy Markets 2007*, DOE/EIA-SR/CNEAF/2001-01 (Washington, DC, April 2008).
[61] Residential and average system rates must not be less than 120 percent of the average for all utilities in the State, and, either per capita income, or household income, must be less than State average per capita income or the State median household income.

cooperative and not for profit lending institutions such as the National Rural Utilities Cooperative Finance Corporation (CFC). It should be noted that, in this section, loans made by RUS will be identified as direct loans and loans made by the FFB or CFC will be identified as guarantees. In the next chapter, loans made by the FFB and guaranteed by DOE will also be called direct loans while loans made by privately owned lending institutions and guaranteed by DOE will be called a loan guarantees.[62]

Estimates of the subsidy provided by RUS electric loans and loan guarantees

Since RUS administers federal credit programs, the Federal Credit Reform Act of 1990 requires that they compute a credit subsidy cost associated with such programs. The CSC is the expected (in a mathematical sense) cost to the government of direct RUS loans and guarantees, and is computed by first estimating the cash inflows and outflows over the entire life of the loan.[63] These cash inflows and outflows are then adjusted for expected (again, in a mathematical sense) defaults and recovery rates if the loan is not paid, and then everything is discounted back to the present using Treasury rates. In most cases, an appropriation equal to the CSC is needed from Congress before loans can be made, and thus, the CSC, and the assumed default and recovery rates are reported in agencies' budget submissions to Congress. Thus, from a budgetary viewpoint, the CSC is a direct measure of the subsidy provided by the RUS direct loans and guarantees.

Unlike many other federal credit programs, the CSCs for RUS's electric loans, as reported in their budget submissions, is negative implying that the expected (in a mathematical sense) cost to the government is negative. From a purely budgetary viewpoint, RUS's electric loans will decrease government expenditures, and thus, from a budgetary viewpoint there are no subsidies associated with RUS's electric loans. There are probably two reasons why the CSCs are negative. First, the interest rates paid by RUS borrowers are slightly greater than the Treasury rates used to discount these costs back to the present. Thus, if there are no defaults, the CSCs must be negative. Second, the default rates assumed by RUS for their direct electric loans are about 1-2 percent, and the assumed recovery rates are about 80-90 percent. Since the expected costs associated with defaults are very small, negative CSCs are not surprising.

As was done with the implicit loan guarantees to the debt holders of federal utilities, another measure of the subsidy resulting from the explicit RUS guarantees is the reduction in interest expenses. The size of this subsidy is a function of the spread between the cost of borrowing with RUS backing relative to the cost of uninsured long-term debt available in commercial capital markets. The latter reflects a risk premium associated with a borrower's credit worthiness. Without detailed information about the direct loans and loan guarantees that RUS holds in its portfolio, it is impossible to estimate this spread. Therefore, the subsidy estimates reported in this section will be computed by comparing the embedded yields of RUS loans and loan guarantees to a range of investment grade bonds for 2009. The investment grade bond rates used here are those for Aaa, Aa, A, and Baa rated investor-owned utility fixed-income securities. This range is provided, because it is unclear what rate RUS electricity borrowers would face in private markets without the RUS guarantees.

[62] As will be seen in the next chapter, to date, all of DOE's guaranteed loans are made by the FFB.
[63] The FCRA of 1990 and the computation of the CSC are discussed in detail in the next chapter of this report.

The most current data available from RUS is for the year 2009, and thus, embedded debt rates in 2009 are compared with 2009 bond yields. RUS collects detailed financial data on utilities that currently have RUS direct loans. Included in these data are interest expenses and the dollar value of debt for two types of loans: 1) RUS direct loans; and, 2) loans made by the FFB/CFC and guaranteed by RUS. What is not reported is the amount of RUS guaranteed debt held by utilities that receive no RUS direct loans. Since the measure of FFB/CFC loans that are guaranteed by RUS is incomplete, as was done in the 2008 study, only the subsidy resulting from RUS's direct loans will be computed.[64] Additionally, to be consistent with other annual data estimates presented in this report, both the actual amount of debt and interest expenses were inflated to 2010 dollars. Thus, all of the subsidy estimates will also be presented in 2010 dollars. Additionally, as of May 2011, the DOE has guaranteed more than $25 billion in loans all of which were, or will be, issued by the FFB. There are also about $15 billion in loans issued by FFB/CFC and guaranteed by RUS that are held by current holders of RUS direct loans. Thus, the amount of energy-related loans issued by RUS and by the FFB/CFC and guaranteed by RUS or DOE is in excess of $75 billion.[65]

The subsidy estimates are shown in Table 23. The size of the subsidy estimates will be a function of the spread between RUS's embedded debt rates and the assumed rates if the loans were made by private uninsured firms. In general, the subsidies have fallen from 2007 to 2010. In 2007, the estimates ranged from about $93 million to $305 million and in 2009 they ranged from about $56 to $319. (The $800 million estimate in 2009 appears to be an outlier and is due to usually high yields on Baa rated bonds in 2009 of more than 7 percent.)

When judging the actual risk of RUS loans, it should be noted that the assumed default rates of 1-2 percent used to compute the CSC are similar to historical default rates on bonds that were initially rated Aaa. (The rating of a typical bond issued by an investor owned electric utility is Baa.) Additionally, several analyses have concluded that in the past, RUS faced a significant risk of large loan defaults. For example, a 1997 Government Accountability Office (GAO) study found that $618 million of the outstanding electricity loan portfolio was owed by borrowers who were delinquent in their payments and that $7.4 billion of the outstanding debt was owed by borrowers who were in financial distress. At that time the outstanding RUS electricity debt totaled $32.3 billion, of which approximately 25 percent was at risk of not being fully repaid. In a subsequent report, GAO found that the RUS wrote off more than $3.2 billion in loans made to three borrowers.[66] Much of the problem debt was associated with loan guarantees for borrowers' investments in high-cost nuclear plants in the early 1980s. For example, the Wall Street Journal reported that more than $1.5 billion in debt was written down for two borrowers in 1996. In 2006, the RUS reported $818,000 in a loan write-down due to the default of the Vermont Electric Generation and Transmission Cooperative.[67]

---

[64] Total interest expenses for RUS's direct loans and guarantees are reported. The interest expenses for direct RUS loans were imputed using the ratio of RUS direct loans to total debt.

[65] Again, this is a lower bound estimate since the amount of RUS guarantees held by utilities that current hold no direct RUS loans is not reported.

[66] Government Accountability Office, *Rural Utilities Service: Opportunities to Better Target Assistance to Rural Areas and Avoid Unnecessary Financial Risk*, GAO-04-647 (Washington, DC, June 2004), p. 8

[67] Conversation with Chris Tuttle of the Rural Utilities Service, July 30, 2007.

Table 23. Interest subsidy to RUS borrowers 2007 and 2010 (million 2010 dollars)

	Treasury Rate	Aaa IOU Rate	Aa IOU Rate	A IOU Rate	Baa IOU Rate
2007					
1. Benchmark Interest Rate (%)	NA	5.67	5.94	6.07	6.33
2. Outstanding Debt ($)	NA	32,273	32,273	32,273	32,273
3. Average Cost of Outstanding Debt (%)	NA	5.39	5.39	5.39	5.39
4. Actual Interest Expense ($)	NA	1,738	1,738	1,738	1,738
5. Interest Expense Computed at Benchmark Rate ($) [(1) x (2)]	NA	1,831	1,917	1,960	2,043
6. Estimated Interest Subsidy at Benchmark Interest Rate ($) [(5)-(4)]	NA	93	180	222	305
2010					
1. Benchmark Interest Rate (%)	NA	4.96	5.23	5.46	5.92
2. Outstanding Debt ($)	NA	35,746	35,746	35,746	35,746
3. Average Cost of Outstanding Debt (%)	NA	5.07	5.07	5.07	5.07
4. Actual Interest Expense ($)	NA	1,813	1,813	1,813	1,813
5. Interest Expense Computed at Benchmark Rate ($) [(1) x (2)]	NA	1,773	1,869	1,951	2,132
6. Estimated Interest Subsidy at Benchmark Interest Rate ($) [(5)-(4)]	NA	NA	56	138	319

Note: NA indicates that some of the cost of outstanding debt exceeds the benchmark interest rate. There is no subsidy when benchmark rates are less than the weighted cost of capital.

Table 24. Interest subsidy to federal utilities and RUS borrowers 2007 and 2010 (million 2010 dollars)

	Treasury Rate	Aaa IOU Rate	Aa IOU Rate	A IOU Rate	Baa IOU Rate
2007					
1. Benchmark Interest Rate (%)	4.84	5.67	5.94	6.07	6.33
2. Outstanding Debt ($)	83,796	83,796	83,796	83,796	83,796
3. Average Cost of Outstanding Debt (%)	NA	5.23	5.23	5.23	5.23
4. Actual Interest Expense ($)	NA	4,383	4,383	4,383	4,383
5. Interest Expense Computed at Benchmark Rate ($) [(1) x (2)]	NA	4,751	4,977	5,086	5,304
6. Estimated Interest Subsidy at Benchmark Interest Rate ($) [(5)-(4)]	NA	368	594	703	921
2010					
1. Benchmark Interest Rate (%)	4.24	4.96	5.23	5.46	5.97
2. Outstanding Debt ($)	85,988	85,988	85,988	85,988	85,988
3. Average Cost of Outstanding Debt (%)	NA	4.82	4.82	4.82	4.82
4. Actual Interest Expense ($)	NA	4,146	4,146	4,146	4,146
5. Interest Expense Computed at Benchmark Rate ($) [(1) x (2)]	NA	4,265	4,497	4,695	5,133
6. Estimated Interest Subsidy at Benchmark Interest Rate ($) [(5)-(4)]	NA	119	351	549	987

Note: NA indicates that some of the cost of outstanding debt exceeds the benchmark interest rate. There is no subsidy when benchmark rates are less than the weighted cost of capital.

Summary

In 2010, the total value of support provided federal utilities and RUS borrowers is estimated at $119 million (Table 24) at the Aaa benchmark rate, $351 million at the Aa rate, $549 million at the A rate, and, $987 million at the Baa rate. This compares to 2007 support values of $368 million at the Aaa rate, $594 million at the Aa rate, $703 million at the A rate, and $921 million at the Baa rate. The estimate varies using different benchmark interest rates. Federal utilities and participants in RUS electricity lending programs borrow at rates typically below those available to non-publicly-owned power producers. In 2010, the ratio of embedded cost of debt (interest expenses) to the outstanding debt for federal utilities and RUS borrowers indicates that these entities have borrowed at rates ranging from slightly higher than the Treasury's own costs of funds to those for a highly-rated utility with an Aaa bond rating.

5. Loan Guarantee Programs

Introduction

This chapter presents a description of the Department of Energy's (DOE's) loan guarantee programs and presents some estimates of the resulting subsidies. With the exception of RUS and the synthetic fuel program in the 1970s, energy-related explicit loan guarantee programs are new federal interventions in energy financial markets. DOE's initial loan guarantee program was authorized by the Energy Policy Act of 2005 (EPAct2005) and the first guarantee was issued in the fall of 2009. As of the end of calendar year 2010, the Department of Energy (DOE) has actually issued over $25 billion in loan guarantees. Additionally, the staff of the office within DOE that administers the programs has grown from 0 in 2005 to roughly 85 in 2010. Thus, DOE's loan guarantee program is growing and is becoming an important component of the Administration's energy program.

As can be seen from Table 25, the size of federal credit programs in general have increased considerably. Here, the dollar value of the additional loans agencies are authorized to issue in Fiscal Year 2010 is used as the measure of volume. In fact, the total size of federal credit programs has more than doubled over the last 6 years. The growth in DOE's loan guarantee program is therefore one part of the overall trend toward the increased use of federal credit programs. It is also interesting to note that when compared to housing and education, energy-related loan guarantee programs are relatively small.

**Table 25. Additional lending authority for loan guarantee programs in selected government agencies, 2004 and 2010
(thousand 2010 dollars)**

Selected Agencies	2004	2010
Department of Agriculture excluding RUS	$16,656,571	$50,764,352
Department of Education	$91,773,139	$258,868,106
Department of Energy	$0	$47,367,293
Rural Utility Service: Electricity Program	$3,989,410	$7,100,000
Department of Housing and Urban Development	$368,904,121	$741,988,701
Department of Veteran Affairs	$48,450,960	$60,215,650
Department of Transportation	$3,226,777	$2,805,510
Small Business Administration	$21,918,500	$44,852,036
International Assistance programs	$655,000	$4,324,879
Total for Selected Agencies	**$555,574,478**	**$1,218,286,527**

Source: FY 2011 Budget Submission to Congress, Federal Credit Supplement, Spreadsheets.

Although the size of DOE's loan guarantee program is relatively small, the dollar value of the average loan is over $1 billion. Excluding the Troubled Asset Relief Program (TARP), the average size of DOE's loans is the largest in the federal government.[68] Thus, one or two defaults of DOE guaranteed loans could result in substantial losses to the federal government. It is not surprising that the amount of information DOE requires to process a loan request is rather large and the approval process can take a considerable amount of time.

The previous chapter estimated the reduction in borrowing costs of federal utilities because of the "implicit" guarantees on the loans of these agencies. This chapter will estimate the total cost savings resulting from the explicit guarantees. Thus, there are some similarities between the analysis in that chapter and this one. There are, however, some major differences in the analyses. First, the implicit guarantees examined in the previous chapter went to publicly-owned utilities whereas the bulk of DOE's loans went to privately-owned firms. As will be seen later, the calculation of the cost savings of publically and privately-owned firms will be different. Second, in the case of explicit guarantees, federal regulations require agencies to estimate one direct measure of the subsidy supporting those guarantees.

In this chapter, two types of loan guarantee programs will be considered. The first type is a true guarantee by DOE of a loan made by a third party in the private sector such as a commercial bank or investment house. The second is direct loans made by the Department of Treasury's Federal Financing Bank (FFB) to the borrower and guaranteed by DOE. In the latter case, in case of default, the cost would appear on DOE's rather than Treasury's accounts. Almost all of DOE's loan guarantees are actually direct loans made by the FFB. Thus, in this chapter, the focus will be on loans made by the federal government as opposed to ones made by third parties in the private sector. Additionally, the phrases "direct loan" and "loan guarantee" will be used interchangeably.[69] The distinction between direct loans and ones that are originated in the private sector and guaranteed by a federal agency is important because interest rates on the former tend to be slightly lower than the ones on the later.

The organization of the remainder of this chapter is as follows. The budgetary accounting for loan guarantees is unique to the federal government and is governed by the Federal Credit Reform Act (FCRA) of 1990. In fact, the FCRA requires that federal agencies compute the credit subsidy cost which is one direct measure of the subsidy provided by DOE's loan guarantee programs. The next section discusses the FCRA and describes how the credit subsidy cost is computed. The following section 3 describes DOE's loan guarantee programs. Excluding RUS and perhaps the Export-Import Bank, there are a number of very small energy-related loan guarantee programs in the Departments of Agriculture and Housing and Urban Development (Due to their small size these programs are excluded from this analysis). The next section presents some estimates of the subsidy provided by DOE's loan guarantee program. Some conclusions are reached in the final section of this chapter.

[68] FY 2011 Budget Submission to Congress, Federal Credit Supplement, Spreadsheets, Table 2.

[69] As noted in the previous chapter, some agencies have direct lending authority. Since DOE has no such authority this type of loan will not be considered.

The Federal Credit Reform Act of 1990 and the Computation of the Credit Subsidy Cost

After many years of discussions about the problems with the federal budgetary treatment of existing federal credit programs, in 1990 the Congress and Bush Administration agreed to change the accounting guidelines for these programs in the budget. The Federal Credit Reform Act (FCRA) of 1990 required the federal budget to reflect the "true" cost of federal credit programs. The FCRA also changed the budgetary accounting practices so that the cost of a credit program was consistent with the ones for other government activities.[70]

Before the passage of FCRA, the cost of a credit program was computed on a pure cash basis. For a direct loan, the budget would reflect the dollar value of the loan in the year that it was made. Any interest payments and/or repayment of principal would appear on the budget the year the monies were received. In case of default, the funds that were recovered would appear as a receipt the year the default occurred. For loans made by parties in the private sector that were guaranteed by the government, budgetary outlays would only occur if the loan was defaulted. In such cases, the outlay would equal the guarantee less any repayment of the principal. If the loan was not defaulted, there would be no budgetary impacts. Prior to 1990, the cost of a guarantee would be incurred in the future whereas the cost of a direct loan would be incurred when it was made. It was therefore not surprising that prior to 1990, there were relatively few direct loans.

Additionally, before 1990, many credit programs were subject to legislatively imposed limits. According to the Congressional Budget Office (CBO), in some cases, these limits had little effect on actual borrowing activity, because the limits were very high relative to actual demand. Additionally, prior to the passage of the FCRA, many credit programs used revolving funds, an account that was credited with payments from borrowers to finance the continued activity of the program. The only time an appropriation would be needed was when a fund had a negative balance. In such cases, Congress would appropriate enough monies to insure that the fund remained solvent. Thus, at least according to the CBO, Congress had limited control of an agency's actual borrowing activity.[71]

Under the FCRA, the cost of federal credit programs would be recorded on an actuarial, as opposed to a cash basis. In particular, the expected (in a mathematical sense) cash inflows and outflows estimated over the entire life of the loan are estimated. The inflows would include interest payments and repayment of the principal. The outflows would consist of the dollar value of the loan and in the case of guarantees, payments to the lender in case of default. Then, all the expected cash flows are discounted back to the present using yields on Treasury bonds as the discount rate. The result is called the credit subsidy cost (CSC) and is the expected cost of the loan to the government. An explicit appropriation from Congress equal to the CSC is needed before the loan would be made. (The only exception to this is when the borrower pays the CSC.) Thus, Congress now has direct control over the size of a federal credit program. Additionally, the CSC would appear on the federal budget as the cost of the loan when it was made.

---

[70] This borrows very heavily from Congressional Budget Office Staff Memorandum, An Explanation of the Budgetary Changes Under Credit reform, April 1991

[71] Ibid, p 7.

The actual computation of the CSC can be complex. However, the spirit of the computations will be illustrated with a very simply example. In this example, the following assumptions will be made:

1. Size of the loan-$100
2. Length of loan-2 years
3. Probability of default in year 1-0 percent
4. Probability of default in year 2-25 percent
5. Recovery rate in case of default-30 percent
6. Treasury bond rate-5 percent.

Given these assumptions, the computation of the CSC for a direct loan is shown in Table 26. Column a shows the cash outflow which is simply the dollar value of the loan (-$100 in this example.). The cash inflow if the loan is not defaulted is shown in column b. In year 1 the government would receive $5 in interest payments, and in year 2 they would receive the interest payment plus the repayment of the principal ($100 + $5). The expected cash inflow if the loan is not defaulted (column d) is the cash inflow times the probability of not defaulting on the loan ($105 x .75=$78.75). If the loan is defaulted, by assumption, the government could recover 30 percent of the loan or $30. This is shown in column f. The expected cash inflow if the loan is defaulted would simple be $30 times the probability of default of 25 percent. Total expected cash inflows and outflows are shown in column h. The CSC is the sum of the expected cash inflows and outflows all discounted back to the present using yields on Treasury bonds as the discount rate (see column i). In this example, the CSC would be $17 dollars. Again, Congress would have to appropriate $17 before the loan could be made.

Table 26. An example of the computation of the credit subsidy costs

	Columns								
	a	b	C	d	e	f	g	h	i
Year	Cash Out-flows	Cash Inflows if no Default	Probability of not Defaulting	Expected Cash Inflows if Loan is not Defaulted (b x c)	Recovery Rate if Loan Defaulted (percent)	Cash Inflows if Loan Defaulted (100 x .3)	Expected Cash Inflows if Loan Defaulted (f x (1-c))	Total Expected Cash Inflows and Outflows (d + g)	Discounted Cash Inflows and Outflows
0	-$100							-$100	-$100.00
1		$5	100%	$5	NA			$5	$4.76
2		$105	75%	$79	30%	$30	$8	$86	$78.23
Credit Subsidy Cost									-$17.01

Totals may not equal sum of components due to independent rounding.
Source: Office of Energy Analysis, U.S. Energy Information Administration.

The computation of the CSC for a loan that is made by a third party in the private sector and guaranteed by the government is straight forward. If the loan is not defaulted, the expected cost to the government would be zero (0 x .75). If the loan is defaulted, the government would have to reimburse the lender for the principal ($100) and foregone interest ($5). Again, by assumption, the government would recover $30. Thus, the expected cost to the government would be $18.75 ((-105+30) x .25) and when this is discounted back to the present, the CSC would again be $17.

This example illustrates a number of important points. First, it shows the differences in the budgetary reporting of th costs of federal credit programs. Before the passage of FCRA, for a direct loan, the costs are shown in column a, and column b if the loan is not defaulted or column f if it is defaulted, would be reported in the appropriate year. Under FCRA, the subsidy cost, $17, would be reported the year the loan was made. Second, everything else being equal, under the FCRA the CSC for direct loans and guarantees would be the same. Thus, FCRA removed the built-in incentive toward making guarantees as opposed to direct loans. Lastly, many discussions about the value of the CSC focus on default rates. This example illustrates that recovery rates and the timing of the default are also important. In agencies' budget submissions to Congress, they report the assumed default and recovery rates. However, timing issues are seldom discussed.

Energy-Related Loan Guarantee Programs

Other than RUS which was discussed in Chapter 4 and possibly the Export-Import Bank, most of the energy-related loan guarantee programs are administered by DOE. (There are two energy-related loan guarantee programs in the Department of Agriculture, and one in the Department of Housing and Urban Development. All of these are very small.) The DOE has three programs, the oldest of which is authorized by Section 1703 of the Energy Policy Act of 2005 (EPAct05). The second is authorized by Section 406 of the American Recovery and Reinvestment Act (ARRA) of 2009. This section of ARRA amended Title 17 of EPAct05 by adding Section 1705. The third program is called the Advanced Technology Vehicles Manufacturing (ATVM) program. It is authorized by Section 136 of the Energy Independence and Security Act (EISA) of 2007.

The Title 1703 Loan Guarantee Program

Title 1703 of EPAct05 authorizes the DOE to make loan guarantees to fund projects related to the generation and conservation of electricity, including nuclear power. These projects must avoid, reduce or sequester greenhouse gasses and employ new or significantly different technologies compared to ones currently in commercial operation in the United States. To date, participating borrowers had to pay the entire CSC for any loan authorized under Section 1703. This way, the 1703 program is different from the other loan programs administered by DOE.

After EPAct2005 was passed, to implement the program a rulemaking specifying the details was needed. The final DOE rulemaking, issued on October 23, 2007 (and amended on November 4, 2009), established a two step process for applying for a loan guarantee.[72] The DOE first issues a solicitation to invite pre-applications for loan

[72] Federal Register, Tuesday, October 23, 2007,Part III, Department of Energy, 10 CFR Part 609, Loan Guarantees for Projects that Employ Innovative Technologies; Final Rule.

guarantees. Included in these pre-applications are construction cost estimates in reasonable detail; estimates of when the project will be completed; and, descriptions of any revenue generating agreements (i.e., purchased power contacts.). If these pre-applications pass initial screenings, full applications can then be submitted to the DOE. These applications will include detailed estimates of expected construction and operating costs; detailed descriptions of all the milestones leading up to the project's completion; and, a rating of what the project's risk would be without the guarantee made by one of the three major security rating firms.

One of the most controversial aspects of the final rulemaking dealt with the size of guarantee relative to the size of the project. Title 17 of EPAct05 stated that the DOE could guarantee up to 80 percent of total eligible costs. In the proposed rulemaking, the DOE said that they would only guarantee up to 90 of the debt, thus effectively reducing the maximum guarantee to 72 percent (90 x 80 percent) of the debt. DOE initially argued that having some uninsured debt would increase the incentives to successfully complete the project. After reviewing a number of comments to the proposed rule, especially ones made by the nuclear industry, the final rule stated that DOE would guarantee 100 percent of the debt.

When the final rulemaking was passed in 2007, DOE was only authorized to issue $4 billion in loan guarantees and in their FY2008 budget submission DOE requested an additional $9 billion. This would bring the total loan authorization up to $13 billion. With the passage of the FY 2008 Appropriations Act, the Section 1703 loan authorization was increased by an additional $38.5 billion. The legislation allocated the additional $38.5 billion cap as follows: $18.5 billion to nuclear plants; $10 billion for renewable, conservation, distributed energy and transmission/distribution technologies; $6 billion for carbon capture technologies; $2 billion for advanced coal gasification; and, $2 billion for advanced nuclear facilities for the front end of the fuel cycle. This increased the total loan cap to $51.5 billion.[73] The 2011 and 2012 budget submissions contained provisions that would have increased the nuclear cap by an additional $36 billion, which would have brought the nuclear total to $54.5 billion. In 2010, the Senate Appropriations Committee reduced the nuclear cap to $28.5 billion. However, the full Senate or House of Representative never voted on that bill.

To date, about $10.6 billion in conditional and final Section 1703 loans have been awarded. Of this, $8.33 billion was used to finance the construction of the Vogtle 3 and 4 nuclear units. About 45 percent of these proposed units will be owned by Georgia Power, and the remaining 55 percent by three publicly-owned utilities. About $3.4 billion of the loan went to Georgia Power and the remaining $4.9 billion went to the three publically-owned utilities. Areva, a large French publically-owned firm, also received a $2-billion loan to build a nuclear enrichment facilitate in Idaho. The remaining $300 million in 1703 loans went to 2 energy efficiency projects. In sum, these loans will support projects with a total cost of about $16.4 billion. Thus, the dollar value of the loans made under Section 1703 are about 65 percent of the total costs of the projects which is far less than the maximum of 80 percent. The remaining 35 percent would supposedly be equity financed.

[73] FY 2011 Budget Submission to Congress, Appendix, Department of Energy, p 441.

Title 1705 Loan guarantee program

Section 406 of the ARRA amended Title 17 of the EPAct05 by establishing Section 1705, a temporary loan guarantee program designed to support the rapid deployment of renewable energy and electric power transmission projects. Unlike Section 1703 loans, the DOE and not the borrower pays the CSC and thus DOE would need an explicit appropriation from Congress. Additionally, the requirement that the technology must be new was removed. To receive a loan under Section 1705, construction of the project must begin by September 30, 2011.

DOE has issued three solicitations under this program one of which established the Financial Institution Partnership Program (FIPP.) Under this program, if private sector lenders would fund eligible projects, DOE would guarantee up to 80 percent of the debt. In effect, the guarantee was used as "seed" money to stimulate private sector funding of eligible projects. However, based on information from the Loan Guarantee Office's Web site, only three Title 1705 projects were funded under the FIPP.

As of 2011, $2.5 billion in CSCs have been appropriated for Section 1705 loans As will be seen in the next section, the Credit Subsidy Rate (the CSC divided by the dollar value of the loan) for 1705 loans is about 10 percent.[74] This $2.5 billion appropriation will therefore support about $25 billion in loans. As of January 2011, a total of 14 conditional and final Section 1705 loans with a dollar value of about $7 billion have been made. The total cost of the projects receiving Section 1705 loans are about $11.4. Thus, the dollar value of the loan was about 64 percent of the total costs.

Table 27 shows the dollar value of the loans for various renewable and transmission technologies. There have been three loans with a dollar value of about $3.8 billion for large solar power plants. The total capacity of these power plants is about 800 megawatts. Estimated solar capacity in 2010 is about 700 megawatts.Assuming that all of these projects become operational, total solar capacity would more than double. About $1.3 billion of the $1.43 billion of guarantees for wind went to the Caithren Shepards Flat Project. The size of this wind farm would be 845 megawatts and upon completion one of the largest wind farms in the United States. As of January 2011, this was the only project funded under the FIPP.

Advanced Technology Vehicle Manufacturing Loan Guarantee Program

Unlike the bulk of the Title 17 loans, the Advanced Technology Vehicle Manufacturing (ATVM) loan guarantee program focuses on developing the infrastructure needed to produce Advanced Vehicles. In particular, Section 136 of authorized DOE to make grants and loan guarantees for projects that reequip, expand, or establish manufacturing facilities to produce advanced technology vehicles, or necessary components. Here, an advanced vehicle is defined as a light duty car that meets required emissions standards and has a fuel economy that is 125 percent of base year standards for automobiles with similar attributes. Thus, in this context, an advanced vehicle is effectively an electric powered automobile. Section 136 also authorized DOE to make grants and loan guarantees to cover the costs of certain engineering activities needed to produce advanced technology vehicles. In EIAS2007, a qualified component is one that is designed for an advanced vehicle and installed for the purpose of meeting the 125 percent fuel efficiency performance standards.

[74] FY 2012 Budget Submission to Congress, Appendix, Department of Energy, p 420.

Table 27. Section 1705 loans by technology as of early 2011 (billions of dollars)

Technology	Loan Size
Biofuels	0.241
Geothermal	0.181
Solar-generating facility	3.817
Solar Infrastructure	0.935
Wind	1.433
Storage	0.060
Transmission	0.350
Total	**7.017**

Totals may not equal sum of components due to independent rounding.
Source: Computed from data from U.S. Department of Energy, Loan Guarantee Program Office, https://lpo.energy.gov/?page_id=45, accessed March 23, 2011.

As was the case for the Title 1705 loans, under ATVM program the government will pay the subsidy costs, and, thus an explicit appropriation is needed. The Continuing Resolution Appropriations Act of 2009 appropriated $7.5 billion in CSCs that would support a maximum of $25 billion in loans.[75] The rulemaking issued by DOE in November 2008 stated that the maximum loan as a present of the total costs would be 80 percent. This is consistent with the rulemaking for the Title 17 loans. Lastly, DOE's authority to make loans under this program expires in 2017.

Table 28 shows the ATVM loans made to date. The loan to Ford Motor Company will be used to upgrade factories across Illinois, Kentucky, Michigan, Missouri and Ohio to produce some of their hybrid and electric automobiles. The loan going to Nissan Motor Company will be used to retool its Smyrna Tennessee plant to produce all-electric automobiles, and to construct an advanced battery manufacturing facility. The loans to Fisker Automotive and Tesla Motors will be used for similar functions. Interestingly, the loan going to the Vehicle Production Group will support the development of a wheelchair accessible vehicle that will run on compressed natural gas. As of early 2011, about $8.3 billion in ATVM loans have been made that will support projects with a total cost of about $14.4 billion. Thus, the dollar value of ATVM loans is about 58 percent of the project's total costs.

Other Energy related Loan Guarantee programs

There are four other energy-related loan guarantee programs. The largest one is under the RUS which was discussed in the previous chapter. The Rural Energy for American program provides loan guarantees to farmers, ranchers, and small rural businesses to purchase renewable energy systems and make energy efficient improvements. The Biorefinery Assistance program provides loan guarantees to fund the development,

[75] FY 2012 Budget Submission to Congress, Appendix, Department of Energy, p 417.

Table 28. ATVM loans made as of January 2011
(billions of dollars)

Company	Loan Size
Nissan	1.400
Tesla	0.465
The Vehicle Production Group	0.050
Ford	5.900
Fisker Associates	0.529

Totals may not equal sum of components due to independent rounding.
Source: Computed from data from U.S. Department of Energy, Loan Guarantee Program Office, https://lpo.energy.gov/?page_id=45, accessed March 23, 2011.

construction, and retrofitting of commercial size advanced biorefineries. Both of these programs are also in the Department of Agriculture. The last one is the Green Retrofit Program which offers either grants or loans to owners of Housing and Urban Development (HUD) assisted multifamily housing properties to fund energy efficient retrofits. As of 2010, excluding RUS, these programs have made less than $100 million in loans. Since they are so small, they will not be considered in the analysis described in the next section.

Subsidies Resulting from DOE's Loan Guarantee Program

This section describes the estimation of subsidies resulting from DOE's loan guarantee program. Congress requested that EIA focus on fiscal year 2010. Thus, only loans that received conditional or final approval in fiscal year 2010 will be included in this analysis.[76] The total value of such loans was about $23 billion that supported projects with a total cost of about $37 billion. Additionally, as will be seen shortly, because of the lack of public information about the details of the loans that were guaranteed, the best that could be done to estimate the underlying costs was to estimate ranges; and, in some cases these ranges were rather large. Some of the analysis also deals with the effects of financial leverage. For reasons that will be discussed below, in some cases, cooperative and municipal utilities were excluded from the calculations.

There are a number of ways of estimating the subsidy provided by DOE's loan guarantee program. A multi trillion dollar private market for insurance against loan defaults exists. In theory, a firm receiving a loan guarantee from the government could have instead purchased insurance from private insurers such as MBIA. In such cases, one direct measure of the subsidy would be the insurance premium a recipient of a government provided loan guarantee would have to pay if the insurance was purchased from private insurers. There is an extensive theoretical literature on this subject, and in the past, there have been attempts to estimate this insurance premium on government-provided loan guarantees.[77] This, however, it would involve a major research effort that is far beyond the scope of this analysis.

[76] Ford Motors received final approval for their $5.9 billion loan in late September of 2009. Fiscal year 2010 began on October 1, 2009. Because of the size of this loan it was included in the calculations.
[77] Robert McDonald, Derivative Markets, (New York: Addison-Wesley, 2003), Chapter 10; and, Congressional Budget Office, *Estimating the Value of Subsidies for Federal Loans and Loan Guarantees*, August 2004.

Credit Subsidy Cost Estimates

Another way to estimate the subsidy is to use the credit subsidy cost (CSC). Again, the FCRA requires an explicit appropriation equal to the CSC for every loan guarantee made unless the borrower pays the CSC. Since the CSC is the expected cost to the government for a loan guarantee, it measures the cost paid by the taxpayer, as opposed to the borrower, for insuring a loan and, thus, is another direct measure of the subsidy. There are, however, a number of problems with using the CSC. First, since the CSC is forward looking, it is different from the other subsidy estimates which are estimates at a particular point in time. Second, the CBO has shown that after accounting for risks other than ones related to default, the CSC, whose computation is dictated by the FCRA, will understate the actual cost of a loan guarantee--sometimes by a large amount.[78]

Lastly, every year that DOE requests authorization from Congress to issue additional loan guarantees, they often report the estimated CSCs. DOE also reports the estimated default and recovery rates used to compute these CSCs. In their budget submission to Congress, DOE clearly notes that the estimated CSCs are based on a portfolio of placeholder loans. (DOE does compute the CSCs for the loans that they actually guarantee, but they do not make those figures public.) The average credit subsidy rate (CSR) for the Title 1705 loans was about 11 percent which is based on estimated default rates in excess of 25 percent and recovery rates of about 55 percent. (The CSR is simply the CSC divided by the dollar value of the loan.) Additionally, on average the DOE-estimated CSRs for the ATVM loans are about 21 percent based on default rates of about 40-50 percent and recovery rates in excess of 25 percent.

If the risks of the placeholder loans are at all indicative of the risks of the underlying loans, then the actual and estimated CSRs should not be grossly different. Given this assumption, one could use the estimated CSRs as proxies for the actual ones which in turn could be used to estimate the actual CSCs for the Section 1705 and ATVM loans that are actually made. That is, the estimated CSCs for loans would simple equal the estimated CSR times the dollar value of the loans outstanding. Since the borrower pays the CSCs for the 1703 loans, to the extent that the actual CSCs reflects the expected cost to the government, there would be no subsidy resulting from these loans.

Again, the CSRs for the 1705 placeholder loans were about 10 percent which are based upon default rates in excess of 25 percent. Thus, the placeholder 1705 loans were assumed to be somewhat risky. The question is whether the actual loans will be equally risky. The four large loans for solar and wind projects are in States that have renewable portfolio standards, and it appears that most of these projects have some type of purchase power contracts. Thus, unless the renewable portfolio standards are abolished or not enforced and/or the purchased power contracts are short term in nature, the market-related risk associated with these loans is at best modest. The solar projects are some of the largest in the United States, and thus, there is always a chance of cost overruns. Additionally, there are uncertainties about the durability and longevity of the solar panels.

The CSRs for the ATVM loans were about 21 percent which is consistent with default rates in excess of 40 percent. Again, the question here is whether the actual loans are as risky as the placeholder loans. The major uncertainties are with the commercial viability of electric automobiles. If it turns out that there is no future market for advanced vehicles, there would be no market for the components and infrastructure used to produce them.

[78] Congressional Budget Office, *Estimating the Value of Subsidies for Federal Loans and Loan Guarantees*, August 2004.

The DOE has never reported the actual CSCs paid by the borrower for the Section 1703 loans most of which were for the Vogtle nuclear unit. However, the Secretary of Energy has been reported to have said that the CSR for the Vogtle loan could be as low as 1-2 percent" which implies that the loan has little risk of default. Roughly 45 percent of Vogtle is owned by Georgia Power, which is a regulated utility. While cost recovery is not guaranteed, it is very likely that the State regulators would allow sufficient cost recovery to insure that the utility remains solvent. (In fact, this did occur in the 1980s.) Thus, the probability of Georgia Power defaulting on their part of the loan is very low. The other 55 percent of the Vogtle project is owned by three municipal utilities, which are much smaller that Georgia Power. In the 1980s, a number of publicly-owned utilities did default on their nuclear related loans, so the part of the loan that went to the publicly-owned utilities has a higher element of risk.

Although none of these loans are risk free, without detailed information about the underlying projects, it is impossible to estimate the probability of default, and thus the CSC. Two cases will therefore be developed. The published CSR for the Calvert Cliffs nuclear power plant was around 11 percent. The power from that nuclear power plant would have been sold in de-regulated markets without long- term fixed price purchased power contracts and, thus cost recovery was not guaranteed. The same might be true for the roughly 55 percent of the Vogtle project that is owned by municipal utilities. The higher case will therefore assume an additional CSC equal to 11 percent of the $4.9 billion in loans that went to publically-owned co-owners of the Vogtle nuclear units. The higher case will also use the average CSRs for the placeholder 1705 and ATVM loans.

It is quite possible that the placeholder CSRs for these placeholder loans could be greater than the ones for the actual loans. Thus, the lower case will assume that the actual CSRs for the section 1705 and ATVM loans are 50 percent of the ones for the placeholder loans. The lower case will not include any additional CSC for the section 1703 loans.

In the high case, the assumed default rates for the Title 17 and ATVM loans are around 20 and 40 percent, respectively, which are similar to historical default rates on bonds that are rated Ba and B by Moody's.[79] The Ba and B ratings are the highest and lowest non-investment grade ratinsg. In the lower case, the default rates on the Title 17 and ATVM loans are around 10 and 20 percent, respectively. These rates are similar to historical ratings for bonds that are rated Baa and Ba by Moody's. The Baa rating is the lowest investment-grade rating and is the one used by EIA in the electric capacity planning part of the NEMS Model.[80]

The estimates of the actual subsidy costs for all DOEs loans that received either conditional or final approval in FY 2010 are shown in Table 29. The subsidy cost for the Title 17 loans ranged from $265 million to $1.1 billion. Thus, the public paid (or will pay) anywhere from $265 million to $1.1 billion to insure loans used to support the development of clean electric related technologies. For all of DOE loans made in FY 2010, the subsidy costs range from $1.1 billion to $2.8 billion. The "insurance premium" paid (or will be paid) by the tax payer to guarantee loans leading to the development of cleaner more fuel efficient cars and clean power generating technologies ranged from $1.1 to $2.8 billion. The total energy related subsidies are about $23 billion. Thus, subsidies related to DOE loans issued in 2010 are at best about 10 percent of the total.

[79] See Moody's Investors Service, Global Credit Research, Historical Default Rates of Corporate Bond Issuers, 1920-1999, Exhibit 16, p 66.
[80] See U.S. Energy Information Administration *Documentation to the Electricity Market Model*, http://www.eia.gov/analysis/model-documentation.cfm, Accessed June 27, 2011.

Table 29. Estimated subsidy costs on DOE loan guarantees (millions of dollars)

	Credit Subsidy Rate	Value of Loans Made (millions)	Estimated Subsidy Costs (millions)
1703 high	5%	$10,600	$530
1703 low	0%	$10,600	$0
1705 high	11.76%	$4,500	$529
1705-low	5.88%	$4,500	$265
ATVM-high	21.21%	$8,344	$1,769
ATVM-low	10.60%	$8,344	$885
Total-high		$23,444	$2,829
Total-low		$23,444	$1,149
Title 17 high		$15,100	$1,059
Title 17 low		$15,100	$265

	Estimated Subsidy Costs (millions)	
Fuel specific breakdown	**Low**	**High**
Nuclear	$0	$530
Coal	$0	$0
natural gas	$0	$0
Renewables	$243	$487
Solar	$156	$312
Wind	$77	$153
Geothermal	$11	$21
Biomass	$0	$0
Conservation	$3	$5
Transmission	$19	$37
Vehicles	$885	$1,769
Total	**$1,149**	**$2,829**

Totals may not equal sum of components due to independent rounding.
Source: Computed from data from U.S. Department of Energy, Loan Guarantee Program Office, https://lpo.energy.gov/?page_id=45, accessed March 23, 2011; and, FY2011 Budget Submission to Congress, Appendix, Department of Energy.

Estimates of the value of DOE's loan guarantee program.

Again, the CSC measures the expected cost of a loan guarantee that is paid by the taxpayer, as opposed to the borrower. As the name suggests, the CSC is one direct measure of the subsidy resulting from the guarantee. However, since the actual CSCs are not reported, the estimates shown in Table 29 are based on the assumption that the actual and estimated ones are not grossly different, an assumption that may or may not be valid. An alternative is to estimate the effects of the subsidy. Such estimates are useful if the focus is on how the loan guarantees affect behavior. In particular, the stated objective of the Title 17 loan guarantees is to provide financial incentives to develop new clean electric generating technologies. As was done in Chapter 4, another measure of the subsidy is the dollar value of those financial incentives. In this chapter, such incentives will be called the value of the subsidy to distinguish the estimates from the subsidy itself.

A loan guarantee will allow a firm to borrow at a much lower rate of interest and substitute relatively low-cost debt for equity financing. However, because of the following reasons the estimates reported in Chapter 4 did not consider the later effect. If the implicit loan guarantee was removed, federally-owned utilities, such as TVA, would probably reduce their amount of outstanding debt. Indeed, TVA's $30 billion debt limit was imposed by Congress to limit TVA's incentive to issue too much debt because of the implicit loan guarantee. In the absence of the implicit loan guarantee, it is unclear whether TVA, for example, would reduce the amount of its debt by building less capital intensive technologies such, as natural gas, or by increasing the amount of equity financed by increasing electricity prices. In other words, it would be very difficult to estimate what federal utilities balance sheets and capital structures would look like if the implicit loan guarantees were removed. For that reason, Chapter 4 just considered only the reduction in costs associated with federal utilities ability to borrow at lower rates.

Additionally, in this chapter because of two reasons, the cost savings from both factors will just be computed for only the privately-owned firms. First, to incorporate both effects the weighted after-tax cost of capital will be computed. The tax adjustment which is crucial is included to account for the fact that payments to shareholders are taxed at both the corporate and individual levels, whereas payments to debt holders are just taxed at the individual level. Such effects are not relevant to publicly-owned companies since they pay no income taxes and distribute no dividends. Second, the major issue with measuring the cost savings from using more debt deals with the effects of financial leverage on a project's costs, and all the underlying theory that was developed for privately-owned firms. Thus, from a conceptual viewpoint, the idea of financial leverage is only relevant for privately-owned firms due to tax savings.

The methodology used here looks somewhat different from the ones used in traditional finance analyses, and thus it will be illustrated with an example. For simplicity, in this example, the tax issues are ignored. This example will also show the assumptions that must be made. In this example, shown in Table 30, the total cost of the project is assumed to equal $1,000. Without the loan guarantee, by assumption, the project would be financed with 30 percent debt and 70 percent equity, with the assumption that the cost of debt and equity capital at 7 and 15 percent, respectively. The cost of debt capital is very easy to estimate, it is simply the interest rate on outstanding loans. However, the cost of equity capital is more difficult to determine since it is an opportunity cost which is not observable. That is, the cost of equity capital is the return that the equity holders could have earned if they had invested in another project of equal risk in the marketplace.[81] In this example, by assumption, if the $700 of equity financing was invested in another project of equal risk in the marketplace, it could have earned a return of $105 ($700 x .15.) Thus, the opportunity cost of investing that equity in the project at hand is $105. With the loan guarantee, by assumption, the project will be financed with 70 percent debt and 30 percent equity, and then the cost of debt would fall to 4 percent. In this example, the cost of equity would remain at 15 percent. (The appropriateness of this assumption is discussed below.)

Table 30. An example of the total savings from the DOE loan guarantee program

	Without loan guarantee			With Loan Guarantee			
	Capital Structure	Cost of Capital	"Costs"	Capital Structure	Cost of Capital	"Costs"	Change in Costs
Debt	$300	7%	$21	$700	4%	$28	$7
Equity	$700	15%	$105	$300	15%	$45	-$60
Total	$1,000			$1,000			-$53

Totals may not equal sum of components due to independent rounding.
Source: Office of Energy Analysis, Energy Information Administration
Note: The Cost of Debt is an out of pocket cost while of cost of Equity is an opportunity cost. That is, the cost of equity is the returns that could have been achieved by investing the amounts shown in another investment of equal risk in the marketplace. Thus, the total is a hybrid cost. It is partly an out of pocket and an opportunity cost.

The last column in Table 30 shows the change in costs. The debt costs actually increased by $7 but the equity costs, which again are opportunity costs, fall by $60, and thus the total cost savings would be $53. Note that the $53 estimate is partly an out-of-pocket and partly an opportunity cost. Except for regulated utilities, this estimate could never be computed by simply observing items on a firm's income statement or balance sheet.[82]

Financial assumptions if the loan is guaranteed

This example shows that assumptions must be made about the capital structure, the cost of equity, and the cost of equity if the loan is guaranteed. Looking first at the capital structure, as already noted, the maximum loan guarantee is by law 80 percent of the total. However, as was noted above, the actual projects are using much less debt than the maximum and, thus, the actual amounts of debt will be used here. In particular, in the calculations the amounts of debt as a percent of the total project costs for all Title 17 and ATM were assumed to equal 64 and 58 percent, respectively. These are averages of the actual percents for all loans made in FY 2010.[83] All of the assumptions are shown in Table 31.

[81] There are at least 3 or 4 different ways to compute the cost of equity. In the electric utility sector, EIA uses the Capital Asset Pricing Model (CAPM). See: U.S. Energy Information Administration *Documentation to the Electricity Market Model*, http://www.eia.gov/analysis/model-documentation.cfm, Accessed June 27, 2011.
[82] In a regulated utility, these equity costs are called the Allowance for Other Funds used during construction. It appears as a non-cash revenue in the income statement. Additionally, the actual estimates reported below were computed by using the change in the weighted after tax cost of capital. It can be shown that using the weighed after tax cost of capital will produce the same results as the one used to the example.
[83] All the data were obtained from the Loan Guarantee Office's Web site at https://lpo.energy.gov/?page_id=45, Accessed March 23, 2011.

Table 31. Assumptions made to compute the total savings from the DOE loan guarantee program

	Scenario			
	Loan guarantee not made			
	Risk			Loan Guarantee made
Assumptions	**Low**	**Moderate**	**High**	**NA**
Title 17				
Bond rating	A	Baa	B	Treasury rate
Cost of Debt	5.44%	6.04%	7.00%	4.50%
Cost of Equity	13.00%	13.00%	13.00%	13.00%
Capital Structure				
Debt	55.00%	45.00%	35.00%	64.00%
Equity	45.00%	55.00%	65.00%	36.00%
Annualized Credit Subsidy costs for Section 1703 Loans (millions)	NA	NA	NA	25
ATVM				
Bond rating	Baa	Ba	B	Treasury rate
Cost of debt	6.04%	7.00%	8.00%	4.50%
Cost of Equity	13.00%	13.00%	13.00%	13.00%
Capital Structure				
Debt	45.00%	35.00%	25.00%	58.00%
Equity	55.00%	65.00%	75.00%	42.00%

Totals may not equal sum of components due to independent rounding.
Source: Office of Energy Analysis, Energy Information Administration.

Most of the Title 17 and ATVM loans are made by the Department of Treasury's Federal Financial Bank at 12.5 basis points above current yields on Treasury bonds, and are guaranteed by DOE. Based upon DOE budget submissions, the Title 17 loans have maturities of 20 plus years. Thus, the cost of debt if the loan was made was assumed to equal the 2010 yields on 30 year Treasury bonds (Table 30). This is noteworthy because in 2010, yields on 30-year Treasury bonds were a full percentage point greater than the ones for 10-year Treasury bonds.

Lastly, there is the question of the appropriate cost of equity to use if the loan guarantee was approved. By itself, the loan guarantees only protect debt holders in case of bankruptcy; it would have no effect on shareholders. However, the increased use of debt would affect shareholder risk. There is a long literature on the relationship between the use of financial leverage (debt capital) and the cost of equity. However, the exact relationship depends upon a number of factors such as how the project is structured, and thus, the exact relationship is difficult to estimate.[84] More importantly, and as noted above, there is more equity in most of the projects than the

[84] See, for example, Alan Shapiro, Modern Corporate Finance,(New York: Macmillan, 1990).

minimum 20 percent allowed by law. Since this might be an attempt to reduce the risk to shareholders, there might be some double accounting if the cost of equity was also increased. Thus, to simplify the presentation, no adjustment will be made to the cost of equity. A sensitivity analysis found that a 1-percentage point increase in the cost of equity resulted in a $50-million decrease in the cost savings. The maximum increase in the cost of equity is probably around 2- to 3 percentage points, and thus the changes would be relatively small when compared to the other estimates presented in this report.

Financial assumptions if the loan was not guaranteed.

In this chapter, three different scenarios that reflect differences in risk with the assumption that the loan was not made will be used. (See Table 30.) Since the ATVM loans have much higher CSRs than the Title 17 loans, the ATVM loans are more risky. Thus, different assumptions will be made for the Title 17 and ATVM loans.

Looking first at the Title 17 loans, in the last two solicitations, DOE required that the projects to be considered eligible must have a bond rating no lower than Ba.[85] This is the highest of the non investment grade ratings, and bonds in this class are considered somewhat speculative. The higher risk scenario assumes that in the absence of the guarantees, the bonds used to finance the average project would be rated Ba. Historically, the default rate on bonds that were initially rated Ba was about 20 percent, which is similar to the assumed default rates on the placeholder loans used to compute the CSC for Title 1705 loans. It is also similar to the default rates implicit in the higher case estimates of the CSCs shown in Table 29.[86]

The moderate risk scenario case assumes that the bonds used to finance the average project will be investment grade and rated Baa by Moody's. (EIA uses yields on investment grade bonds to compute the cost of capital for electric utilities in the NEMS model.)[87] Historical default rates of bonds that were initially rated Baa are about 10 percent. This assumption is consistent with the implicit default rates used in the lower cost CSC estimate shown in Table 29.

In the lower risk scenario, it was assumed that, in the absence of the guarantee, bonds used to finance the average project would be rated A. This is the third highest bond rating and therefore the resulting estimates will be very conservative. The assumed 2010 yields are shown in Table 31.

The moderate risk scenario's capital structure was based on the ones used by EIA in AEO2011 in the electric utility sector (See Table 31). Lower (higher) risk investments could use more (less) debt. In the lower risk scenario, a 10 percentage point increase in the use of debt was assumed. In the high risk scenario a 10-percentage point decrease in the amount of debt was assumed. For simplicity, the same cost of equity was assumed. This simplified the calculations and some sensitivity analysis found that the results were not materially affected by this simplification.

[85] U.S. Department of Energy, Loan Guarantee Program Office, Federal Loan Guarantees for Commercial Technology. Renewable Energy Generation Projects Under Financial Institution Partnership program, DE-FOA-0000166, October 7, 2009; and U.S. Department of Energy, Loan Guarantee Program Office, Federal Loan Guarantees for Projects that Manufacture Commercial Technology Renewable Energy Systems and Components, DE-SOL-0002197, August 10, 2010.

[86] Since DOE uses a 55 percent recovery rate, the CSR would be roughly 50 percent of the default rate.

[87] See U.S. Energy Information Administration, *Documentation to the Electricity Market Model*, http://www.eia.gov/analysis/model-documentation.cfm, Accessed June 27, 2011.

Since the ATVM loans appear to be more risky, the higher case will assume that without guarantees, bonds used to finance these projects would be rated B. This is the lowest of Moody's non-investment grade bond ratings and the historical default rate on such bonds is around 40 percent. Because of the risk of these projects, in the higher case, a 7-percent equity and 25 percent debt capital structure would be used. In the Moderate and Lower risk cases for ATVM loans, the same bond rating and capital structures as was used in the lower and moderate risk cases will be employed. Again, these assumptions are shown in Table 31.

Results

Before presenting the estimates of the cost savings, a number of points about the nature of the estimates and the sample must be made. First, as noted above, loans that received either a conditional or final approvals were used in the computations. Roughly $12 billion of the $23 billion of loans received their final approval in FY 2010, and based on information from the FFB's balance sheet only about $2 billion out of that $12 billion were actually made in that year. Thus, most of the loans will probably be made in FY 2011. Second, it appears that the DOE loans have fixed, as opposed to variable, rates. If the same is true of the loans that the borrower would have received in the absence of the guarantees, then the estimates would be time invariant. That is, the estimates shown below would be the same in FY 2020 than in FY 2010. However, if the loans the borrower would have received without the guarantees have variable rates, in the case of rising interest rates in future years the cost savings could be much greater than the ones shown here.

With regard to the example, roughly 55 percent of the Vogtle loan went to three publicly-owned utilities. Because of the reasons stated above, those three loans will be excluded from the calculations of the cost savings caused by the increased use of debt. Thus, the total cost savings for these three loans were limited to the ability to borrow at lower rates. The loan to Areva was included in the calculation of both effects since Areva does have a well defined capital structure and large amounts of outstanding common stock.

The estimates of the cost savings from the DOE loans approved in FY 2010 are shown in Table 32.

Table 32. Total cost savings from DOE loan guarantee program.
(million dollars)

	Risk without the loan guarantee		
Loan Type or Fuel	**Low**	**Moderate**	**High**
Section 1703 loans	$80	$193	$314
Section 1705 loans	$56	$107	$158
Total Title 17 loans	**$135**	**$300**	**$473**
Total Non Electricity	**$252**	**$416**	**$565**
Total DOE	**$388**	**$716**	**$1,037**
Fuel specific breakdown			
Nuclear	$77	$187	$305
Coal	$0	$0	$0
Natural gas	$0	$0	$0
Renewables	$51	$98	$145
Solar	$33	$63	$93
Wind	$16	$31	$46
Geo	$2	$4	$6
Bio	$0	$0	$0
Conservation	$3	$7	$11
Transmission	$4	$7	$11
Vehicles	$252	$416	$565
Total	**$387**	**$715**	**$10,037**

Totals may not equal sum of components due to independent rounding.
Source: Computed from data from U.S. Department of Energy, Loan Guarantee Program Office, https://lpo.energy.gov/?page_id=45, accessed March 23, 2011.

These estimates suggest that the cost savings resulting from Title 17 loans made in FY 2010 ranged from about $135 to $473 million per year. In total, the savings resulting from all of the DOEs loans made in 2010 ranged from $388 million to about $1 billion. The CSCs for all of DOE's loans made in FY2010 ranged from $1 to $3 billion. Again, the CSC is the expected cost to the government computed over the life of the loan and thus the CSC would be the costs of the loan guarantees. The benefits (cost savings) of the loan program ranged from $388 million to $1 billion per year. The payback period is number of years before the cumulative cost savings (benefits) exceeded the CSCs (cost). Thus, even if the CSC estimates are low by a multiple of 2, the payback period would be less than 10 years.

The cost savings from the nuclear loan guarantees ranged from $77 million to about $305 million. There are two reasons why the nuclear estimates appear to be low relative to a number of recent studies. First, all of the previous analyses assumed a much higher use of debt financing than turned out to be the case. Second, as was stated above, for the Vogtle loan, the cost savings for the municipal utilities that own 55 percent of the project was limited to the ones caused by lower interest rates. As will be seen very shortly, these cost savings are very low. If the municipal utilities were treated as if they were investor-owned, the nuclear related cost savings would increase by $75 million and $200 million in the lower and higher cases, respectively. These results, especially at the upper end of the range are not out of line with previous work in the loan guarantee area.

Lastly, to show the importance of the ability to use more debt financing and the associated tax benefits, a case was run where it was assumed that there would be no increase in the use of debt financing. These results, shown in Table 33, suggest that the cost savings resulting from ability to borrow at lower costs is only about 35-40 percent of the total. Given this, one would expect that the firms would use as much debt as the law allowed, i.e., 80 percent. The reason why they did not must therefore be related to the increased risk that results from highly leveraged investments. These increased risks would accrue to both the equity investors and the debt holders (DOE). It is quite possible that both parties were requiring more equity investment than the law allowed.

Table 33. Reduction in Total Financing Costs Assuming No Change in Capital Structure (million dollars)

	Risk if loan guarantee is not made		
	Low	**Moderate**	**High**
Section 1703 loans	$17	$44	$87
Section 1705 loans	$11	$19	$30
Total Title 17 loans	**$28**	**$63**	**$117**
Total Non Electricity (ATVM)	**$120**	**$196**	**$274**
Total	**$149**	**$258**	**$391**

Totals may not equal sum of components due to independent rounding.

Source: Computed from data from U.S. Department of Energy, Loan Guarantee Program Office, https://lpo.energy.gov/?page_id=45, accessed March 23, 2011.

Conclusions

The various estimates of the subsidy resulting from DOE's loans made in FY 2010 are summarized in Table 34. These results suggest that if the estimates of the actual credit subsidy costs were used, the subsidy resulting from the Title 17 loans would range from $265 million to $1,059 billion. The estimated subsidy from all of DOE's loans ranges from about $1 to $3 billion. These estimates would be the more appropriate ones to use if the focus was on the budgetary impact of these programs. One of the goals of the FCRA was to ensure that the budgetary costs of federal loans programs were the same as other government activities. To the extent that the placeholder CSCs are not grossly out of line with the actual ones, these estimates are conceptually the same as the ones presented in Chapters 2 and 3.

Table 34. Summary of estimates of the subsidies resulting from DOE's loan guarantees made in FY2010 (million dollars)

	Credit Subsidy Costs		Total Reductions in Annual Financing Costs[a]			
	Credit Subsidy Costs		No Change in Capital Structure		Increased Use of Debt Because of DOE Loan Guarantee Program	
Program	**Higher**	**Lower**	**Higher**	**Lower**	**Higher**	**Lower**
Section 1703 loans	$530	$0	$87	$17	$314	$80
Section 1705 loans	$529	$265	$30	$11	$158	$56
Total Title 17 loans	$1,059	$265	$117	$28	$473	$135
ATVM	$1,769	$885	$274	$120	$565	$252
All DOE	$2,829	$1,149	$391	$149	$1,037	$388
Fuel specific breakdown						
Nuclear	$530	$0			$305	$77
Coal	$0	$0			$0	$0
Natural Gas	$0	$0			$0	$0
Renewables	$487	$243			$145	$51
Solar	$312	$156			$93	$33
Wind	$153	$77			$46	$16
Geothermal	$21	$11			$6	$2
Biomass	$0	$0			$0	$0
Conservation	$5	$3			$11	$3
Transmission	$37	$19			$11	$4
Vehicles	$1,769	$885			$565	$252
Total	**$2,829**	**$1,149**			**$1,037**	**$388**

Totals may not equal sum of components due to independent rounding.

Source: Computed from data from U.S. Department of Energy, Loan Guarantee Program Office, https://lpo.energy.gov/?page_id=45, accessed March 23, 2011.

If the focus of the analysis is on how the loan guarantee program affects behavior, estimates of the cost savings would be the more appropriate measure of the subsidy. This is similar in spirit to what was done in Chapter 4. These estimates would range from $135 million to slightly less than $500 million for the Title 17 loans. Estimates of the subsidy, as measured by the cost savings, for all of the DOE loans made in FY 2010 ranged from about $388 million to about $1 billion.

All of these estimates are quite modest when compared to other ones presented in this report. Under current law, DOE's authority to issue Title 1705 loans will expire on September 30, 2011. DOE will still have authority to issue about $40 billion in Section 1703 and $17 billion in ATVM loans. Thus, even without additional budget authority, DOE can still issue about $57 billion in loans. Over the next few years as more loans are made the estimates reported here will increase.

Lastly, DOE's loan program allows firms to borrow at lower costs and to use more relatively inexpensive debt. There are also tax advantages from using more debt. A comparison of the estimates shown in the last four columns in Table 34 suggests that the ability to substitute debt for equity financing is by far the more important of the two effects. Given this, it is very interesting that the amount of debt used to finance the actual projects is much less than the 80 percent maximum.

Appendix A. Request Letter

Congress of the United States
Washington, DC 20515

November 1, 2010

Honorable Richard G. Newell
Administrator
U.S. Energy Information Administration
1000 Independence Ave, SW
Washington, DC 20585

Dear Dr. Newell,

We are writing to request that the Energy Information Administration (EIA) update the report entitled *Federal Financial Interventions and Subsidies in Energy Markets 2007* with the latest available data, preferably for fiscal year 2010. The information in this report has been used extensively by legislators and the public, providing a compendium of data on federal financial involvement in electricity markets that has proven invaluable. An update using the same approach as the previous report would be very beneficial to Congress and the energy community.

As in the 2007 report, we are requesting that you provide a comparison of the subsidies in the electric power sector for each fuel type (oil, natural gas, coal, nuclear, wind, solar, geothermal, etc.), reporting both the overall annual cost of the subsidy and the annual cost per unit of electricity generated (e.g. cost per megawatt hour). As with the previous report, the scope of the study should be limited to subsidies provided by the federal government that are energy-specific and that provide a financial benefit with an identifiable federal budget impact. The analysis should include the following type of subsidies: tax expenditures (e.g. deductions, credits, and loan guarantees), direct expenditures (e.g. direct grant programs), federal research and development programs targeting electricity and its fuel inputs, and federal electricity programs (e.g. support for the Bonneville Power Administration). If a significant change to the amount or scope of the subsidy since the 2007 report has occurred, a detailed explanation for the change should be documented in the report.

It would be most helpful if the updated report could be made available to the Congress no later than the beginning of 2011.

Thank you for your assistance in this matter. Should you have any questions, please contact Mike Jerman in Rep. Jason Chaffetz' office at mike.jerman@mail.house.gov or (202) 226-7714.

Sincerely,

Jason Chaffetz
Member of Congress

Marsha Blackburn
Member of Congress

Roscoe G. Bartlett
Member of Congress