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EIA Service Report

Federal Energy Subsidies

Direct and Indirect Interventions in Energy Markets

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Executive Summary

The Energy Information Administration (EIA) was mandated by Congress to prepare a report which would cover both direct and indirect Federal energy subsidies, methods of valuing those subsidies, and a survey of the subsidies currently in place. This report fulfills that legislative mandate.

Energy markets today do not represent the *laissez faire* model of free competition with no governmental involvement envisioned by Adam Smith when he penned the first major book in economics. Energy markets are a combination of multinational giants and small independents, of traditional fuels competing with renewables, of utilities facing challenges from independent power producers, and firms whose history is over a hundred years old and those whose technological discoveries have just recently brought them into the marketplace. No single economic model could possibly capture either the richness or the diversity of all of those who participate in the determination of energy supply, demand, prices, and technology.

The Government has not been content to let energy markets function without interference. This report has attempted to encompass the extent of that governmental involvement. Government has consistently selected from a menu of policy alternatives, various means to tilt the playing field, to favor certain producers or consumers of energy over others. The hoped-for result is to produce energy at prices which are more politically acceptable, a more pristine environment, or safer conditions than would have prevailed in the absence of the intervention.

Preparation of this report on energy subsidies was a difficult task. The first problem encountered in the preparation of this report was the definition of a subsidy, since EIA was charged to look at both direct and indirect subventions. The mandate is for a wide-ranging study that was not confined to a limited number of policy options. EIA incorporated a broad definition of subsidization including most governmental actions which had as their function alteration of energy markets by benefiting some group of producers or consumers. Since most governmental actions have some influence on energy markets, however slight, the programs considered were limited principally by purpose. If there was no clear energy-related rationale behind the provision, it was excluded. Some would contend that programs such as the Strategic Petroleum Reserve and the Highway Trust Funds should have been included. They were not included because their main reason for being was national security and public transport, not to benefit certain energy consumers or producers. Consistent with the mandate, only Federal programs were considered.

The most obvious subsidy is the direct expenditure from the Federal budget. As the report shows, these direct expenditures account for only a tiny fraction of the total impact of Federal Government intervention in energy markets. In addition, tax subsidies had to be considered. These are the tax incentives which are received by producers or consumers of various forms of energy. In this case, the Government does not spend money, but it loses revenue that it would have otherwise received. The effect is basically the same. Those who receive the tax subsidies benefit in either their production or their consumption activities.

In addition, the Government often directly sells energy or energy services through organizations such as the Tennessee Valley Authority and the Bonneville Power Administration. The consumers of these governmental utilities are subsidized if the prices of governmental provision to them are less than the rates that would have been charged by private producers. Certain Government utilities are also subsidized because their capital expenditures can be financed through tax-exempt municipal bonds. Rural Electric Cooperatives are able to receive Government loans at interest rates which are below those in the market. These features reduce their costs of production.

Government also maintains trust fund programs supported by levees on energy producers. There is a subsidy to the producers and to their customers if fees do not compensate for its costs in providing the service. A negative subsidy or tax results when fee collections are in excess of governmental costs. In many instances the Government has assumed the actual or potential liabilities associated with environmental safety and health concerns arising from energy production. A subsidy exists if the expected outlays under the program are in excess of the fees that are being levied on the industry for the cleanup or if the Government itself assumes the responsibility for paying the cleanup bill.

The Federal Government has an extensive program of funding energy research and development activities. Much of the funding for energy takes the form of basic research and therefore cannot be allocated to a particular fuel or type of producer or consumer. Government grants are of importance particularly to the nuclear and coal industries, as well as in support of renewables. To the extent that this Government-supported research can be used by the industries involved, it represents a subsidy to them as they do not have to pay the expense of developing new technologies.

This quick overview indicates that the scope of Government subsidies is vast. Within the pages of this study topics are covered ranging from the tax treatment of oil and gas drilling, nuclear waste disposal, and uranium enrichment to public power and renewable sources of energy. There are those who will disagree with the list, feeling that we have included either too much or too little. This report was not meant to be definitive, but it does follow the consistent philosophy that Government activities designed to directly influence either the production or consumption of energy do constitute a subsidy and should not be ignored.

In recent years, Government regulation of the private sector has been used to accomplish what could have been done through direct or indirect Government subsidization. It is regulation and not subsidization that has the greatest impact on energy markets. Regulation produces results which are similar to subsidies. By requiring that certain procedures or practices be followed, costs are increased in the same manner as if a tax was levied. Regulation involves no outlay by the Government or direct loss of income to the Federal treasury, but it does involve costs to some producers or consumers and benefits to others. While not counted as subsidies in this report, selected energy regulations are discussed to illustrate their significant impact.

Even after disposing of the question of what are subsidies, an equally difficult question appears: what is the value or cost of the subsidy? In case of direct subsidies or tax preferences the cost is the outlay or loss of receipts. But the value to the recipient may be more or less than what appears on the accounts. For low-cost loans what is the appropriate comparative interest rate to be used? In the case of public production of electricity, is the comparison to be made using market rates charged by other suppliers or rates that would be high enough to achieve the same rate of return that an investor-owned utility would require? The answer depends on the approach taken. This report shows how the alternate methods of valuation can produce widely differing results.

There are several general conclusions about Federal energy subsidies which can be reached from this report in addition to the specific ones detailed herein.

- There are a wide variety of Federal actions which can be used to influence energy markets. The breadth of this report supports this conclusion. Taxes, expenditures, trust funds, insurance, low-cost loans, and varieties of regulation can all be used to achieve Government objectives. This report makes no attempt to evaluate the effectiveness of any of these alternate approaches. But such an evaluation would be appropriate in selecting which policy instruments should be used to achieve a desired objective.

- The character of Federal intervention in the energy market has changed over time. Actions to promote the development of energy sources, particularly fossil fuels, have declined in importance relative to actions designed to deal with the external costs of energy use. This trend is consistent with the growing concern for environmental issues and the social costs involved with the consumption of certain fuels.

- Federal energy subsidies are not large compared to the total value of energy production. This report delineates an annual cost of between $5 billion and $10 billion from Federal energy subsidies for 1990. The total value of production in all energy industries is close to $475 billion. This meant that Federal subsidies were approximately 1 to 2 percent of the value of sales. This does not mean that subsidies are not important and have not influenced either production or consumption patterns for energy, but it does indicate that energy is not a heavily subsidized industry.

- The impact of energy regulation is more important than either direct or indirect Federal subsidies. While Federal subsidies amount to between $5 billion and $10 billion, the economic impact of just those energy regulatory programs considered in this report total at least five times that amount. Increasingly the Government has preferred the regulatory method of influencing market outcomes, rather than the subsidy approach.

This work is exploratory and intends to provide a preliminary perspective rather than a definitive conclusion on this topic. It is viewed as a building block which others can use as well as a means of framing the parameters of the debate for discussion on the Federal role in energy markets. This report does not advocate or criticize any particular approach. The intent of this report is to enumerate Federal programs and to attempt to estimate their cost.

The Energy Policy Act (EPACT), which was passed in October 1992, is not included in this report, which had been essentially completed before Congress finalized its action. Changes in the existing scheme of subsidies and regulations brought about by EPACT have been mentioned in the text, but no analysis of them has been performed. In many instances these new initiatives are likely to produce significant results on energy markets and are worthy of future analysis.

1. The Scope of Energy Subsidies

In the Fiscal Year 1992 budget, the Congress instructed the Energy Information Administration (EIA) to prepare a report on Federal energy subsidies.

> "Within available funds, EIA is directed to produce a one-time study defining *direct* and *indirect* Federal energy subsidies, *methods of valuation* of such subsidies, and a survey of existing subsidies, as well as an analysis of actions and costs necessary to produce a periodic report" (emphasis added).[1]

This report has been prepared in response to that directive. This chapter discusses the concept of subsidy, describes the types of subsidies covered in this report, discusses methods of valuing subsidies, and summarizes the results of the report.

There is no universally accepted definition of what constitutes a subsidy. A typical textbook definition of a subsidy is a transfer of economic resources by the Government to the buyer or seller of a good or service that has the effect of reducing the price paid, increasing the price received, or reducing the cost of production of the good or service. The net effect of such a subsidy is to stimulate the production or consumption of a commodity over what it would otherwise have been.[2] This transfer must be contingent in some way on the recipient actually producing or consuming the subsidized good. Subsidies can be both positive and negative, in the sense that the Government can either make or extract payments in order to either stimulate or discourage production or consumption of a particular product.

However, recent critiques of energy policy employ a much broader definition of subsidy. Some observers argue that subsidies exist whenever Government fails to implement programs to internalize uncontrolled environmental costs in energy markets. Others argue that Government regulation creates a subsidy when it fails to set electricity prices equal to the marginal cost of production.[3]

The Congressional request to define both "direct" and "indirect" Federal energy subsidies further complicates the problem of definition. The tools of economic policy available to Government to effect energy markets are many and varied. Tax policy can achieve subsidy-like effects in energy markets.[4] So too can loans, loan guarantees, the direct operation of Government enterprise, and regulation. In fact, the Federal Government employs any and all tools of economic policy in varying combinations which affect prices and costs on energy markets. In this context, the concept of subsidy embraces the broad scope of government actions designed to influence energy market outcomes. This perspective on the definition of "subsidy" was chosen to shape the content of this report.

There is a long history of Government interventions in energy markets.[5] Policies to stimulate oil and gas production were first formulated during World War I. Multiple purpose economic development efforts in the West and Southeast led to substantial development of Government produced electric power in the 1930's. Developing peacetime uses of nuclear energy became a major research and development concern in the 1950's. The energy crisis of the 1970's stimulated search for oil substitutes. Growing environmental concern in the 1980's encouraged interest in conservation and non-polluting energy sources. It prompted also a greater recognition that social costs not captured in energy market transactions could be brought into the equation through taxes or through regulation. As social

[1]U.S. House of Representatives, *Appropriations Committee Report: Department of Interior and Related Agencies Appropriation Bill* (Report 102-116), June 19, 1991, p. 115.

[2]cf. Carl Shoup, *Public Finance* (Chicago: Aldine Publishing Company, 1969), p. 145.

[3]Mark Kosmo, *Money to Burn? The High Costs of Energy Subsidies* (Washington, DC: World Resources Institute, 1987), p. 12.

[4]Donald Watson, *Economic Policy* (Cambridge: The Riverside Press, 1960), pp. 147-170. See also: Battelle Pacific Northwest Laboratory, *An Analysis of Federal Incentives Used to Stimulate Energy Production*, PNL-2410 REV. II (Richland, WA: February 1982).

[5]The literature reviewing this history is extensive. See for example: *Energy Supply and Government Policy*. Edited by Robert J. Kalter and William H. Vogeley (Ithaca, NY: Cornell University Press, 1976). Richard H. K. Vietor, *Energy Policy in America Since 1945* (New York, NY: Cambridge University Press, 1984).

objectives and energy markets have evolved, so too have the mix of Federal policies affecting energy markets.

This report is intended to describe the current status of Government energy policy across various energy sources and uses. The focus is on Government policies that increase or reduce costs and prices in energy markets relative to results which would occur without market intervention. The programs reviewed include those in which the Government intervention involves some form of direct financial commitment. Also included are programs which have subsidy-like effects due to market regulations. The report does not seek to make policy recommendations, nor to evaluate the effectiveness of existing policy. However, it is hoped that by providing a perspective on the existing policy baseline, this report will contribute to informing any future debate on related energy policy issues.

Types of Energy Subsidies Reviewed

In some sense, most Federal policies have the potential to affect energy markets. Policies supporting economic stability or economic growth have energy market consequences; so also do Government policies supporting highway development or affordable housing. The interaction between any of these policies and energy market outcomes may be worthy of study. However, energy impacts of such policies would be incidental to their primary purpose and are not examined here. Instead, this report focuses on Government actions whose prima facie purpose is to affect energy market outcomes, whether through financial incentives, regulation, public enterprise, or research and development.

One of the sources of public interest in energy subsidies is concern with how energy subsidies affect competition between energy and nonenergy investments, and competition between different forms of energy. For example, some argue that investments in energy efficiency, conservation, and renewable energy are hindered by Federal subsidies to more conventional forms of energy.[6] Past studies of subsidies have been motivated by concern that Federal intervention in energy markets tilts “the level playing field.”[7] Only Federal programs that discriminate between energy and non-energy investment, or between types of energy, are of particular interest in this context.

Subsidies in the form of direct payments to producers or consumers are termed **direct** subsidies. Direct subsidies also include tax expenditures. Tax expenditures are provisions in the tax code which reduce the federal tax liability of firms and individuals who qualify because they undertake particular specified actions. Energy-related examples include tax credits for certain kinds of activity (drilling coalbed methane wells) or favorable treatment of capital recovery (percentage depletion for independent oil producers). When these payments or tax expenditures are made conditional on the recipient engaging in energy production or consumption, then they become direct energy subsidies.

There are also many **indirect subsidies.** Indirect subsidies consist of Government actions that do not involve direct payments to producers or consumers, but involve other forms of Federal financial commitment which affect the cost of consumption or production of some form of energy. Indirect subsidies include provision of energy or energy services at below-market prices; loans or loan guarantees; insurance services; research and development; and the unreimbursed provision by the Government of environmental, safety, or regulatory services. Listed below are the types of indirect subsidies examined in this report.

- **Provision of energy and energy services.** Government sales of energy or energy services are a subsidy if the price charged is less than the market price. If there are no comparable market prices, then energy sales are subsidized if revenues from sales are less than the cost.

- **Provision of loans.** Loans are a subsidy if the fees and interest rates charged do not compensate the Government for its cost of funds plus some allowance for risk of default. Loan guarantees are not of current practical importance, since the principal source of energy-related loan guarantees, the Rural Electrification Administration, largely guarantees funds provided by the Federal Government.

- **Tax exempt interest on debt.** The interest paid on the debt of publicly owned electric utilities (in

[6]“. . . electricity is about eleven times as heavily subsidized as direct fuels (as of 1984) . . . .” Amory Lovins, “Four Revolutions in Electric Efficiency,” *Contemporary Policy Issues*, Vol. VIII (July 1990), p. 123.

[7]For example, this argument is made in H.R. Heede et al., *The Hidden Costs of Energy* (Washington, DC: The Center for Renewable Resources, October 1985).

common with other State and local government entities) is exempt from Federal taxation. This is a subsidy as it reduces publicly owned utility costs compared with investor-owned utilities.

- **Assumption of environmental, safety, and health liabilities.** The Government may assume actual or potential liabilities of the private sector, sometimes funded (in principle) by a levy on the industry. In principle, there is a subsidy if the expected present value of the cost of the liability exceeds the levy on the industry.

- **Research and development.** The budgetary cost of Government-funded research and development (R&D) is easy to measure. Determining the extent to which Government energy R&D is a subsidy is more problematic: often it takes the form of a direct payment to producers or consumers, but the payment is not tied to the production or consumption of energy in the present. If successful, Federal-applied R&D will affect future energy prices and costs, and so could be considered an indirect subsidy.

- **Provision of Regulatory Services.** Several Federal Government agencies regulate energy industries. In some cases (such as the Federal Energy Regulatory Commission or the Nuclear Regulatory Commission) costs of regulators are defrayed through taxes levied on the regulated industry. In other cases (Mining Safety and Health Administration) regulation is provided at public expense. Unrecovered costs of regulators constitute a (small) subsidy.

The issue of subsidy in energy policy analysis extends beyond consideration of actions involving some form of financial commitment by the Federal Government. Subsidy-like effects flow from the imposition of a range of regulations imposed by Government on energy markets. Regulations may directly subsidize a fuel by mandating a specified level of consumption, thereby creating a market which might not otherwise exist. The imposition of oxygenate requirements for gasoline in the winter of 1992, which stimulates demand for alcohol-based additives, is a recent example. Regulations more often explicitly penalize rather than subsidize the targeted fuel. To the extent that regulations on coal emissions raise costs of coal use, the competitive opportunities for alternatives, including renewables, natural gas, and conservation, are enhanced. The additional costs that influence the consumption of coal versus other fuels do not require any exchange of money between the Government and buyers and sellers of energy. However, this in no way diminishes the policy's potential impact on resource allocation and relative prices of energy products.

Much current debate on energy policy focuses on externalities associated with energy use. Many believe there is a large implicit subsidy to energy production and consumption insofar as pollution results in environmental costs not fully charged to those responsible. Failure to internalize "recognized" externalities in the context of current fuel use may result in conventional energy being underpriced compare to other energy sources. Advocates of increased use of renewable energy claim this form of "subsidy" to be central to the continued dominance of fossil fuels as a component of energy supply.

In fact, the effort to deal with environmental concerns has become a central feature of Federal energy policy. Substantial costs which were formerly outside the market mechanism have, through the implementation of a series of taxes and regulations, been internalized to energy markets. This report examines these developments as components of the current energy debate regarding the significance of direct and indirect energy subsidies. In that context, a variety of environmental trust funds and components of the Clean Air Act are examined. The report does not address the question of how much and what kind of externalities remain to be addressed through further revision of policy. Such considerations are far beyond the scope of this effort.

There could be legitimate debate over whether some of the programs described in this report are primarily directed towards energy or towards some broader objective, or alternatively whether programs excluded from this report ought to have been included. Programs that provide incentives for broad classes of economic activity, such as investment in fixed capital or investment in basic research, have been excluded, because they affect neither the choice between energy and nonenergy investment, nor the choice among particular forms of energy. Some may consider the Strategic Petroleum Reserve (SPR) to be a subsidy to energy consumers, while others may consider it to be a program to protect the vital national interests of the United States. The SPR is not included in this report. Some of the more expansive definitions of energy subsidies have included defense expenditures related to contingencies in the Persian Gulf. U.S. defense expenditures are designed to provide security, and the level of oil prices is not functionally related to the level of defense activity. Therefore defense expenditures are not considered here. Some may consider Federal transportation programs to be forms of energy subsidy, while others may think the energy impact of transportation programs is incidental to their intended purpose. Transportation programs are not included. State and local programs (which are significant in a number of cases) have been excluded by definition, since this report is about Federal subsidies.

Subsidies can be both positive and negative, in the sense that Government actions can increase or reduce costs within or across energy markets. While a Government grant may reduce energy costs, an excise tax for general revenue purposes can identically and symmetrically increase energy costs, and thus may be viewed as a negative subsidy. A special exemption from a general excise tax would function as a positive subsidy. Changing rules in energy markets can also significantly modify production methods and costs.

Measuring the Cost of Subsidies

Measuring the cost of subsidies presents a number of difficult problems. Direct subsidies and many indirect subsidies can involve payment or receipts of money dispensed or collected by the Government and accounted for in Federal budget documents. On the other hand, the costs or benefits of many indirect subsidies are not reflected in budget documents but rather in the financial accounts of affected energy consumers and producers.

This report attempts to measure subsidies using, to the greatest extent possible, Federal Government outlays, and several near equivalents: the outlay equivalent value of tax expenditures, and Federal receipts foregone in the case of sales of Government services.

The costs of a subsidy to the Government may be very different from the benefit to the recipient. Administrative costs drive a "wedge" between costs and benefits. Subsidies can also take forms that are costly to the Government, while the benefit to the recipient is small. However, a more common phenomenon is that a Federal program will incur known costs to produce social benefits difficult (and controversial) to value in pecuniary terms. Therefore, this report focuses on costs.

The concept of cost becomes more difficult to apply to indirect subsidies. This report presents one or more of several alternative approaches, depending on the type of subsidy being considered. The main categories of techniques are:

- **Fiscal measures of cost:** Used for programs primarily implemented through the Federal outlays or excise taxes

- **Valuing energy services:** Techniques used for valuing the output of Government enterprises and Government-provided financial services

- **Valuing regulatory compliance costs:** Used to assess the costs imposed on producers and consumers by Federal regulation.

A full-scale policy analysis would develop cost-benefit comparisons for each Government program examined. However, in this limited review, the programs considered are presumed to reflect a public policy decision that the benefits of these programs exceed any identified costs of implementation. This report considers only cost-based estimates or estimates of market-price effects with no consideration of the benefits accruing to the effects measured.

Fiscal Measures of Cost

- **Federal budget costs.** Any survey of the range of direct and indirect Government subsidies affecting energy markets most conveniently begins by examining the budget implications of existing programs. Subsidies reflected in the budget are subject to explicit review and can be controlled in the context of the annual budget cycle. Budget reforms since the 1970's have promoted an increasingly comprehensive review of the budget implications of ongoing programs. Since 1974, the unified budget has been required to include annual estimates of tax expenditures.[8] In 1990, the requirement was extended to include estimates of the annual cost of various Federal loan subsidy and loan guarantee programs.[9]

- **Tax expenditures.** This report's estimates of the value of tax expenditures are drawn from the estimates made by the Office of Management and Budget in the annual Federal budget. Tax expenditures are measured both on "Federal revenue foregone" and also on an "outlay equivalent" basis (the value of the Government

[8]The Congressional Budget and Impoundment Act of 1974 (Public Law 93-344), Section 601.
[9]The Federal Credit Reform Act of 1990 (Public Law 101-508), Title VI.

payment required in order to match the value of the tax benefit).

- **Energy excise taxes.** While budget expenditures tend to encourage energy consumption and production, excise taxes that raise the cost of energy tend to do the reverse. However, the largest component of energy excise tax collections supports trust funds which finance the development and maintenance of highways, airports, waterways, and harbors. The use of such taxes to expand and improve transportation infrastructure is likely to encourage travel and increase fuel use. Thus in this report, only energy excise taxes not earmarked for transport development are counted as collections which could restrain energy demand.

Valuing Energy Services

Government involvement in energy markets includes provision of various forms of insurance, and the production and sale of energy products. Several approaches to valuing these activities are used.

- **Variation from market price.** For sales of energy or energy services, the best measure is the market price of the service. This is a reasonable yardstick when a well-developed market exists. The underlying principle is that the Government could sell its product at the market price, but refrains from doing so as a matter of policy. The subsidy is the difference in revenues between the product sold at the market price and the product sold at the actual price, less an allowance for the effect of the subsidy on market prices.

- **Loan subsidy costs.** When the Federal Government makes loans, it should recoup its costs, here defined as the Government's borrowing rate plus some allowance for default risk. This report uses two rates: the Federal 30-year bond rate, and corporate bond rates for investor-owned utilities (0.8 percent higher than the Federal 30-year bond rate). The investor-owned utility rate is a proxy for borrowing cost plus compensation for default risk. The subsidy is then measured as the difference between the actual interest charged on the Government's loan portfolio and amount of interest that would be charged at the alternative rates, less an allowance for the reduction in the demand for loans at the higher rate.

- **Historical cost.** If there is no market, it is possible to compute the cost of providing the service by a process akin to that used by regulated utilities to compute sales prices. However, this approach requires making numerous assumptions, including: the appropriate rate of return on assets for Federal projects; exactly which assets should be included in the asset base; the appropriate valuation of assets that may be very old; and the treatment of accumulated losses or historical costs not recovered in prior years.[10]

Valuing Regulatory Compliance Costs

As noted above, selected regulations have been included in this report because of their importance and because of their subsidy-like characteristics. However, measuring the cost of regulation in energy markets poses many problems of estimation. Generally, regulatory impacts can be measured only by estimating energy prices and quantities with and without compliance. The conduct of comparative analyses of this type requires indepth reviews in many specific market contexts. A full enumeration of all Government regulations that influence energy is beyond the scope of this study. Nonetheless, an effort is made to identify areas of significance and direction of impact to make available a more complete picture of Federal policy impacts on energy markets.

- **Environmental trust funds.** The establishment of fee collection systems to fund the costs of unwanted side effects of energy production has become increasingly important in recent years. In each case, the Government has assumed a liability, and in exchange, has levied an excise tax to fund the liability. Trust fund programs can be considered subsidies (narrowly defined) if actual and anticipated tax receipts are less than the anticipated outlays necessary to fund the liability assumed by the Government. Estimating the ultimate cost of these liabilities is difficult and controversial, and this report does not attempt it. Instead, the report examines budget excise tax collections, current trust fund outlays, and trust fund balances.

- **Compliance costs.** In the case of regulation, this report considers compliance costs. These are the costs imposed by the Government and borne by the regulated industry and its consumers in pursuit of social benefits. Unlike the estimates of the costs of other programs, they are not costs borne by the Federal Government.

[10]The contemporary view of how electricity ought to be priced by utilities is to set price equal to long-run marginal cost. However, the complexity and specificity of real-world computations of long-run marginal cost militate against its use in this context.

Previous Studies of Government Subsidies

Past studies addressing the question of energy subsidies identify a host of programs of potential significance in affecting energy prices and uses. Specific quantitative findings of earlier studies are of limited current interest, given the manner in which energy policy has evolved. They are, however, instructive for at least two reasons:

- At any one point in time, large variations in estimates of subsidy values are possible (both for specific programs and in total) depending on the array of programs included when developing the valuation assessment.

- The potential for variations can be greatly compounded depending on the methodology used in calculating the subsidy value attributed to each program.

Appendix A of this report briefly summarizes past efforts to identify and value subsidies affecting U.S. energy markets.

Guide to the Report

The intent of this study is to identify Federal Government programs that intentionally seek to influence the allocation and pricing of energy resources. Where possible, a quantitative assessment of costs is presented.

The report is divided into seven chapters. This chapter discusses methodological issues: it describes the definition of subsidy used to prepare the report, describes types of subsidies, and discusses valuation problems. The remaining chapters cover:

- **Direct Expenditures (Chapter 2).** This chapter reports on programs listed in the Federal budget, using budget computations as the valuation method. Federal direct expenditures which could be considered energy subsidies totaled about $3.6 billion in fiscal year 1992. The largest single program is the Department of Health and Human Services' Low Income Home Energy Assistance Program (LIHEAP) with outlays of $1.1 billion.

- **Energy Tax Expenditures (Chapter 3).** Energy tax expenditures can be defined either as "outlay equivalents" or as the "Federal revenue lost" from special tax treatment of energy industries under Federal tax laws. Energy income tax expenditures totaled $2.1 billion on an outlay equivalent basis ($1.5 billion on a Federal revenue foregone basis), along with another $0.5 billion for the ethanol exemption from Federal excise taxes. The largest single items were the percentage depletion allowance for the oil, gas, and coal industries ($0.7 billion), and the alternative fuels production tax credit largely used to develop coalbed methane ($0.5 billion).

- **Trust Funds and Energy Excise Taxes (Chapter 4).** Energy trust funds are Federal funds earmarked to a particular public purpose, financed by excise taxes or similar levies on energy commodities, particularly gasoline and coal. Total energy-related trust fund tax receipts were $21.6 billion in fiscal year 1992. The largest trust fund is the Highway Trust Fund, earmarked for road construction, and financed by a tax on gasoline. Other trust funds are designed to compensate for social costs of energy production otherwise ignored in the energy market place. The largest collections are designed to support waste management and spill protection programs. At present, environmental trust fund receipts equal about $1.9 billion. In addition, $3.1 billion of Federal excise taxes (mostly on motor fuels) are used for general Government purposes, and thus constitute a tax or negative subsidy.

- **Research and Development (Chapter 5).** Federal energy-related research and development appropriations totaled about $6 billion in fiscal year 1992. However, some $3.7 billion was for basic research, including fusion research and the super-conducting supercollider, which is more a subsidy to the development of knowledge in general rather than to energy in particular. The balance ($2 billion on an outlay basis), including the Clean Coal program, was spent on programs that could be construed as benefiting particular energy industries.

- **Public Power Issues (Chapter 6).** About 24 percent of U.S. electricity is sold to consumers by State and local government agencies, rural electric cooperatives, and Federal utilities. The U.S. Government provides a mix of tax exemptions on income and debt, loans, loan guarantees, and low-priced wholesale power to these organizations. Since these benefits do not take the form of cash subventions, the subsidy element (if any) must be estimated. This can be done in several different ways. This chapter examines alternate perspectives for valuing Federal programs that benefit public power.

- **Regulation (Chapter 7).** There are many Federal regulations affecting various aspects of the energy industries. In this report, we have chosen to examine a group of important regulations with large consequences for energy markets. The regulations chosen are aimed directly at energy industries and have relatively large financial impacts. Most (but not all) of the selected regulations function as negative subsidies, imposing costs on the energy industries in order to achieve environmental objectives. Among the more costly are the gasoline reformulation provisions of the Clean Air Act Amendments with prospective annual costs (based on published estimates by other researchers) of up to $11 billion, and provisions to prevent leakage of underground petroleum storage tanks with annual costs of $4 billion.

Main Findings

As noted above, there are various means of valuing subsidies, and different methods produce different answers. Despite the hazards of valuation, aggregating subsidy estimates may help give readers a general view of the magnitude of Federal energy subsidies. Table 1 illustrates such an aggregation for those subsidies which can be valued on the basis of Federal budget outlays.

Particular subsidy types are unevenly distributed across fuels. Most tax expenditures pertain to oil and gas production, while general-revenue producing excise taxes are levied entirely on petroleum products. Research and development spending, on the other hand, is concentrated on coal and nuclear power. “Energy Services” costs are electric power generation and transmission capital expenditures by the Army Corps of Engineers, the Bureau of Reclamation, the

Table 1. Summary of Subsidy Elements in Federal Programs by Program Type and Fuel on a Budget Outlay Basis, FY 1992
(Million Dollars)

Type of Subsidy	Tax Expenditures		Direct Expenditures			Excise Taxes Without Offsetting Liabilities	R&D	Total
	Income	Excise	LIHEAP	Energy Services	Cost of Regulators			
Total	**2,100**	**460**	**1,143**	**1,743**	**523**	**-3,132**	**2,043**	**4,880**
Oil	999		262	72	215	-3,132	75	-1,509
Gas	461		563		92		21	1,137
Coal	310		3		207		551	1,071
Nuclear				([a])	9		890	899
Renewables	80	460	63				244	847
Electricity	[b]250		137	1,409			5	1,801
Conservation			115	262			258	635

[a]Excludes uranium enrichment net outlays. Receipts exceed outlays by $197 million.
[b]Excludes tax expenditures for interest on tax-exempt bonds issued by publicly owned utilities. See Chapter 6.

Notes: LIHEAP = Low Income Home Energy Assistance Program. R&D = Research and Development. Tax expenditures and “cost of regulators” allocated to oil and gas by share of value of domestic production. Tax expenditures for “certain energy facilities” are assumed to be electric power or cogeneration projects. Research and Development excludes basic research. LIHEAP allocated by fuel according to percent fuel use by LIHEAP households in 1990. Electricity R&D is solely electricity end-use R&D and excludes generation technology R&D, which is distributed by fuel. REA credit subsidies included in “energy services” for electricity. Army Corps of Engineers and Bureau of Reclamation hydropower construction funding included in electricity.

Source: See subsequent chapters. Most information drawn from Office of Management and Budget, *Budget of the United States Government, FY 1993* (Washington, DC, February 1992).

Tennessee Valley Authority (TVA) and the Power Marketing Administrations (PMAs).

However, as noted earlier, there are alternative methods of valuing subsidies beyond Federal budget outlays.

- Uranium enrichment is not listed on Table 1. On a budget basis, uranium enrichment revenues exceeded outlays by $197 million, implying a negative subsidy. On the other hand, the price at which DOE sells enrichment services is basically limited by competition with other service providers, so that DOE's sale price is probably close to the market price. Thus, measured on a market-price basis, there is no subsidy. However, the current revenues do not recover the historic cost of enrichment services, nor account for the ultimate cost of decommissioning. On a historic cost basis, then the subsidy may be in the range of $0.3 billion to $1.5 billion per year.

- Table 1 includes $3.1 billion in transportation excise taxes put into the general fund. It does not include estimates for trust funds set up to cover the cost of liabilities assumed by the Federal Government. Federal energy excise taxes collect some $20.6 billion annually, $15.6 billion of which is allocated to transportation trust funds. Energy excise taxes aimed at paying for environmental, safety, and health liabilities collect about $1.9 billion annually.

- In Table 1, net outlays for Federal power operations are about $1.4 billion, including the amount by which outlays exceed receipts for the Tennessee Valley Authority and the PMAs, as well as capital spending on hydro projects by the Bureau of Reclamation and the Army Corps of Engineers. There are two alternative valuation methods. If one views the PMAs as quasi-independent organizations that borrow money from the Federal Government, they received interest rate subsidies of $0.8 billion to $1.2 billion in 1990. Alternatively, the Government forgoes revenues by below-market power sales by an estimated $2 billion in 1990, though the amount depends on the estimate of wholesale market electricity prices in the areas where PMAs operate.

- The figure in Table 1 for "energy services" includes a $44-million subsidy element for the FY 1992 loans made by the Rural Electrification Administration (REA). An alternative view of the interest rate subsidy embedded in the REA's $40+ billion low-interest electricity loan portfolio is $0.8 billion to $1.1 billion in 1990, depending on the unsubsidized "market" rate of interest chosen for comparison.

- Table 1 does not include an estimate for the value of tax expenditures arising from the tax exemption for the interest paid on bonds issued by publicly owned electric utilities. The Office of Management and Budget, in its tax expenditure estimates, lumps this figure together with all other "public-purpose municipal bonds."[11] In Chapter 6, the value of this subsidy to publicly owned utilities is estimated at about $1.7 billion in 1990, based on the difference between municipal bond interest rates and investor-owned electric utility rates.

- Compliance costs of a selected group of important regulations, described in Chapter 7, amount to tens of billions of dollars annually.

In studying these programs, their history, and their consequences, several themes emerged.

- **Defining and valuing Federal energy subsidies are unavoidably complex.** The programs discussed within this report cover some of the most contentious issues in energy policy. These issues are contentious precisely because the set of available facts is subject to multiple interpretations.

- **Uneven distributions of particular types of subsidies tend to offset one another.** Coal and nuclear power receive R&D assistance, while oil and gas receive tax preferences. Renewable energy receives a mix of R&D and tax preferences.

- **Regulation is the most consequential form of Federal intervention in the energy industries.** Published estimates of the annual cost of an ad hoc collection of major energy regulations suggest an annual cost of compliance to firms well in excess of the cost of direct and indirect subsidies. Many of these interventions are designed to yield environmental benefits.

- **The impact of energy regulation is more important than either direct or indirect Federal subsidies.** While Federal subsidies described in this report amount to between $5 billion and $10 billion, the economic impact of just those energy regulatory programs considered in this report total at least five times that amount.

[11] Office of Management and Budget, *Budget of the United States Government, Fiscal Year 1993* (Washington, DC, February 1992), Part 2, p. 28.

- **Federal intervention in energy markets is far less pervasive than in previous years.** Direct expenditures for nearly every category of Federal energy activity, including research and development, synthetic fuel subsidies, and development of federal electric power capacity have all declined precipitously from levels of the period from 1979 through 1981. The Tax Reform Act of 1986 eliminated many tax preference items for various energy industries. In the realm of direct controls, wellhead price regulation of crude oil has been eliminated along with the complex entitlements program. Wellhead natural gas prices have been deregulated, and the current trend of natural gas regulation has a strong market-oriented basis. The principal remaining stronghold of regulation in the U.S. energy industries is the electric power industry. The recently enacted Energy Policy Act of 1992 is designed to increase competition in electricity by revising the Public Utilities Holding Company Act.

- **There have been significant shifts in the focus of Federal intervention in energy markets.** Prior to 1980, the most important interventions in Federal energy markets were aimed at either increasing production of energy commodities or at securing energy consumers from the market power of suppliers. Both types of interventions have been on the wane. On the other hand, market interventions aimed at limiting the environmental or health consequences of energy production or consumption have steadily gained in importance. The Clean Air Act Amendments of 1990 is one of the more important recent examples of this phenomenon.

Should There Be a Periodic Report?

The congressional directive requested an analysis of actions and costs necessary to produce a periodic report. Title XXX of the Energy Policy Act of 1992 requires the Department of Energy to contract with the National Academy of Sciences to conduct a study of subsidies and other legal and institutional factors that influence energy. Thus, the Congressional directive may have been overtaken by events. Nonetheless, the following section considers “actions and costs necessary to produce a periodic report.”

To do this, it is first necessary to determine what the content and the frequency of a periodic report ought to be. Only then is it possible to describe costs and requirements.

Contents of a Periodic Report

Many facts about energy subsidies can be readily ascertained. The quantity of electricity sold by Federal utilities, the value of loans outstanding by the Rural Electrification Administration, and R&D spending by the Department of Energy are all matters of public record, about which there should be little dispute. It is true that some of these facts are not well known, and wider public knowledge of them may be useful.

However, the interpretation of these facts is both difficult analytically and likely to be controversial politically. There is no universal definition of a subsidy and no universally agreed-upon method for valuing subsidies. Further analysis would produce results with more detail, more programs covered, and more effort expended on alternative valuation methods. Further analysis could also quantify some of the energy market consequences of the price and cost changes described in this report. Nonetheless, the results of further analysis would be no less controversial, and the broad outlines of the conclusions would probably change little.

Analyzing Federal energy subsidies requires command of an enormous range of issues, including expertise in energy economics, cost/benefit analysis, tax law, the arcana of the Federal budget, detailed knowledge of Federal regulations, the ins and outs of the nuclear fuel cycle as well as expertise on all of the energy industries from electric power to petroleum. A sensible strategy for managing such a range of issues would be to use the framework developed in this report to prepare a series of special reports, each focusing on subsidies in a particular topic area. This strategy would permit the EIA to match available expertise to a particular topic, and permit (if desirable) pre-publication consultation and review with organizations discussed in the report. Once a particular topic has been examined in detail, it is much easier to update the numbers in smaller scale followup reports.

The results of the special reports could be updated and collated into a periodic overview report generally similar to this report, which need not be annual. Even given a stable policy regime and consistent valuation techniques, subsidy estimates will shift with changing market prices and new Congressional appropriations. However, these year-to-year changes will not necessarily have significant policy implications. On the other hand, if there are large changes in energy prices, or if there are large shifts in the policy regime, then a return to the broad overview would be desirable. Many current Federal programs were not intended as subsidies at the time they were created, but gradually became such as the economic environment shifted while the laws remained unchanged.

Both a broad overview and detailed studies of particular programs are of potential policy interest. A broad overview will permit interested persons to gain a better comprehension of the scope and impact of Federal policy. Detailed studies will provide the information necessary to evaluate particular programs.

Many of the programs that could potentially be examined in the context of Federal energy subsidies have already been extensively studied in other contexts. However, few programs have been analyzed as Federal energy subsidies, with a view towards ascertaining their public costs and energy consequences. Also, there have been few comprehensive recent examinations of the cumulative impact of existing Federal policy, rather than reviews of potential new policies. This change in point-of-view is, in itself, sufficient to warrant further study.

The Frequency of a Periodic Report

If the "special report" format is adopted, then the frequency of these reports is a matter of the resources made available, the level of interest in particular programs, and administrative convenience. Overview reports do not need to be issued more frequently than every 5 years or even longer. These reports may provide new insights if major policy changes are implemented. In these cases, the reports should be prepared long enough after the policy changes to allow the actual consequences of the policy change to be investigated.

Actions and Costs Necessary

The actions and costs necessary to create a periodic report on subsidies depend on the type and depth of investigation that the Congress deems desirable. The detailed studies of particular sectors may require developing expertise not currently possessed by EIA, particularly with respect to valuing tax expenditures and estimating actuarial costs of environmental liabilities. The last full-scale attempt by the U.S. Government to enumerate, in detail, all Federal programs affecting the energy industries took more than 2 years to prepare and cost in excess of $8 million in 1978 through 1980.[12] Thus, additional resources are prerequisite for any significant additional work in this area.

A decision to investigate the consequences of transportation programs, for example, or a range of regulatory issues would multiply the potential scope of work, and consequently, the resources required. Therefore, it seems best to await a more precise expression of Congressional intent before describing a possible program in detail.

[12]Battelle Pacific Northwest Laboratory, *An Analysis of Federal Incentives Used to Stimulate Energy Production*, PNL-2410 REV. II (Richland, WA: February 1982). The report was prepared by a team of 22 persons.

2. Direct Expenditures

As noted in Chapter 1, the textbook definition of an energy subsidy is a payment designed to reduce the price or cost of energy. This chapter describes payments relating to Federal interventions in the energy industry that can be traced in the Federal budget.

Actual budget reporting can be difficult to interpret. Budget reporting is usually intended to match actual cash outlays during the fiscal year. However, it does not consistently distinguish between investment and consumption spending, sometimes treats loan dispersals as spending, loan repayments as revenue, and can combine outlays and receipts. It is therefore often difficult to discern the actual nature of the underlying transaction.

Federal direct expenditures in this chapter are divided into four different types of activities:

- Grants such as the Department of Energy's conservation grants and the Department of Housing and Urban Development's Low Income Housing Energy Assistance Program (LIHEAP)

- Federal loans and loan guarantees, channeling credit to borrowers who might otherwise have to pay higher interest rates or be unable to obtain credit at all

- Provision of energy services including the production and sale of electricity and enriched uranium

- Provision of regulatory, safety, and resource management services in the public interest, such as the operations of the Nuclear Regulatory Commission or the Mining Safety and Health Administration.

This chapter will report on outlays as presented in the budget and will attempt, where relevant, to give perspective on a range of transactions not well represented by the budget format. Table 2 summarizes Federal energy-related direct expenditures on a budget basis.

Budgetary Costs in FY 1992

Grants

The Low-Income Housing Energy Assistance Program (LIHEAP). By far, in FY 1992, the largest program among direct expenditure energy subsidies was the Low-Income Housing Energy Assistance Program, which totaled $1.1 billion in outlays. The LIHEAP disburses block grants to the States (and to 113 Indian Tribes) who in turn provide assistance to about 5.8 million low-income households for payment of utility bills and for weatherization of residences.[13] The precise eligibility criteria vary from State to State but, in general, recipients must have income that is less than 150 percent of the poverty level for their State, or less than 60 percent of the median income. Alternatively, at least one member of the household must be receiving Aid to Families with Dependent Children, Supplementary Social Security Income Payments, food stamps, or certain needs-tested veteran's and survivor's payments.

About 63 percent of LIHEAP funding is used for winter heating assistance, 1.5 percent for cooling assistance, 12 percent for year-round assistance or "crisis intervention," 9 percent for program administration, 8 percent for weatherization, and about 3 percent is transferred for use in nonenergy programs. Some 5.5 million recipients receive heating assistance, 360,000 households receive cooling assistance, and 150,000 households receive weatherization assistance.

The effects of LIHEAP are hard to quantify, in part because the actual administration of the LIHEAP program is in the hands of the States, and the States apply differing eligibility criteria and do not collect uniform information from recipients. Based on sample

[13]Information on the LIHEAP program in this section, unless otherwise cited, is drawn from U.S. Department of Health and Human Services, *Low Income Home Energy Assistance Program: Report to Congress for Fiscal Year 1990* (Washington, DC, September 1991).

Table 2. Outlays for Direct Expenditure Energy Subsidies, FY 1992
(Million Dollars)

Programs	Gross Outlays	Offsetting Receipts	Net Outlays
Total	**13,749**	**10,357**	**3,212**
Grants			
Low-Income Home Energy Assistance	1,143	0	1,143
DOE Conservation and Technical Assistance	[a]262	0	[a]262
Synthetic Fuels Subsidies	72	0	72
Federal Loans and Guarantees: Rural Electrification Administration	**[b]44**	**0**	**44**
Provision of Energy Services			
Tennessee Valley Authority[c]	5,823	5,897	457
Power Marketing Administrations	3,597	3,251	346
Corps of Engineers Power Projects	463	0	463
Bureau of Reclamation Power Projects	99	0	99
Uranium Enrichment	1,350	1,547	-197
Regulation and Resource Management			
Nuclear Regulatory Commission	[d]380	373	[d]7
Mining Safety and Health Administration[e]	94	0	94
Office of Surface Mining Reclamation and Enforcement	108	0	108
Minerals Management Service (administration)	208	0	208
Bureau of Land Management (energy and minerals)	84	0	84
Minor Programs	22	0	22

[a]Outlays estimated by ratio of outlays to budget authority for the entire program.
[b]Includes interest subsidies for new electricity-related loans in FY 1992 ($23.4 million) and administration of rural electrification program ($20.4 million).
[c]Power program only. Non-power operations had net outlays of $117 million in FY 1992.
[d]Excludes nuclear safety research, which is included in Federal energy R&D.
[e]Includes coal program only. Total outlays were $179 million in FY 1992.
Sources: Office of Management and Budget, *Budget of the United States Government, Fiscal Year 1993* (Washington, DC, 1992). Data for Corps of Engineers and Bureau of Reclamation were provided by those agencies.

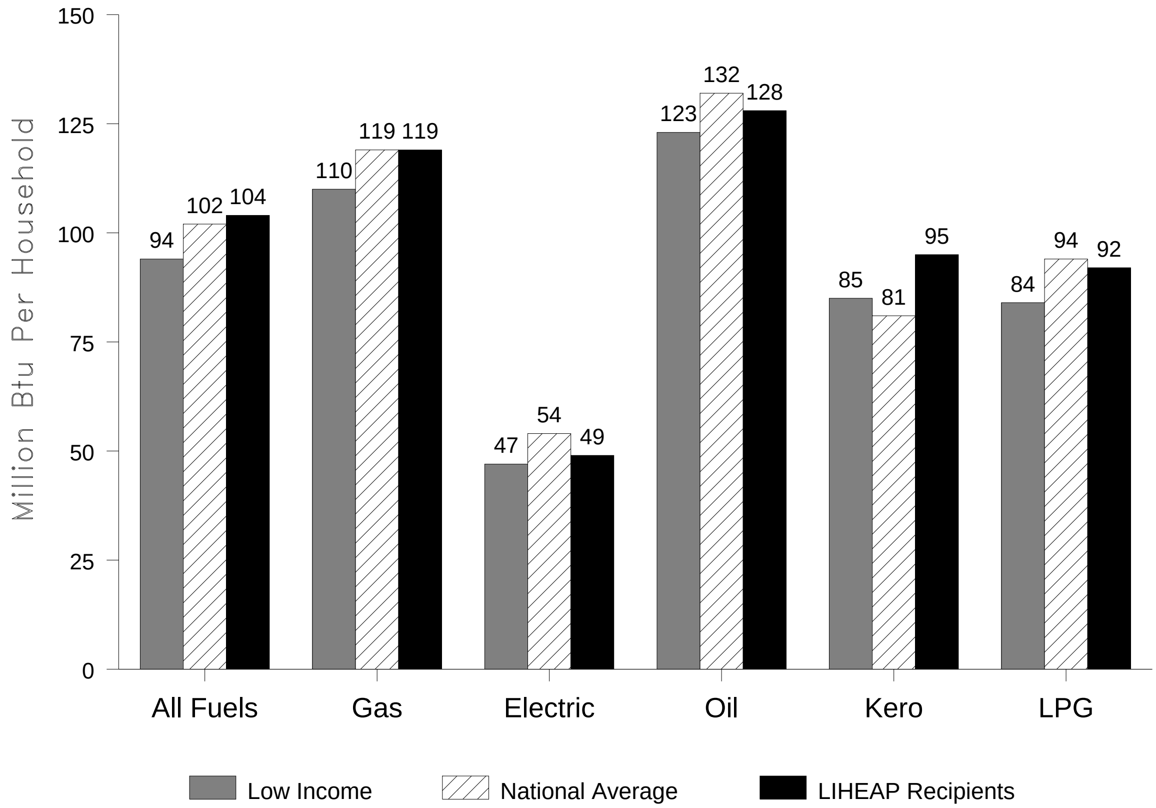
survey data, about 55 percent of LIHEAP recipients heat their homes with natural gas, 20 percent with electricity, 18 percent with petroleum products, and the balance (6 percent) with other fuels.

In 1990, LIHEAP grants accounted for about 51 percent of recipients' annual energy expenditures. As a group, LIHEAP recipients have lower income than the average low-income household: more than 90 percent of LIHEAP recipients have annual incomes less than $12,000. Low income notwithstanding, the average LIHEAP household consumed about 2.3 percent more energy than the national average and about 10 percent more energy than the average low-income household (Figure 1). When divided between heating and cooling, LIHEAP recipients used about 10 percent more energy than the national average household for heating, but 41 percent less energy for cooling, mirroring the pattern of LIHEAP assistance.[14] Though it is not its primary purpose, it appears that, excluding weatherization grants, this program functions as a subsidy to energy consumption.

Department of Energy Conservation Grants. Also included in the grant category is the Department of Energy's (DOE) program of grants for conservation and

[14]Subsidies may not be the only cause of the high energy consumption of LIHEAP recipients. LIHEAP recipients may tend to be concentrated in parts of the country that experience more severe winters than the population as a whole, and/or they may live in housing with unusually poor insulation and inefficient appliances.

Figure 1. Annual Energy Consumption by Fuel of the Average U.S. Household, Average Low-Income Household, and LIHEAP Recipients, 1991



Source: U.S. Department of Health and Human Services, *Low Income Home Energy Assistance Program: Report to Congress for Fiscal Year 1990* (Washington, DC, September 1991), p. 19.

technical assistance, with FY 1992 outlays of $262 million. This program provides grants to cover a portion of the cost of investments in energy conservation in public and quasi-public buildings. Investments in energy conservation might include better insulation and weatherization, high-efficiency lighting systems, or more efficient heating/cooling systems. Typical recipients are schools, hospitals, local government office buildings, and churches. This program also provides grants to establish and operate State and local energy offices, which do much of the work of identifying grant recipients. In contrast to LIHEAP, the DOE program subsidizes energy conservation and is designed to reduce energy consumption.

Synthetic fuel subsidies. The Synthetic Fuels Corporation (SFC) was established as a Government agency in 1979 and abolished in early 1986. Four projects funded by the SFC were given long-term price guarantees. Two price guarantees remain in effect: Dow's Syngas project in Louisiana ($622 million in guarantees expiring in 1997) and the Forest Hills heavy oil project in Texas ($60 million in price guarantees expiring in 1995).[15] When the SFC was abolished, its liabilities were transferred to the Department of the Treasury's "Energy Security Reserve" account. Treasury Department outlays for the residual obligations of the SFC were $72 million in FY 1992, the bulk of which funded price supports for the Dow Syngas plant. This

[15]A description of SFC projects approved at the time the Corporation was abolished is given in *Coal & Synfuels Technology* (December 23, 1985).

plant produces 30 billion Btu per day of medium-Btu gas from western coal. The Government-guaranteed price is $11 per million Btu.[16]

Federal Loans and Loan Guarantees

In the past, there have been numerous energy-related loan and loan guarantee programs. At present, the only remaining program is the Rural Electrification Administration (REA). The REA's current loan program has little budgetary impact, since REA is permitted to function as a "revolving fund" for budget purposes and to net loan dispersals and repayments. The Federal Credit Reform Act of 1990 required certain Federal loan programs, including REA, to report interest subsidy costs in their budget presentations, beginning in FY 1992. In FY 1992, interest subsidy outlays stemming from electricity loans made in FY 1992 were $23 million. This amount represents only the interest subsidy associated with new loans in FY 1992. Administrative costs of the electricity lending program were $20 million (out of an REA administrative budget of $38 million) in FY 1992. The REA loan program is analyzed in detail in Chapter 6, where the total interest subsidy on REA's loan portfolio is estimated at $1.2 billion.

Provision of Energy Services

When the Federal Government enters the market and sells electricity or energy services to itself or to the private sector, the possibility always exists that the services may be sold at a price that is too high or too low when compared to prices which would exist without the Government intervention. Energy services sold at a price that is "too low" would subsidize the consumer. However, in order to determine whether the Federal Government's price is "too low," one must decide upon the "right" price for the service.

This report uses three general approaches to determine the "right" price for energy services. The approaches yield different answers, and the "best" approach may be different for different programs. The three types of approaches are:

- **Budget cost.** This is the easiest method to compute. One simply takes revenues and outlays from the Federal budget. If the service is priced so that revenues exceed outlays, the pricing decision functions as a tax. If outlays exceed revenues, the price is "too low" and constitutes a subsidy. This method sometimes gives misleading results, since the budget approach does not distinguish between capital and operating expenses, and makes no allowance for recovery of past capital outlays.

- **Market price.** In a well-developed market there are competing producers with differing costs, but only a single market price. At the market price, some producers may make substantial profits, while others will only break even. If the Government is participating in a well-developed market, the "right" price is the market price, so long as the market price is greater than the Government's operating cost. Thus, if the Government sells below the market price, it is a subsidy. The revenues foregone by charging a below-market price is a measure of the subsidy, since the Government, in principle, has the option of selling its services at the market price.[17] Unfortunately, market prices do not always exist, or such prices may be difficult to observe.[18]

- **Historical cost.** If markets do not exist, then the unsubsidized price is one that recovers the cost of production. However, defining "cost" is not necessarily simple. Direct maintenance and operation costs would universally be considered legitimate components of cost. Depreciation of capital assets used in production would generally be considered legitimate. However, deciding which assets should be included in the asset base are matters of judgment, as is the depreciable life of the assets. More controversial is the determination of an

[16]Terms of the Dow price guarantees are quoted in "Texaco Contests Dow on Process," *Synfuels Week* (April 9, 1984), p. 3. The transition from the SFC to the Treasury and funding for the Energy Security Reserve is described in Office of Management and Budget, *Budget of the United States Government, Fiscal Year 1993*, Appendix 1, p. 791. Details of the transition are described in "Treasury SFC Transition Team Picked," *Coal & Synfuels Technology* (March 31, 1986), p. 6.

[17]However, if the Government is a major participant in a particular market, its subsidized pricing strategy may affect overall market prices, which would then need to be taken into account in computing the subsidy estimate.

[18]There may be no market prices because the Government is the sole provider of a particular service. Historically, many Government programs were initiated because of the absence of private sector providers. Alternatively, the Government's market share may be so large that the Government effectively acts as a price setter for that market. Market prices may be difficult to observe if the product sold has a complex bundle of attributes that make it difficult to compare one transaction with another.

appropriate "rate of return" for Government-owned assets.[19] Further, some computations of historical cost in the literature attempt to add unrecovered subsidies from prior years into the cost base.[20] Neither depreciation nor cost of capital allowances are normally included in budget costs.

At present, the Federal Government engages in several programs which sell energy or energy services. The Federal Government produces and sells about 66,000 barrels per day of petroleum from Naval Petroleum Reserve-1, in Elk Hills, California, and 2,700 barrels per day from Naval Petroleum Reserve-3, at Teapot Dome. Annual revenues are about $500 million, and FY 1992 outlays (capital and operating expenses) were $220 million. Since Naval Petroleum Reserve oil is sold competitively on the open market, this report concludes that there is no subsidy element in these sales. Federal oil and coal leases are generally auctioned, establishing the presumption that the Government gets a market price for its property.[21] On the other hand, there are two programs which arguably do have a subsidy element: sales of uranium enrichment services and sales of Federal power.

Uranium Enrichment. In order for natural uranium to be used as fuel in nuclear power plants, it must be enriched. Until enriched uranium became the fuel for commercial nuclear power plants, the technology of uranium enrichment was a closely held nuclear secret, one of the technologies that gave the United States its nuclear monopoly.

When commercial nuclear reactors first appeared in the early 1960's, the Atomic Energy Commission (AEC) was the sole purchaser and enricher of natural uranium, with most production fed to the nuclear weapons program. The commercial enrichment program was undertaken as a by-product of the weapons program. The enrichment program was put on a more commercial basis in 1969. About $1.5 billion in assets were transferred from the AEC's defense-related program to its commercial program, and the costs of these assets were to be recovered from enrichment sales.

DOE enriches uranium at gaseous diffusion plants in Kentucky and Ohio, built prior to 1960 for the nuclear weapons program. Total annual capacity is about 19.3 million Separative Work Units (SWU).[22] Actual use is about 13 million SWU, about two-thirds for U.S. customers, and a third for overseas customers, primarily in the Far East.[23] Both plants have high operating costs (about $70 per SWU) compared with more recently built gas centrifuge plants in Europe.[24]

To decide whether or not provision of enrichment services constitutes a subsidy, one must determine at what price uranium enrichment services ought to be sold. There are at least three bases for computing this price:

- **Budget cost.** In FY 1992, the U.S. Government spent $1.35 billion on the provision of uranium enrichment services (including $0.1 billion for capital investments), and received offsetting receipts of $1.54 billion, leaving a net cash surplus of $0.19 billion. This is the picture of uranium enrichment presented in the budget. On this basis, there is no subsidy. However, this computation makes no allowance for recovery of capital assets acquired in previous years, nor for the Government's cost of capital.

[19]When the Federal Government levies taxes or borrows money in order to make an investment, it should, in principle, try to ensure that the resources it commands are being put to more productive use than if the funds had been left in the private sector. To do this, the Government should try to ensure that projects earn a pecuniary or social return on investments greater than their cost. Exactly what rate of return the Government ought to seek, however, is not obvious. For a survey of the literature on this topic, see Raymond Mikesell, *The Rate of Discount for Evaluating Public Projects* (Washington, DC: American Enterprise Institute, 1977).

[20]cf. U.S. General Accounting Office, *Uranium Enrichment: Some Impacts of Proposed Legislation on DOE's Program*, GAO/RCED-89-170BR (Washington, DC, July 1989), which makes this argument for the uranium enrichment program.

[21]Offshore oil leases have always been auctioned. The Federal Onshore Oil and Gas Reform Act of 1987 required all onshore leases to be auctioned, though it authorized the noncompetitive sale of leases on tracts without known oil potential for which no auction bids were submitted. See U.S. General Accounting Office, *Mineral Revenues: Implementation of the Federal Onshore Oil and Gas Leasing Reform Act of 1987*, GAO/RCED-89-108 (Washington, DC, May 1989).

[22]A SWU is a measure of the amount of enrichment "effort" required to create a unit of fuel-grade uranium.

[23]U.S. General Accounting Office, *Uranium Enrichment: Congressional Action Needed to Revitalize the Program*, GAO/RCED-88-18, p. 21.

[24]U.S. General Accounting Office, *Uranium Enrichment: Some Impacts of Proposed Legislation on DOE's Program* (Washington, DC, July 1989), p. 39.

- **Market price.** There is an international market for enrichment services, characterized by chronic excess capacity. At present, DOE charges approximately $117 per SWU, on average, for uranium enrichment services. European operators have been willing to undercut DOE prices to gain U.S. business. The Russians have been charging $50 to $60 per SWU.[25] There is little opportunity for the DOE to raise prices in order to recover either historic costs or future decommissioning costs, since lost sales are likely to negate the benefits of higher prices. On this basis, then, DOE's price is the market price, and there is no subsidy (as long as enrichment revenues exceed operating costs).

- **Historical cost.** Controversial issues include whether or not to attempt to recover the $3.4 billion cost of a never-completed enrichment plant, and how (and whether) to value the Government's large commercial stockpile of enriched uranium. An estimated range of values for enrichment enterprise assets based on varying assumptions is on the order of $1.5 to $7 billion. Consequently, in order to earn a 15-percent return on the depreciated value of assets, DOE would have to charge $130 to $190 per SWU. This, in turn, would imply a subsidy in current prices ranging from $0.3 billion to $1.5 billion annually.

As a practical matter, changes in world politics have recently made enriched uranium rather plentiful, and enrichment prices will continue to be low.

Titles IX, X, and XI of the recently passed Energy Policy Act of 1992 make major changes in Federal uranium enrichment activities. The new law creates a Government-owned Uranium Enrichment Corporation, and transfers DOE uranium enrichment assets to the Corporation in exchange for equity held by the Treasury. The Corporation is instructed to prepare a plan to privatize itself within 2 years. The new law also reduces an important obstacle to privatization by retaining partial Federal liability for the decommissioning costs of uranium enrichment plants. The Federal liability will be funded by an annual assessment of $480 million on nuclear plants that have purchased DOE enrichment services in the past. The Corporation will also be required to contribute to a trust fund to pay its share of future decommissioning costs.

Power Marketing Administrations and the Tennessee Valley Authority (TVA). The subsidy element in Federal electric power sales are covered in considerable detail in Chapter 6. They are discussed here for the sake of completeness in presenting the budget effects of Federal programs. The revenues of Federal utilities (except for TVA) are treated as receipts, while their capital and operating costs are treated as outlays.

Capital costs for Federal utilities are scattered throughout the budget. Expenditures for hydroelectric dam construction are made by the Department of the Interior's Bureau of Reclamation and the Army Corp of Engineers. Project costs are prorated between power generation, irrigation, and flood control. As shown in Table 2, the electric power share of projects in the FY 1992 budget for these agencies is $0.56 billion. Capital costs for the Power Marketing Administrations (mostly for transmission work) are funded through direct appropriations to these agencies.

Federal utilities, however, are expected to repay capital costs, with interest, by remitting funds to the Treasury over the life of the project. "Repayments" and "interest" are paid out of "excess" cash flow. These computations have an artificial character, however, since this is money that the Federal Government owes to itself.

The financing of the Tennessee Valley Authority is somewhat different. The TVA is one of a handful of Federal agencies permitted to borrow on its own account, though TVA borrowing is backed by the full faith and credit of the United States, and consequently does not differ materially from borrowing by the Treasury. The power program had receipts of $5.4 billion in FY 1992, and operating expenses of $4.7 billion. This positive cash flow, along with $1 billion in new borrowing, was used to fund $1.6 billion in FY 1992 capital expenditures and an $80-million repayment to the Treasury. On a cash basis, TVA power program outlays exceeded receipts by $0.5 billion in FY 1992.

Table 3 shows current outlays and receipts for the TVA and the Power Marketing Administrations as a group.

[25]U.S. General Accounting Office, *Uranium Enrichment: Some Impacts of Proposed Legislation on DOE's Program* (Washington, DC, July 1989). The DOE continues to retain customers in part because enrichment services are sold on the basis of multiyear contracts, which cannot easily be changed, and in part because the Russians may not be perceived as reliable suppliers. There have been a number of recent developments in uranium enrichment. The U.S. International Trade Commission is investigating allegations that the Russians have been dumping (selling below cost of production) enriched uranium. As noted in the text, computing an unsubsidized enrichment cost for the United States is difficult and potentially controversial. Computing Russian enrichment costs is essentially impossible. In any case, the U.S. Government has decided (on foreign policy grounds) to purchase Russian highly enriched uranium as a substitute for U.S. enriched uranium.

Table 3. Outlays for Power Marketing Administrations and the Tennessee Valley Authority, FY 1992
(Million Dollars)

Agency	Gross Outlays	Offsetting Collections	Net Outlays	Past Debt Financing Subsidies
Tennessee Valley	5,822.8	5,366.0	456.8	NA
Alaska Power	3.5	0.3	3.2	0.0
Southeastern Power	32.1	7.7	24.5	36.6
Southwestern Power	34.1	8.8	25.3	21.3
Western Area Power	488.5	187.5	301.0	44.0
Bonneville Power	3,039.1	3,047.6	-8.5	288.6
Total	**9,420.1**	**8,617.9**	**802.2**	**390.5**

NA = Not available.
Source: Office of Management and Budget, *Budget of the United States Government, Fiscal Year 1993* (Washington, DC, 1992).

Outlays exceed receipts by $0.8 billion. In addition to net outlays, Table 3 also illustrates "past debt financing subsidies" of $0.5 billion in FY 1992, which covers unrecouped interest and principal on appropriations made in prior years. When TVA and PMA net outlays are combined with capital investments for new power facilities made by the Corps of Engineers and the Bureau of Reclamation (Table 2), outlays exceed receipts for Federal power by about $1.4 billion.

These figures are an illustration of the deficiencies of the budget approach for measuring subsidies. On a budget basis, net outlays are about $1.3 billion (Table 2). Since outlays mix recurrent expenditures and investment, there is no way of determining from the budget whether these agencies are covering current costs, nor whether they are recouping past investments. Hence, there is the need for a more careful study of these agencies, which is undertaken in Chapter 6. On a market-price basis, Chapter 6 suggests that consumers of Federal electricity may be receiving a subsidy from below-market pricing of about $2 billion annually. Estimating costs on a historic-cost basis would raise the subsidy estimate to $4.1 billion. A subsidy of this magnitude, however, implies that unsubsidized prices must be higher than market prices in some cases.

Provision of Safety and Regulatory Services

Most Federal safety and regulatory programs are funded by a levy on the industries they regulate. The Federal Energy Regulatory Commission, charged with regulating interstate natural gas pipelines, power transmission and operations of hydroelectric facilities, had estimated outlays of $138 million in FY 1992. This cost is recovered from a small levy on gas transported through interstate pipelines. The Nuclear Regulatory Commission (NRC) is also largely financed through fees levied on the nuclear power industry. In recent years, however, fee collections have fallen slightly short of expenses, producing a small subsidy to the nuclear industry.

The Nuclear Regulatory Commission (NRC). The NRC is charged with regulating civilian nuclear power and the use of nuclear materials to protect the public health and safety. In FY 1992, the NRC had outlays of $495 million, of which $115 million was expended for nuclear safety research, covered in Chapter 5. The Nuclear Regulatory Commission's costs are recouped through a $19.5-million transfer from the Nuclear Waste Trust Fund (this transfer is intended to cover the costs of NRC's nuclear waste management program, discussed in Chapter 3), through a (1 mill per kilowatthour) fee levied on nuclear power generation, fees levied for handling nuclear material, and fees for specific services provided by the Commission staff. Levies for FY 1991 fell short of covering the NRC's costs by $6.7 million.[26] The FY 1992 shortfall (if any) has not yet been reported. For the purposes of subsidy reporting in Tables 1 and 2, this report assumes that the FY 1992 shortfall is equal to the FY 1991 shortfall, or $7 million.

Mine Safety and Health Administration (MSHA). This agency, within the Department of Labor, is charged

[26]U.S. Nuclear Regulatory Commission, *Annual Report 1991*, pp. 214-215.

with enforcing the Federal Mine Safety and Health Act of 1977. Its purview includes the development and promulgation of health and safety standards, inspection of mines to ensure that the mines meet these standards, education programs, and technical support. MSHA is also authorized to provide emergency funding for rescue operations in the event of a major mining disaster. MSHA is responsible for regulating all types of underground mines. However, much of its effort is devoted to the regulation of coal mining. Approximately $94 million of its $182 million FY 1992 appropriation is allocated for enforcement of coal mining regulations. There are no offsetting collections from the coal or mining industries.

Office of Surface Mining Reclamation and Enforcement. This Office, located within the Department of the Interior, had outlays of $108 million in FY 1992. It is charged with enforcing the Surface Mining Control and Reclamation Act of 1977, which requires that the land surface be restored after surface mining is complete. Slightly less than half of the Office's outlays ($48 million) are in the form of grants to State regulatory agencies. This is a regulatory agency. Actual reclamation costs (if paid by the Federal Government) are funded through the Abandoned Mine Reclamation Fund, treated in Chapter 4. There are no offsetting collections for this Office.

Department of the Interior minerals management programs. Through its ownership of land and undersea resources, the Federal Government is the largest single owner of energy resources in the United States. Federal management of these resources has increased the opportunities for exploration and production, yielding increased supplies of U.S. energy. The Federal costs of energy resource management include the Bureau of Land Management's energy and minerals management program ($80.4 million) and the Minerals Management Service's royalty management, Outer Continental Shelf leasing ($207 million), and administrative costs. Oil and gas production from the Outer Continental Shelf generated rents and royalties of $2.3 billion in FY 1992.

Minor programs. The Economic Regulatory Administration, within the Department of Energy, is charged with resolving remaining enforcement actions undertaken against oil companies charged with violating oil price controls prior to their elimination in January, 1981. FY 1992 outlays were $14.8 million. The Federal Mine Safety and Health Review Commission decides contested enforcement actions under mine safety legislation (predominantly coal). FY 1992 outlays were $4.9 million. The Office of the Nuclear Waste Negotiator, funded at $2.5 million in FY 1992, is directed to attempt to find a State or Indian tribe willing to accept a nuclear waste storage site.

Trends Over the Decade

During most of the 1980's, the budgetary cost of direct expenditure subsidies declined (Figure 2). Net outlays were at a peak of $4.5 billion in FY 1982 and were reduced to $2.3 billion in FY 1990. Since 1990, overall net outlays have risen more than 1.2 billion. The rise in appropriations was slower, but equaled 4.5 billion in 1992.

An instructive way of viewing direct expenditure and credit subsidy programs is by the type of energy sources to which the programs are directed (Figure 3). This grouping shows the changing emphasis of Federal support and delineates the affected energy markets. Categories of review in this section are: public power, which includes TVA, PMAs, and the electrification portion of the REA; services in support of the nuclear power industry, which consists of the uranium enrichment program and activities of the NRC (excluding R&D); fossil fuel programs; and energy conservation, which is represented by the DOE's grants for conservation and technical assistance (excluding R&D). Since the LIHEAP can result in expenditures for a variety of home heating sources, this program is in a category of its own.

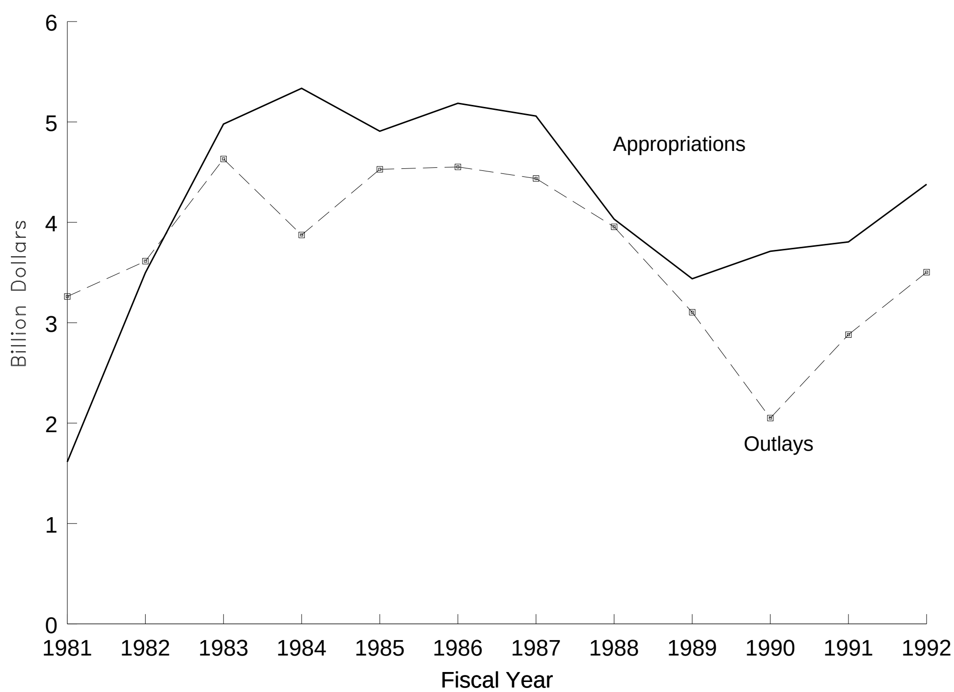
Direct expenditures declined between FY 1984 and FY 1989. Over this period, net appropriations[27] for uranium enrichment services fell by nearly $500 million, reflecting reduced activity. Through the first half of the 1980's, the Uranium Supply and Enrichment Program built large inventories. The program increased production but demand fell short of expectations, as electric utilities canceled the construction of numerous nuclear power plants. In 1985, the program began selling off inventories and reduced the level of enrichment activity.

Among the direct expenditure programs, appropriations for the LIHEAP have fallen gradually since the mid-1980's. This decline largely reflects the generally lower level of heating oil costs since 1986 and lower natural gas prices.

[27]In order to provide comparability of budget data for uranium enrichment services before and after FY 1990, offsetting receipts for enrichment services are subtracted for all years shown in Figure 3.

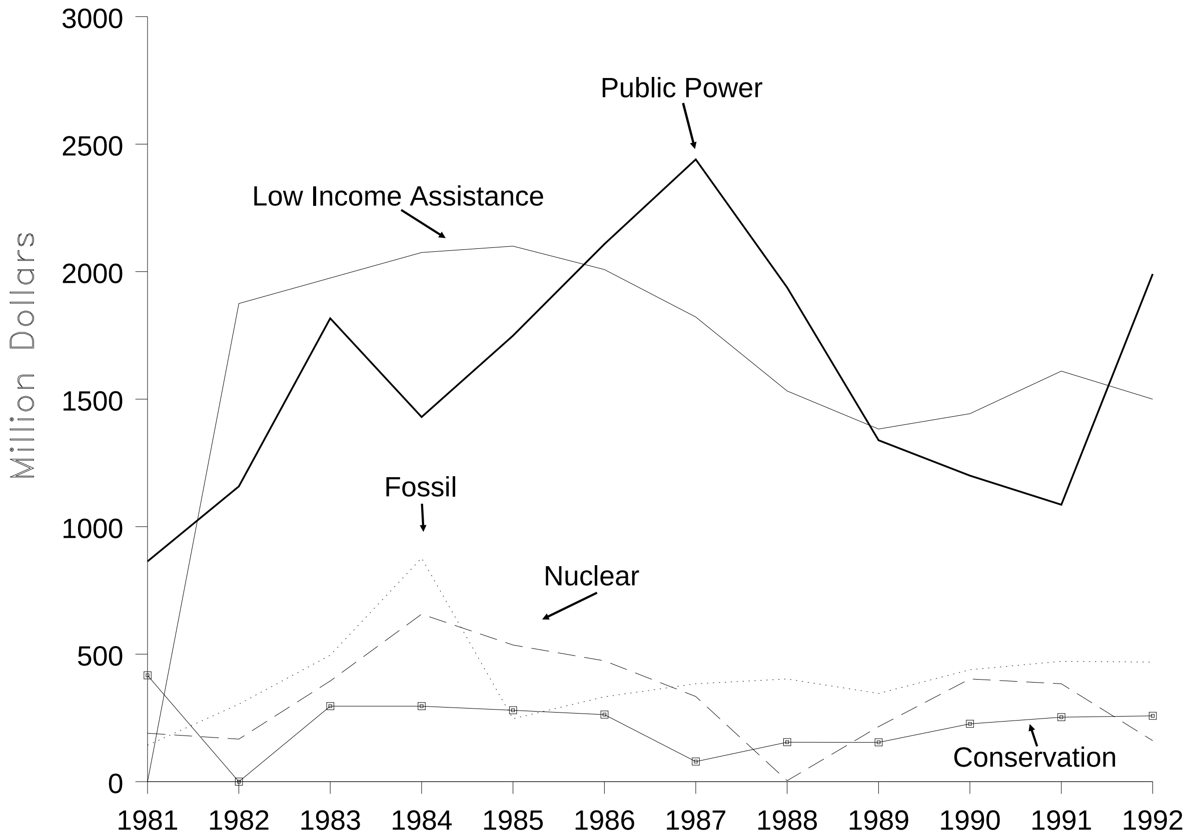
Net appropriations for public power programs have shown a varied pattern over the past decade, ranging from slightly over $1 billion in FY 1982 and FY 1991 to a peak value of $2.4 billion in FY 1987. The sharp dip during FY 1988 to FY 1990, followed by an even steeper upturn in appropriations for these programs in FY 1991, was largely accounted for by the variations in Federal funding for the TVA. The TVA's capital appropriations were cut as nuclear power projects were suspended. TVA's capital spending then began to grow again.

Figure 2. Direct Expenditures and Credit Subsidies: Total Appropriations and Outlays, FY 1981 - FY 1992



Source: Office of Management and Budget, *Budget of the United States Government Fiscal Year 1993: Supplement, February 1992* (Washington, DC, February 1992).

Figure 3. Direct Expenditures and Credit Subsidies, Net Appropriations by Program Categories, FY 1981 - FY 1992



Source: Office of Management and Budget, *Budget of the United States Government Fiscal Year 1993: Supplement, February 1992* (Washington, DC, February 1992).

3. Energy Tax Expenditures

Tax expenditures are reductions in Government revenues resulting from preferential tax treatment for particular taxpayers. They are termed tax expenditures because the objectives they are intended to achieve can also be reached by a direct expenditure of Government funds. The term "tax expenditures" is applied to preferential tax treatment provided by Federal income tax laws. However, it can also be applied to the income tax laws of other jurisdictions, such as States and municipalities. The concept could also be extended to include nonincome taxes, such as excise taxes. All but one of the tax expenditure provisions reviewed in this chapter are Federal income taxes that are applied preferentially to energy. The exception is the partial exemption from the Federal energy excise tax on alcohol fuels.[28]

Many tax expenditure programs are functionally equivalent to direct expenditure programs. The basis for selecting one or the other approach to provide benefits to taxpayers is not always clear. Several factors may be considered during the selection process. Tax expenditures, in particular, may be less subject to annual review in the normal budget cycle. Also, tax expenditure programs are less visible than direct expenditure programs in the budget process. The ultimate decision as to which approach to use in a subsidy program will depend on the specific characteristics of each program.[29]

The economic basis, or justification, that is frequently asserted for adopting tax expenditures differs with the particular type of tax expenditure program. The typical justification for tax expenditures that relate to capital recovery is to bring tax depreciation into closer conformity with actual economic change in the market value of the asset. Examples of differential capital cost recovery for energy tax purposes that have used this rationale include immediate expensing of intangible drilling costs and percentage depletion.[30] Intangible drilling costs were asserted by producers to be conventional operating expenses that therefore should be expensed. Granting accelerated write-offs for investment improves after-tax profits and encourages additional mineral exploration and development. The use of percentage depletion rather than cost depletion has a similar consequence.[31] A second justification for tax expenditures is to stimulate the production of goods deemed to provide benefits which are not sufficiently valued in the market. An example is the alternative fuel production credit which encourages increased use of renewable energy and conserves on petroleum use. A third source of tax expenditures relates to the exclusion of taxation of one level of government by another. Because of this exclusion, the interest on industrial development bonds issued by State or local governments to finance certain energy facilities, such as municipal electric and gas utilities, is exempt from Federal tax.

Tax expenditures exist when actual tax treatment for particular kinds of taxpayers deviates from standard tax treatment. There is disagreement as to what constitutes standard treatment, both in principle and in practice. As a result, lists of tax expenditure items and associated values can and do differ. With minor modification, the list and values used in this report are those prepared by the U.S. Treasury Department and reported by the Office of Management and Budget in the U.S.

[28]Excise taxes are reviewed in Chapter 4. However, the partial exemption of alcohol fuels from excise taxes on transportation fuels is closely related to energy tax expenditures and, for this reason, is reviewed in this chapter.

[29]Some of the factors relating to the two approaches are discussed in Martin Feldstein, "A Contribution to the Theory of Tax Expenditures: The Case of Charitable Giving," pp. 99-122, in Henry J. Aaron and Michael J. Boskin, *The Economics of Taxation* (Washington, DC: The Brookings Institution, 1980).

[30]Intangible drilling costs are defined as oil and gas well drilling expenses that do not have salvage value and are "incident to and necessary for the production of oil and gas." Typical intangible costs include well logging, labor, fuels, and site preparation expenses, and usually account for about 70 percent of the cost of drilling wells. A textbook discussion of intangible drilling costs can be found in R.A. Gallun and J.W. Stevenson, *Fundamentals of Oil and Gas Accounting,* 2nd edition (Tulsa, OK: Pennwell Books, 1988), pp. 224-227.

[31]Each tax expenditure category, including those that relate to intangible drilling costs and percentage depletion, is discussed later in the report and in detail in the fact sheets that comprise Appendix B.

Government's annual budget.[32] That list is the only one with values for both current and past fiscal years. The Joint Committee on Taxation staff reports annually, but presents only "projections," which may or may not be representative of realized tax expenditures.[33] Neither group includes preferential energy excise tax expenditures, which are included here, within their formulations of tax expenditures.[34] The status of the tax expenditure provisions covered in this report extends only through fiscal year 1992.[35]

Generally, tax expenditures are both tax benefits to preferred taxpayers and revenue losses to the Federal Government. This distinction creates two alternative means of measuring the effects of tax expenditures: "revenue losses" and "outlay equivalents." Revenue losses are defined as the revenue foregone by Treasury. The benefits or losses can also be expressed as "outlay equivalents," which are the amounts that would have to be paid to the taxpayer if he were to derive the same after-tax income that he obtained under the revenue loss approach. Outlay equivalents will exceed revenue losses whenever outlays add to the taxable income of those who benefit from the tax expenditure program. For example, producers pay no tax on the tax credit they receive for producing alternative fuels, and their net income increases by the full amount of the credit. The direct budget outlay required to produce the same increase in net income would be greater than the credit since the outlay would be subject to income tax. Conversely, outlay equivalents will equal revenue losses whenever outlays do not add to taxable income. This typically occurs when tax expenditures take the form of tax deferrals. Tax deferrals are essentially loans. Loans, such as those implicit when exploration and development costs are expensed (or immediately charged against income) do not directly affect taxable income.

This report presents both revenue losses and outlay equivalents. The outlay approach eases comparisons with other types of subsidies discussed elsewhere in this report, which are usually on an outlay basis. The effects of interactions among tax preferences on the aggregate value of energy tax expenditures are reported by the Treasury Department only on an outlay equivalent basis.

Aggregate tax expenditures measured in terms of outlay equivalent have remained relatively constant during the last 10 years and have typically approximated $400 billion annually, except in 1986 and 1987 when they exceeded $450 billion (Table 4).[36]

Income tax credits for Commerce and Housing have consistently accounted for more than one-third of tax expenditures since at least 1983. Tax expenditures for that program together with those for Income Security and Health annually account for about three-fourths of total expenditures. Energy's contribution to the total has been among the smallest since at least 1987 and currently accounts for only $1 billion, or less than 0.5 percent of all tax expenditures. The unrounded value of the $1 billion is $1.46 billion for 1992. Neither the rounded nor the unrounded value includes the $460 million excise tax expenditure for alcohol fuels for that year, which is discussed later.

Energy's contribution to the total was not always so small. In 1983, for example, it was valued at $4 billion. Energy's principal contribution was through the use of percentage depletion rather than cost depletion for mineral resources. Under percentage depletion a specified percentage of gross income from a mineral resource property is deductible for tax purposes. Under cost depletion the value of the deduction is limited to the amortization of the investment value committed to the depleting resource. Percentage depletion benefitted principally oil and gas producers but also benefitted producers of certain other natural resources, particularly coal. In 1969, the percentage depletion rate for oil and gas was reduced; and, beginning in 1975,

[32]Office of Management and Budget, *Budget of the United States Government, Fiscal Year 1993* (Washington, DC, 1992). Also see earlier editions. Treasury's compilation of tax expenditures is limited to special exceptions in the Federal income tax code that serve specific programs listed in the budget, such as energy, health, and defense.

[33]Joint Committee on Taxation (Staff), *Estimates of Federal Tax Expenditures for Fiscal Years 1992-1996*, March 11, 1991 (Washington, DC, 1991). Also see earlier editions. Most energy subsidy studies that involve tax expenditures adopt the list of expenditure items and associated values generated by the Treasury Department or, alternatively, those reported by the staff of the Joint Committee on Taxation (JCT). Generally, it would be expected that the Treasury list would be shorter than the JCT list since Treasury takes a broader view of what constitutes basic tax law. Nevertheless, the lists are usually similar. In one recent year only one JCT item was not included in the Treasury list.

[34]The basic rationale against including preferential energy excise taxes in formulations of tax expenditures is that excise taxes lack a basic structure against which deviations (preferences) can be measured. See Paul R. McDaniel and Stanley S. Surrey, "Tax Expenditures: How to Identify Them; How to Control Them," *Tax Notes* (May 24, 1982), p. 610.

[35]The omnibus energy bill sent to the President for his signature in October 1992 contains energy tax expenditure provisions. Those provisions are not covered in this report.

[36]The value for 1986, which is not shown in Table 4, is $474 billion.

Table 4. Estimated Outlay Equivalent of Federal Tax Expenditures, by Program, Selected Fiscal Years, 1983-1992
(Billion Dollars)

Program	1983	1985	1987	1989	1991	1992
Commerce and Housing Credit	171	189	221	153	146	152
Income Security	97	103	96	76	84	88
Health	27	35	40	47	60	65
General Purpose Fiscal Assistance	32	32	40	35	38	40
Education, Training, etc.	23	28	28	21	22	24
Social Security	19	18	18	19	21	23
International Affairs	4	4	7	6	8	9
National Resources and Environment	3	2	3	3	3	3
General Science, Space and Technology	3	7	4	4	4	3
National Defense	2	2	2	2	2	2
Community and Regional Development	1	1	1	2	2	2
Veterans Benefits and Services	3	2	2	2	2	2
Energy[a]	4	3	1	1	1	1
Interest	1	1	1	1	1	1
Agriculture	1	1	1	1	1	1
Transportation	*	*	*	*	*	*
Total Before Program Interactions	**392**	**428**	**466**	**373**	**395**	**417**

[a]Does not include the outlay equivalent of any preferential energy excise taxes.

* = Less than $0.5 billion.

Notes: •The values shown for any given program are after interactions among components of the program but before interactions between programs. Technically, the program values are not additive because of their high degree of interaction. Actual totals with program interactions are not available but would probably differ substantially from those shown. •Sum of components may not equal total due to independent rounding. •All data have been rounded to the nearest billion.

Source: Office of Management and Budget, *Budget of the United States Government, Fiscal Year 1993* (Washington, DC, 1992). Also see earlier issues.

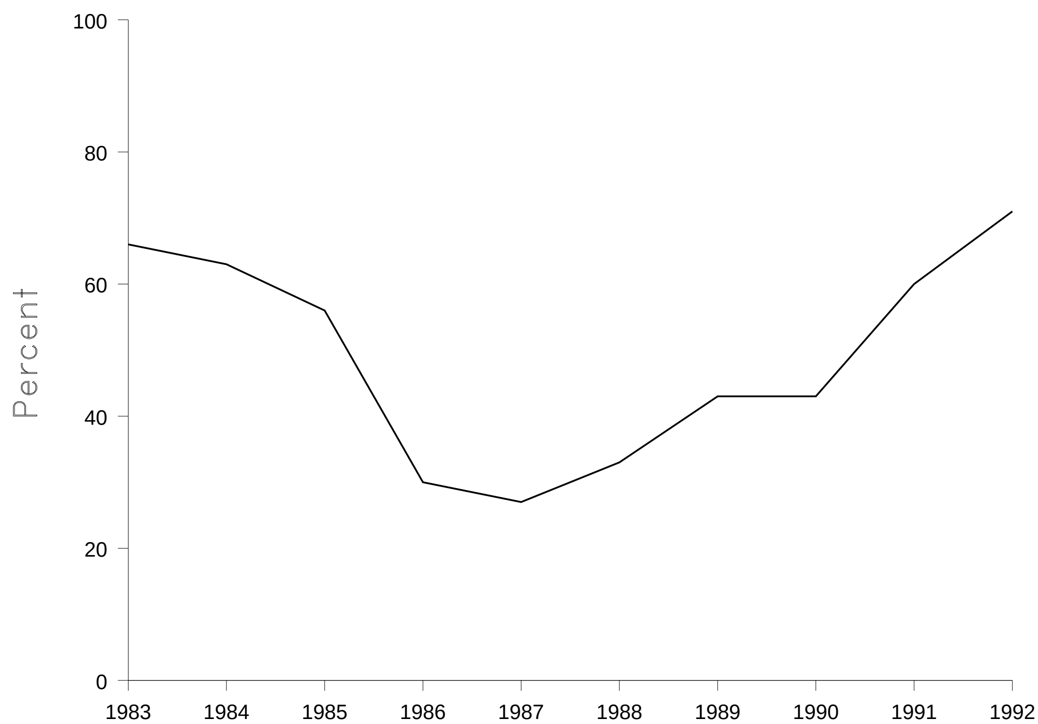
integrated oil and gas producers were prohibited from using percentage depletion altogether. The rate that applied to the remaining oil and gas producers, the "independents," was further reduced between 1981 and 1984. A number of additional developments have also contributed to reduce energy tax expenditures to a small fraction of their pre-1984 levels. They include the more recent elimination of preferential tax treatment for other specific energy tax components,[37] decreases in the volume of oil produced, weak oil and gas prices, and low or stagnant domestic exploration and development investment expenditures. Although small in dollar terms, the oil and gas sector currently accounts for nearly three-fourths of total energy tax expenditures (Figure 4).

Types of Tax Expenditures and Their Measurement

Four major types of energy tax expenditures can be identified (Table 5). They are preferential tax rates, tax deferrals, tax credits, and measures that reduce taxable income. They differ substantially in terms of dollar value. Measures that reduce taxable income, such as the excess of percentage over cost depletion, have the greatest value. These measures include special deductions and exclusions and were valued at $870 million in fiscal 1992. The second most valuable type is tax credits, which were valued at $575 million. The credits apply to items such as investment in new energy technology and alternative fuels.

[37]These include the elimination of income tax credits for equipment using energy from nonconventional sources, credits for equipment used to extract oil from shale, natural gas from geopressured brine, and credits for investment in wind energy equipment.

Figure 4. Oil and Gas Share of Total Energy Federal Tax Expenditures (Outlay Equivalent), FY 1983 - FY 1992



Source: Office of Management and Budget, *Budget of the United States Government, Fiscal Year 1993* (Washington, DC, 1992).

The third most valuable group of tax expenditures consist of tax deferrals. Tax deferrals originate when tax law and regulations allow income earned in one period to be reported and taxed in a later period or allow acceleration of the deduction of expenses. When deferred, taxes are reported as positive tax expenditures (that is, as a loss in Government revenue). When repaid, they are reflected as a negative tax expenditure (that is, as a gain in Government revenues). In fiscal year 1992, net energy tax deferrals were valued at $45 million. The tax deferrals covered here originate from expensing certain energy exploration and development costs, from expensing tertiary injectants that are used to enhance the process of recovering oil, and from the exception from the passive loss limitation for working interests in oil and gas properties. Preferential tax rates are the fourth and least important form of energy tax expenditures. They amounted to only $10 million in fiscal year 1992. Table 5 also shows the only energy tax expenditure covered in this chapter that does not originate from the income tax system. This is the alcohol fuels excise tax preference. It was valued at $460 million in fiscal year 1992. Each type of energy tax expenditure is discussed in the following section. Additional details are provided in the fact sheets that comprise Appendix B.

Individual Energy Tax Expenditures

Energy tax expenditures are among the smallest tax expenditures that correspond to specific budget programs. In fiscal year 1992, they amounted to about $2.0 billion on a revenue loss basis when preferential energy excise taxes are included (Table 5), or to $2.6 billion on an outlay equivalent basis (Table 6).[38]

Most of the energy tax expenditures and preferential energy excise taxes are accounted for by only a few provisions, but those provisions are important in terms of their effects. These few provisions apply principally to oil and gas and, to a lesser extent, coal and alcohol for motor fuels. Alternative forms of energy benefit to only a small degree.

Table 5. Estimated Federal Energy Tax Expenditures (Revenue Loss) by Type of Expenditure and Form of Energy, FY 1992
(Million Dollars)

Tax Expenditures	Oil	Gas	Coal	Alcohol[a]	Other Energy	Certain Energy Facilities	Total
Preferential Tax Rates							
Capital Gains Treatment of Royalties on Coal	0	0	10	0	0	0	10
Tax Deferrals							
Expensing of Exploration and Development Costs	[b]-45	[b]-45	[c]35	0	[d]0	0	-55
Expensing of Tertiary Injectants	[b]10	[b]10	0	0	0	0	20
Exception from Passive Loss Limitation for Working Interests in Oil and Gas Properties	[b]40	[b]40	0	0	0	0	80
Tax Credits							
New Technology Credit	0	0	0	0	0	[e]45	45
Alternative Fuel Production Credit	[f]0	[g]450	0	0	[h]0	0	450
Alcohol Fuel Credit	0	0	0	80	0	0	80
Income Reducing Measures							
Deduction:							
Excess of Percentage Over Cost Depletion	[b]285	[b]285	[c]175	0	[d]0	0	745
Exclusion:							
Interest on Certain State and Local Bonds	0	0	0	0	0	[i]125	125
Exemption	0	0	0	0	0	0	0
Total Before Component Interactions	290	740	220	80	0	170	1,500
Total After Component Interactions	NA	NA	NA	NA	NA	NA	NA
Addendum: Alcohol Fuels Excise Tax	0	0	0	460	0	0	460

[a]Alcohol for use as a motor fuel.
[b]Derived by allocating an aggregate value for oil and gas equally between the two forms of energy.
[c]May include small values for "Other Energy."
[d]There may be small values for uranium, oil shale, and geothermal. Any such values are included in the value for coal.
[e]Solar and geothermal energy facilities.
[f]There could be small values for oil produced from shale and tar sands. Any such values are included in the value for gas.
[g]Although the tax expenditure provision applies to oil, gas, solids, and steam produced from other than conventional sources, the $450 million income tax credit is estimated to be almost entirely for methane gas produced from coal seams.
[h]There may be very small values for synthetic fuels produced from coal, fuel from qualified processed wood, and steam from solid agricultural byproducts. Any such values are included in the value for gas.
[i]Estimated to be principally for natural gas and electric facilities.
NA = Not available.
Notes: • In addition to the income tax expenditures in the table, there exists a gasoline excise tax preference which amounted to an estimated $460 million in fiscal year 1992. See addenda in table. • All effects are net of the Alternative Minimum Tax.
Source: Office of Management and Budget, *Budget of the United States Government, Fiscal Year 1993* (Washington, DC, 1992). Data for tertiary injectants are from Joint Committee on Taxation (Staff), *Estimates of Federal Tax Expenditures for Fiscal Years 1992-1996*, March 11, 1991 (Washington, DC, 1991).

[38]The tax expenditures in these tables are net of the effects of the Alternative Minimum Tax.

Table 6. Estimated Outlay Equivalent of Federal Energy Tax Expenditures by Type of Expenditure and Form of Energy, FY 1992
(Million Dollars)

Tax Expenditures	Oil	Gas	Coal	Alcohol[a]	Other Energy	Certain Energy Facilities	Total
Preferential Tax Rates:							
Capital Gains Treatment of Royalties on Coal	0	0	10	0	0	0	10
Tax Deferrals:							
Expensing of Exploration and Development Costs	[b]-45	[b]-45	[c]35	0	[d]0	0	-55
Expensing of Tertiary Injectants	[b]10	[b]10	0	0	0	0	20
Exception from Passive Loss Limitation for Working Interests in Oil and Gas Properties	[b]50	[b]50	0	0	0	0	100
Tax Credits:							
New Technology Credit	0	0	0	0	0	[e]65	65
Alternative Fuel Production Credit	[f]0	[g]670	0	0	[h]0	0	670
Alcohol Fuel Credit	0	0	0	80	0	0	80
Income Reducing Measures:							
Deduction:							
Excess of Percentage Over Cost Depletion	[b]380	[b]380	[c]265	0	[d]0	0	1,025
Exclusion:							
Interest on Certain State and Local Bonds	0	0	0	0	0	[i]185	185
Exemption	0	0	0	0	0	0	0
Total Before Component Interactions	395	1,065	310	80	0	250	2,100
Total After Component Interactions	NA	NA	NA	NA	NA	NA	1,460
Addendum: Alcohol Fuels Excise Tax	0	0	0	460	0	0	460

[a]Alcohol for use as a motor fuel.
[b]Derived by allocating an aggregate value for oil and gas equally between the two forms of energy.
[c]May include small values for “Other Energy.”
[d]There may be small values for uranium, oil shale, and geothermal. Any such values are included in the value for coal.
[e]Solar and geothermal energy facilities.
[f]There could be small values for oil produced from shale and tar sands. Any such values are included in the value for gas.
[g]Although the tax expenditure provision applies to oil, gas, solids, and steam produced from other than conventional sources, the $670 million income tax credit is estimated to be almost entirely for methane gas produced from coal seams.
[h]There may be very small values for synthetic fuels produced from coal, fuel from qualified processed wood, and steam from solid agricultural byproducts. Any such values are included in the value for gas.
[i]Estimated to be principally for natural gas and electric facilities.
NA = Not available.
Notes: • In addition to the outlay equivalent of Federal energy income tax expenditures in the table, there exists a gasoline excise tax preference which amounted to an estimated $460 million in fiscal year 1992. See addenda in table. • All effects are net of the Alternative Minimum Tax.
Source: Office of Management and Budget, *Budget of the United States Government, Fiscal Year 1993* (Washington, DC, 1992). Data for tertiary injectants are from Joint Committee on Taxation (Staff), *Estimates of Federal Tax Expenditures for Fiscal Years 1992-1996*, March 11, 1991 (Washington, DC, 1991).

Preferential Tax Rates

Only one preferential tax rate type of energy tax expenditure is currently operative. It applies to royalty income derived from certain coal operations. The royalty income of individual owners of coal leases is taxed at the lower individual capital gains tax rate of 28 percent rather than at the higher regular individual top tax rate of 31 percent, if the owners so choose. Corporate owners have the same option, but since the corporate income and corporate capital gains tax rates are each 34 percent, the option is of little or no advantage to them. Individuals and corporations opting for the capital gains tax rate cannot also use the percentage depletion tax expenditure provision discussed later. In practice, the percentage depletion provision is generally more beneficial, at least for corporations. The small preferential rate tax expenditure (revenue loss) for coal of $10 million in Table 5 (and its outlay equivalent in Table 6) therefore only benefits individual owners at present.[39]

Tax Deferrals

Tax deferrals generate tax expenditures that have two unique features. First, the expenditures can be negatively valued. Second, the expenditures differ from the value of the subsidy. Tax deferrals can be viewed as interest-free loans by the Government to taxpayers. These temporary revenue losses are recorded as positively valued tax expenditures. When the loans are repaid they are treated as negative tax expenditures.[40] In any given year the measured net of newly made loans and loans repaid can therefore be either positive or negative. However, actual subsidies associated with tax deferrals can never be negative since interest-free loans always benefit the recipient. The value of the subsidy in any given year can be viewed as the amount that can be earned by investing the loans that are outstanding in that year.

Three tax deferral types of energy tax expenditures exist. They are the expensing of exploration and development expenditures, the expensing of tertiary injectants, and the exception from the passive loss limitation for working interests in oil and gas properties.

Exploration and Development Expenditures

Tax law allows energy producers, principally oil and gas producers, to expense certain exploration and development (E&D) expenditures rather than capitalizing them and depreciating them over time. The most important of these expenditures consist of intangible drilling costs (IDCs) associated with oil and gas investments. IDCs are costs incurred in developing and drilling oil, gas, and geothermal wells up to the point of production.[41] Major (or integrated) oil companies can expense 70 percent of their IDCs for successful domestic wells and 100 percent for unsuccessful domestic wells.[42] The remaining 30 percent must be amortized over 5 years. Independent (or nonintegrated) oil producers can expense 100 percent of their IDCs for all domestic wells. Producers of other fuel minerals can also expense certain E&D expenditures. For example, coal producers can expense 70 percent of their surface stripping and other selected expenditures. The remainder must be amortized over 5 years.

The value of the E&D tax expenditure provision was an estimated negative $55 million in fiscal year 1992 (Tables 5 and 6). This consisted of a negative $90 million for oil and gas and a positive $35 million for coal. The negative value represents a gain in Government revenue rather than a loss. The gain was, in effect, a repayment of the "principal" on a Government loan (or prior tax deferral). The $35 million for coal, on the other hand, represents net loans to the coal industry in fiscal year 1992.

The value of the E&D tax expenditure provision as it applies to oil and gas for fiscal 1992 is small by historical standards. Positive tax expenditure values in excess of $1 billion occasionally existed prior to 1986. The recent small values reflect reductions in the extent to which IDCs can be expensed, due to tax reform, and

[39]The $10-million value for the outlay provision in Table 6 is equal to the revenue loss in Table 5, because the entries in both tables have been rounded to the nearest $5 million. Equality between values can also result when tax expenditures operate as tax deferrals or price reductions that do not directly enter into the taxpayer's pre-tax income.

[40]Technically, this is referred to either as a reversal or a turnaround of deferred taxes, depending on whether the emphasis is on all loans or individual loans.

[41]IDCs include costs such as labor, fuels, and site preparation. They exclude the cost of acquiring the property itself, as well as costs such as pipelines and other tangible facilities to control and transport the oil and gas produced.

[42]A major oil company is one which has integrated operations from exploration and development through refining or distribution to end users.

the adverse effects on petroleum investment resulting from the collapse of oil prices in 1986 and the relatively low oil and gas prices after that time.

The value of the subsidy associated with the expensing of E&D costs cannot be precisely estimated. By one measure, the subsidy is equal to the total interest charges the taxpayer would have had to pay to borrow the funds. This depends on the interest rate at which the taxpayer would borrow and the period of deferral. Although the amount of outstanding funds effectively borrowed through tax deferrals is not known, their subsidy equivalent in fiscal year 1992 could have amounted to as much as $1 billion.[43]

The provision that allows the expensing of E&D costs for oil, gas, and other fuels increases the return on investment in those resources and adds to other exploration and development incentives. Domestic crude oil and natural gas production is greater than it otherwise would be and capital is diverted from other productive activities. Also, all IDCs that are incurred outside the United States must be capitalized, thus providing a disincentive for foreign oil and gas exploration. The deferral particularly benefits the development of coal mines rather than the exploration efforts that precede development.[44] Additionally, on a per-dollar-of-investment basis, the expensing provision benefits high-capital/low-variable cost mines (such as deep-mined eastern coal) to a greater degree than those with a less-capital-intensive ratio (such as strip mines in the West).

Title XIX of the recently passed Energy Policy Act of 1992 has increased the future value of these provisions for independent oil and gas producers by limiting the extent to which intangible drilling costs are treated as tax preference items for purposes of computing the Alternative Minimum Tax. This provision will reduce independent producers' Alternative Minimum Tax liability.

Tertiary Injectants

The second of the three tax deferrals is the expensing of tertiary injectants. Taxpayers can expense certain chemical injectants that are used to enhance the process of recovering oil rather than capitalizing them and depreciating them over time. The value of this tax expenditure is estimated at $20 million for fiscal year 1992 (Tables 5 and 6).[45] The subsidy prolongs the lives of some wells, thus increasing the total volume of hydrocarbons recovered from those wells.

Passive Loss Limitation

The third tax deferral is an exemption from passive loss limitations for working interests in oil and gas properties.[46] The exemption allows owners of working interests to offset their losses from passive activities against active income. Under normal rules, passive losses remaining after being netted against passive incomes can only be carried over to future period passive incomes. The passive loss limitation provision and the oil and gas exception to it apply principally to partnerships and individuals rather than corporations.

The value of this tax expenditure was an estimated $80 million (or $100 million in outlay equivalent) in fiscal year 1992 (Tables 5 and 6). The value of the subsidy does not equal the value of the tax expenditure for the same reason cited above: the expenditure is equivalent to a loan and the subsidy is equivalent to the gross interest that the loan earned, or could have earned, for the taxpayer. The value of the subsidy in fiscal year 1992 is equal to the interest not only on the net new loans of $80 million for that year but also to the interest on the cumulative net new loans in prior years. On this basis, and assuming an 8-percent interest rate, the subsidy in 1992 was about $40 million.

The impact of the subsidy may be greater than its small value for 1992 suggests. To some degree the low

[43]This figure was derived by summing the positive and negative tax expenditures values reported annually by the Treasury Department for the expensing of E&D costs for oil and gas back to 1975. This provided a very rough estimate of the amount of funds or loans, outstanding in 1992, to which an interest rate of 8 percent was applied. The 8-percent rate is the rate projected for 10-year Treasury notes for 1991 in Office of Management and Budget, *Budget of the United States Government, Fiscal Year 1993* (Washington, DC, 1992), Part 1, p. 36.

[44]Mine development expenses can be immediately written off. Typically, exploration costs can also be immediately written off but the benefits of the early writeoff are nullified if the mines become profitable. See National Research Council, *Energy Taxation: An Analysis of Selected Taxes*, prepared for the Information Administration, DOE/EIA-0201/14 (Washington, DC, September 1980), pp. 78-79.

[45]The $20-million tax expenditure reported in Tables 5 and 6 for 1992 is the maximum estimated value as are the $20-million values for each of the prior years back to 1989 in the fact sheet for tertiary injectants in Appendix B. The values prior to 1989 were apparently too small to be reported separately.

[46]A working interest is an interest in a mineral property that entitles the owner to explore, develop, and operate a property. The working interest owner bears the costs of exploration, development, and operation of the property, and any liabilities arising from these activities, and, in return, is entitled to a share of the mineral production from the property or to a share of the proceeds.

subsidy value reflects the fact that the subsidy has been in effect only since the Tax Reform Act of 1986, and cumulative outstanding loans to date are small. A second reason for the small subsidy value is that the subsidy generally applies to only the noncorporate and closely related segments of the industry, and the level of funds obtained by independents through limited partnerships in recent years has been low.[47]

The interest cost to the U.S. Government (or subsidy value to the U.S. energy industry) of the three tax deferral types of energy tax expenditures probably accounted for no more than $1.1 billion for the fiscal year 1992. The bulk of this subsidy was directed to oil and gas producers. After accounting for interactions among energy programs, the tax deferral subsidy may have been substantially less. This statement assumes that the known aggregate reduction in tax expenditures that results from the simultaneous interaction of all energy tax expenditures, as shown in Table 6, also results in a reduction for the tax deferral components of those expenditures and, therefore, in the subsidies associated with them.

Tax Credits

The three energy tax credit expenditure provisions are a new technology credit, an alternative fuel production credit, and an alcohol fuel credit. The three credits have one common feature: they apply to unconventional forms of energy or means of producing energy.

Investment Credit for New Technology

The tax credit provision for investing in new technology formerly included a wide variety of items but is now limited to investment in solar and geothermal energy facilities. The credit is equal to 10 percent of the investment in those facilities and is valued at $45 million for fiscal year 1992 ($65 million in terms of outlay equivalent) (Tables 5 and 6). The credit encourages the production and consumption of energy generated in those facilities. Production costs have declined over time but still exceed those for conventional fuel.[48] Present levels of solar and geothermal energy production are small despite the subsidies.

Production Credit for Alternate Fuels

The second tax credit provision applies to the production of alternative (or nonconventional) fuels. This is the largest energy tax credit. At the end of fiscal year 1992, the qualifying fuels had to be produced from specified wells drilled or certain facilities placed in service between January 1, 1980 and December 31, 1992, and sold through the year 2002. They are:

- Oil produced from shale and tar sands
- Gas from geopressurized brine, Devonian shale, coal seams, tight formations, or biomass
- Liquid, gaseous or solid synthetic fuels produced from coal
- Fuel from qualified processed wood
- Steam from solid agricultural byproducts.

The tax credit for these fuels is $3 per barrel of oil equivalent produced.[49] The credit is fully effective when the price of crude oil is $23.50 per barrel or less and phases out gradually as the price of oil rises to $29.50 per barrel. All prices as well as the credit are specified in 1979 dollars but for actual use are indexed for inflation relative to that base. The credit is reduced if other subsidies are used.[50] The current value of the credit is an estimated $450 million for fiscal year 1992 and $667 million in terms of its outlay equivalent (Tables 5 and 6).

This tax credit provision has a substantial impact on only one of the alternative fuels: gas produced from coal seams, and that impact is recent. Production of coal seam gas has recently reached unprecedented levels, principally because of the expectation that gas produced from qualified wells and facilities placed into service after 1992 would be ineligible for the credit. The credit for qualified gas was about $0.86 per million Btu in 1990, or about one-half the wellhead price of U.S.-produced natural gas in that year.

[47]The passive loss rules generally apply to individuals, trusts, estates, personal service corporations, and closely held corporations.

[48]Energy Information Administration, *Geothermal Energy in the Western United States and Hawaii: Resources and Projected Electricity Generation Supplies*, DOE/EIA-0544 (Washington, DC, September 1991).

[49]Conversion factors are used to convert the various fuels into their crude oil equivalent for purposes of calculating the credit.

[50]The credit is offset by any benefits received from energy investment credits, tax-exempt financing, and benefits received from Government grants.

Production Credit for Alcohol Fuels

The third tax credit provision is for alcohol fuels. It is the only income tax expenditure for which there is also a preferential excise tax, in the form of an exemption. Motor fuels composed of at least 10-percent alcohol are exempt from 5.4 cents of the per-gallon Federal excise tax on gasoline, diesel fuel and other motor fuels.[51] The income tax credit is 54 cents per gallon for alcohol used as a motor fuel and can be taken in lieu of the excise tax exemption. The income tax credit is granted to producers of alcohol fuels, defined as distributors who blend the alcohol and motor fuels. The credit may differ from 54 cents depending on the proof of the alcohol. A new Federal income tax credit of an extra 10 cents per gallon is also available to eligible small producers of ethanol.[52]

The alcohol fuels income tax credit was not used to any significant degree until fiscal year 1992. Even then it amounted to only $80 million (Tables 5 and 6), a value that could reflect the initial use of the new "small producers of ethanol" credit. Blenders generally use the excise tax exemption rather than the income tax credit. The excise tax exemption provides them with an immediate cash flow. The subsidy they received from this exemption in fiscal year 1992 was an estimated $460 million.

The alcohol fuels income tax expenditure and preferential excise tax programs affect not only the motor fuels industry but other industries and the environment as well. The alcohol fuels industry can only exist for motor fuel purposes with Government subsidies, since the price of the alcohol fuel would not otherwise be competitive with gasoline or other alternatives. State government subsidies are also required in some instances to assure a viable enterprise. Because of the subsidies, gasoline/ethanol blends account for somewhat less than one-tenth of U.S. motor fuel consumption and production.[53] The result is a small (less than 1 percent) reduction in the volume of gasoline required to meet the demand for motor fuels and a probably negligible reduction in the prices of gasoline and other petroleum products relative to those that would otherwise prevail. Corn prices are higher, since nearly all U.S. ethanol is made from corn.

The future impacts of the two alcohol motor fuel expenditure subsidies are highly uncertain in view of recent changes in those subsidies. Both the excise tax exemption and the income tax credit were only recently reduced to current levels, which will tend to constrain future growth in alcohol fuel use. However, these alcohol fuel tax credits were extended through the year 2000. This extended time period, together with the new "small producer of ethanol" added income tax credit of 10 cents per gallon, may cause some further increase in the production and use of alcohol fuels in the near future. The Clean Air Act Amendments of 1990 may also increase the use of alcohol in fuels in order to meet environmental requirements.

Taxable Income Reducing Measures

There are two taxable income reducing measures. They are the percentage depletion allowance and the tax-free interest on certain State and local bonds.

Percentage Depletion

The most important of the two income-reducing tax expenditure provisions is the percentage depletion deduction. Independent oil and gas producers and royalty owners, and all producers and royalty owners of certain other natural resources, including mineral fuels, may take percentage depletion deductions rather than cost depletion deductions to recover their capital investment.[54] Under cost depletion, the annual deduction is equal to the reduction in the remaining value of the resource that results from the current year's additional production.[55] Under percentage depletion, taxpayers deduct a percentage of gross income from resource production at rates of 10 percent for coal; 15 percent for oil, gas, oil shale, and geothermal deposits; and 22 percent for uranium. However, two special provisions apply to oil and gas.

[51]Title XIX, Section 1920 of the Energy Policy Act of 1992 raised the exemption from 5.4 cents per gallon to 6.1 cents per gallon, and created smaller exemptions for blends with as little as 5.7 percent alcohol. This will increase the value of this provision in the future.

[52]An eligible small producer of ethanol generally means a person who, at all times during a year, has a productive capacity for alcohol not in excess of 30 million gallons.

[53]Ethanol is an alcohol that, when blended with gasoline, provides an effective fuel additive. Gasohol commonly refers to a blend of 10 percent ethanol and 90 percent gasoline.

[54]The excess depletion allowance is classified as a deduction because it permanently reduces income tax expense. If it merely deferred the expense it would be classified as a tax deferral.

[55]Specifically, the annual deduction is equal to the unrecovered cost of acquisition and development of the resource times the proportion of the resource removed during that year.

First, percentage depletion for independent producers[56] and royalty earners is limited to 1,000 barrels per day. Second, the 15-percent rate is increased by 1 percentage point for each dollar that the average wellhead price of domestically produced crude oil is less than $20 a barrel. The maximum increase allowed is 10 percentage points. This special provision applies only to oil and gas wells with marginal production, generally defined to include production from stripper wells[57] and from wells substantially all of whose production is heavy oil. Marginal production eligible for the higher rate has a prior claim on the 1,000-barrel-per-day limitation.

The percentage depletion deductions based on gross income are subject to net income limitations. The annual deduction for oil and gas is limited to 100 percent of net income from the property, geothermal is limited to 65 percent, and the other mineral fuels are limited to 50 percent. Since percentage depletion is based on gross income rather than on the cost of the underlying assets, the resultant allowances can exceed the actual acquisition and development costs for the property from which the resource is extracted.

The use of percentage depletion instead of cost depletion to calculate income tax liability reduces Federal Government revenue by more than any other energy-related tax expenditure provision. This applies to oil and gas as well as to coal. In fiscal year 1992, the reduction in liabilities was $570 million for oil and gas and $175 million for coal (Table 5). The outlay equivalent of these revenue losses was substantially greater, $760 million and $265 million, respectively (Table 6). Any reduction in tax liabilities for uranium, oil shale and geothermal are exceedingly small and included in the values for coal.

Percentage depletion will continue to provide developmental incentives in the future. This results in part from differences in the net income limitations and differences in production and distribution costs. However, the many constraints imposed on the use of percentage depletion for oil and gas since 1975, including the use of percentage depletion by only independent producers and royalty owners and then only up to 1,000 barrels per day, has and will continue to limit that tax expenditure provision to small-scale oil and gas operations. Independent producers would not generally engage in large off-shore operations or in areas such as the North Slope even with the advantage of the depletion allowance. Nevertheless, they will continue to enjoy after-tax profits and royalties that are greater than they would be in the absence of percentage depletion.

Title XIX of the recently passed Energy Policy Act of 1992 has increased the future value of percentage depletion for independent oil and gas producers by ceasing to define excess percentage depletion as a tax preference item for purposes of computing the Alternative Minimum Tax. This provision will reduce independent producers' future Alternative Minimum Tax liability.

Coal, uranium, oil shale, and geothermal operations will continue to be affected differentially by the percentage depletion provision. The differential effect reflects in large part the different depletion rates that exist for the sources of energy as well as different net income limitations. As a practical matter, coal is the only energy industry, other than oil and gas, of any consequence with respect to percentage depletion since the other industries operate at very low levels.

Exempt Interest

The second taxable income reducing measure that applies to energy is the exclusion from Federal income taxation of interest on State and local industrial development bonds for certain energy facilities. The relevant facilities are principally municipal electric and

[56]For purposes of percentage depletion, an independent producer is defined, in general, as one who does not retail petroleum or petroleum products or refine crude oil. However, if the aggregate retail sales of the oil, natural gas, and products do not exceed $5 million per year, and if his refinery runs do not exceed 50,000 barrels a day on any day during a tax year, the producer is still classified as an independent.

[57]Generally, for purposes of this provision, a stripper well property is one which produces a daily average of 15 or less barrels of oil equivalent per producing well over the course of a calendar year.

gas utilities.[58] The Federal revenue loss from this provision is currently about $125 million annually (Table 5). This is the amount of Federal income tax payment that would have been made on interest earnings on taxable bonds for energy facilities that are otherwise similar to those that are tax free. The outlay equivalent is $185 million (Table 6).[59]

[58]The interest on industrial development bonds issued by State and local governments has generally been subject to Federal tax except for the interest on certain issues, including select energy issues. The narrow scope of the exclusion is the basis for adopting it as a tax expenditure. In contrast, the income tax exemption granted to State and local governments by the Federal Government for essentially all commercial or quasi-commercial operations, including electric utility operations, is not considered a tax expenditure in this section. Generally, a tax expenditure is deemed to exist only if favorable tax treatment is offered to a narrow group of taxpayers or operations. Since the exemption is granted to "all" operations of all State and local governments, rather than to just the energy or other small subset of their operations, the exemption is arguably not an energy-related tax expenditure. Nevertheless, the Federal tax practice does affect the energy industry. An estimate of the cost of the tax exemption for State and local electric utilities is given in Chapter 6.

[59]Until 1986, there existed an additional and closely related tax expenditure provision. Interest on State and local government debt issued to finance private pollution control and waste disposal facilities was excludable from income subject to tax. The pollution control component was repealed by the Tax Reform Act of 1986. The Act also placed a cap on the amount of debt that could be issued for waste disposal facilities. The subsidy associated with energy waste disposal facilities could not be determined and is not considered further in this report.

4. Trust Funds and Energy Excise Taxes

Excise taxes to fund highways, waterways, airports, and other infrastructure projects have a long history. Other energy excise taxes and associated trust funds have become increasingly common over the past two decades as a mechanism for internalizing some of the social costs of energy production and consumption. Trust funds have two parts: in the first part, the Federal Government imposes a tax on a particular industry; in the second part, the Federal Government assumes responsibility for some liability, often environmental, safety, or health-related. Responsibility for the liability may have formerly rested with the industry, but more commonly was poorly defined under pre-existing law. While the amount of the tax is known, the amount and timing of the liability assumed by the Federal Government has yet to be determined through experience. Most recently established trust funds currently run a surplus. However, the Black Lung Disability Trust Fund is in deficit and requires Federal appropriations in addition to current excise tax collections in order to maintain its solvency.

The ultimate cost of storing high-level nuclear waste, or reclaiming “orphaned” leaking underground oil storage tanks cannot be known with precision. Unlike the older transportation-oriented trust fund programs, the costs may be far in the future. The beneficiaries of future trust fund payments may not necessarily be current energy consumers, who pay the excise taxes. Thus, evaluating the full costs of trust fund programs raises complex questions of intergenerational equity, as well as on the actuarial sufficiency of the excise taxes and their accompanying trust funds. This report does not attempt to address either the issue of sufficiency or the issue of intergenerational transfers. Instead, the report describes the principal energy excise taxes and trust funds, and reports on tax collections, trust fund accruals, and outlays from trust funds on a cash basis.

FY 1992 energy excise tax and fee collections were $22 billion. Of this total, only $3 billion was collected for general revenue use (Table 7). The balance of collections was earmarked for a variety of energy-related trust funds. The most important use of Federal energy-related trust funds is to improve and maintain highway and other transportation facilities. In fiscal 1992, an estimated $16.7 billion of excise taxes from motor fuels and related fees were collected for that purpose. An additional $7.1 billion in excise taxes on other goods and services (including, for example, taxes on tires, airline tickets, and fishing equipment) were collected for transportation facility trust funds (Table 8). Other energy excise tax collections ($1.8 billion) serve to fund a variety of programs that address environmental and safety problems associated with the production and distribution of petroleum and coal. In addition, approximately $600 million of user fees are collected from nuclear power producers to fund the development of nuclear waste disposal facilities.

Transportation Trust Funds

Excise taxes that fund transportation infrastructure finance a collection of well-developed programs. In 1992, outlays for highway, airport, and other transportation facility development totaled about $23 billion (Table 8), about the same as total collections. Although the earmarked taxes increase the cost of fuel and transportation services on which they are levied, they should not be viewed as negative subsidies relative to energy use since the tax proceeds are expended to improve transport facilities which will increase overall transport demand.

Energy Trust Funds

In recent years, the trust fund concept has been extended to address a variety of safety and environmental concerns (Table 9). Over the past decade, the balances and outlays from these energy-related trust funds have grown several-fold (Figure 5).

Table 7. Estimated Energy Excise Tax Receipts, FY 1992
(Million Dollars)

Fund	Amount
Trust Funds	
Collections to Fund Improvements and Maintenance	16,658
Highway Trust Fund	
Gasoline	12,656
Diesel Fuel Used on Highways	3,661
Aquatic Resources Trust Fund: Boat Motor Fuel	131
Airport and Airway Trust Fund: Aviation Fuels	139
Inland Waterways Trust Fund: Diesel and Other Liquid Fuels	71
Collections to Internalize Environmental Impacts	1,863
Superfund: Petroleum and Petroleum Products	570
Underground Storage Tank Trust Fund: Gasoline and Other Motor Fuels	145
Oil Spill Liability Trust Fund: Crude Oil	283
Black Lung Disability Trust Fund: Coal[a]	627
Abandoned Mine Reclamation Fund: Coal	238
Total Trust Funds	**18,521**
General Fund	
Total General Fund	**3,132**
Motor Fuels	
Gasoline	2,603
Highway Diesel Fuel	528
Rail Diesel Fuel	84
Refunds	-109
Aviation Fuels (Net of Refunds)	26

[a]This tax on coal is a production tax but not an excise tax. It is included here because it is similar to other taxes that are intended to internalize environmental impacts and for consistency with other parts of this report.

Sources: All data except the values for Superfund petroleum and petroleum products and Abandoned Mine Reclamation Fund for coal are from Joint Committee on Taxation (Staff), *Schedule of Present Federal Excise Taxes (as of January 1, 1992)*, March 27, 1992. (Washington, DC, 1992). The Superfund value is for calendar year 1989 and is from Susan Mahler, "Environmental Excise Taxes, 1989," *Statistics of Income Bulletin*, Internal Revenue Service, Winter 1991-1992, p. 55. The Abandoned Mine Reclamation Fund value for coal is from the Office of Management and Budget, *Budget of the United States Government, Fiscal Year 1993* (Washington, DC, 1992), Appendix 1, p. 586.

Taxes and fees to finance these funds are designed to impose costs on energy producers that formerly escaped valuation in the marketplace. They include health risks to production workers or damage to the environment from land damage accidents or waste disposal. Growth in the use of trust funds to finance programs related to environment, safety, and health can be traced in part to a shift in the use of market-based incentives to address these problems. Tying trust fund collections to products and activities responsible for damages is intended to cause their prices to reflect the costs of programs for remediation and prevention and thus more closely reflect the real costs of energy use and production. Accompanying the establishment of these funds are a number of regulatory programs which impose performance requirements additional to the fees collected for fund finance. For example, the oil spill funds are part of a program designed to minimize the risk of spills via implementation of underground storage tank replacement programs and tanker replacement for waterborne transit.

Table 8. Trust Funds for Improvement and Maintenance of Transport Infrastructure, FY 1992
(Million Dollars)

Name of Fund	Beginning Balance	Collections	Other Receipts (Net)	Outlays	Ending Balance	Source of Receipts
Total	**35,525**	**23,789**	**1,856**	**23,312**	**37,857**	
Highway Trust Fund	19,496	18,279	716	17,400	21,092	12,656 Gasoline Taxes 1,087 Truck and Bus Taxes 277 Tire Tax 3,661 Diesel Taxes 598 Use Tax on certain vehicles 716 Interest, Transfers, and Refunds
Airport and Airway Trust	15,263	5,203	1,306	5,746	16,025	4,567 10% Passenger Ticket Tax 237 Waybill Tax 139 Fuel Tax 260 International Departure Tax 1,306 Interest, Transfers, and Refunds
Aquatic Resources Trust	549	236	-152	71	562	131 Motor Boat Fuel Tax 77 Tax on Sport Fishing Equipment 28 Boat Import Tax 110 Interest and Other Income
Inland Waterway Trust	217	71	-14	95	178	71 Inland Waterway Tax 16 Interest Income

Source: See sources for Table 7.

Coal-Related Trust Funds

The oldest energy-related trust funds involve coal mine operations. The Abandoned Mine Reclamation Fund is designed to assure that mine operations pay for remedying problems stemming from mine closure when the liable firms cannot be located or no longer exist. These problems include risks of mine subsidence, acid drainage, erosion, and despoliation of scenery.

The Black Lung Disability Fund is directed toward work-related disabilities of underground miners. Long-term inhalation of coal dust can cause irreversible damage to miners' lungs. Current mine operating practice greatly reduces the prospects of miners contracting black lung. The fund was established to compensate for black lung disabilities of miners whose mine employment terminated before 1970 or where no mine operation can be assigned liability. As of 1992, the fund was inadequately supported by coal excise taxes and substantial allocations from general revenues have been necessary to continue the program (Table 9).[60]

Nuclear Waste Disposal

Concerns about the safety, health, and environmental effects of the disposal of nuclear wastes and controversies associated with the siting of nuclear waste disposal facilities led to the assumption of leadership by the Federal Government in developing appropriate facilities.

[60]The potential liabilities from underaccrued trust funds can be very large. Annual outlays to supplement the Black Lung Disability Trust Fund were $970 million in FY 1992. Under the Mine Safety and Health Act of 1977, the Federal Government also assumed responsibility (without offsetting excise taxes) for payments to coal miners disabled prior to 1973. This program, administered by the Social Security Administration, had outlays of $831 million in FY 1992. Office of Management and Budget, *Budget of the United States Government Fiscal Year 1993* (Washington, DC, March 1992), Appendix 1, pp. 516 and 690.

Table 9. Energy-Related Environmental Trust Funds, FY 1992
(Million Dollars)

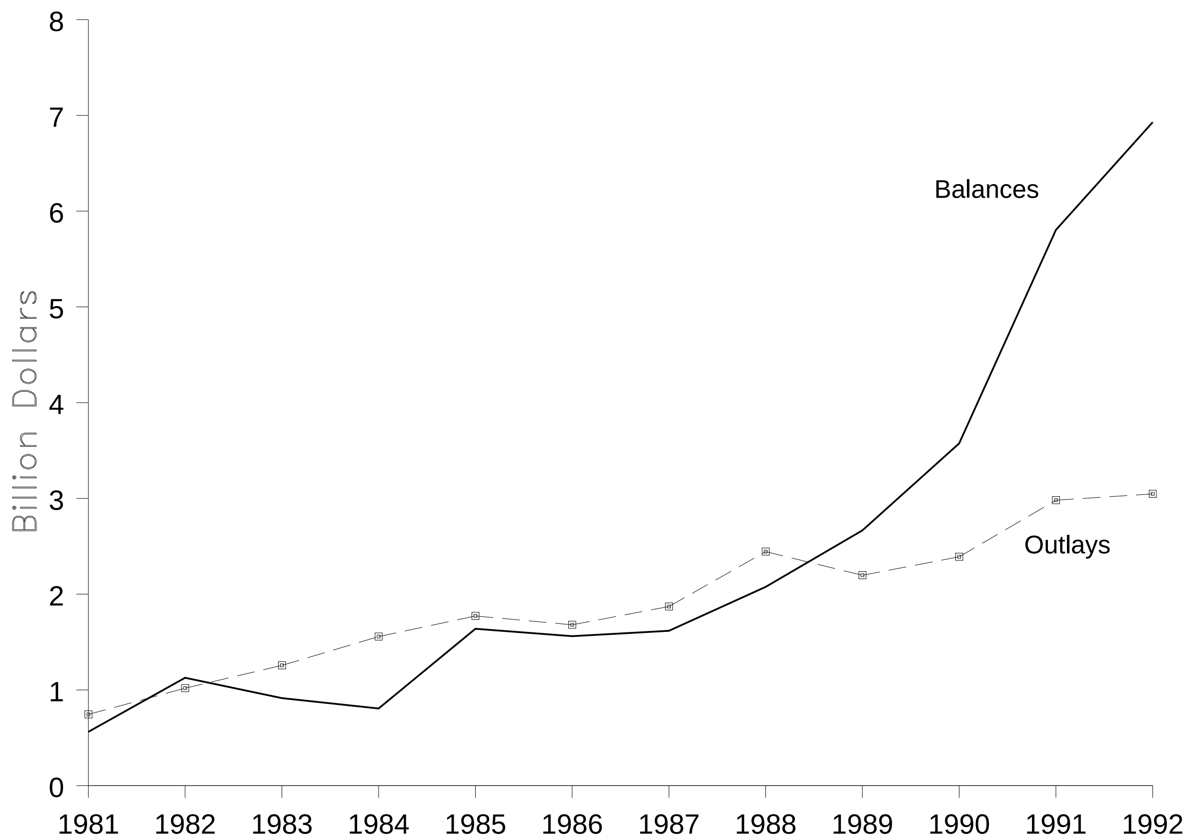
Fund	Beginning Balance	Collections	Other Receipts (Net)[a]	Outlays	Ending Balance	Composition of Receipts	Sources of Receipts
Total	5,803	3,217	1,046	3,136	6,930	--	--
Coal							
Black Lung Disability	17	627	381	970	55	627	Excise tax on mined coal
						339	General revenues
						2	Interest on balance
Abandoned Mine Reclamation	574	238	7	154	665	238	Per-ton fee on U.S. coal mine production
						40	Interest on balance
Nuclear							
Nuclear Waste Disposal	2,831	568	167	264	3,302	568	Fees paid by nuclear powered electric utilities
						231	Interest on Investments
Petroleum							
Oil Spill Liability	647	283	118	154	894	283	5-cent-per-barrel oil import fee
						118	Interest on balance and other income
Oil Spill Response	--	--	9	9	--	--	Funded from Oil Spill Liability Trust Fund
Leaking Underground Storage	468	145	47	87	573	145	0.1 cent-per-gallon fuel tax
						34	Interest
Pipeline Safety Fund	17	14	-2	12	18	14	User fees collected from pipeline operators
Superfund							
Hazardous Substance Superfund	1,249	1,341	319	1,486	1,423	250	Paid from General Fund
						1,190	Taxes collected on chemicals ($620) and petroleum ($570)
						214	Interest on balance
						150	Fees and penalties

[a]Includes balancing item to adjust for difference between outlays and appropriations.
Source: Office of Management and Budget, *Budget of the United States Government, Fiscal Year 1993* (Washington, DC, 1992).

Current efforts are mainly directed to studying the feasibility of a working site at Yucca Mountain in a desert region of Nevada. Since the establishment of the Nuclear Waste Disposal Fund in the early 1980's, collections from nuclear utilities have greatly exceeded outlays, resulting in a trust fund balance in excess of $3 billion in FY 1992.[61] The $231 million of interest income alone earned on trust fund balances in that year nearly equalled the $264 million in outlays. Beginning in 1993, an additional trust fund will be established to deal with the costs of eventual decommissioning of uranium enrichment plants. Revenues from the trust fund will be accrued from Federal sales of enrichment services. (See Chapter 2).

[61]The Department of Energy is required to periodically evaluate the adequacy of the Nuclear Waste Fund Fee. A recent assessment report is: U.S. Department of Energy, Office of Civilian Radioactive Waste Management, *Nuclear Waste Fund Fee Adequacy: An Assessment*, DOE/RW-0291P (Washington, DC, November 1990). This report concludes: "There are several reasons why a fee increase at this time is not clearly indicated." A General Accounting Office report indicated the possibility of a $2.4 billion net present value deficit in the fund. See: U.S. General Accounting Office, *Nuclear Waste: Changes Needed in DOE User Fee Assessments to Avoid Funding Shortfall*, GAO/RCED-90-65 (Washington, DC, June 1990).

Figure 5. Energy-Related Environmental Trust Funds, Total Outlays, and End-of-Year Balances, FY 1981 - FY 1992



Source: Office of Management and Budget, *Budget of the United States Government, Fiscal Year 1993*, various issues.

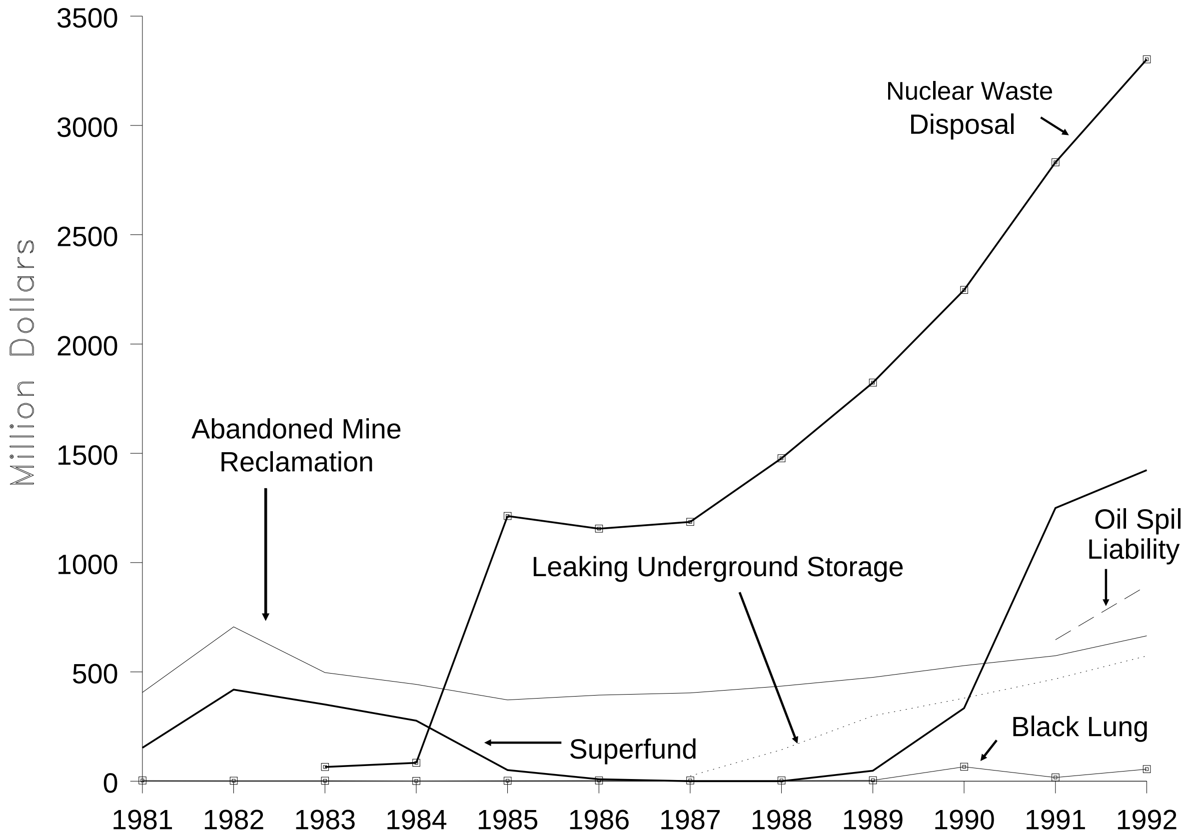
Superfund

Cleanup of hazardous waste sites and development of an emergency response capability to hazardous material disasters became part of the Federal Government's environmental protection policies in the 1970's. The Hazardous Substance Superfund was established in 1980 to fund the Federal Government's efforts for these purposes. Hazardous substances within the definition of the law include industrial and agricultural chemicals as well as energy products, but half of the revenue collected comes from excise taxes on crude oil and petroleum products. In FY 1992, $620 million in collections for the Superfund came from taxes on chemical products, with most of the balance coming from taxes on petroleum and petroleum products. Until the implementation of the Superfund Amendments and Reauthorization Act of 1986, the Superfund was underfunded, as evidenced by the shrinkage of the fund's balances between FY 1982 and FY 1987 (Figure 6). In recent years, the Superfund's balances have grown, so that, currently, with $1.4 billion in balances, the Superfund is second only to the Nuclear Waste Disposal Fund. Measured by appropriations, the Superfund is the largest environmentally related Federal program financed by trust funds (Table 9).

Petroleum Trust Funds

Petroleum trust funds are directed toward past and potential environmental damages and safety problems arising from the storage and transport of petroleum and other hydrocarbons. All of these programs are of recent origin. Their funding is directly tied to per-unit taxes and user fees on the related products or activities. These programs are clear examples of the recent shift of Federal efforts, both to reflect the costs of environmental and safety problems in the prices of

Figure 6. Energy-Related Environmental Trust Funds, End-of-Year Balances, FY 1981 - FY 1992



Source: Office of Management and Budget, *Budget of the United States Government, Fiscal Year 1993*, various issues.

associated products and to provide funding for remedial and preventive programs.

In terms of fund balances and revenue collections, the largest of the petroleum-related programs is also the newest (Figure 6 and Table 9). The Oil-Spill Liability Trust Fund was established in 1989. This fund is financed by a 10-cent-per-barrel tax on oil entering U.S. ports. The fund finances oil-pollution prevention and cleanup efforts of various Federal agencies. Also financed by this fund is EPA's Oil-Spill Response program. Collections of $300 million in FY 1992 greatly exceeded outlays of $66 million, in part reflecting the newness of the program and the contingent nature of oil-spill pollution.

The Leaking Underground Storage Tank Trust Fund is financed by a 0.1-cent-per-gallon tax on motor fuels, which totaled $145 million in FY 1992. Programs supported by this fund are directed toward enforcement and cleanup of releases from leaking underground petroleum storage tanks. On an annual basis, expenditures have been small relative to collections. In general, the person or firm owning a storage tank has been made responsible for upgrading and repair of leaking tanks, and remediation of environment consequences. The trust fund is intend to finance remediation of sites where the responsible party cannot be found or cannot pay.[62]

[62]A recent report estimates an underground storage tank remediation cost of $32 billion to $67 billion (in 1990 dollars). This estimate does not distinguish, however, between private requirements and Federal requirements. See M. Russell, E.W. Colglazier, and M.R. English, *Hazardous Waste Remediation: The Task Ahead*, (Knoxville, TN: Waste Management Research and Education Institute, December 1991), pp. A-3.26 - A-3.30. In most cases, there will be an identifiable responsible party, and the cost will be borne by the industry. See Chapter 7 of this report for a discussion of leaking underground storage tank regulation.

The smallest of the energy-related trust funds is the Pipeline Safety Fund, with FY 1992 outlays of $12 million. Pipeline safety programs of the States are the major recipients of funds. Revenues for this fund come from user fees collected from pipeline operators.

Off-Budget Trust Funds

In addition to the trust funds listed in the Federal budget, the Federal Government can also require firms to establish their own trust funds. In this case, the tax, the fund, and the ultimate liability are internal to the firm. The most prominent example of such an "off-budget" trust fund is the Nuclear Regulatory Commission (NRC) rulemaking on the decommissioning of nuclear power plants.[63] Each nuclear power plant operator is required to create and place in a trust fund no less than $105 million for each pressurized water reactor in service and $135 million for each boiling water reactor (both in 1986 dollars).[64] Each nuclear operator is required to undertake a site-specific decommissioning study at least 5 years prior to a planned decommissioning, and to provide any additional funds needed to cover the anticipated decommissioning cost prior to the date of actual decommissioning.

Nuclear operators recover their trust fund contributions through an increase in electricity rates, which is functionally similar to an excise tax. State and local regulators may impose additional funding requirements on nuclear operators and regulate the conditions under which decommissioning costs can be recovered through higher rates.

The NRC also imposes a somewhat similar requirement on domestic uranium producers, who are required to estimate future reclamation costs and provide guarantees or trust funds equal to the estimated costs. Under the Uranium Mill Tailings Reclamation and Control Act of 1978, the Federal Government assumed the liability for uranium mills and tailings abandoned prior to 1978.

These "off-budget" trust funds are fundamentally different from the "on-budget" trust funds described above: *the ultimate liability for decommissioning expenses continues to lie with the power plant owner, and not with the Federal Government.* Thus, the Federal Government has not assumed any new liabilities, but merely required the private sector to make arrangements to meet an important future private liability. Consequently, off-budget trust funds cannot be considered a subsidy, either positive or negative, on a narrow definition of the term. They are, however, a Federal intervention which imposes costs on a particular industry and illustrate an alternative "off budget" approach to dealing with the problems of internalizing social costs.

Direct Price Effects of Fees for Energy Trust Funds

Energy excise taxes are generally less than 10 percent of the untaxed value of the product. The excise taxes on coal are estimated to be equal to 3 percent of the average freight-on-board mine price of taxable coal in fiscal year 1992 (Table 10). On January 1, 1992, the

Table 10. Energy-Related Trust Fund Receipts Compared to Value of Commodity

Trust Fund	FY 1992 Receipts (Million Dollars)	Relevant Commodity	Unit	Receipts as a Share of Value of Commodity (percent)	Receipts per Unit of Commodity
LUST	145	Gasoline Sales	Gallons	0.012	0.1 cents per gallon
Black Lung	627	Coal Production	Tons	2.90	$0.63 per ton
Mine Reclamation	238	Coal Production	Tons	1.10	$0.24 per ton
Oil Spill	283	Oil Imports	Barrels	0.56	$0.10 per barrel
Superfund—Oil	570	Oil Consumption	Barrels	0.49	$0.09 per barrel
Nuclear Waste	568	Nuclear Generation	Kilowatthours	1.36	0.9 mills per kWh

Source: Office of Management and Budget, *Budget of the United States Government, FY 1993* (Washington, DC, 1992).

[63]Persons interested in this topic may consult Martin Pasqualetti and Geoffrey Rothwell, "Nuclear Decommissioning Economics: Estimates, Regulation, Experience and Uncertainties," *The Energy Journal*, Volume 12, Special Issue (1991), which contains 24 articles on various aspects nuclear power plant decommissioning.

[64]Robert Wood, "Federal Regulation of Decommissioning Economics," *The Energy Journal*, Volume 12, Special Issue (1991), p. 48.

maximum tax on coal from underground mines was $1.10 per ton and the maximum tax on coal from surface mines was $0.55 per ton. The estimated average excise tax rate on all taxable coal in fiscal 1992 is estimated to be about $0.63 per ton. The oil spill and hazardous waste trust fund charges are less than 20 cents per barrel. The nuclear waste fund imposes an additional 1.4-percent cost for power provided from this source.

Energy Excise Taxes for General Revenue

At the outset of the chapter it was noted that the vast bulk of energy-related excise taxes and fees are collected to support the funding of a range of specific activities. Prior to 1990, all energy excise taxes were for earmarked projects. However, in 1990, the Congress for the first time levied transportation fuel taxes to support general revenue funding. Energy excise tax collections for general revenues of $3.1 billion (Table 7) accounted for about 15 percent of all energy excise tax collections in fiscal year 1992, and consisted largely of motor gasoline taxes of $2.6 billion. This component of gasoline taxes amounted to about 2 cents per gallon of U.S. gasoline consumption. However classified, energy excise taxes *per se* are disincentives to the production and consumption of the fuels on which they are levied. Excise taxes on the most important of these fuels, transportation fuels, increase their prices and reduce the volumes consumed. Some shift in the relative importance of the various modes of transportation occurs because the various fuel taxes are applied differentially. Generally, the aggregate and compositional effects on transportation fuel consumption can be greater in the long run as consumers adjust further to the higher prices and as demand for more fuel-efficient cars, trucks, airplanes, and other means of transportation increases.

It should also be noted that many State and local governments levy fuel-specific excise and sales taxes on energy commodities: for example, gasoline taxes. Many States also levy severance taxes on oil, gas, and coal production. State and local programs are not covered in this report.[65]

[65]Persons interested in State and local severance taxes should consult Energy Information Administration, *Energy Severance Taxes, 1972-1987* (Washington, DC, August 1988). State oil and gas severance tax collections totaled $3.4 billion in 1987, and coal severance taxes totaled $430 million. State gasoline tax receipts were $17.8 billion in 1988. U.S. Department of Commerce, *Statistical Abstract of the United States 1991* (Washington, DC, 1991), p. 607.

5. Federal Energy Research and Development

The Federal Government's role in financing large-scale civilian research and development (R&D) dates from the early 1950's. The principal landmarks were President Eisenhower's decision to commercialize nuclear energy in the wake of his "Atoms for Peace" speech in 1953 and partly due to the furor following the Soviet "Sputnik" satellite launch in 1956.

Figure 7 illustrates trends in U.S. Government R&D outlays since 1950, in constant 1991 dollars. Current expenditures exceed $60 billion, two-thirds of which are defense- related. In the 1980's, total Government R&D spending rose about 40 percent. The increase was due mostly to increased emphasis on defense R&D. However, in the late 1980's, spending on health research also increased in relative importance. In the FY 1993 budget, health research and development exceeds all other categories of R&D except national defense. Current appropriations for energy R&D total $6 billion, about 25 percent of all civilian Government-funded research and development.

Overview of Federal Energy Research and Development

Research and Development Defined

Federal energy-related R&D can be described as falling into three classes: basic research, research which seeks to develop new technologies and new forms of energy supply, and research which seeks to improve existing technologies.

- **Basic research**. The potential beneficiaries of basic research could be considered to be the population of the United States or the world as a whole. Basic research includes research projects which are designed to pursue the advancement of scientific knowledge and the understanding of phenomena rather than projects designed to have predetermined specific applications.

- **Research to develop new technologies and new forms of energy production**. The efforts in this context involve attempts to discover new scientific knowledge which can have commercial application. Though the end objective of this research is known, the research task is difficult and uncertain.

- **Research and development to improve existing technologies**. These efforts emphasize the use of scientific knowledge to design and test new processes that may have substantial technical and cost uncertainties. The immediate beneficiaries are generally well defined: current producers and consumers of particular fuels or operators and customers of the technology being improved. The scientific risks of reducing development efforts to practice may not be large.

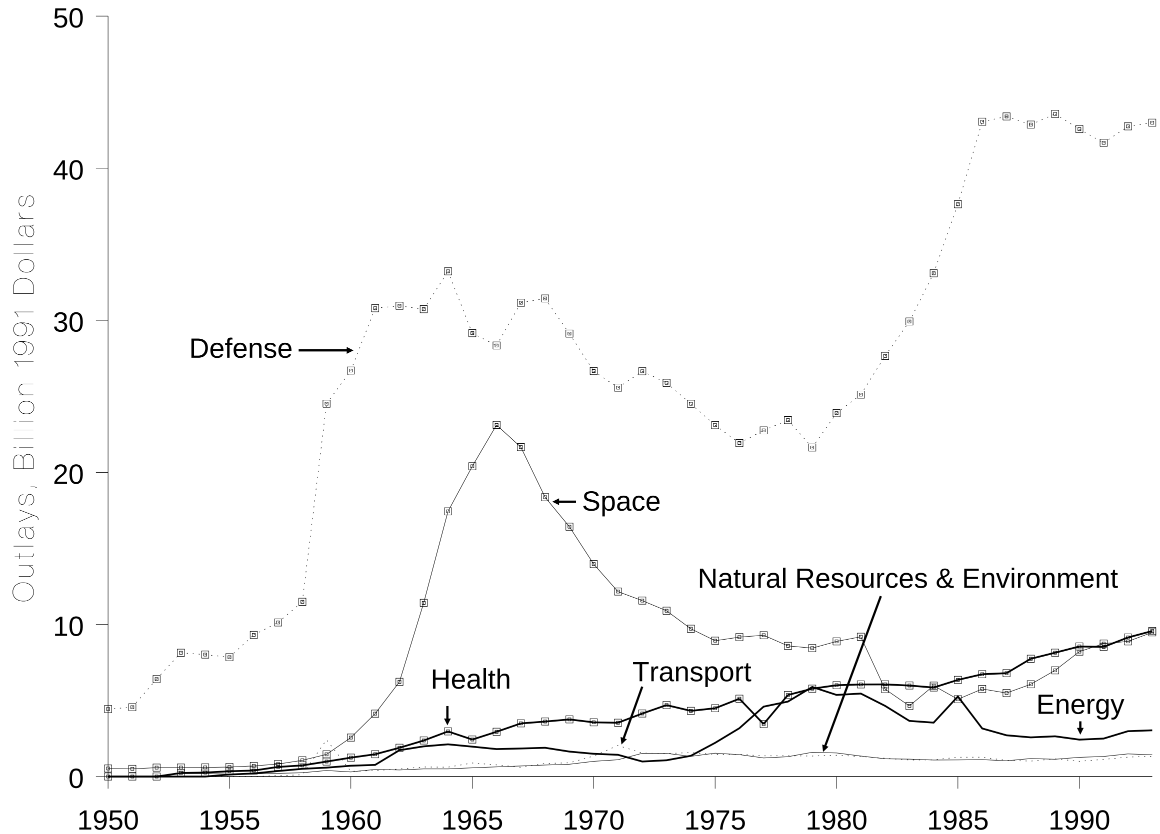
Energy R&D as a Subsidy

Energy R&D spending is easier to measure than it is to characterize from a subsidy perspective. R&D spending is intended to create useful knowledge that benefits society. Thus, all Federal R&D spending could, in a general way, be considered a subsidy to knowledge. However, the extent to which specific R&D programs actually affect energy markets is more difficult to ascertain.

The results of research are inherently uncertain. Many programs will advance knowledge across a range of energy and nonenergy applications, rather than in the context of a particular fuel or form of consumption. Further, the knowledge obtained may be negative, in the sense that the research reveals technical or economic "dead ends," henceforth to be avoided.[66] Thus, only a portion of Federal energy R&D is likely to

[66]Several studies suggest that the return to Federal R&D investment is much lower than private sector R&D, implying relatively high failure rates for Government projects. cf. N. Terlecyyj, *Effects of R&D on the Productivity Growth of Industries: An Exploratory Study* (Washington, DC: National Planning Association, 1974), and Zvi Griliches, "Returns to R&D in the Private Sector," in J. Kendrick and B. Vaccara (eds.), *New Developments in Productivity Measurement and Analysis,* NBER Studies in Income and Wealth No. 44 (Chicago, IL: University of Chicago Press, 1980), pp. 419-454. This result need not be surprising, as the Federal Government's research portfolio may be much riskier than that chosen by the private sector.

Figure 7. Federal Research and Development Outlays by Program, FY 1950 - FY 1993



Source: Office of Management Budget, *Budget of the United States Government, Fiscal Year 1993: Supplement, February 1992*, pp. 128-134.

achieve results (in the form of changes in energy costs or consumption) that can be specifically attributed to a particular R&D program. Moreover, to the extent that there are attributable results, they are likely to be measurable only years after the funded research effort is initiated.

Federal R&D is intended to support research that the private sector would not undertake. It is not supposed to substitute for private sector R&D. However, the creation of a Government-funded R&D program could, under some circumstances, "crowd out" or substitute for private sector research and development. Were this to occur, the Federal program would not produce any net new knowledge, but simply reduce private costs. It is impossible, however, to know with certainty what private sector firms would have done in the (hypothetical) absence of a Federal program. In general, the less "basic" the R&D program, and the more focused on near-term commercialization, the greater the risk that the program is substituting for private R&D.

There are no means to determine conclusively whether or not particular Federal energy R&D projects are substitutes or complements for private sector activities. Moreover, since research is risky, with failure an inherent part of the process, the effectiveness of Federal R&D cannot easily be assessed. This report makes no judgments on either of these issues. Rather, it surveys the current composition of Federal R&D spending and provides a degree of historical perspective on the changing composition of Federal energy R&D efforts.

Energy R&D Trends

Table 11 allocates Federal energy R&D by energy type and function. Currently, nearly two-thirds of Federal energy R&D ($3.7 billion) is allocated to basic research. The largest single basic research program at the Department of Energy (DOE) is the fusion research program, funded at $765 million in FY 1992. Spending on basic research, which includes the DOE categories "general science," "fusion," and "general energy

Table 11. Federal Energy R&D Appropriations by Program, FY 1991 - FY 1993
(Million Dollars)

Category	FY 1991 Actual	FY 1992 Estimate	FY 1993 Requested
Basic Research			
General Science	1,144.8	1,466.1	1,644.4
General Energy Science	798.4	880.0	937.8
Fusion	273.6	764.7	813.9
Environment/Safety/Health	497.7	513.0	551.4
Unallocated	35.6	41.5	90.1
Total	**2,750.1**	**3,665.3**	**4,037.5**
Nuclear Power			
New Nuclear Plants	94.9	122.0	108.7
Waste/Fuel/Safety	438.0	619.7	728.2
Unallocated	134.4	147.8	144.1
NRC Safety Research[a]	103.8	115.0	120.3
Total	**771.2**	**1,004.5**	**1,102.4**
Coal			
Preparation/Mining	87.1	81.3	53.9
Coal Conversion	58.5	50.6	38.0
Power Generation	143.5	147.5	62.0
Clean Coal Technology Program	391.0	415.0	500.0
Interagency NAPAP	25.3	31.1	0.0
Unallocated Fossil	83.9	78.8	55.8
Total	**789.3**	**804.3**	**709.7**
Other Fossil Energy			
Oil	41.8	51.4	54.5
Gas	15.9	12.6	40.0
Shale Oil	17.2	5.7	2.5
USGS Energy R&D	26.0	26.0	26.0
Total	**100.9**	**95.8**	**123.0**
Renewable Energy			
Photovoltaic/Wind/Other Solar	86.0	137.0	146.1
Biofuels	33.4	21.4	22.0
Geothermal	27.3	27.2	24.4
Hydroelectric	1.0	1.0	1.1
Electricity Technologies	40.7	38.0	40.1
Unallocated	11.9	18.9	16.1
Total	**200.0**	**243.6**	**249.7**
Energy End Use			
Transportation	83.8	110.2	162.4
Buildings	43.1	47.4	52.5
Industrial	83.5	97.5	105.2
Utility	4.2	4.7	6.0
Unallocated	3.9	2.7	3.3
Total	**218.7**	**262.5**	**329.4**
Total R&D Appropriations	**4,830.2**	**6,076.0**	**6,551.7**
Energy R&D Outlays in Table 1			
Total R&D Appropriations	4,830.2	6,076.0	6,551.7
Less Basic Research	2,750.1	3,665.3	4,037.5
Less NRC Revenues	103.8	115.0	120.3
Less Clean Coal Adjustment[b]	267.6	253.0	338.0
Estimated Energy-Related Outlays	1,708.7	2,042.7	2,055.9

[a]The cost of NRC safety research is recovered through fees paid by nuclear power plant operators.

[b]Outlays for the Clean Coal Technology Program are considerably less than appropriations. FY 1991-1993 outlays were $123.4 million, $162 million, and $184 million, respectively. For other categories of energy R&D, appropriations and outlays coincide more closely.

Sources: U.S. Department of Energy, *U.S. Department of Energy Posture Statement and Fiscal Year 1993 Budget Overview*, and *U.S. Department of Energy Posture Statement and Fiscal Year 1992 Budget*; Office of Management and Budget, *Budget of the United States Government, Fiscal Year 1993* (Washington, DC, March 1992); National Acid Precipitation Assessment Program, *Mission, Goals, and Program Plan Post 1990* (Washington, DC, Public Review Draft, November 1991).

sciences," grew slowly throughout the 1980's. However, spending accelerated in the past 2 or 3 years as appropriations for fusion-related research doubled.

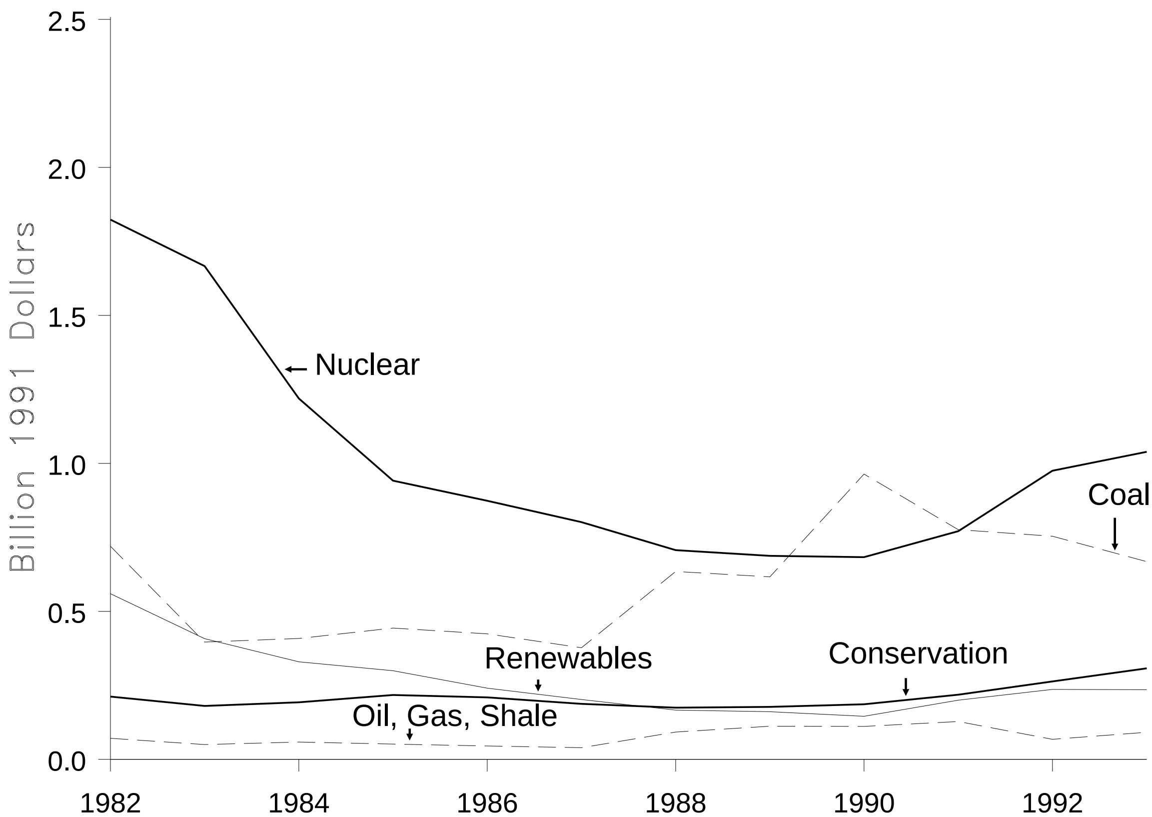
Basic research is difficult to characterize as an energy subsidy because it is impossible to allocate it rationally between energy and nonenergy benefits, or among forms of energy. Therefore, the balance of this chapter focuses on applied energy R&D.

Appropriations for applied energy research and development were about $2.4 billion in FY 1992. Applied R&D is primarily aimed at efforts to improve existing technology. Of that amount, more than two-thirds is allocated to nuclear and coal activities. Within the range of nuclear projects, most spending focuses on environmental management. For coal, the bulk of spending supports development of clean coal technologies. Solar energy absorbs the major share of renewable energy research funds ($146 million out of a total of $250 million). End-use conservation spending focuses on transportation and industrial activities ($270 million out of a total of $327 million).

Figure 8 illustrates trends in Federal applied energy R&D appropriations from FY 1978 through FY 1993. The FY 1978 to FY 1992 data are based on appropriations by Congress, while FY 1993 data are based on the President's request to Congress. There were sharp reductions in energy R&D appropriations during the early 1980's, and growth since 1990.

The detailed Federal appropriations shown in Figure 8 and in subsequent figures in this chapter are documented in Appendix C.

Figure 8. Federal Energy R&D Appropriations by Program, FY 1978 - FY 1993



Source: U.S. Department of Energy, Comptroller's Office, Department of Energy Appropriation History Tables (mimeo, March 29, 1991), and *U.S. Department of Energy Posture Statement and Fiscal Year 1993 Budget Overview.*

R&D spending by fuel type is dominated by nuclear power R&D, which has increased substantially since 1990 as emphasis on waste management research has grown. Coal appropriations have been boosted in the late 1980's by the advent of the Clean Coal Technology Program. Renewables and conservation appropriations have also risen since 1988. Only small amounts of Federal R&D are related to oil and gas. Oil and gas-related Federal R&D spending was $96 million in FY 1992. If the definition is expanded to include all programs that provide liquid transportation fuels, then the amount rises to $300 million. The discussion which follows presents additional detail regarding the composition of Federal applied R&D efforts.

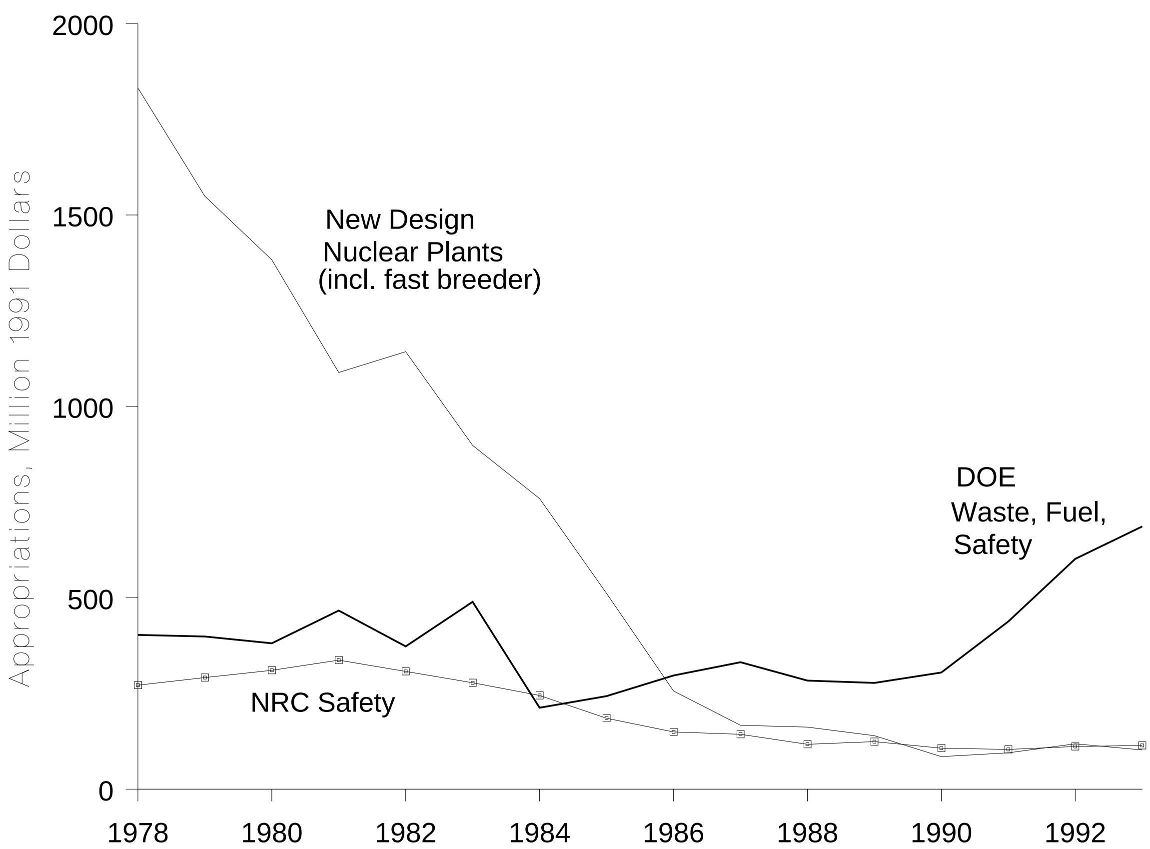
Another recent trend in Federal research and development is a tendency for Congress to mandate research on particular projects. Title XIII of the Energy Policy Act writes much of the Department of Energy's coal research and development program into law, and adds some new areas of research, mandating R&D on coal-fired diesel engines, non-fuel coal use, coalbed methane, metallurgical coal development, coal gasification, coal liquefaction, low-rank coal use, and magnetohydrodynamic power generation. There are similar detailed provisions for research on other energy sources, including nuclear power, end use, and renewable energy, throughout the law.

Energy R&D Programs Described

Nuclear Power

Figure 9 illustrates trends in DOE's nuclear power-related R&D. DOE received an appropriation of $331 million for "nuclear R&D" in FY 1992.[67] Nearly a third of the DOE appropriation ($96 million) was devoted to

Figure 9. Federal Nuclear-Related R&D Appropriations, FY 1978 - FY 1993



Source: U.S. Department of Energy, Comptroller's Office, Department of Energy Appropriation History Tables (mimeo, March 29, 1991), and *U.S. Department of Energy Posture Statement and Fiscal Year 1993 Budget Overview.*

[67]This and subsequent references to particular DOE budget figures are taken from Adm. James D. Watkins (USN, Ret.), *U.S. Department of Energy Posture Statement and Fiscal Year 1993 Budget Overview*, pp. 103-112. All figures refer to FY 1992 budget authority.

nuclear power systems for spacecraft (categorized by this report as nonenergy R&D), $115 million was allocated to safety-related R&D and the balance ($120 million) for new reactor designs.

New reactors. DOE allocated $120 million in FY 1992 to the development of new nuclear reactors, including improvements to existing light water designs and studies of advanced reactors. In 1989, DOE and the Electric Power Research Institute signed a contract to provide $50 million, each, to Westinghouse to complete the design of the AP-600, a 600-megawatt pressurized water reactor of advanced "passively safe" design. If approved by the Nuclear Regulatory Commission (NRC), the design "would become a standard product, available off the shelf from Westinghouse."[68] A similar $50-million contract was let to General Electric to develop a competing design.

Environmental, safety, and waste research. Two agencies conduct civilian nuclear power research and development: the Department of Energy and the Nuclear Regulatory Commission. Within the Department of Energy, some $620 million of "Energy Supply R&D" was actually devoted to nuclear purposes, principally "Environmental Restoration and Waste Management." This research is aimed both at finding ways to treat and store nuclear waste, and to decommission obsolete nuclear reactors safely. DOE's environmental, safety, and fuel-related research allocations are rising. The FY 1993 budget request is $730 million.

The NRC received budget authority for $115 million in nuclear safety-related R&D in FY 1992.[69] NRC's safety research (like the rest of the NRC's budget) is funded through fees paid by nuclear power plant licensees (See Chapter 2). Thus, since the annual budget authority is offset by actual fees received, the NRC research program has no net impact on the Federal budget and is not a subsidy.[70]

Coal

DOE's coal programs include a formal research and development program and the Clean Coal Program, which funds advanced technology demonstration facilities (Figure 10). DOE's fossil energy program also received some $68 million in budgetary authority in FY 1992 for "Program Direction and Management Support" in the area of fossil fuels, which are dominated by coal research. The bulk of the money went to support the three DOE-owned Energy Technology Centers in Morgantown, West Virginia, Pittsburgh, Pennsylvania, and Bartlesville, Oklahoma. Coal R&D appropriations hit a short-run peak of $930 million in FY 1990. Coal budgets have declined since: the FY 1992 allocation was $777 million. Coal R&D can be divided into three classes of expenditures: coal preparation and treatment, coal conversion, and coal-fired power generation.

Coal technology and coal preparation. The FY 1992 budget allocated $51 million for control technology and coal preparation, as well as $11 million for fossil energy environmental restoration, associated with problems of mine waste and mine closing. These are the only Federal R&D programs associated with mining coal.

Coal conversion R&D. Coal conversion covers R&D on technologies to convert coal into either petroleum products or synthetic gas. FY 1992 allocations were about $50 million, cut to $38 million in the FY 1993 request. Coal conversion technologies are inherently very high-cost technologies. The United States has a lengthy history of Government-funded efforts to create a synfuels industry.[71] This effort has proven the technical possibility of producing synthetic fuels from coal. However, existing technologies are not competitive in current energy markets.[72]

Coal-fired power generation. DOE's Power Generation Program undertakes research on advanced power

[68]Thomas Lippman, "Energy Dept. to Finance Design of New Reactor," *Washington Post* (September 6, 1989).

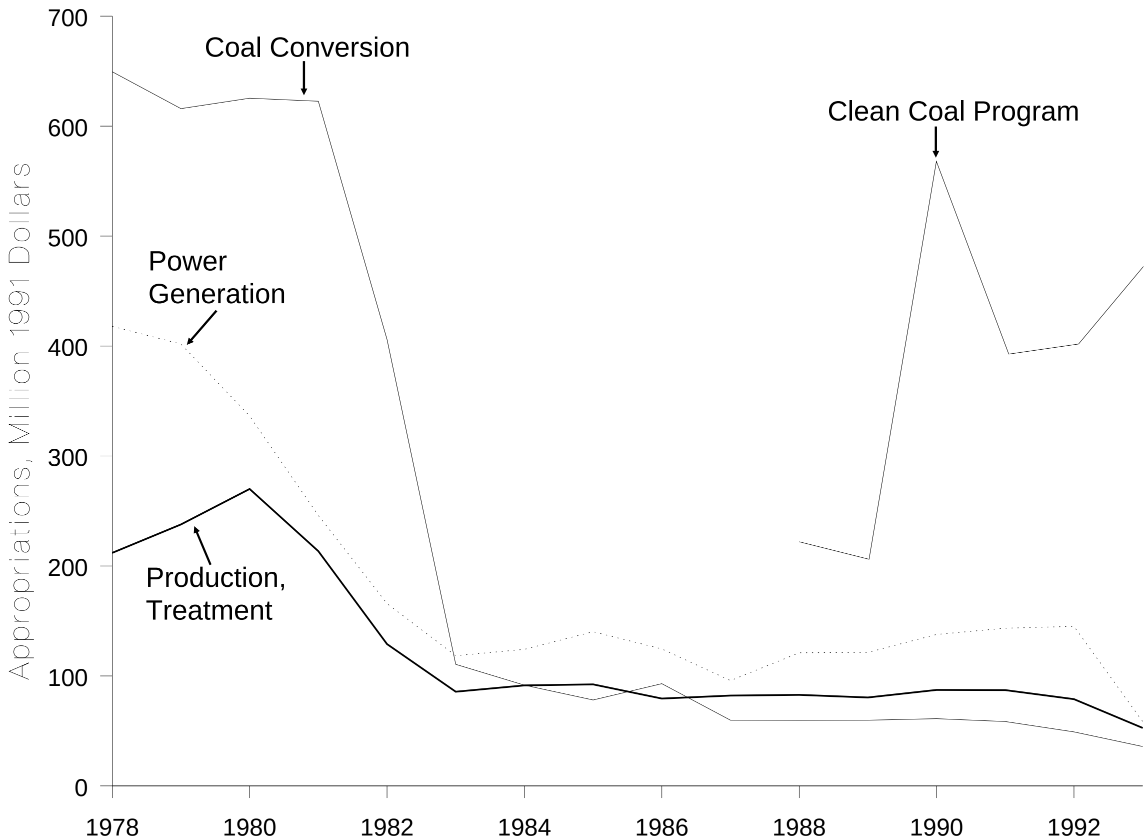
[69]National Science Foundation, *Federal R&D Funding by Budget Function, Fiscal Years 1989-1991*, NSF 90-311 (Washington, DC, April 1990), p. 81.

[70]Details of the NRC safety research program can be found in Nuclear Regulatory Commission, *Annual Report 1991*, pp. 141-193.

[71]Interested readers can learn about the history of synfuels programs in Richard Vietor, *Energy Policy in America Since 1945* (New York, NY: Cambridge University Press, 1984), pp. 44-63 and pp. 163-189. See also Linda Cohen and Roger Noll, *The Technology Pork Barrel* (Washington, DC: The Brookings Institution, 1991), pp. 259-319.

[72]A National Research Council study estimated that coal liquefaction plants, based on future technology developed through current R&D spending, would require oil prices ranging from $30 to $89 per barrel. National Research Council, *Fuels to Drive Our Future* (Washington, DC: National Academy Press, 1990), pp. 160-161.

Figure 10. Principal DOE Coal-Related R&D Appropriations, FY 1978 - FY 1993



Source: U.S. Department of Energy, Comptroller's Office, Department of Energy Appropriation History Tables (mimeo, March 29, 1991), and *U.S. Department of Energy Posture Statement and Fiscal Year 1993 Budget Overview.*

generation technologies, including research on exotic technologies such as magnetohydrodynamic (MHD) power generation and fuel cells. The DOE program is funded at $150 million in FY 1992. The basic objective of DOE power generation research is to find ways to burn coal more efficiently and with less pollution. Coal remains a relatively inexpensive fuel. However, its ability to compete in the long run requires development of technologies which make coal use more environmentally friendly.

DOE research is complemented by an interagency program to study the effects of acid rain, the National Acid Precipitation Assessment Program (NAPAP). Funding for NAPAP has been spread across several agencies, including the DOE. Total FY 1992 NAPAP funding was $31 million, including $4 million from DOE, $5.8 million from the Department of the Interior, $1.5 million from the National Oceanographic and Atmospheric Administration, and $12.8 million from the Environmental Protection Agency budget.[73]

Clean coal technology. One of the most heavily funded DOE programs, begun after the precipitous fall of synfuels funding (Figure 10), is the Clean Coal Technology Program, which is not formally counted as research and development. This program (funded at $415 million in FY 1992) was established to provide large cost-sharing grants to organizations wishing to build demonstration or commercial-scale coal plants using advanced, low-pollution technologies. Projects funded to date include a coal-cleaning plant, an atmospheric fluidized bed boiler for a utility repowering project, refits of "Low NO_x Burners" to conventional coal-fired plants, and advanced technology SO_2-removing "scrubbers" for existing plants. Projects being negotiated included several integrated gasification combined cycle (IGCC) coal-fired

[73]U.S. National Acid Precipitation Assessment Program, *Mission, Goals, and Program Plan Post 1990* (public review draft, November 1991), pp. 38-41.

power plants, pressurized fluidized bed combuster (PFBC) power plants, a low-Btu coal gasification project, and a coal-to-methanol conversion project. The DOE's maximum share of the cost of the projects is typically 40 to 50 percent, but may run as low as 20 percent in some cases.

The Clean Coal Technology Program began with a $500-million transfer of funds from the Government-owned Synthetic Fuels Corporation, which was abolished in 1985. Since then, some $2 billion in multi-year budget authority has been appropriated through FY 1992. The FY 1993 budget request is $500 million. Despite the large appropriations, relatively little money has yet been spent. Actual budget obligations totaled $425 million (less than a quarter of the funds appropriated) through December 1991. FY 1992 outlays were $172 million.[74]

Of the 55 projects originally selected for funding by the DOE, 13 have been withdrawn by their sponsors, 12 are still being negotiated, 20 are in design or construction phases, and 3 have been completed.[75] Table 12 lists approved Clean Coal projects by project type. The monies listed on Table 12 are multi-year project costs, and include funds that have already been spent along with funds not yet obligated. Of the 11 Clean Coal advanced power generation projects, two are operational and six others (including the $900 million, 330 megawatt Tidd Pressurized Fluidized Bed Combustor project) are being restructured or renegotiated. The remaining three projects are in the design phase.

The original Clean Coal Technology solicitation included provision for eventual repayment of the Clean Coal grant through revenues from the operation of the project after completion of the demonstration period, sale of project assets after completion, or through royalties or license fees on the technology demonstrated. According to DOE, the recoupment provisions were among the most contentious issues in negotiations on the original solicitation. Subsequent solicitations limited the Government's ability to recoup its investment to a 2- to 3-percent royalty on subsequent use of the demonstrated technologies, and permitted grant recipients to request waiver or deferment of the royalty obligation if payment places the recipient at a "competitive disadvantage."[76]

In general, Clean Coal Technology power generation projects have capital costs higher than current conventional coal-fired steam turbine plants with scrubbers.[77] Capital costs for the existing technologies are well developed and have been subject to continuous improvement efforts over several decades. The Clean Coal grant reduces private costs to make new technology more competitive with existing technologies. The focus on demonstration projects has meant that most Clean Coal sponsors are capital equipment manufacturers, rather than operators.[78]

Table 12. DOE Clean Coal Technology Project Costs by Type of Project

Type of Project	Number of Projects	Total Costs of Projects (million dollars)	DOE Contribution (million dollars)	DOE Share of Costs (percent)
Pollution Control Equipment	21	682.4	308.5	45
Coal Processing	6	483.0	227.4	47
Industrial Applications	4	238.9	69.3	29
Advanced Power Generation	11	3,476.6	1,300.8	37
Total	**42**	**4,880.9**	**1,906.0**	**39**

Source: U.S. Department of Energy, *Clean Coal Technology Demonstration Program: Program Update 1991* (Washington, DC, February 1992), p. 3-9.

[74]Office of Management and Budget, *Budget of the United States Government FY 1993*, Appendix 1, p. 476.

[75]U.S. Department of Energy, *Clean Coal Technology Demonstration Program: Program Update 1991*, DOE/FE-024/7P (Washington, DC, February 1992), p. 4-1.

[76]U.S. Department of Energy, *Clean Coal Technology Demonstration Program: Program Update 1991*, DOE/FE-024/7P (Washington, DC, February 1992), pp. 3-9 - 3-10.

[77]The Clean Coal power generation projects currently under consideration have project costs that range from $2,000 to $4,000 per kilowatt, even though several projects are repowering projects which use existing generators and turbines. The average overnight cost for a typical coal-fired steam turbine plant with scrubber is $1,200 to $1,400 per kilowatt.

[78]In a number of cases, Clean Coal Technology grants will help foreign capital equipment manufacturers to introduce their products into the U.S. market. Of the 42 Clean Coal sponsors, 7 are foreign-owned, including Swedish-owned ABB Combustion Engineering (sponsoring three projects). Primary technology providers for American-sponsored clean coal projects include Finland's Tampella, Mitsubishi, Chiyoda, ABB (again), British Steel, and Saarberg-Holter-Umwelttechnik GmBH.

Oil, Gas, and Oil Shale

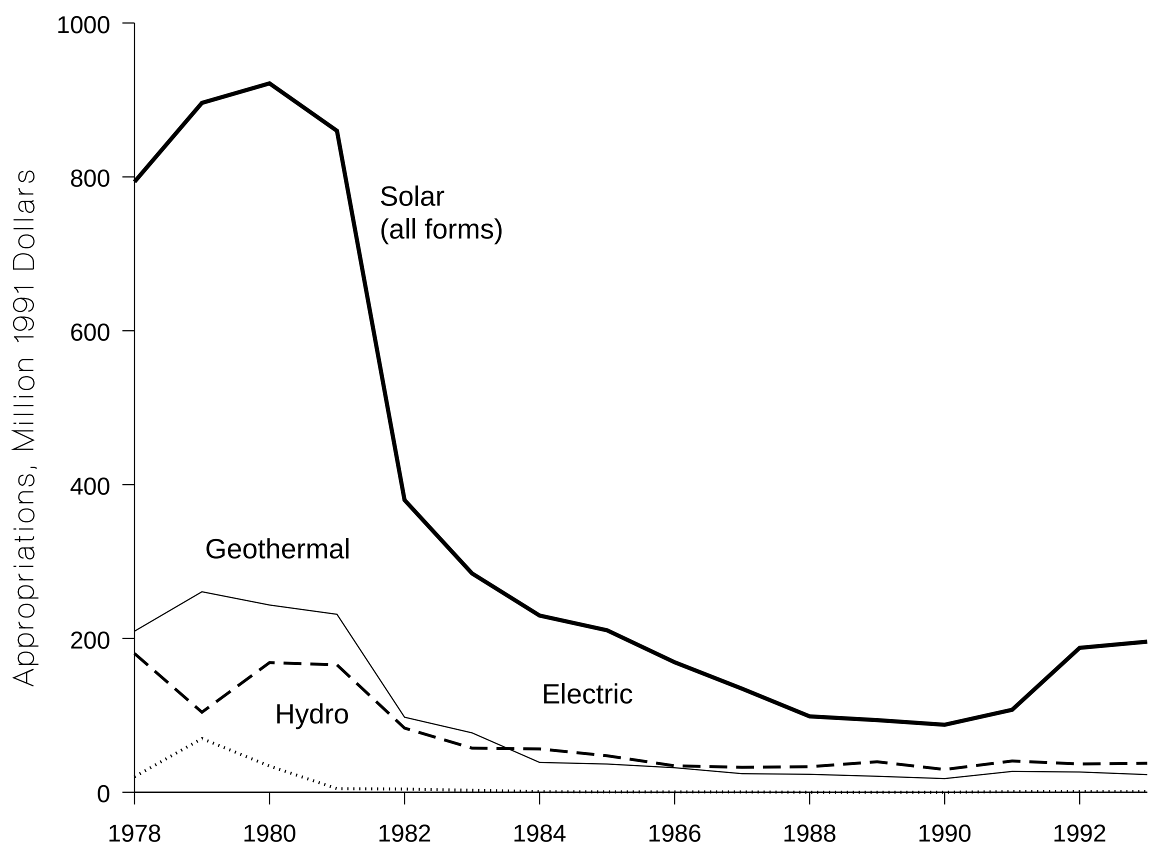
DOE's oil and gas research efforts are relatively small. Private sector R&D spending in this area far exceeds that of the Government.[79] Annual R&D budget authority for oil-related programs amount to $51.3 million in FY 1992, mostly aimed at research on enhanced oil recovery. The Natural Gas Program received $12.5 million in FY 1992, tripling to $40 million in FY 1993 request, for "Unconventional Gas Recovery." Finally, DOE maintained a very low level of research on liquefaction of oil shale ($6 million in FY 1992, $2.5 million in FY 1993).

The U.S. Geological Survey maintains a program of energy and offshore geological surveys that are counted as research and development. This expenditure is about $26 million per year. This amount raises Government R&D expenditures related to the oil and gas industry to nearly $100 million per year.

Renewable Energy

The DOE renewable energy R&D program is large in relationship to the size of the current renewable energy industry, but its purpose is to help expand that industry. Figure 11 illustrates the distribution of R&D expenditures across renewable technologies. DOE's

Figure 11. DOE Renewable Energy-Related R&D Appropriations, FY 1978 - FY 1993



Source: U.S. Department of Energy, Comptroller's Office, Department of Energy Appropriation History Tables (mimeo, March 29, 1991), and *U.S. Department of Energy Posture Statement and Fiscal Year 1993 Budget Overview.*

[79]The Energy Information Administration collects financial data of the 23 largest U.S. oil companies. In 1991, these firms collectively spent $1.4 billion on oil and gas research and development, $60 million on coal research and development, and $95 million on alternative energy R&D. See Energy Information Administration, *Performance Profiles of the Major Energy Producers 1991* (Washington, DC, December 1992), Chapter 4.

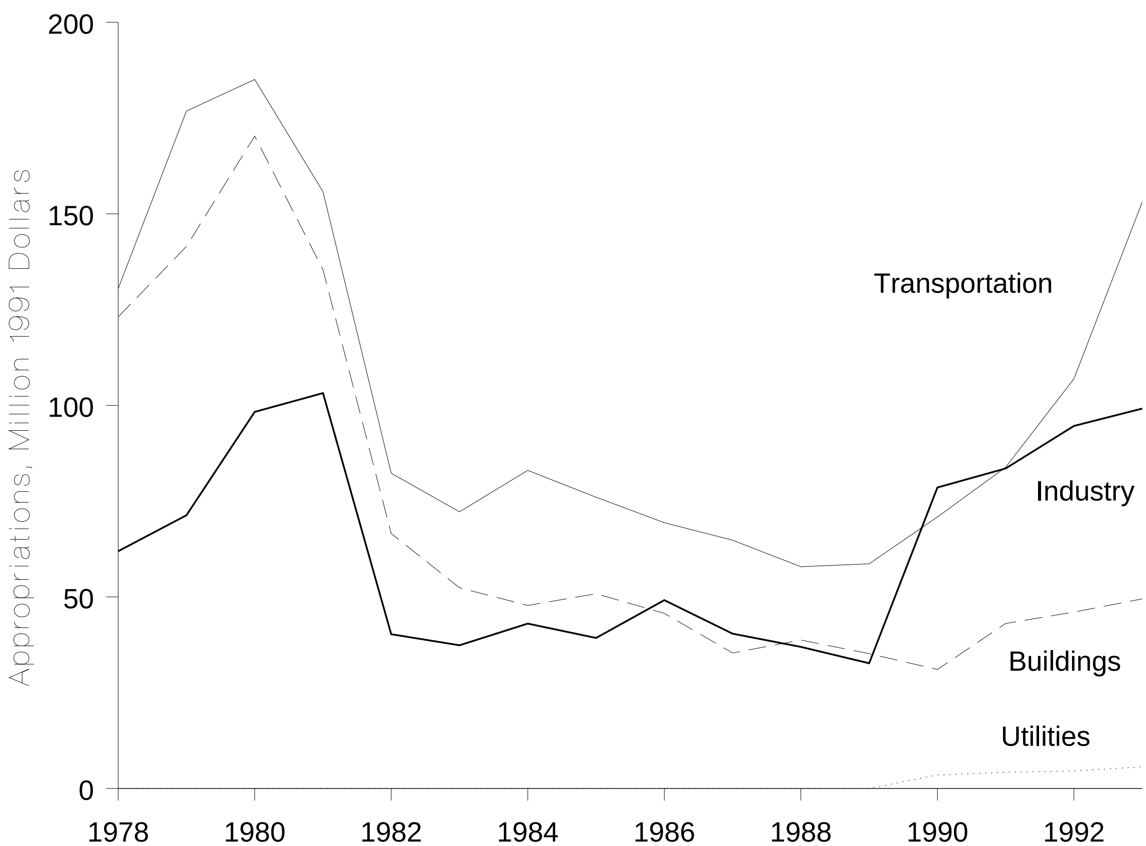
biggest single renewable energy program is research on photovoltaics, at about $60 million per year. Solar thermal systems are funded at $28 million per year, wind systems at $20 million per year, and geothermal R&D about $25 million per year.

Another pair of programs, funded through renewables, are aimed at improving the efficiency of electrical supply and storage systems. Storage systems are important to many forms of renewable energy because they produce power only intermittently. This effort is funded at about $38 million per year. In addition, program support and direct financing for the National Renewable Energy Laboratory totals $20 million per year.

Energy End Use and Conservation

DOE also operates research and development programs aimed at conserving energy. In addition, other Federal agencies (particularly the National Aeronautics and Space Administration and the Department of Transportation) operate large transportation R&D programs not aimed directly at energy consumption, but which may significantly affect energy consumption in the future. In common with other R&D programs, the DOE conservation effort includes some unallocable expenditures. These funds include some $35 million for "nongrant technical and financial assistance," which covers policy management and various types of loans and cost-sharing programs. Figure 12 illustrates trends in conservation R&D spending.

Figure 12. Principal DOE Conservation-Related R&D Appropriations, FY 1978 - FY 1993



Source: U.S. Department of Energy, Comptroller's Office, Department of Energy Appropriation History Tables (mimeo, March 29, 1991), and *U.S. Department of Energy Posture Statement and Fiscal Year 1993 Budget Overview.*

Residential/commercial. The DOE Residential/ Commercial Program is described as "Buildings," and aims at finding more energy-efficient construction technologies such as better insulation, better window designs, and more efficient appliances.[80] The program has been funded at about $50 million per year.

Industrial. The Industrial Program, funded at $105 million per year, is double the size of the Buildings Program. The program has two main thrusts: developing more energy-efficient industrial processes, and developing methods of reducing and using waste materials. Among the industrial process projects is a joint project with the American Iron and Steel Institute to develop an energy-saving direct steelmaking process. Other projects seek to develop more energy-efficient "building block" technologies common to many industrial processes such as heat pumps, heat exchangers, and industrial boilers.[81]

DOE transportation research. The Transportation Program is 50 percent larger than the Industrial Program, with an FY 1993 request of $162 million. Transportation research has gained in importance since the passage of the Clean Air Act Amendments of 1990, which will require owners of fleets of vehicles to acquire a certain percentage of alternative-fueled vehicles after 1995. State and local air quality agencies in California may also require "zero emissions" vehicles by the end of the decade to meet air quality standards in the Los Angeles area. The only known zero emissions vehicle is an electric-powered vehicle. Current technology electric vehicles, however, are hampered by short range, poor performance, high cost, and short service life, due largely to the limitations of conventional lead acid batteries.

The main thrust of the Transportation Program is the U.S. Advanced Battery Consortium. The Advanced Battery Consortium is jointly owned by Ford, General Motors, and Chrysler, with funding of $262 million through 1994 provided by these firms, the Department of Energy (50 percent of the total), and the utility-financed Electric Power Research Institute. The objectives of the consortium are to accelerate the market potential of electric vehicles by jointly researching the most promising advanced battery alternatives, and to establish a domestic advanced battery manufacturing capability.

Other DOE transportation programs include research on methanol, ethanol, and natural gas-fueled vehicles, advanced gas turbines for vehicular use, and advanced ceramic materials for use in more energy-efficient engines.[82]

Other agency transportation R&D. Other Departments also have extensive transportation research and development programs, notably the National Aeronautics and Space Administration and the Department of Transportation. As this report excludes transportation expenditures by definition, they are not discussed here.[83]

Utility. R&D on utility conservation is a relatively new program, funded at $4.7 million in FY 1992, rising to $6 million in the FY 1993 request. Most of this appropriation ($4.0 million) is directed to promoting "Integrated Resource Planning," the concept that utilities should plan their investment programs based on the full cost of the energy service provided, from the customer's light bulb to the coal mine's reclamation cost, rather than focus on just electricity production and supply. The DOE program aims both at promoting integrated resource planning and at developing analytical tools (such as fuel cycle cost analysis) intended to help utilities undertake integrated resource planning.[84]

Off-Budget Research and Development

In addition to directly funded research and development, the Natural Gas Policy Act of 1978 mandated the creation of a private sector natural gas research and development agency, the Gas Research Institute (GRI). The Gas Research Institute is funded by

[80]National Renewable Energy Laboratory, *Conservation and Renewable Energy Technology for Buildings*, DOE/CH10093-85 (Washington, DC, May 1991).

[81]National Renewable Energy Laboratory, *Conservation and Renewable Energy Technologies for Industry*, DOE/CH10093-87 (Washington, DC, October 1991).

[82]National Renewable Energy Laboratory, *Conservation and Renewable Energy Technologies for Transportation*, DOE/CH10093-84 (Washington, DC, May 1992).

[83]The National Aeronautic and Space Administration allocated $784 million in FY 1992 to Aeronautical Research & Technology and $5 million for "Transatmospheric Research & Technology." National Aeronautics and Space Administration, *Background Material: NASA FY 1993 Budget Briefing* (mimeo press release dated January 29, 1992). The Federal Aviation Administration expends $180 million per year on R&D. The Federal Highway Administration expends some $180 million per year on ground transportation R&D, much of which is safety-related. The Coast Guard also funds $20 million annually in water transportation-related R&D.

[84]National Renewable Energy Laboratory, *Conservation and Renewable Energy Technologies for Utilities*, DOE/CH10093-86 (Washington, DC, April 1992), pp. 8-10.

a levy of $0.0151 per thousand cubic feet of gas in interstate transport.[85] This levy raised $180 million in calendar year 1991. GRI also received revenues of about $4.3 million on gas moving in intrastate transport. GRI's 1991 research and development expenses were about $191 million. The budget included $20.5 million of spending on basic research, $74 million on gas end use, $52 million on gas supply, $26 million on transport and storage, and $23 million on environmental and safety research. GRI programs included research on enhanced gas recovery, coalbed methane production, natural gas vehicles, and more efficient gas appliances.

The research arm of the electric utility industry is the Electric Power Research Institute (EPRI). EPRI is a private organization, and membership (and hence, research funding) is voluntary. Hence, it cannot be considered a Government intervention in the energy industry. EPRI's 1991 research budget was $444 million.[86]

[85]Gas Research Institute, *1991 Annual Report*, p. 28.

[86]Electric Power Research Institute, *1991 Annual Report,* p. 23.

6. Public Power Issues

Chapter 1 of this report described alternative approaches to estimating the cost of various indirect subsidies. This chapter provides a case study in the uses of these alternative approaches as they apply to a group of Federal subsidies provided to public power. These programs are only partially depicted in the Federal budget. Therefore, analysis of the programs required harnessing an array of extra-budgetary data sources.

About 80 percent of residential electricity customers in the United States are served by privately owned, publicly regulated electric utilities, often called investor-owned utilities (IOUs). The remaining 20 percent (accounting for 24 percent of electricity sold) receive their power from Government agencies or cooperatives. These organizations operate in a different legal, financial, and tax environment than their private-sector counterparts. This different environment creates measurably lower prices to their consumers.

Electric utility sales can be divided into two types of transactions: sales to ultimate consumers (i.e., electricity sold to households and industries for their own use) and sales for resale (primarily electricity sold to other electric utilities). Most publicly owned utilities are State or local agencies, accounting for about 14 percent of U.S. electricity sales to final consumers (Table 13). The largest publicly owned utilities in the United States are the City and County of Los Angeles and the New York State Power Authority.[87] Publicly owned utilities do not, however, generate all of the electricity that they sell. In 1990, they purchased about a third of the electricity that they sold to ultimate consumers.

A further 7 percent of U.S. electricity sales to ultimate consumers is accounted for by rural electric cooperatives (RECs), which are private organizations, owned by their members, but which are also usually, but not universally, nonprofit, tax-exempt organizations. Cooperatives generate only three-quarters of the power that they sell.[88]

Finally, six large Federal utilities (the Tennessee Valley Authority and five Power Marketing Administrations (PMAs)) sell wholesale power.[89] These agencies were originally established to market hydroelectric power generated from dams built by the Bureau of Reclamation and Army Corps of Engineers. They account for about 3 percent of U.S. electricity sales to ultimate consumers. However, less than a fourth of the power generated by Federal utilities is sold to ultimate consumers. By law, most Federal electricity is sold to publicly owned utilities and rural electric cooperatives for resale to their ultimate (retail) customers.

The large Federal utilities as a group have only 350 end-user customers, of whom just eight customers are classed as residential and one as commercial.[90] The other 341 industrial customers are generally bulk purchasers such as the Department of Energy (for uranium enrichment) and aluminum smelters in the Pacific Northwest. Table 14 illustrates that Federal industrial customers pay electricity prices 23 percent lower than national average industrial electricity prices.

Table 13 and Figure 13 also illustrate the lower prices paid by customers of publicly owned utilities. Publicly owned utilities sell their electricity at prices which are, on average, 13 percent lower than IOU prices. However, the discount is concentrated on residential customers: publicly owned utility retail prices are 21 percent lower than investor-owned utility retail prices, while industrial prices are only 6 percent lower.

[87] Energy Information Administration, *Financial Statistics of Publicly Owned Electric Utilities 1990*, DOE/EIA-0437(90)/2 (Washington, DC, February 1992), p. 21.

[88] U.S. Department of Agriculture, Rural Electrification Administration, *1990 Statistical Report, Rural Electric Borrowers*, IP 201-1 (Washington, DC, August 1991).

[89] There are 10 Federal utilities, of which 4 are very small. The smallest is not required to file reports with the Energy Information Administration. Two others are distribution-only utilities run by the Bureau of Indian Affairs to provide power to 25,000 customers. The largest of the four, run by the Army Corps of Engineers, operates a 20-megawatt hydroelectric plant in Michigan. See Energy Information Administration, *Financial Statistics of Selected Publicly Owned Utilities*, DOE/EIA-0437(90)/2 (Washington, DC, February 1992), pp. 3 and 337-344. This report will hereafter concentrate on the six large Federal utilities.

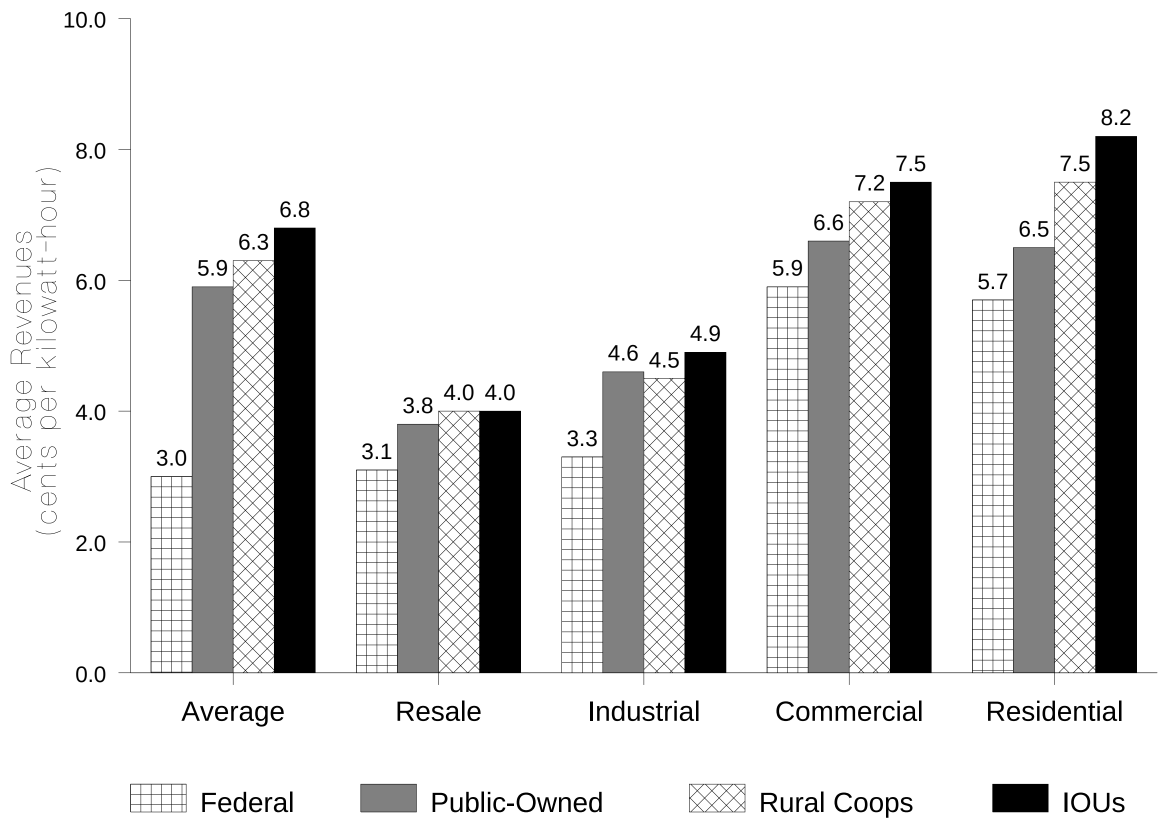
[90] Energy Information Administration, *Selected Financial Statistics of Publicly Owned Utilities*, DOE/EIA-0437(90)/2 (Washington, DC, February 1992), pp. 343-344.

Table 13. Electricity Revenues and Revenues per Kilowatthour from Sales to Ultimate Consumers, by Type of Utility Ownership, 1990

Type of Utility	Electricity Generated	Electricity Sold to Ultimate Consumers	Share of Electricity Sold to Ultimate Consumers	Revenues from Sales to Ultimate Consumers	Revenues from Sales for Resale
	(billion kilowatthours)		(percent)	(cents per kilowatthour)	
Investor-owned Utilities	2,111	2,071	76.3	6.8	4.0
Publicly-Owned Utilities	287	385	14.2	5.9	3.8
Rural Electric Cooperatives . .	156	200	7.4	6.3	4.0
Federal Utilities	253	55	2.1	3.1	3.1
Total	2,808	2,713	100.0	6.6	3.7

Source: Form EIA-861, "Annual Utility Report," as reported in Energy Information Administration, *Financial Statistics of Selected Publicly Owned Electric Utilities* and *Financial Statistics of Selected Investor-Owned Utilities* (December 1991). Also annual reports of Power Marketing Administrations, Alaska Power Administration's *Divestiture Summary Report: Sale of Eklutna and Snettisham Hydroelectric Projects* (April 1992), and USDA/REA, *1990 Statistical Report, Rural Electric Borrowers*, IP 201-1 (August 1991).

Figure 13. Retail Electricity Prices by Customer Class and Type of Utility, 1990



Source: Energy Information Administration, Form EIA-861, "Annual Utility Report."

This pattern does not hold for rural electric cooperatives: RECs sell only a small portion of their electricity to industrial customers, so there is little opportunity for cross-subsidy between customer classes. REC industrial and residential customers pay rates that are about 8 percent lower than investor-owned utility rates, while commercial customers pay rates that are 4 percent lower. Public power and cooperative residential customers have consumption rates that are more than 20 percent higher than investor-owned utility customers. Residential customers dominate public power agency sales. Moreover, lower prices may not be the sole cause of these higher consumption rates. Other causes may play a role. For example, public power customers may be concentrated in regions that have more extreme weather conditions than IOU customers. Cooperative customers are often farmers whose total electricity usage (including farm use) is counted as residential usage. Investor-owned utility commercial and industrial customers consume more electricity per customer, despite the higher prices.

Policies Affecting Public Power Costs and Pricing

Programs

The lower prices charged by public power are due to their legal status and to the benefits of several long-established Federal programs. The programs are:

- **Access to low-priced Federal power from power marketing administrations.** Federal power marketing administrations (PMAs) such as Bonneville Power Administration, are required to preferentially sell their electricity to publicly owned utilities. These sales account for about 10 percent of the electricity generated in the United States (Table 1). By Congressional mandate, PMA electricity is sold "at the lowest possible rate," which is typically less than the cost of alternative supplies.
- **Access to Rural Electrification Administration (REA) credits.** Rural electrification cooperatives, under a program dating from 1937, are eligible for low-interest long-term loans from the Federal Government. These loans were made at a 2-percent interest rate through 1973. Loans made after 1973 have been made at a 5-percent interest rate, with loan periods of 30 to 50 years.[91] At the end of 1990, some $43 billion in Federal loans and guarantees were outstanding to cooperatives.
- **Tax-exempt borrowing rights.** Publicly owned utilities can issue "municipal bonds" whose interest is exempt from Federal income tax. Municipal borrowers can therefore obtain lower interest rates than either private borrowers or the U.S. Treasury. In 1990, publicly owned utilities had some $69 billion in long-term debt outstanding, on which they paid an average interest rate of about 7 percent.[92]
- **Exemption from Federal (and State) income tax.** Both publicly owned utilities and cooperatives are not subject to Federal income tax on their profits or retained earnings. Under current circumstances, the tax exempt status of these organizations does not cost the Treasury much money, as utilities make only incidental profits.[93]

Public power agencies also have lower nonincome tax burdens, but this is a State and local subsidy, rather than a Federal subsidy, and consequently is not treated here.[94]

Public power agencies are not intended to make a profit, and consequently, are under no obligation to earn a market return on capital. In 1990, investor-owned utilities in the United States earned an average before-tax return of 10.8 percent on utility assets. Publicly owned utilities earned a return of 1.5 percent.[95] Their nonprofit status permits publicly owned utilities to charge lower prices. As Federal law neither prohibits nor compels public ownership, this is

[91]U.S. Department of Agriculture, Rural Electrification Administration, *Report of the Administrator: Fiscal Year 1990*, IP 100-2, p. 29.

[92]Computed from data in Energy Information Administration, *Financial Statistics of Selected Publicly Owned Utilities*, DOE/EIA-0437(90)/2 (Washington, DC, January 1992). See "A Note on Data Sources" at the end of this chapter.

[93]The actual 1990 net income of publicly owned utilities as a group was $970 million in 1990, and the net income of Rural Electric Cooperatives was $700 million. At average tax rates typical of IOUs (23 percent), taxing this income would raise $380 million. However, public power agencies do not use the same definition of "profit" as IOUs and do not keep their books with an eye to minimizing potential tax liabilities. Thus, the computed estimate is not a good guide to the extent of foregone tax revenues.

[94]In 1990, IOUs paid $11.4 billion in non-income taxes, equivalent to about 8.1 percent of sales, presumably sales and property taxes. Publicly owned utilities are less subject to such taxes, paying the equivalent of only 3.5 percent of sales in non-income taxes. The effect of this partial exemption, which is doubtless implemented differently in different jurisdictions, is to reduce the costs of publicly owned utilities by about $2 billion in the aggregate, or about 3 mills per kilowatthour. The revenues are not foregone by the Federal Government, but by State and local agencies. See sources cited in "A Note on Data Sources" at the end of this chapter.

[95]Computed from data in Energy Information Administration, *Financial Statistics of Selected Investor-Owned Electric Utilities 1990*, DOE/EIA-0437(90)/1, and *Financial Statistics of Selected Publicly Owned Utilities*, DOE/EIA-0437(90)/2 (Washington, DC, March 1992).

a State and local matter, and is not treated in this report.

Valuation Methods

Each of these programs, by itself, would act to reduce the cost of public power, compared with power provided by investor-owned utilities. As discussed in Chapter 2, there are three ways to go beyond budget outlays in measuring the cost of the subsidies provided by Government enterprises:

- **Interest rate subsidy.** One element of Federal aid to public power is through low-cost credit. Rural cooperatives receive REA loans, while Federal utilities receive appropriations to be repaid at the 30-year treasury rate. Publicly owned utilities receive funding through tax-exempt municipal bonds. The magnitude of the subsidy can be computed by comparing the actual interest rate paid for credit with market interest rates.

- **Market prices.** If well-functioning markets exist, then market prices can be observed directly. If public power agencies sell power at below-market prices, then the value of the subsidy is the difference between the revenues that would be earned selling electricity at the market price and the actual revenues of the agency, less an adjustment for the effect of the subsidy on market prices.[96]

- **Historic cost basis.** However, well-functioning markets do not always exist. The predominant theory that U.S. regulators use to determine the "right" price for electricity is to set prices so as to provide a market-based return on the historical cost of the assets employed.[97] Thus, if sales of services provided by Government-owned assets provide a below-market return on the assets, this would be a subsidy, since the electricity is being sold below "cost."

Table 14 summarizes this report's computation of the cost of the different types of public power subsidies using the three valuation methods described above, plus the budget estimate drawn from Chapter 2. Federal utilities, cooperatives, and publicly owned utilities all receive interest rate subsidies. The sum of all interest rate subsidies to public power agencies is estimated at $2.8 billion to $4.0 billion in 1990, depending on the interest rate chosen. The computation of this estimate is described in the next section.

Federal utilities receive an interest rate subsidy (estimated here at $0.8 billion to $1.2 billion in 1990), but this is an incomplete measure of the subsidy element in Federal power sales. More comprehensive measures would compare the market price of the electricity sold with the actual price (estimated subsidy $2.0 billion), or the full cost of providing electricity compared to the actual price (estimated subsidy $4.2 billion). These different methods are *not* additive. They are detailed in the following sections.

Subsidies to Public Power

Federal Power Sales

Background. The U.S. Government first began to build dams during World War I to supply electric power for the munitions industry. During the depression, the Government began funding large-scale construction of hydroelectric plants on public lands, and set up agencies to sell the power wholesale. The best known of these agencies was the Tennessee Valley Authority, which was set up with a broader charter than subsequent agencies.

The enabling legislation for all of the power marketing administrations is similar. The text below is taken from the law authorizing construction of one of the Alaska Power Administration dams:

[96]A cessation of low-priced Federal power sales might reduce overall electricity prices. The benefits of below-market Federal power sales are concentrated on a relatively small group of customers. If Federal utilities began to auction power, the result would be much higher prices (assuming costs are passed on to final consumers) for the previously favored group, who would consequently reduce their electricity consumption. This would make additional electricity available for sale to IOUs, who would not buy additional power unless it was cheaper than their existing sources, thus reducing overall market prices. The result is that Federal utilities would, in principle, sell their electricity at higher prices than previously, but not as high as the pre-existing market price.

[97]cf. Sanford V. Berg and John Tschirhart, *Natural Monopoly Regulation: Principles and Practice* (New York, NY: Cambridge University Press, 1988), pp. 291-307. As this source points out, the definition of allowable costs, the valuation of the regulated firm's capital, and the definition of a "fair" rate of return have all proven to be enduringly ambiguous and controversial.

Table 14. Estimates of Annual Subsidy in Federal Support to Public Power Using Alternative Valuation Methods
(Million Dollars)

Type of Subsidy	Federal Net Outlays	Interest Rate Subsidy Only		Subsidy at Estimated Market Price of Electricity	Subsidy at Historic Cost with Full Cost Recovery
		Valued at Federal 30-year Bond Rate	Valued at Investor-Owned Utility Rate		
Federal Utility Electricity Sales . .	1,280	837	1,160	2,026	4,192
Rural Electrification Loans	44	809	1,140	NA	NA
Tax-Exempt Bond Interest for Publicly Owned Utilities	0	1,112	1,680	NA	NA
Total	**1,326**	**2,758**	**3,980**	**NA**	**NA**

NA=Not applicable. This method is not applicable to this program.

Notes: Federal 30-year bond rate is 8.55 percent, and IOU long-term rate is 9.4 percent in 1990. Historic cost method assumes 15 percent operating return on utility assets (equal to IOU rate in 1990). Federal net outlay data refer to FY 1992. Other estimates are calculated for 1990, the most recent year for which comparable financial data is available for all utilities of interest.

Source: Computations described in this chapter and in Chapter 2.

> Electric power . . . generated . . . shall be disposed by the Secretary . . . in such a manner as to encourage the most widespread use thereof at the lowest possible rates to consumers consistent with sound business principles. Rate schedules shall be drawn having regard to recovery of the costs of producing and transmitting the power and energy, including the amortization of the capital investment over a reasonable period of years, with interest at the average rate . . . paid by the United States on its marketable long-term securities outstanding on the date of this Act . . . . In the sale of such power . . ., preference shall be given to Federal Agencies, public bodies, and cooperatives.[98]

As these clauses have been interpreted, each Federally owned PMA has established a "debt" to the Treasury in the amount of Federal money appropriated for each dam. In principle, electricity sales rates have been set at a level sufficient to recover "interest" on the debt in the amount of the long-term Treasury rate prevailing at the time that funds were appropriated. Since most dams were built between 1935 and 1965, average interest rates are often very low compared with today's rates. In practice, appropriations for specific projects and administrative decisions by the Executive Branch frequently mandated interest rates that were actually much lower than market rates.[99]

PMAs are not generally required to amortize their loans on a schedule. Loans are amortized in irregular amounts, larger when cash flow is strong, smaller or nonexistent if cash flow diminishes.[100] In practice, however, PMAs have tended not to amortize their loans. This practice has kept old, low-interest debt on their balance sheets decades after it would normally have been amortized.

Federal utilities have also limited accounting costs by establishing lengthy estimated service lives for utility plant and equipment, which reduces expenses and multiplies the impact of inflation on assets valued at historical costs. The Bonneville Power Administration depreciates transmission assets over 45 years, and generation assets over 85 years. The Western Area Power Administration uses 64- to 93-year lives.[101]

[98]Flood Control Act of 1962, Section 204. Quoted from Alaska Power Administration, *Divestiture Summary Report: Sale of Eklutna and Snettisham Hydroelectric Projects* (April 1992).

[99]This history is detailed for the Bonneville Power Administration in David Shapiro, *Generating Failure: Public Power Policy in the Northwest* (Lanham, MD: University Press of America, 1989), pp. 60-65. For example, Bonneville was receiving Federal appropriations for certain long-construction-time projects at 2.5 percent interest as recently as 1975. This helps produce low average interest rates: the average rate paid by the Western Area Power Administration on its debt in 1990 was 4.8 percent, while the Southwestern Power Administration paid 2.4 percent. (See "A Note on Data Sources" at the end of this chapter).

[100]The FY 1993 budget request sets fixed amortization schedules for Federal Power Marketing Administrations.

[101]Bonneville Power Administration, *1989 Financial Summary*, p. 30. Western Area Power Administration, *1990 Annual Report*, p. 33.

With the price fixed "at the lowest possible rate," the enabling legislation also specifies priorities for allocation: Federal agencies, publicly owned utilities, and rural electric cooperatives. Federal utilities sell about 20 percent of their power to ultimate consumers. The ultimate consumers, as noted above, are usually bulk purchasers.

Table 15 lists electricity sales and revenues per kilowatthour of the Federal utilities. There is a large variation in prices across utilities. While the Southeastern, Southwestern, and Western Area Power Administrations sell power for resale at less than 20 mills (2 cents) per kilowatthour, Bonneville Power Administration sells power at 23 mills, and the Tennessee Valley Authority sells power at 44 mills per kilowatthour.[102]

Table 16 lists net utility assets, long-term debt, and interest paid by the Federal utilities. The dams producing the power are often multipurpose power generation, flood control, and irrigation dams. The

Table 15. Electricity Sales and Unit Revenues for Federal Utilities, 1990

Federal Utility	Electricity Sold to Ultimate Consumers (billion kWh)	Ultimate Consumer Revenue (cents/kWh)	Electricity Sold for Resale (billion kWh)	Sales for Resale Revenue (cents/kWh)	Power Purchase Costs (cents/kWh)
Alaska Power Administration	0.0	1.60	0.4	2.21	NA
Bonneville Power Administration	28.3	2.26	56.4	2.27	1.60
Southeastern Power Administration	0.0	NA	8.6	1.58	2.96
Southwestern Power Administration	0.0	NA	6.7	1.29	4.20
Western Area Power Administration	6.4	1.45	28.0	1.51	1.92
Tennessee Valley Authority	19.5	4.71	95.4	4.42	12.99
Others	0.5	3.53	0.1	0.72	2.81
Total	**54.7**	**3.07**	**195.7**	**3.18**	**2.92**

kWh = kilowatthour.
NA = Not available. Prices not available since no transactions took place.
Source: Form EIA-861, "Annual Utility Report," and other sources cited in Table 13.

Table 16. Assets, Long-Term Debt, Interest Paid, and Financial Ratios for Federal Utilities, 1990

Federal Utility	Net Utility Assets	Long-Term Debt	Interest Paid	Average Interest Rate	Ratio of Debt to Utility Assets	Ratio of Utility Assets to Electricity Sales
	(million dollars)			(percent)		(dollars/kWh sold)
Alaska Power Administration	103.8	102.0	3.0	2.9	98.2	0.24
Bonneville Power Administration	14,322.1	14,964.6	686.0	4.5	104.5	0.17
Southeastern Power Administration	1,449.4	1,457.4	113.6	7.8	100.6	0.13
Southwestern Power Administration	814.1	818.9	19.7	2.4	99.4	0.11
Western Area Power Administration	4,202.5	2,818.6	136.3	4.8	67.1	0.12
Tennessee Valley Authority	22,907.3	18,805.0	1,599.2	8.5	82.1	0.19
Others	36.7	9.6	0.0	NA	25.1	0.06
Total Federal Utilities	**43,835.9**	**38,979.1**	**2,557.8**	**6.6**	**88.9**	**0.17**

NA = Not available. Interest rate not available because no interest payments were reported.
Note: Federal appropriations are treated as long-term debt and interest payments on Federal appropriations as interest on debt.
Source: Form EIA-861, "Annual Utility Report," and sources cited in Table 13.

[102]Most of the power administrations also buy power. Except for the Western Area Power Authority, the amounts purchased are very small. The Western Area Power Administration generates hydropower in drought-stricken California. After a string of poor hydro years, it has begun buying bulk power to fulfill its long-term firm power contracts.

assets listed are the prorated "electricity" share of these assets, as computed by the Federal utilities themselves.[103]

There is a large concentration of utility plant debt in the hands of the Bonneville Power Administration (BPA) and the Tennessee Valley Authority (TVA). This concentration is mirrored in the ratio of assets to electricity sales, in which the tiny Alaska Power Administration, BPA, and TVA head the list. The other Federal utilities have much lower ratios of assets per kilowatthour sold. This ratio is a measure of the depreciated historic cost of the assets required by each Federal utility to produce the electricity it sells.

Through the Federal utilities, the Government builds, owns, and operates certain capital assets: dams; hydroelectric, coal, and nuclear power plants; and transmission lines. These assets produce a valuable marketable product: electricity. There are four ways of computing the subsidies associated with the sale of this product: budget cost, as an interest rate subsidy, by comparison with market prices, and at historical cost.

Budget cost. This approach is described in detail in Chapter 2, and the relevant budget figures are shown on Table 1. FY 1992 outlays for the TVA and the PMAs exceeded receipts by $802 million. Outlays for the capital costs of new hydroelectric projects by the Army Corps of Engineers and the Bureau of Reclamation total $560 million. The total budget cost, or the amount by which outlays exceed receipts, is $1.36 billion.

Interest rate subsidy. The interest rate subsidy approach argues that Federal utility prices are low because they are cost-based prices that are subsidized through low-priced credit. The subsidy inherent in this credit can be computed by calculating how large the interest charge would be if the Federal utilities had to pay a market rate of interest. This method runs afoul of the difficulty in determining the appropriate "market" rate of interest. This is a complicated issue for which no single answer would command universal assent.[104]

The size of the subsidy is a function of the interest rate chosen. Table 17 illustrates a computation of Federal utility interest subsidies by making two alternative assumptions: the first assumption is that the appropriate "unsubsidized rate," for comparison with the rate actually paid, is the 1990 average Federal long-term bond rate: 8.55 percent. The alternative approach presumes that if the Federal utilities are quasi-independent entities, then the unsubsidized rate is a "private-sector" borrowing rate that includes an allowance for default risk. In this case, it is the rate paid by investor-owned utilities: 9.4 percent. The total amount of the subsidy is the difference between actual Federal utility interest payments and the amount they would have paid at the higher interest rates: $0.8 billion at the Federal rate, or $1.2 billion if the investor-owned utility rate is the standard for comparison.

TVA's share is relatively small, because it pays near-market interest rates on its recently acquired debt. BPA's share is larger, in part because much of its recently acquired debt is actually low-rate tax-exempt debt of the Washington Public Power Supply System (WPPSS), which will be discussed in more detail below.

Figure 14 illustrates the relationship between the size of the interest rate subsidy, measured in cents per kilowatthour of electricity sold, and the unsubsidized interest rate chosen.

[103]The Bonneville and Western Area Power Administrations are required by statute to use power revenues to repay the Treasury for costs of certain water projects "that are determined to be beyond the ability of irrigation water users to repay." Bonneville estimates that the undiscounted future costs of such repayments is $813 million, while the Western Area Power Administration estimates cumulative undiscounted future costs at $1.4 billion. See: Western Area Power Administration, *1990 Annual Report*, p. 34, and Bonneville Power Administration, *1989 Financial Summary*, p. 34. These repayments are treated as a disposition of net income (akin to a dividend), rather than as an expense item, and consequently are not directly included in any of the computations in this chapter, save that they are included in the current actual price charged to PMA customers. In these cases, electricity revenues are used to cross-subsidize water sales in these agencies.

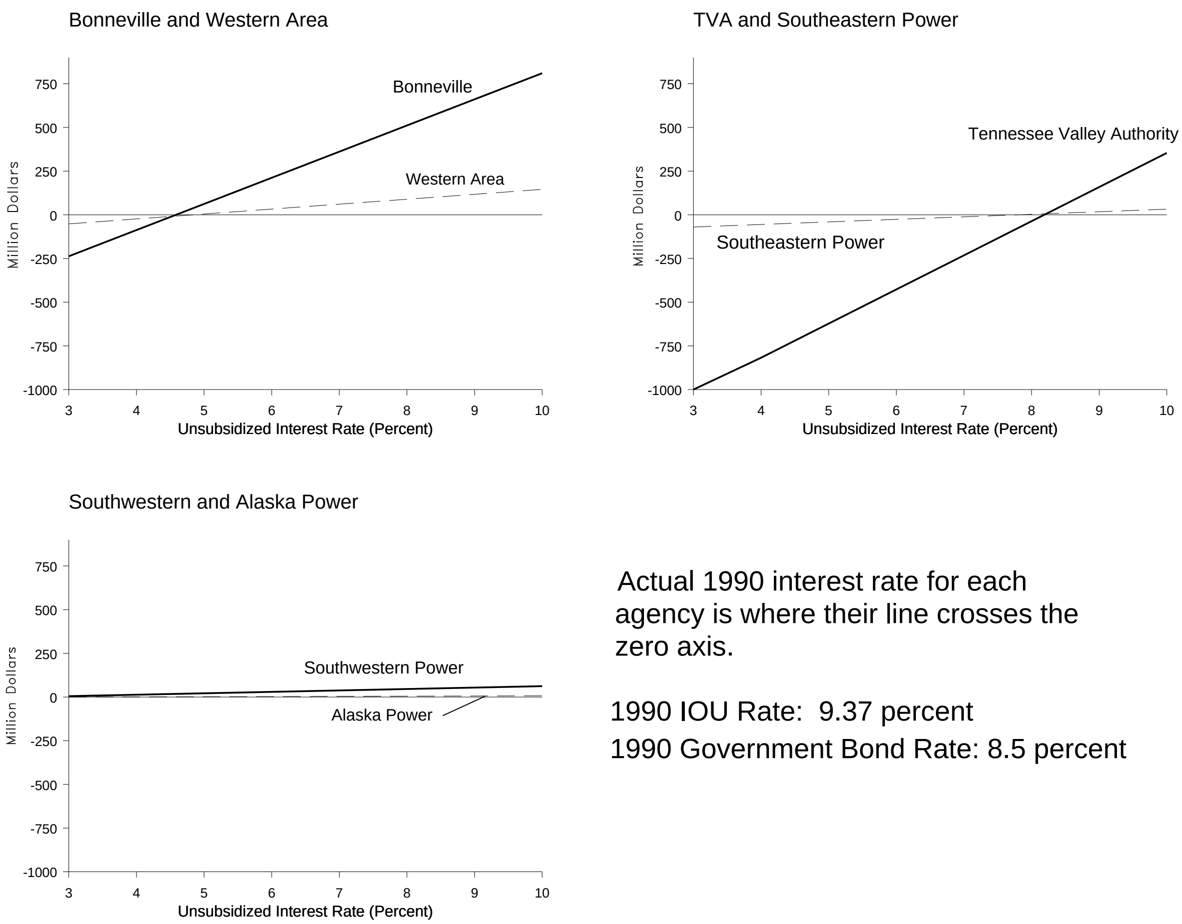
[104]The Congressional Budget Office and OMB have agreed to use the current 30-year bond rate as the appropriate rate of interest for evaluating subsidies. Another issue is that average interest rates for all utilities are based on a portfolio of debt, borrowed at different times and varying rates, depending on market conditions and the utility's creditworthiness at the time of issue. Thus, a more detailed computation of interest subsidies would compare the actual interest rate on each bond issue with a comparable "market" rate (by whatever definition), producing average unsubsidized interest as the sum of unsubsidized interest on all bond issues. In this case, there would not be any particular subsidy element in 3-percent, 30-year money borrowed in 1937, if that was the market rate prevailing at the time. This approach, while theoretically more accurate, is computationally unmanageable for the purposes of this study. Further, in a market environment, many of the oldest and lowest interest loans would have been amortized years ago, and failure to do so reflects a deliberate policy choice to reduce electric rates. The method chosen, while imperfect, gives a manageable first approximation of the subsidy level, is easy to understand, and is not computationally burdensome.

Table 17. Computation of Subsidy Element in Interest Payments by Federal Utilities, 1990
(Million Dollars)

Federal Utility	Actual Interest Payment	Hypothetical Payment (Investor-Owned Utility Rate)	Estimated Subsidy (IOU Rate)	Hypothetical Payment (Government Bond Rate)	Estimated Subsidy (Government Bond Rate)
Alaska Power Administration	3.0	9.6	6.6	8.7	5.7
Bonneville Power Administration	686.0	1,402.2	716.2	1,279.5	593.5
Southeastern Power Administration	113.6	136.6	23.0	124.6	11.0
Southwestern Power Administration	19.7	76.7	57.0	70.0	50.3
Western Area Power Administration	136.3	264.1	127.8	241.0	104.7
Tennessee Valley Authority	1,599.2	1,830.3	231.1	1,670.0	70.9
Others	0.0	0.9	0.9	0.8	0.8
Total Federal Utilities	**2,557.8**	**3,720.3**	**1,162.6**	**3,394.7**	**837.0**

Source: Form EIA-861, "Annual Utility Report," and sources cited in Table 13.

Figure 14. Estimated 1990 Interest Rate Subsidy to Federal Utilities as a Function of the Estimated Unsubsidized Interest Rate



Source: Computed based on values shown in Tables 16 and 17.

Market-price approach. Defining the subsidy provided by Federal utilities as an interest rate subsidy is equivalent to viewing the Federal utilities as quasi-independent bodies that receive low-cost financing from the Government. However, in fact, Federal utilities are Government bodies, and interest subsidies are only part of the picture. An alternative method of measuring the subsidy would be to argue that Federal utilities actually face wholesale power markets in which multiple buyers and sellers determine market prices through competition.[105] Hence, one can actually observe market prices for bulk electricity by examining the price at which investor-owned utilities buy and sell bulk power in the regions in which the Federal utilities operate.

This approach recognizes that the U.S. Government may own assets (in this case, power plants) of various costs and vintages, financed at various dates and by various methods, all of which produce a common product: electricity. This approach focuses attention on the market value of the power produced, rather than on the historic cost of building the facilities used to produce the power. Cost-based computations are most useful when there is no market price available.

Table 18 illustrates prices paid and received for electricity by investor-owned utilities in regions where Federal utilities operate. The prices shown in this table can only be considered crude and approximate guides to actual market prices.[106] As in the case of the interest computations, the calculated value of the subsidy will depend on the assessment of market price for the electricity. It would be difficult to determine actual market prices without a market experiment: for example, a power auction. Actual market prices would doubtless vary from those shown. Table 18 illustrates how actual transaction prices might compare with the prices currently charged by Federal utilities.

Table 18. Average Electricity Sold for Resale and Purchased Power Price for Selected Investor-Owned Utilities Compared to PMA Prices, 1990
(Cents per Kilowatthour)

Federal Utility	Nearby Investor-Owned Utilities (IOUs)	Nearby IOU Wholesale Electricity Prices: (Selling-Buying)	PMA Actual Wholesale Electricity Selling Price	PMA Estimated Market Price Used for Computation
Alaska Power Administration	NA	NA	2.2	4.0
Bonneville Power Administration	Pacificorp, Puget Sound P&L, Portland GEC, Washington WPC, Idaho P&L, Montana Power	2.9-1.6	2.2	2.5
Southeastern Power Administration	Duke Power, Georgia Power, SCGC, Carolina P&L	3.8-7.0	1.5	4.0
Southwestern Power Administration	Arkansas P&L, OK G&E, PSC OK, KS P&L, KS G&E, Centel, KC P&L, Empire, Union, UtiliCorp	2.8-4.6	1.2	4.0
Western Area Power Administration	PG&E, SCE, San Diego, Arizona PSC, Tucson, Century	5.0-6.2	1.5	5.0
Tennessee Valley Authority	Louisville G&E, KY Power, KY Utilities, Alabama, Duke, Georgia, SCGC, Carolina P&L	3.7-6.0	4.3	4.5
Others	NA	NA	0.7	NA

NA = Not available. There is no comparable investor-owned utility.
Source: Form EIA-861, “Annual Utility Report,” and sources cited in Table 13.

[105]The Federal utilities, by building regional transmission grids, have actually helped to create these markets.

[106]The prices shown on the table are averages blending a multitude of different types of transactions, including high value sales of firm power under long-term contracts, spot sales of electricity (which could conceivably have prices much higher or lower than long-term contract prices), and purchases of cogeneration power at “avoided cost” under PURPA. Most sales are structured as a combination of a “capacity charge” which defines the cost per peak kilowatt drawn, and a usage charge on each kilowatthour used. Table 19 combines the two charges.

The final column in Table 18 indicates the estimated market prices chosen as a means of actually computing a value for the subsidy element in Federal power sales. The prices are based on actual investor-owned utility prices.[107] There is some risk that the estimated market price for the Bonneville Power Administration (2.5 cents per kilowatthour) may be understated. Low-priced power purchases by investor-owned utilities near the Bonneville Power Administration may actually reflect purchases from BPA or Canada, or exchanges with BPA under BPA's residential exchange program.[108]

Table 19 describes the results of applying these prices to the electricity sales of the Federal utilities. The first column shows the actual 1990 electricity sales revenues of the Federal utilities. The second column shows what the revenues would have been if the electricity had been sold at the estimated market prices shown in Table 18. The third column, which is the difference between the first and second columns, is the estimated value of revenue foregone by the Federal Government by selling electricity at a below-market price. The total amount is $2 billion, dominated by the Western Area Power Administration, with a subsidy value of $1.2 billion. Western Area produces power with assets that have a very low book value compared to the quantity of electricity sold (Table 16), and consequently sells its power at very low prices in a region where actual transaction prices tend to be much higher.

These numbers provide an upper bound for the subsidy estimate, assuming that Federal utilities are "small" participants in their respective markets, and that charging market prices for Federal electricity would not reduce aggregate electricity consumption and, consequently, regional market prices. If market prices were to decline, then the value of the subsidy would have be calculated on the basis of the post-decline price, rather than on the basis of the current price.

The extent to which market prices might decline is difficult to estimate. There are, however, good reasons to think that the effect on the subsidy estimate may not be significant. First, the demand for electricity is

Table 19. Computation of Federal Utility Electricity Subsidy on a Market Price Basis, 1990
(Million Dollars)

Federal Utility	Actual Revenues	Revenues at Estimated Market Prices	Estimated Subsidy	Subsidy per Unit Electricity Sold	Operating Return on Utility Assets at Market Price
	(million dollars)			(cents per kWh)	(percent)
Alaska Power Administration	9.6	17.4	7.8	1.8	13.1
Bonneville Power Administration	1,919.0	2,132.3	213.3	0.3	8.2
Southeastern Power Administration	136.6	352.8	216.2	2.5	29.5
Southwestern Power Administration	85.9	288.9	203.0	2.8	27.7
Western Area Power Administration	517.3	1,723.1	1,205.8	3.5	31.9
Tennessee Valley Authority	5,133.7	5,313.9	180.2	0.2	6.1
Others	27.9	27.9	0.0	0.0	6.1
Total	**7,830.0**	**9,856.3**	**2,026.4**	**0.8**	**10.3**

kWh = kilowatthour.
Source: Form EIA-861, "Annual Utility Report," and sources cited in Table 13.

[107]The prices were selected as a round number close to the lower limit of the observed range of IOU prices in each region. There are no suitable Alaskan investor-owned utilities that can be used to determine comparable prices for the Alaska Power Administration. For Alaska, we have chosen 40 mills per kilowatthour as being a typical cost for the fossil power plant electricity and, consequently, a typical price for industrial and resale power sales in the "Lower 48" States.

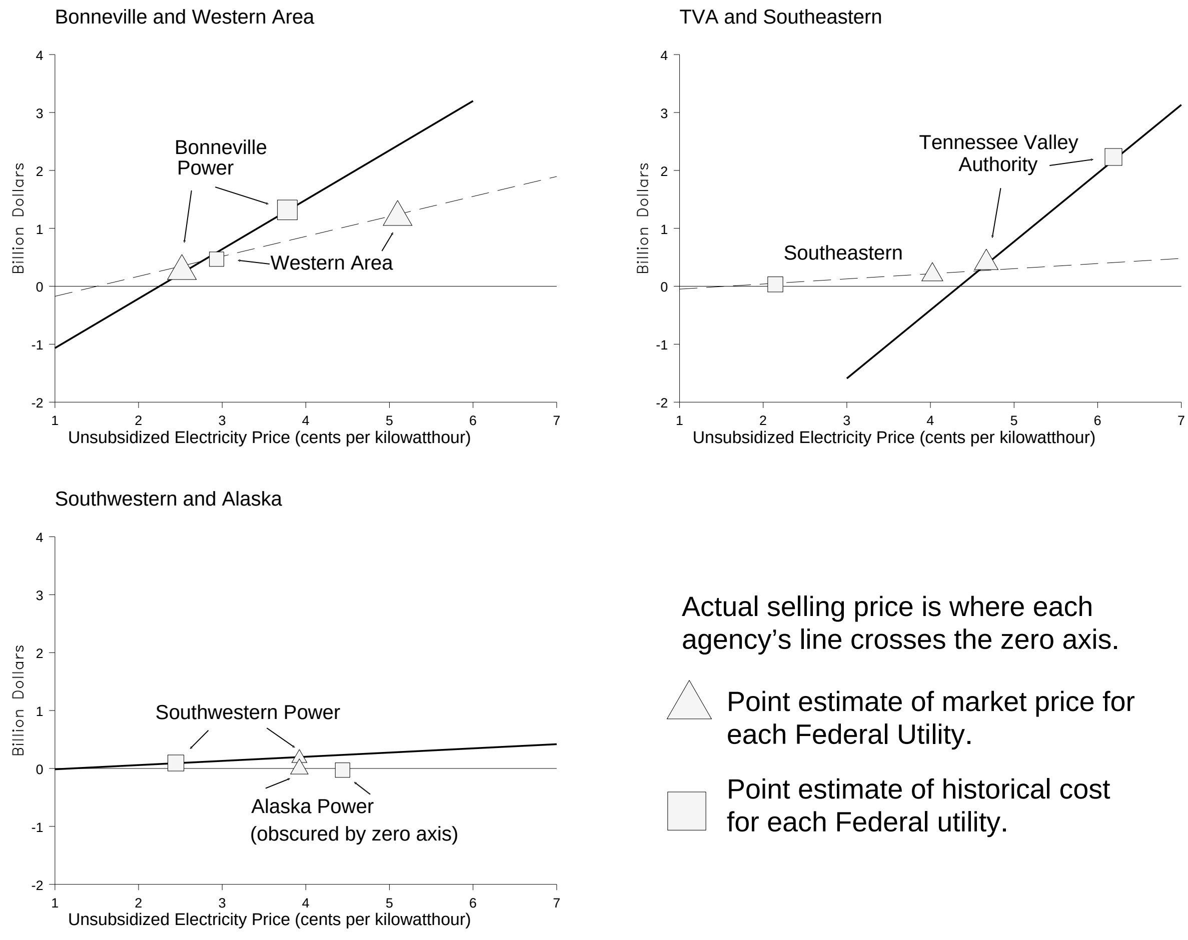
[108]The residential exchange program was created by the Pacific Northwest Electric Power Planning and Conservation Act of 1980, in order to spread the benefits of low-cost power to rural consumers served by investor-owned utilities. Under this program, Bonneville sells cheap electricity to investor-owned utilities in the region, and buys back an identical amount of expensive electricity. The investor-owned utility rates are supposed to pass on the savings to their customers. This program costs BPA $150 million to $200 million per year, which is recovered by raising rates to all customers. See Bonneville Power Administration, *Annual Report 1990*, p. 30, and U.S. General Accounting Office, *Federal Electric Power: Bonneville's Residential Exchange Program*, GAO/RCED-90-34 (Washington, DC, February 1990).

relatively inelastic.[109] This implies that large price changes produce much smaller changes in consumption. Further, Federal utilities' sales account for only a portion of total electricity sales in their region.

Federal utilities can be divided into three groups. In the first group, the TVA supplies about 50 percent of the power sold in its North American Electric Reliability Council (NERC) regions, while Bonneville supplies 17 percent of the power in its region.[110] They are large sellers in their regions, but have prices that are already close to market rates. Market-based pricing might not produce noticeable declines in overall market prices. The second group, comprising the Alaska, Southeastern and Southwestern Power Administrations, are minor producers in their respective regions. Their pricing policies probably do not affect regional market prices. Finally, the Western Area Power Administration has both low prices and a significant presence (7 percent of sales in its NERC region). Thus, the probability of significant price effects, and hence an overestimate of the subsidy, is greatest for the Western Area Power Administration.

The prices used in this subsidy computation are rough estimates, based on a wide range of prices actually observed in the areas served by the Federal utilities. Figure 15 illustrates the computation of subsidy for the

Figure 15. Estimated 1990 Subsidy for the Federal Utilities as a Function of the Unsubsidized Electricity Price



Source: Computed based on values shown in Tables 19 and 29.

[109]The classic survey of the literature is Douglas Bohi, *Analyzing Demand Behavior: A Study of Energy Elasticities* (Baltimore, MD: Resources for the Future, 1981). Bohi's survey found short-run price elasticity estimates for residential electricity consumption ranging from -0.03 to -0.54, and long-run estimates from -0.46 to -2 (pp. 57-59).

[110]These computations are based on Federal utility sales data in Table 15, and regional electricity sales by North American Electric Reliability Council (NERC) region from Energy Information Administration, *Electric Power Annual 1990*, DOE/EIA-0348(90) (Washington, DC, January 1992), p. 86. TVA's regions are SERC and ECAR, while Bonneville and Western's region is WSCC.

principal Federal utilities as a function of the estimated price of electricity. The price concept used in Figure 15 is the Federal utility's overall average price, encompassing both sales for resale and sales to end users. Figure 15 also indicates prices required to recover the historical cost of Federal investments in the Federal utilities and a market-related rate of return, to be discussed in the next section.

The final column in Table 19 computes the operating rate of return on utility assets employed by the various Federal utilities, and helps to explain the distribution of subsidies. The variation in returns highlights an important difference between market-related pricing and regulatory cost-related pricing. In market pricing, the historical cost of assets does not matter. Several PMAs (Western Area, Southeastern, and Southwestern) have relatively old assets with low book values, supported by relatively low-interest debt. Consequently, the market value of the power they produce is much higher than the historical cost-based price that they actually charge for it. If they computed costs based on market interest rates, they would charge higher prices, but prices that would still be considerably lower than the market value of their electricity. Consequently, the subsidy provided to their customers is very large. On the other hand, the cost-based prices Bonneville Power Administration and the TVA charge appear to be very close to this report's estimate of market prices, even with the interest subsidy. Consequently, the subsidy provided to their customers appears to be small or nonexistent.

The concentration of assets and debt cause the relatively high prices charged by Bonneville Power and the TVA. In both cases, the utility plant and the debt were accumulated while pursuing large-scale nuclear power programs. The Bonneville Power Administration guaranteed much of the debt of the Washington Public Power Supply System (WPPSS), owned by a group of municipal utilities in Washington State. When WPPSS defaulted on its debts in 1982, BPA acquired its assets, comprising three partially completed nuclear power plants and some small hydro plants with a current (1990) book value of $6.9 billion, along with some $6.8 billion of municipal debt.[111] One nuclear plant (WNP-2) was ultimately completed, while completion of the other two (WNP-1 and WNP-3) has been indefinitely deferred.[112] Bonneville carries more than $2 billion in assets for the deferred plants on its books, depreciates them, and repays the debt. The added costs of WPPSS have quadrupled Bonneville's prices over the past 10 years, raising them from 5 mills per kilowatthour in the late 1970's to over 20 mills today.[113]

During the 1950's, the Tennessee Valley Authority moved from building dams to building coal-fired power plants. In 1966, TVA launched what became the largest nuclear power program in the United States, starting construction of nine nuclear power plants. Two of these plants were deferred, two are still under construction, three have been shut down for safety reasons, and two are currently operational. Nearly half of the value of TVA's utility plant is in nuclear assets.[114] Unlike the dams, these projects were largely funded during the 1970's and 1980's when interest rates were relatively high, and interest charges have been passed on to TVA's customers.

Historical cost approach. A typical textbook definition of cost for a private-sector electric utility would be operating cost plus depreciation of capital assets plus some allowance for cost of capital.[115] To the extent that actual Federal utility electricity prices fail to recover "cost," they would be a subsidy to the purchaser, with the amount of the subsidy equal to the difference between revenues sufficient to recover costs, and revenues at the actual selling price.

Measuring operating costs and depreciation is straightforward, as the relevant information can be extracted from Federal utility financial statements. However, deciding what the "unsubsidized" rate of return on assets for a Federal utility ought to be is not so obvious. This report uses a simplified measure of comparative financial performance, using operating rates of return (net income before interest and taxes

[111]Bonneville Power Administration, *Annual Report 1991*, pp. 26-32. WPPSS began construction of five nuclear plants in the mid-1970's. The projects were beset with cost overruns, schedule delays, and mudslides. Bonneville did not guarantee debt issued to pay for two plants (WNP-4 and WNP-5), and bondholders lost their investments on these plants.

[112]A history of the WPPSS can be found in D. Victor Anderson, *Illusions of Power: A History of the Washington Public Power Supply System* (New York, NY: Praeger, 1985).

[113]Bonneville Power Administration, *1989 Financial Summary*, p. 2.

[114]TVA's annual report is not very informative. For more detailed financial information, see U.S. General Accounting Office, *Financial Audit: Tennessee Valley Authority's Financial Statements for 1987*, GAO/AFMD-88-80 (Washington, DC, September 1988).

[115]cf. Sanford V. Berg and John Tschirhart, *Natural Monopoly Regulation: Principles and Practice* (New York, NY: Cambridge University Press, 1988), pp. 297-307.

divided by net utility assets) of 15.3 percent.[116] This is the rate earned by investor-owned utilities in 1990. Federal utilities as a group actually earned a 5.6-percent operating rate of return in 1990.

Generating revenues sufficient to earn a 15-percent operating return for Federal utilities would require that their average prices rise by 53 percent, implying a revenue increase of $4.2 billion. The required revenue increase is more than double the market-price-based estimate presented in the previous section (Table 20 compared to Table 19). The distribution of the cost-based subsidy varies greatly across Federal utilities. On a historical cost basis, the TVA and Bonneville provide the largest subsidies, with estimated values of $2.3 billion and $1.2 billion, respectively. The TVA's subsidy on a cost basis is 10 times larger than its subsidy on a market-price basis (compare Table 19 and 20). On the other hand, the Western Area Power Administration has an estimated subsidy value of only $0.5 billion: less than half of its estimate based on market prices.

The problem with the historic cost approach is that cost-based prices can be either much higher or much lower than the agency could actually recover in the marketplace. The TVA, for example, would have to sell its power at an average price of 6.2 cents per kilowatthour (Figure 15). It is unlikely that the TVA would actually be able to sell wholesale electricity at 6 cents per kilowatthour. TVA's customers would find less expensive alternatives, including generating their own power or contracting with independent power producers.

On the other hand, historic cost-based prices for some of the smaller PMAs are still much lower than they could recover in the market place. The Southeastern Power Administration, whose territory adjoins the TVA, could make its 15-percent return by selling power for 3 cents per kilowatthour. Yet TVA just breaks even while selling bulk power for 4.4 cents per kilowatthour. The decision to forego revenues by selling electricity at below-market prices would still create a subsidy, even if the smaller PMAs were earning market returns.

Access to Rural Electrification Administration Credits

Background. The Rural Electrification Administration (REA) was established in the late 1930's to help provide electricity to rural areas where costs were high and service density was low. Residents of rural areas were invited to form electrification cooperatives, owned by their members, and offered the opportunity to buy low-cost bulk power from newly built Federal dams. They were also offered long-term loans at a 2-percent interest rate. This rate approximated the market rate for long-term Government debt at the inception of the program, but as inflation and interest rates rose during and after

Table 20. Computation of Federal Utility Electricity Subsidy on a Historical Cost Basis, 1990
(Million Dollars)

Federal Utility	Actual Revenues	Revenues to Recover Historical Costs	Estimated Subsidy	Subsidy per Unit Electricity Sold	Operating Return on Utility Assets at Prices to Recover Cost of Capital
	(million dollars)			(cents per kWh)	(percent)
Alaska Power Administration	9.6	19.7	10.1	2.3	15.3
Bonneville Power Administration	1,919.0	3,151.5	1,232.5	1.4	15.3
Southeastern Power Administration	136.6	190.5	53.9	0.6	15.3
Southwestern Power Administration	85.9	187.6	101.7	1.4	15.3
Western Area Power Administration	517.3	1,022.8	505.5	1.5	15.3
Tennessee Valley Authority	5,133.7	7,419.5	2,285.7	1.9	15.3
Others	27.9	31.3	3.4	0.5	15.3
Total	**7,830.0**	**12,022.9**	**4,192.9**	**1.6**	**15.3**

Source: Form EIA-861, "Annual Utility Report," and sources cited in Table 13.

[116]The operating return on assets measure was chosen, rather than the more familiar net income or return on equity, in order to abstract from the differing role of debt in public-sector versus private-sector utilities. Public-sector utilities usually have debt that equals or exceeds their assets, and then set prices so that there is little or no net income remaining after interest payments.

World War II, it gradually came to incorporate a growing subsidy element. In 1973, the interest rate for new loans was raised to 5 percent, where it has remained. In 1990, there were 942 active cooperatives serving a total of about 11 million households.[117]

The electrification of the United States was essentially completed by the early 1950's. However, supplies of Federal electricity eventually proved inadequate to provide for the cooperatives' growing electricity demand. The REA helped launch a new type of cooperative: the electric power supply cooperative, often called "Generation and Transmission," or G&T cooperatives. G&T cooperatives are usually owned by a group of distribution cooperatives, and sell wholesale electricity back to their owners. G&T cooperatives rarely receive direct funding from the Rural Electrification Administration. Instead, the REA provides a loan guarantee, and the actual loan is usually provided by another U.S. Government agency, the Federal Financing Bank at an interest rate which approximates the current 30-year U.S. Government bond rate. Thus, most REA-guaranteed loans are actually made by the U.S. Government.

It is relatively rare for the G&T cooperatives to own 100 percent of a large generation plant. More typically, they own a minority interest in a plant that is built and operated by an investor-owned or publicly owned utility. In 1990, cooperatives owned some 30 gigawatts of capacity (about 5 percent of the U.S. total), including part-interests in 15 nuclear power plants totaling 3 gigawatts of capacity and 85 fossil steam plants with 24 gigawatts of capacity.[118]

In terms of finances, The G&T program has gradually come to dominate the whole REA program. The 884 active distribution cooperatives carry $13.6 billion of long-term debt, $10 billion of which has been advanced by the REA directly. The 58 G&T cooperatives carry $29.5 billion in long-term debt, of which $7.7 billion has been advanced directly by REA. Essentially all of the non-REA debt ($23.5 billion) has been guaranteed by the REA. The G&T cooperatives paid at an average interest rate of 7.3 percent, while distribution cooperatives paid an average rate of 5.3 percent.[119] While the default rate on REA direct loans is minuscule, a single G&T cooperative, the bankrupt Wabash Valley Power Association, defaulted on $1.1 billion in REA-guaranteed loans.[120]

A single G&T borrower, the Oglethorpe Power Corporation of Georgia, accounts for almost $4.4 billion in Federally guaranteed debt, funding minority interests in Georgia Power Corporation's Hatch nuclear plant and two large coal-fired plants. This cooperative accounts for 10 percent of all borrowing under REA authority. The eight largest G&T borrowers collectively account for more than $15 billion in REA or REA-guaranteed debt, more than a third of the total program.

In fiscal year 1990, the REA made $622 million in new electricity loans, all at a 5-percent interest rate. It guaranteed a further $72 million in Federal Financing Bank loans at the 30-year bond rate (circa 8.5 percent).[121] Measures of subsidy used by Office of Management and Budget are typically used to calculate the subsidy impact of these new loans made in a given fiscal year, using the appropriate Federal borrowing rate and expected default rate as a yardstick. Calculations of this nature do not clearly show the cumulative impact of decades of low-interest REA funding on electricity prices. A more general measure of this subsidy element would examine the balance sheet costs of REA and equivalent funding. In 1990, rural electric cooperatives owed some $43 billion in long-term debt, on which they paid an average interest rate of 6.7 percent (Table 21).

Interest rate subsidies. Since the REA program is a loan program, the Federal Government's program costs can be computed by calculating the difference between actual interest payments and the Government's

[117]U.S. Department of Agriculture, Rural Electrification Administration, *1990 Statistics Report, Rural Electric Borrowers*, IP 201-1 (Washington, DC, August 1991), pp. xiii and xvi.

[118]U.S. Department of Agriculture, Rural Electrification Administration, *1990 Statistical Report, Rural Electric Borrowers*, IP 200-1 (Washington, DC, August 1991), p. xx.

[119]Debt and interest rate information computed from U.S. Department of Agriculture, *1990 Statistical Report, Rural Electric Borrowers*, IP 201-1 (Washington, DC, August 1991).

[120]Wabash Valley owned a 17-percent interest in Northern Indiana Public Service Company's (NIPSCO) never-completed Marble Hill nuclear power plant. The Indiana State Public Utilities Commission refused permission for Wabash Valley to raise its rates sufficiently to repay its REA loans, and Wabash Valley consequently filed for bankruptcy. The Indiana PUC also refused permission to NIPSCO to include Marble Hill costs in its ratebase. The shareholders in investor-owned NIPSCO suffered the consequent loss. See Lori Burkhart, "The REA Versus the State PUCs," *Public Utilities Fortnightly*, Vol. 123, No. 12 (December 15, 1991), p. 31.

[121]U.S. Department of Agriculture, Rural Electrification Administration, *1990 Statistical Report, Rural Electric Borrowers*, IP 200-1 (Washington, DC, August 1991), p. xx.

Table 21. Assets, Long-Term Debt, Interest Payments, and Financial Ratios for Selected Publicly Owned, Investor-Owned, and Federal Utilities, 1990

Type of Utility	Net Utility Assets	Long-Term Debt	Interest Paid	Average Interest Rate	Ratio of Long-Term Debt to Utility Plant	Ratio of Utility Plant to kWh Sold
	(billion dollars)			(percent)		(dollars per kWh/year)
Investor-Owned Utilities	352.7	167.9	15.7	9.37	47.6	0.17
Publicly Owned Utilities	64.0	68.9	4.8	6.94	107.6	0.19
Rural Electric Cooperatives	43.8	43.1	2.9	6.67	99.2	0.22
G&T Cooperatives	(24.9)	(29.5)	(2.1)	7.29	118.1	0.10
Distribution Cooperatives	(19.0)	(13.6)	(0.7)	5.34	71.9	0.12
Federal Utilities	43.6	39.7	2.6	6.44	91.1	0.16
Total or Average	503.7	319.4	4.8	8.12	63.4	0.17

kWh = kilowatthour.

Note: Federal Appropriations of the power marketing administrations are included as long-term debt, and interest payments on Federal Appropriations are included as interest on debt. Also included are $6.8 billion of utility plant acquired by the Bonneville Power Administration from the Washington Public Power Supply System, $6.9 billion of WPPSS debt assumed by BPA, and $0.3 billion of interest payments on former WPPSS debt. Electricity sold measured as sales to ultimate consumers, except for Federal utilities and G&T cooperatives, measured as the sum of sales to ultimate consumers and sales for resale.

Source: Form EIA-861, "Annual Utility Report," and sources cited in Table 13.

borrowing rate on the REA's loan portfolio. Valuing REA loan guarantees is a largely theoretical issue, because, as noted above, most REA-guaranteed debt is also provided by the Federal Government. On the other hand, the default risk on REA lending to G&T cooperatives has moved from a theoretical possibility to actual financial loss, with the Wabash Valley default accounting for more than 3 percent of the value of loans to G&T cooperatives. Given that G&T cooperative debt is 99.2 percent of the value of cooperatives' utility assets, the possibility of future defaults cannot be ruled out.

These points would indicate that the cost of the REA program is actually higher than the Government's borrowing rate. This report uses two rates: the Government's 30-year borrowing rate (8.55 percent) and the average interest rate paid by investor-owned utilities (9.37 percent).

Rural cooperatives paid $2.9 billion in interest on long-term debt in 1990. If their debt had been incurred at the investor-owned utility rate, they would have paid $4.0 billion, a difference of $1.2 billion per year. If the difference between investor-owned utility rates and REC rates were averaged over cooperatives' sales to end-users, this subsidy is worth about 9 percent of sales, or about 6 mills per kilowatthour. If the Government long-term bond rate is used, the difference is $0.8 billion, equal to 6 percent of cooperatives revenues, or 4 mills per kilowatthour.

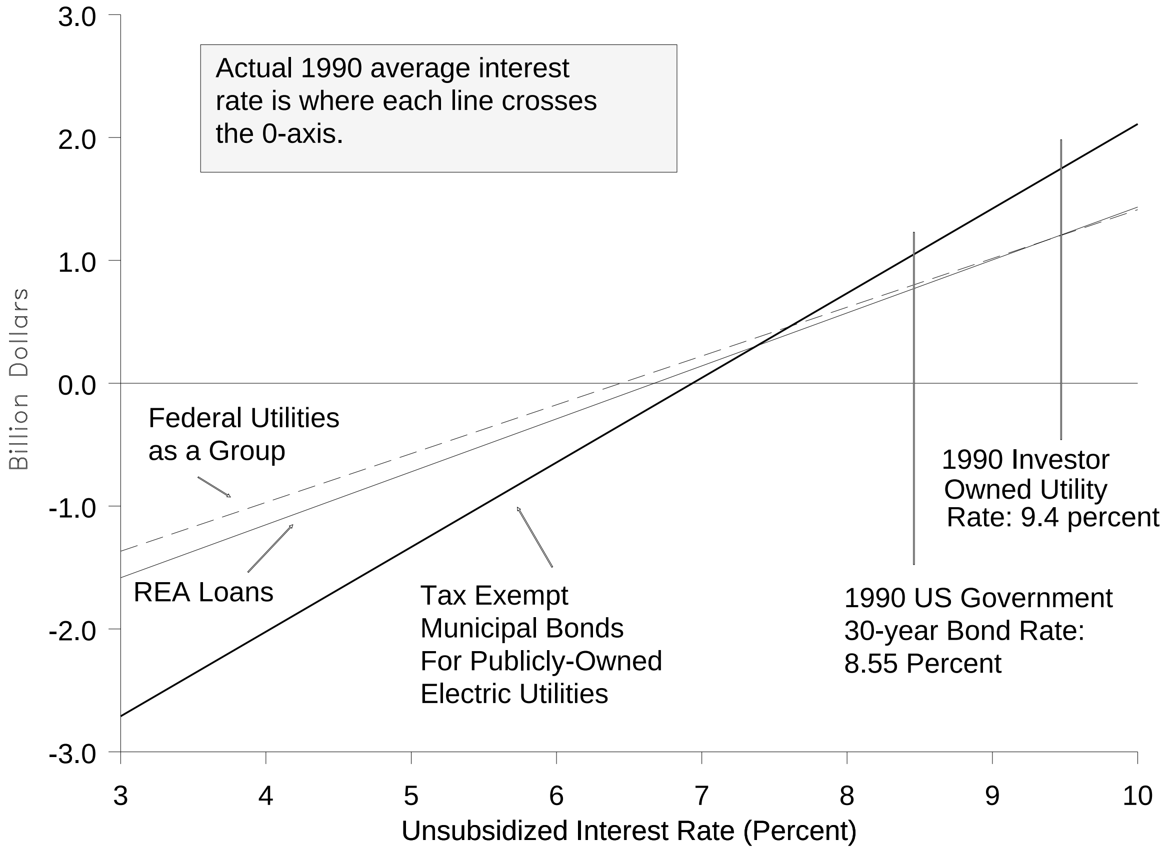
Views may differ on the appropriate unsubsidized rate of interest to compare with the interest rates paid by REA borrowers. Figure 16 illustrates the annual amount of subsidy for REA borrowers, Federal utilities as a group, and publicly owned utilities (treated in the following section) as a function of the interest rate chosen.

Publicly Owned Utilities' Access to Tax-Exempt Bonds

Background. While rural electric cooperatives gain direct access to low-interest funding through Federal loans and guarantees, publicly owned utilities receive low-interest funding through access to tax-exempt municipal bonds. Good quality municipal bonds typically command interest rates that are not only lower than the debt of investor-owned utilities, but lower than the borrowing costs of the U.S. Treasury.

The tax-exempt character of municipal bonds has been established for decades. However, when State and local governments engage in commercial enterprises, particularly capital-intensive enterprises such as electric power generation, access to tax-exempt financing gives Government enterprises a measurable cost advantage vis-a-vis their private-sector counterparts. This cost advantage is hardly unique to the electric power industry. It applies to other public services provided by State and local enterprise, ranging from public transit

Figure 16. 1990 Annual Interest Rate Subsidy for REA Borrowers, Federal Utilities, and Publicly Owned Utilities as a Function of Estimated Unsubsidized Interest Rates



Source: Computed based on values shown in Table 21.

to public water and sewerage. Thus, municipal bond interest exemptions are arguably not energy subsidies, since they are not specific to the energy industry. They are included here primarily because of the importance of the municipal bond exemption in providing lower cost electricity to a particular group of consumers, and because, due to institutional arrangements in the public sector, electricity and nonelectricity investments rarely compete directly for public-sector dollars.

Estimating the subsidy. From the point of view of the Federal Government, this phenomenon is really a form of tax expenditure. Unfortunately for the purposes of this report, the Office of Management and Budget does not separately compute tax expenditures for publicly owned utility bonds, lumping them together in a $14.8 billion category, "Public Purpose State and Local Debt."[122] There is no convenient mechanism for decomposing this expenditure.

However, a first approximation of the outlay equivalent value of this subsidy, as well as a measure of the benefit to the recipients, is the difference between interest rates paid by (nonexempt) investor-owned utilities and the actual rates paid by publicly owned utilities. Publicly owned electric utilities had some $69

[122] Office of Management and Budget, *Budget of the United States Government, Fiscal Year 1993* (Washington, DC, February 1992), Part 2, p. 28.

billion in long-term debt outstanding as of 1990.[123] Their interest payments totaled $4.8 billion, or an average interest rate of 6.9 percent. If these funds were borrowed at the same rate paid by investor-owned utilities (9.4 percent), interest costs would rise to $6.4 billion, an increase of $1.7 billion. Figure 16 illustrates the effect of alternative interest rates on this computation. This would be equivalent to about 11 percent of the revenues of publicly owned utilities, or about 6 mills per kilowatthour.

A Note on Data Sources

Comparable financial data on public power agencies is not easily obtained. The primary data source for this chapter is data collected on Form EIA-861, "Annual Electric Utility Report," Form EIA-412, "Annual Report of Public Electric Utilities," and FERC Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others." Data for IOUs and Publicly Owned Utilities for 1990 from these forms are published in two annual Energy Information Administration reports, *Financial Statistics of Selected Investor-Owned Utilities*, DOE/EIA-0437(90)/1 (Washington, DC, January 1992), and *Financial Statistics of Selected Publicly Owned Electric Utilities*, DOE/EIA-0437(90)/2). The data in these reports create certain ambiguities which detail-oriented readers should note:

- EIA publishes data only for "selected" investor-owned utilities. EIA identified 267 IOUs as of 1990; however, only 182 were sufficiently large to be required to file a FERC Form 1. The 182 "selected" utilities account for 99 percent of the electricity sold by IOUs to ultimate consumers, so the data lost by ignoring the missing 85 small IOUs are not of great importance. IOU data are on a calendar-year basis.

- Similarly, EIA publishes data only for "selected" publicly owned utilities. In this case, the EIA has identified 2,011 publicly owned utilities, but reports on data for only 467 publicly owned utilities large enough to be required to fill out the form. The 467 "selected" utilities account for 88 percent of the electricity sold by publicly owned utilities to ultimate consumers. The 1,544 missing utilities have been ignored for the purposes of this report. Were data available for this group, the subsidy estimate for tax-exempt municipal bonds might increase by around 10 percent.

- Publicly owned utilities have fiscal years that end at various dates. Most have fiscal years that end on June 30 or December 31, though others end at intermediate dates. Form EIA-412 permits respondents to use their customary fiscal year for financial reporting. Aggregate Publicly Owned Utility financial data for this report were computed by summing across agencies with differing definitions of fiscal year 1990.

For rural electric cooperatives, data were obtained from U.S. Department of Agriculture, Rural Electrification Administration, *1990 Statistical Report, Rural Electric Borrowers*, IP 201-1 (Washington, DC, August 1991). Cooperative data are collected on a uniform basis for calendar year 1990. There are 154 "inactive" cooperatives that no longer borrow from the REA (some nonborrowers may no longer exist), 2 cooperatives in default, and 8 to 10 nonrespondent cooperatives that are not included in the data.

Federal utilities file Form EIA-412, and their financial results are published in EIA's *Financial Statistics of Selected Publicly Owned Utilities.* However, the Federal utilities do not fill out their forms in the same way. Some treat "Federal appropriations" (which are the principal source of their capital) as equity, while others treat it as debt. Interest payments on Federal appropriations are also not treated uniformly. Consequently, this report uses Form EIA-412 for financial data only for the Tennessee Valley Authority, though some operating data (number and type of customers) are drawn from this source. For the PMAs, the 1990 annual report of each agency was used, except for the Alaska Power Administration, which does not publish an annual report. However, detailed 1990 financial statements for the Alaska Power Administration were published in Alaska Power Administration, *Divestiture Summary Report: Sale of Eklutna and Snettisham Hydroelectric Projects* (April 1992). All Federal utility data are for fiscal year 1990.

[123]In 1990, publicly owned utilities paid annual interest of $4.8 billion on their long-term debt, for an interest rate of approximately 7 percent. At the same time, they held financial assets of about $24 billion, while earning some $2.2 billion in nonutility income, for an apparent interest rate of about 9 percent. The spread between publicly owned utilities' borrowing and lending rates is worth about $0.6 billion annually. Financial assets are concentrated, with five utilities accounting for one-fourth of the total. The Intermountain Power Agency, of Utah, holds some $2.7 billion. Other large holders include the New York State Power Authority ($1.8 billion), the Georgia Municipal Power Authority ($1.3 billion), the Jacksonville (Florida) Electricity Authority ($0.8 billion), the North Carolina Municipal Power Authority ($0.8 billion), and the Sacramento Municipal Utility District ($0.5 billion).

7. The Regulation of Energy Markets

The regulation of energy markets can have the same consequences for energy prices, production, and consumption as the direct payment of a cash subsidy or the imposition of a tax. For example, in the case of limiting the emissions from combustion of fossil fuels, the Government has the choice of taxing emissions to the degree necessary to reduce them to a mandated level in the economic interest of the fuel user; or, the Government can impose restrictions that prohibit emissions above a mandated level. In either case the Government action leads to a reduction in emissions to a given level and an increase in the cost of energy consumed.

Accordingly, energy market regulation can serve the same purposes and yield the same results as taxes and subsidies. Regulation is a particular kind of market intervention, among many kinds of market interventions, that the Government might select to pursue a specific social goal. Unlike most of the Government programs discussed in the other chapters of this report, Government regulation usually (although not always) increases the costs of the energy industry to which it is directed. However, from the perspective of the concept of *subsidy, per se*, if a given regulation works to the disadvantage of one energy industry, then it works to the advantage of competitors of that industry. Indeed, if there is significant environmental harm or damage as a consequence of energy consumption, it could be argued that the *failure* to regulate is a subsidy of the polluting fuel.[124] As a result, regulation stands *in principle* as another way in which the Government can intervene in energy markets to accomplish the same ends that it might otherwise accomplish through direct subsidies and / or taxation.

There are so many Government regulations concerning energy that it is difficult to identify and analyze all of them. Only a small sample of regulations are discussed here. The overriding consideration for selection of the programs listed here is *actual or potential significance* from the standpoint of the cost of compliance with the regulation. Cost implications reported are those developed and reported in other publications. Only Federal regulations have been examined. As a result, State and local regulations are not included.

A number of specific Federal regulatory programs not included clearly have significant compliance costs. Regulations affecting coal miner health and safety and most regulations concerning nuclear safety are not analyzed here. Such regulations have unquestionably influenced the prices of coal and nuclear power; however, a comparative analysis requiring conjectures about how "unsafe" or "unhealthy" these energy industries would be without regulation is beyond the resources of this study. Provisions of the Clean Air Act Amendments of 1990 which regulate the quality of gasoline and emissions of electric utilities *are* examined here. These regulations are also intended to reduce the potential harm to persons (and property) associated with producing and consuming energy. Their inclusion reflects the fact that the restrictions called for are new, and the costs of implementation have been studied recently.

The restrictions of the Clean Air Act Amendments of 1990 dramatize the trend over the past several decades of recognizing the "external" costs of energy conversion and consumption. The regulatory principle is that, absent Government intervention, the prices of some energy products will not reflect the costs of environmental damage associated with their use. Government actions such as taxes, restrictions, and prohibitions are intended to charge for, reduce, or avoid the environmental harm and have the effect of "internalizing" the associated costs into the prices paid by energy consumers. Among other things, higher prices due to internalized environmental costs increase the economic incentives to use cleaner, often renewable fuels. Competition is also being used to reduce the overall costs of compliance with the Clean Air Act Amendments of 1990 emissions restrictions. The use of tradable emissions permits is intended to ensure that the necessary reductions in emissions will be undertaken by those facilities that can do so the most economically.

[124]As a convention for this report, the lack of a Government policy, even if advocated by many to be necessary, is not investigated as a source of "subsidy." This omission is not meant to minimize the potential importance of such "unpaid costs" of energy, to the extent that they exist. Instead, it reflects a limit to the scope of the report due to resource limitations.

Evaluating regulatory compliance costs. Of all of the types of Government programs discussed in this report, energy market regulations provide the most difficult problem in estimating the dollar value of program impacts. Compared with the subsidy valuations reported in other chapters, the magnitudes given in Tables 22 and 23 are on a far less secure basis. The estimates come from a variety of secondary sources, and the underlying assumptions and methods of derivation have not been directly evaluated or correlated. Generally, actual outlays or collections of money in association with a regulatory program do not indicate the magnitude of the consequences of the regulations on energy markets. Instead, regulatory compliance costs generally must be found by projecting energy prices or costs with and without compliance with a given regulation.

The compliance costs of this limited sampling of regulations (even allowing for uncertainty in the estimates) are large compared to the energy subsidy programs considered in this report. Table 22 shows estimates of current compliance costs for selected regulatory initiatives already in place. The programs selected for review in this report include the removal of lead from gasoline, and fuel efficiency standards for

Table 22. Current Costs of Selected Federal Regulations
(Billion 1991 Dollars)

Program	Estimated Annual Cost	Impact
Regulatory Programs		
Unleaded Gasoline[a]	9.20	Higher gasoline prices
Oxygenated Gasoline[b]	0.54	Higher gasoline prices
Gasoline Volatility Restrictions (Phase II)[c]	0.83	Higher gasoline prices
Oil Storage Tank Safety[d]	3.60	Higher petroleum product prices
Automobile Efficiency Standards (CAFE)[e]	0.37	Higher motor vehicle prices
Price-Anderson Act[f]	3.05	Lower electricity prices
ANS Export Ban[g]	0.35	Lower selling prices
Total	**17.94**	

[a]Environmental Protection Agency, *Environmental Investments: The Cost of a Clean Environment* (Washington, DC: Island Press, 1991), Table 3-3A, pp. 3-20 - 3-21. The figure given in the text is for all "mobile sources" for the year 1992. These costs have steadily increased from $1.6 billion in 1972 to $9.6 billion in 1989 due to increases in capital costs for catalytic devices requiring unleaded gasoline and associated emissions standards. The costs given are the sum of amortized capital costs assuming a 7-percent interest rate and a 10-year capital life, plus operating and maintenance (O&M) costs. EPA found that the trend in cost increases was arrested in 1990 due to the reduced cost differential between leaded and unleaded gasoline, and also due to increased engine efficiency and reduced O&M costs due to improved catalytic devices. Even given these savings, the trend in cost increases is projected to resume through the year 2000.

[b]One-cent-per-gallon cost from *Short-Term Energy Outlook*, Second Quarter 1992 (STEO2Q92), p. 12; average gasoline consumption in the fourth quarter 1991 through first quarter 1992 is 7.1 million barrels per day (STEO2Q92, p. 27).

[c]The Phase II restrictions were implemented in May 1992. EPA estimates the cost of the restrictions to be 1.1 cents per gallon (*Federal Register* (June 11, 1990), p. 28663). The figure given in the table applies this cost to gasoline consumption projected for the balance of 1992 (STEO3Q92, Table 6, p. 26).

[c]Louise K. Duffy, "Regulation of Underground Petroleum Storage," *Petroleum Supply Monthly* (August 1991), pp. xiii-xix. Further analysis can be found in U.S. Environmental Protection Agency, Office of Underground Storage Tanks, *Regulatory Impact Analysis of Technical Standards for Underground Storage Tanks* (August 24, 1988).

[e]R.W. Crandall, "Corporate Average Fuel Efficiency Standards," *Journal of Economic Perspectives*, Vol. 6, (1990), pp. 171-180, gives total cost for the period 1978-1989 as $4 billion. This comes to an average of $0.37 billion per year in 1991 dollars. R.W. Crandall and J.D. Graham "The Effect of Fuel Economy Standards on Automobile Safety," *Journal of Law and Economics*, Vol. 32 (1990), pp. 97-119, gives costs as $1 billion per each mile per gallon efficiency standard imposed on the fleet. The $0.37 billion-per-year estimate is used here.

[f]J.A. Dubin and G.S. Rothwell, "Subsidy to Nuclear Power through Price-Anderson Liability Limit," *Contemporary Policy Issues*, Vol. 8 (1990), pp. 72-79. The amount given is $27.7 million (in 1991 dollars) for each of 110 units operating in 1990.

[g]Pacific Rim refineries are willing to pay a relatively higher price for ANS crude compared to West Coast refineries. The value of the impact given in the table is a linear interpolation of estimates of the export ban's impact in 1988 and 1995 given in Energy Information Administration, *Implications of lifting The Ban On The Export of Alaskan Crude Oil: Price And Trade Impacts*, SR/EMEU/90-3 (Washington, DC, 1990), p. 23.

automobiles. The recent Environmental Protection Agency (EPA) estimate given in the table (see note c, Table 22) for compliance with safety standards for underground oil storage tanks is currently $3.6 billion per year. This amount is more than double *any* single outlay by energy source identified in Table 1 and is almost twice *all* outlays identified in Table 1 for oil. Even larger is EPA's estimate of the cost of unleaded gasoline, and the catalytic devices requiring unleaded gasoline, needed to achieve emissions standards for autos and light trucks. Estimated to be $9.2 billion in 1992, this cost exceeds the total of all values found in Table 1 ($5.1 billion). Although there are measurement problems associated with these estimates, they nevertheless reflect the fact that the effects of energy market regulation when measured by the cost of compliance are considerable, and are generally larger than the effects of other types of Government programs.

Estimates provided in Table 23 are based on projections of energy markets in the future. Compliance cost estimates for two regulatory initiatives, reformulated gasoline and emissions restrictions, provide costs on a present-value basis, using projections of energy markets almost 10 years into the future. The costs are based upon regulations to be phased in over the next several years due to the Clean Air Act Amendments of 1990. The costs found exceed any of the individual budget outlays, by fuel, given in Table 1. Uncertainty surrounds preparation of these estimates. Reformulated gasoline rules have yet to be specified in their final form. Significant technological experimentation is underway to improve the emission characteristics of gasoline. Thus, the estimate of $3.2 billion in costs for reformulated gasoline may ultimately be reduced by better technology in the future. Compliance costs for the desulfurization of diesel fuel are also provided. Compliance with this regulation is scheduled to begin in October 1993. The number given in the table is the projected compliance cost in the year 2000 (discounted to 1992). In spite of these uncertainties, the estimates communicate an important result: the value of regulatory costs is relatively large compared to other Government energy market interventions. Energy market regulation can lead to large consequences compared to Government taxation and expenditure. As measured by the magnitude of associated costs, energy

Table 23. Prospective Costs of New Regulations
(Billion 1992 Dollars)

Regulation	Estimated Annual Cost	Year of Cost Estimate	Impact
Prospective Costs of New Regulations			
Reformulated Gasoline[a]	3.2	2000	Higher gasoline prices
Emissions Restrictions[b]	2.0	2000	Higher electricity prices
Diesel Fuel Desulfurization[c]	0.6	2000	Higher fuel prices
Total (present value in 1992)[d]	**5.8**		

[a]Estimates range from 10 to 15 cents per gallon (*Oil and Gas Journal*, May 27, 1991); 8 cents-per-gallon gasoline price increase in *Assumptions for the Annual Energy Outlook 1992*, DOE/EIA-0527(92) (Washington, DC, January 1992), p. 49; EPA projecting 6- to 8-cents-per-gallon price increase (speech by Roy Sugimoto of Dewitt and Company before the World Methanol Conference, December 4-6, 1990). The 8-cents-per-gallon figure is used here with the 7.68-million-barrels-per-day projection for motor gasoline consumption in the year 2000 with the EIA projection of 58 percent market share for reformulated gasoline.

[b]Energy Information Administration, *Improving Technology: Modeling Energy Futures for the National Energy Strategy*, SR/NES/90-01 (Washington, DC, January 1991), pp. 54-55.

[c]U.S. Environmental Protection Agency, *Regulation of Fuels and Fuel Additives: Fuel Quality Regulations for Highway Diesel Fuel Sold in 1993 and Later Calendar Years* (Washington, DC, 1990), pp. 7, 19. A cost of 4 cents per gallon is given in Energy Information Administration, *Assumptions for the Annual Energy Outlook 1992*, DOE/EIA-0527(92) (Washington, DC, January 1992), p. 48. Diesel fuels subject to regulation are projected as 48 percent of distillates produced in the year 2000 as given in *Annual Energy Outlook 1992*, DOE/EIA-0383(92), p. 72.

[d]All magnitudes discounted to 1992 at the (8/12/92 Federal 30-year bond) rate of 7.3 percent.

market regulation is the major instrument used to pursue the social goals of Government in energy markets.

In the discussion that follows, Federal regulations are classified by energy industry. Only a brief summary of the highlights of each program is provided. Regulations addressing oil and petroleum product supply include: product-quality requirements for transportation fuels, geographical limitations on exploration and development, limitations on Alaskan exports, underground storage-tank requirements, and automobile fuel-efficiency standards. For natural gas, the regulations discussed relate to the "unbundling" of natural gas as a commodity from its transportation, and to general accessibility of pipeline services that link buyers and sellers. For nuclear power, regulatory reform of license-renewal procedures, and the insurance limitations provided in the Price-Anderson Act are noted. For electricity regulation, the roles of reform pursuant to the Public Utility Holding Company Act (PUHCA), the Public Utility Regulatory Policies Act (PURPA), and the Clean Air Act Amendments of 1990 are examined.

Regulation of Oil and Petroleum Products

Oil import dependency has been a major energy policy concern since the 1973-1974 Arab oil embargo. Corporate Average Fuel Economy (CAFE) standards on automobiles and the ban on Alaskan North Slope oil exports are oil market regulations that were designed to reduce the level of oil imports. Other Government regulations discussed in this section reflect concern for the environmental consequences of using petroleum products. These are the mandated switch to unleaded gasoline and the more recent requirements for oxygenated and reformulated gasolines, diesel fuel desulfurization, and underground storage tank safety.

Unleaded, Oxygenated, and Reformulated Fuels and Diesel Fuel Desulfurization

Air pollution from automobiles has been an environmental issue for over two decades. In 1970, Congress passed legislation to improve ambient air quality by regulating automobile fuel additives. Specifically, a schedule to phase out lead-based anti-knock compounds in gasoline was established. Today, leaded gasoline makes up an insignificant percentage of all gasoline sold in the United States. The costs of emissions control, including the cost of catalytic devices requiring unleaded gasoline, have steadily increased since 1972 and are estimated to be $9.2 billion in 1992. Although EPA has estimated gains in operating efficiency in recent years, the costs are estimated to increase to $11.4 billion in the year 2000.[125] The mandatory phaseout of lead in gasoline was the first in a series of steps to make gasoline use less damaging to the environment.

The Clean Air Act Amendments of 1990 contain a number of requirements, restrictions, and prohibitions that affect energy in general; but for oil, they specifically affect fuel use in transportation. The Clean Air Act Amendments of 1990 require the oxygen content of gasoline to be increased primarily to reduce carbon monoxide (CO) emissions in CO noncompliance areas. Not all regulatory requirements under the Clean Air Act Amendments of 1990 take effect simultaneously. Beginning in November 1992, only oxygenated gasoline with a minimum of 2.7 percent oxygen will be sold in 39 cities during winter months. Recent estimates of the cost of compliance indicate that the additives used to meet the winter 1992 requirements will increase gasoline prices by 3 to 5 cents per gallon in noncompliance areas.[126] The annual cost estimate shown in Table 22 is $540 million. Requirements for desulfurized diesel fuels go into effect

[125]U.S. Environmental Protection Agency, *Environmental Investments: The Cost Of A Clean Environment* (Washington, DC: Island Press, 1991), Table 3-3A, pp. 3-20 - 3-21. The figure given in the text is for all "mobile sources" for the year 1992. These costs have steadily increased from $1.6 billion in 1972 to $9.6 billion in 1989 due to increases in capital costs for catalytic devices requiring unleaded gasoline and associated emissions standards. The costs given are the sum of amortized capital costs assuming a 7-percent interest rate and a 10-year capital life, plus operating and maintenance (O&M) costs. EPA found that the trend in cost increases was arrested in 1990 due to the reduced cost differential between leaded and unleaded gasoline, and also due to increased engine efficiency and reduced O&M costs due to improved catalytic devices. Even given these savings, the trend in cost increases is projected to resume through the year 2000.

[126]Averaging compliance and noncompliance areas, the national average increase in gasoline prices will be about 1 cent per gallon. Energy Information Administration, *Short-Term Energy Outlook*, Second Quarter 1992, DOE/EIA-0202(92/2Q) (Washington, DC, May 1992), p. 12; average gasoline consumption in the fourth quarter is 7.1 million barrels per day (p. 27). States can set lower percentages for oxygen content, subject to EPA approval, as part of a comprehensive implementation plan (e.g., California's revised standard of 2 percent is pending EPA approval).

on October 1993. The estimated cost of 4 cents per gallon applied to a projected 48-percent share of eligible distillates in the year 2000 gives a compliance cost of $600 million (Table 23).

Requirements for reformulated gasoline are scheduled to be effective beginning in 1995. Reformulation requirements will call for the blending of gasoline with a variety of additives, including oxygenates, and excluding highly volatile ingredients such as butane and benzene. The latter contribute to smog when exposed to sunlight. It is estimated that reformulated gasoline will have a market share of 58 percent by the year 2000. The cost of the additives will increase expenditures on gasoline by as much as $3.2 billion in the year 2000.[127]

The primary objective of the requirements for oxygenated and reformulated gasoline is to avoid environmental damage associated with smog and ozone accumulation in virtually every major metropolitan area of the United States. If the value of the damage avoided justifies the cost, imposition of the requirements promotes economic efficiency. This report does not examine damage estimates which are assumed to be greater than regulatory costs reported here. Given the projected injury to health associated with emissions byproducts of gasoline use, failure to impose the restrictions would itself be a subsidy to the use of conventional fuels.[128]

Corporate Average Fuel Economy Standards (CAFE)

Passed as part of the 1975 Energy Policy Conservation Act, the CAFE standards became mandatory in 1978.[129] From a standard of 18.0 miles per gallon in 1978, CAFE standards have risen to their current levels of 27.5 miles per gallon for cars and 20.2 miles per gallon for light trucks. A vehicle's fuel economy rating is established by EPA testing. Overall fuel economy is determined by summing city miles per gallon multiplied by 0.55 and highway miles per gallon multiplied by 0.45. CAFE standards apply separately to domestic and imported fleets.[130] Manufacturers may offset failures to achieve CAFE standards with credits earned from earlier model-year fleets which exceeded the standards. If unable to do so, manufacturers face civil penalties equal to 5 dollars for each 0.1 mile per gallon below standards multiplied by all vehicles produced during the model year. Designed as a conservation measure, it is estimated the CAFE standards have added $4 billion in automobile ownership costs for the period 1978 to 1989 for an average of $0.37 billion per year in 1991 dollars.[131]

Underground Storage Tank Regulation

Environmental damage associated with leaking underground storage tank systems led Congress to

[127]The value given is discounted to 1992. Estimates range from 10 to 15 cents per gallon, *Oil and Gas Journal* (May 27, 1991); 8-cents-per-gallon gasoline price increase in *Assumptions for the Annual Energy Outlook 1992*, DOE/EIA-0527(92) (Washington, DC, January 1992), p. 49; EPA projecting 6- to 8-cents-per-gallon price increase, speech by Roy Sugimoto of Dewitt and Company before the World Methanol Conference (December 4-6, 1990). The 8-cents-per-gallon figure is used here with the 7.68-million-barrels-per-day projection for motor gasoline consumption in the year 2000 with the EIA projection of 58 percent market share for reformulated gasoline.

[128]Emissions reductions are to be accomplished in part through mandatory use of cleaner fuels in autos, trucks, and buses. These requirements supplement fuel-quality regulations already described. The Clean Air Act Amendments of 1990 introduce fuel-use standards for commercial and Government vehicles. Section 219 calls for the Administrator of EPA to set forth standards for urban buses; Section 246 calls for the conversion of centrally fueled fleets; and Section 248 calls for the conversion of Federal agency fleets to alternative fuels. In 22 urban areas, fleet owners operating 10 or more cars and light-to-medium trucks would be required to purchase alternative-fuel vehicles in 1995 (10 percent growing to 90 percent by the year 2000). Requirements that certain vehicles be configured to use alternative fuels make a market for those fuels, reduce uncertainty for suppliers, and provide incentives for fuel production and distribution. The Federal Government purchases 44,000 light-duty vehicles per year and maintains a fleet of 200,000 cars and light trucks (*National Energy Strategy* (1991), p. 68). Cost estimates associated with these regulations are not included in this report.

[129]R.W. Crandall, H. Gruenspecht, T. Keeler, and L. Lave, *Regulating the Automobile* (Washington, DC: The Brookings Institution, 1986), p. 122.

[130] Domestic fleets are defined by 75 percent U.S. or Canadian value added. To further increase pressures for improved fleet fuel efficiency in 1990, a "gas guzzler" tax was enacted to severely penalize those automobile buyers who choose not to buy fuel-efficient automobiles. The tax penalty ranges from $1,000 to $7,700 for automobiles with gas mileage ratings of less than 22.5 miles per gallon. *Schedule of Present Federal Excise Taxes* (Washington, DC, 1992), p. 15.

[131]R.W. Crandall, "Corporate Average Fuel Economy Standards," *Journal of Economic Perspectives*, Vol. 6 (1990), pp. 171-180, gives total cost for the period 1978-1989 as $4 billion. This comes to an average of $0.37 billion per year in $1991. R.W. Crandall and J.D. Graham, "The Effect of Fuel Economy Standards on Automobile Safety," *Journal of Law and Economics*, Vol. 32 (1989), pp. 97-119, gives costs as $1 billion per each mile per gallon efficiency standard imposed on the fleet. The $0.37 billion per year estimate is used here.

charge the EPA with regulating the nearly 2 million underground storage tanks in the United States. In September 1988, EPA issued technical standards covering design, construction and installation of new tanks as well as requirements for mandatory upgrading of existing tanks.[132] Regulations for existing tanks were to be phased in over 4 years. In October, 1988, EPA promulgated financial responsibility regulations requiring owners of underground storage tanks to demonstrate the ability to cover costs of third-party liability and corrective actions.[133] These financial requirements were phased in over 2 years. EPA estimated that the cost of these regulations would be $3.6 billion per year over 30 years, with an expected 1-cent-per-gallon rise in gasoline prices (Table 22).[134]

Alaskan North Slope Oil Export Ban

The Export Administration Act of 1979 states: "No domestically produced crude oil transported through the Alaskan pipeline may be exported from the United States." The motivation for the regulation involves the national security-related "external cost" associated with oil imports.

In 1991, 24 percent of U.S. domestic crude oil production came from Alaska.[135] In principle, if the ban is binding, producers would in some instances get a higher price for exporting crude oil than they would receive domestically. If the ban were not in effect, additional oil imports to compensate for the exported oil could also cost more.

The impact of the Alaskan North Slope (ANS) export ban has been projected to diminish as time passes. If revoked, exports were projected to be 1.5 million barrels per day in 1988, with a price increase of $2.25 per barrel due to the relatively higher prices that Pacific Rim refineries are willing to pay for ANS crude. If the ban were removed in 1995, exports were projected to be 0.4 million barrels per day with a price increase of $0.225 per barrel.[136] Using a simple linear interpolation of this range of values gives exports of 0.87 million barrels per day in 1992 with a price increase of $1.09 per barrel. Given this, the cost of the ban would be $347 million in 1992.

Restrictions on Oil Resource Development

Oil is projected to meet almost 40 percent of U.S. energy demand in the year 2000 with imported crude oil and products comprising over 50 percent of oil supply.[137] Regulatory barriers prevent the development of domestic oil resources in fields thought to exist on ANS, the Arctic National Wildlife Refuge (ANWR), and certain areas of the Outer Continental Shelf (OCS). In the DOE's National Energy Strategy, removal of the current prohibition of oil resource development in the ANWR was identified as a potentially important source of future oil supply. It is estimated that development of ANWR could lead to production rates of 0.87 million barrels per day by the year 2005. The coastal plain to be developed makes up 8 percent of the ANWR and includes no designated wilderness areas. The 0.87 million barrels per day is about 8 percent of the 10.85 million barrels per day of net petroleum imports projected for the year 2005.[138] Further development of ANS and OCS resources could add 4.1 billion barrels of oil and 9.4 trillion cubic feet of natural gas to the nation's recoverable resources, if environmental concerns could be successfully resolved.[139] No estimate of the dollar value of these restrictions was developed as part of the National Energy Strategy.

Regulation of Natural Gas

Federal involvement in natural gas regulation has a long and varied history. Its focus has always been on issues of competition and monopoly. However, as in

[132] *Federal Register* (September 23, 1988), pp. 37082 and 37212.

[133] *Federal Register* (October 26, 1988), p. 43322.

[134] Louise K. Duffy, "Regulation of Underground Petroleum Storage," *Petroleum Supply Monthly* (August 1991), pp. xiii-xix. Further analysis can be found in U.S. Environmental Protection Agency, Office of Underground Storage Tanks, *Regulatory Impact Analysis of Technical Standards for Underground Storage Tanks* (August 24, 1988).

[135] Energy Information Administration, *Annual Energy Review 1991*, DOE/EIA-0384(91) (Washington, DC, June 1992), p. 121.

[136] Pacific Rim refineries are willing to pay a relatively higher price for ANS crude compared to West Coast refineries. The value of the impact given in the table is a linear interpolation of estimates of the export ban's impact in 1988 and 1995 given in Energy Information Administration, *Implications of Lifting the Ban on the Export of Alaskan Crude Oil: Price And Trade Impacts*, SR/EMEU/90-3 (Washington, DC, 1990), p. 23.

[137] Energy Information Administration, *Annual Energy Outlook 1992*, DOE/EIA-0383(92) (Washington, DC, January 1992), p. 63.

[138] Energy Information Administration, *Annual Energy Outlook 1992*, DOE/EIA-0383(92) (Washington, DC, January 1992), p. 72.

[139] U.S. Department of Energy, *National Energy Strategy, First Edition 1991/1992* (Washington, DC, February 1991), pp. 70 and 80.

other regulated industries, the style of regulation has shifted dramatically in recent years to the establishment of market rules which allow price to be determined in a relatively competitive framework. The recently issued Federal Energy Regulatory Commission (FERC) Order 636 may be viewed in the context of this trend.[140]

This Order is part of the Federal policy to allow market forces to play the largest role possible in the interstate natural gas industry. Effective May 18, 1992, the FERC changed its regulations with Order 636 to enhance competition in the transportation of natural gas. The specific purpose of the changes was to eliminate any remaining competitive advantage of gas pipeline companies over other sellers of gas. The advantages at issue are based on a pipeline company's ability to "bundle" gas, its transportation, and other related services into a composite commodity. Heretofore, pipeline operating practice tended to favor the transportation of its own product to the disadvantage of gas provided by other sellers for delivery by the pipeline. The change should help maximize the number of sellers (buyers) that a buyer (seller) could reach when purchasing a service of a given quality. Generally, it should enable buyers to pay the lowest available price and sellers to receive the highest available price while still having access to appropriate transportation services.

The success of Order 636 will be determined through experience. It is intended to correct past regulatory practice. The regulatory environment prior to Order 636 and its predecessors could be argued to provide the net effect of a subsidy for pipeline company gas over third-party gas. The degree of inefficiency present in the gas allocation prior to the Order's effective date cannot be independently assessed here. Analysis supporting the National Energy Strategy focused on the need for regulatory reform in the natural gas industry. The study preceded issuance of Order 636 and viewed natural gas regulatory issues in a broader context. In addition to the regulatory reform provided by Order 636, other regulatory barriers to efficient gas supply included regulatory uncertainty in building new pipeline capacity, the regulation of natural gas imports and exports, and restrictions on the development of natural gas resources in certain areas of the OCS. For all of these changes taken together, reduced costs due to regulatory reform could save consumers about $140 million in 2000 and $2 billion in 2010. Moreover, on an annual basis the increased use of gas could reduce SO_2 emissions by 670,000 tons, NO_x emissions by 200,000 tons, and carbon dioxide emissions by 11 million tons by the year 2010.[141]

Regulation of Nuclear Energy

The emergence of nuclear power resulted in a very dramatic enlargement of the Federal role in the electricity sector. By its very nature, this form of power was treated quite differently from other forms. The potential danger of the materials involved in nuclear power generation has provided the impetus for close Federal regulation of the nuclear fuel cycle by the Nuclear Regulatory Commission (NRC). The NRC's actions are broadly divided into materials licensing and handling, reactor licensing and regulation, waste management and assorted other research and legal functions. At the end of 1991 there were 110 nuclear power plants operating in the United States. Taken together, these plants generated 19 percent of total U.S. electricity production. Currently, there are only two nuclear plants actively under construction.[142] Changes in safety regulations, especially since the Three Mile Island incident, have tended to increase nuclear plant construction costs, making nuclear generation less competitive as a source of new electric power generation.

The Price-Anderson Act

A Federal regulation that continues to have a cost-reducing effect on the nuclear power industry is the Price-Anderson Act (1959). This Act placed a limit of $560 million on the liability of individual nuclear power plants for damage due to any one accident. In 1988, amendments to the Act increased the potential liability limits to $7 billion per accident. These limits provide a subsidy to the nuclear industry to the degree private insurance premiums paid by operators of individual plants are reduced. In a 1983 study, the NRC concluded that the liability limits were sufficiently significant to constitute a subsidy. However, a quantification of the

[140] *Federal Register*, Vol. 57, No. 74, Rules and Regulations (April 16, 1992), p. 13268. Extensive discussion of Order 636 and its background is provided. The next section is based on this discussion.

[141] U.S. Department of Energy, *National Energy Strategy, First Edition 1991/1992* (Washington, DC, February 1991), p. 88. The point of this section is that, although dollar values cannot be broken out for individual aspects of natural gas regulation, the impacts of regulation are substantial, as expressed by the potential impacts of regulatory reform.

[142] Energy Information Administration, *Annual Energy Outlook 1992*, DOE/EIA-0383(92) (Washington, DC, January 1992), p. 42.

amount of the subsidy was not attempted.[143] At issue are the probability distributions for various kinds of accidents and valuations of the consequences of accidents, all done on a plant-by-plant basis. The amount of the subsidy would then be found by calculating the differential effect on the insurance premium of imposing the liability limits.

In 1990, Dubin and Rothwell developed estimates of these components of insurance rates and concluded that the amount of the subsidy was $74.3 million per nuclear unit prior to the 1988 amendments and $27.7 million per unit thereafter.[144] For 110 units operational in 1991, the total amount of the subsidy for this estimate would be $3 billion (Table 22). For 613 billion kilowatthours of nuclear-based power generated in 1991, this amount is equivalent to a subsidy of 5 mills per kilowatthour.

Regulatory Reform

In the baseline projections used to assess the effects of National Energy Strategy initiatives, nuclear power was forecast to virtually disappear as a source of energy supply by the year 2030 unless significant regulatory reform or technical advances in nuclear power generation were to be achieved.[145] Regulatory reform was identified as one strategy for ensuring that nuclear energy would remain a serious alternative for utilities. The reforms called for reducing the regulatory risk to utilities due to procedures involving post-construction licensing of a new nuclear generating unit. There is also the potential for reform in license renewal procedures for existing plants. The National Energy Strategy found that as much as 66 gigawatts of new generating capacity in 2030 could be satisfied by extending the life of existing nuclear power plants. Altogether, the National Energy Strategy initiatives (including regulatory reform) are projected to reduce the cost of nuclear-based electric power from 99 mills per kilowatthour to 66 mills per kilowatthour and increase nuclear power production by about 0.5 quadrillion Btu in 2010 and 12 quadrillion Btu in 2030 over what it would have been otherwise.[146] The dollar value of these developments were not estimated in the National Energy Strategy documents. Title XXVIII of the Energy Policy Act of 1992 implements this reform by permitting the Nuclear Regulatory Commission to issue combined construction and operating licenses for any nuclear plants built in the future.

Regulation of Electricity

Federal involvement in electric utility regulation in part involves the traditional issues of prevention and control of monopoly. However, as the industry evolved, regulatory reform has sought to foster and enlarge the role of actual and potential competition as a supplement to direct regulation. The aim of the reforms is to assure efficient market performance in the production and distribution of electric power. At the same time, there has been an increased concern over the environmental consequences of fuel consumption in electric power generation. The Clean Air Act Amendments of 1990, for which the transportation fuel provisions were previously discussed, is the clearest recent expression of these concerns.

Historical Overview

The regulation of electricity production and prices initially developed at the State and local levels. Excluding Federal involvement in public power projects, the first major Federal regulatory initiative was the Public Utility Holding Company Act (PUHCA).[147] The purpose of this Act was to ensure that utilities could not avoid State and local regulation through the adoption of complex interstate financial structures. At the time (1935), the generation technology and distribution system basically ensured that electric power requirements would be satisfied by regionally

[143]A discussion of the Price-Anderson Act as a subsidy is given in U.S. Nuclear Regulatory Commission, *The Price-Anderson Act: the Third Decade*, NUREG-0957 (Washington, DC, 1983).

[144]J.A. Dubin and G.S. Rothwell, "Subsidy to Nuclear Power Through Price-Anderson Liability Limit," *Contemporary Policy Issues*, Vol. VIII (1990), pp. 73-79.

[145]U.S. Department of Energy, *National Energy Strategy, First Edition 1991/1992* (Washington, DC, February 1991), p. 111. See also, *National Energy Strategy, Technical Annex 2*, pp. 42-43.

[146]The latter development reflects the commercialization of a new generation of nuclear reactors with more advanced safety features than those currently available. Other NES initiatives contributing to these effects are the development of advanced light-water reactors of a standardized design and other advances in other stages of the nuclear fuel cycle (*National Energy Strategy*, pp. 109-116).

[147]A discussion of PUHCA, why it was enacted, how it works, and its effects on the structure of the U.S. electric utility industry is provided in *National Energy Strategy, Technical Annex 1, Analysis of Options to Amend the Public Utility Holding Company Act of 1935*, DOE/S-0084P (Washington, DC, 1991), pp. 1-7.

sited facilities. What is now the Federal Energy Regulatory Commission was given authority by the 1935 Federal Power Act to regulate interstate power transactions among utilities. PUHCA called for Securities and Exchange Commission (SEC) regulation of utilities that chose to operate as holding companies in more than one State. Over time, the U.S. electricity supply system was integrated into large regional networks, and trading of bulk power supplies between regions became increasingly possible, both from a technological and an economic standpoint. Given this, the site of generation facilities could be more geographically remote relative to end-use demand. However, limited access to transmission facilities restricted the development of geographically dispersed generation facilities.[148]

Regulation and Competition

The Public Utilities Regulatory Policies Act (PURPA) was passed in 1978 to promote competition in the market for power generation. PURPA required utilities to connect with nonutility producers of power (originally small qualifying facilities or QFs) and buy power from them at avoided cost. QFs and a new breed of larger-than-QF producers, dubbed “Independent Power Producers” (IPPs), were thus enabled to enter the market for electric power. Qualifying facilities are small (80 megawatts or less) generators that use renewable resources such as solar or wind energy, and cogenerators that use fuel to produce heat or steam for industrial or commercial purposes and for electricity production. Nonutilities supplied 3.9 percent of electric power sold in 1990. Currently, these entities provide a major source of capacity expansion in the utility sector.[149]

Recent forecasts estimate that almost a third of capacity additions for electric power generation through the year 2010 would be from nonutility suppliers. Given this, including power generated for their own use, nonutilities will supply 15 to 20 percent of U.S. electricity by the year 2010.[150] The benefits of increased competition are believed to be decreases in capital costs for new generating plants, penetration of a wider range of generating technologies, improved generating efficiencies, lower electricity prices, and reduced risk of cost overruns associated with capacity expansion.[151]

The experience with nonutility generation of power due to PURPA prompted support for fundamental reform of PUHCA. This law requires utilities, organized in the holding company form and conducting significant multistate operations, to register with and submit to regulation by the SEC. A key element of regulation limits the extent of geographic integration permissible for the controlled utility. This has tended to limit the development of interregional power exchanges. Since there can be large regional differences in the costs of constructing and running power plants, the net effect of PUHCA has been to constrain the ability of electricity suppliers to minimize the costs of power supplied as viewed from the national level.[152]

This issue has been addressed by Title VII of the Energy Policy Act of 1992. Title VII creates a new type of electric power producer, the “exempt wholesale generator.” Exempt wholesale generators may be owned by regulated utilities, but they are exempt from most of the ownership and geographic restrictions of PUHCA, so long as they sell only wholesale electricity to other utilities. The transactions of exempt wholesale generators would continue to be regulated by FERC and state and local regulatory authorities.

Title VII also gives FERC the authority to require owners of power transmission lines to furnish transmission services to third parties, at rates which permit the owner to recover the full cost (i.e. historic cost) of the transmission service.

The potential benefits of further regulatory reform of electric utilities were evaluated in the *National Energy Strategy (1991), Technical Annex 1*. In addition to PUHCA reform, National Energy Strategy initiatives included proper pricing of and open access to electricity transmission services, support for State-integrated resource planning programs, phasing out of Federal utility debt subsidies, and reforming hydropower regulation and the nuclear power licensing process. These initiatives are projected in National Energy Strategy to reduce fuel demand for electric power by 7 quadrillion Btu in the year 2030.[153]

[148]Energy Information Administration, *Annual Energy Outlook 1992*, DOE/EIA-0383(92) (Washington, DC, January 1992), p. 46, and U.S. Department of Energy, *National Energy Strategy (1991), Technical Annex 3, Electricity Transmission Access*, DOE/S-0085P, pp. 1-4.

[149]Energy Information Administration, *Annual Energy Outlook 1992*, DOE/EIA-0383(92) (Washington, DC, January 1992), p. 68.

[150]Energy Information Administration, *Annual Energy Outlook 1992*, DOE/EIA-0383(92) (Washington, DC, January 1992), p. 41.

[151]Energy Information Administration, *Annual Energy Outlook 1992*, DOE/EIA-0383(92) (Washington, DC, January 1992), p. 47.

[152]Energy Information Administration, *Annual Energy Outlook 1992*, DOE/EIA-0383(92) (Washington, DC, January 1992), pp. 46-47.

[153]U.S. Department of Energy, *National Energy Strategy, Technical Annex 1, Analysis of Options to Amend the Public Utility Holding Company Act of 1935*, DOE/S-0084P (Washington, DC, 1991).

Emissions Restrictions on Electric Utilities

Among the provisions of the Clean Air Act Amendments of 1990 that are of particular importance for electric power generation are new restrictions on emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x).[154] These gases are released into the air following the combustion of fossil fuels for (among other things) the generation of electricity. In 1985, electric utilities were responsible for 68 percent of the 23.7 million tons of SO_2 released by all sources and 33 percent of the 21.1 million tons of NO_x. Once released into the air, these gases combine with water vapor to form sulfuric and nitric acids. Ultimately, these fall to earth and acidify both soil and ground water. Although sulfur and NO_x emissions have been regulated for over 20 years, the Clean Air Act Amendments of 1990 call for increased restrictions.

The goals of the Clean Air Act Amendments of 1990 are to reduce annual SO_2 emissions by 10 million tons and NO_x emissions by 2 million tons from 1980 levels by the year 2010. Generators of electricity will be responsible for 87 percent of the annual SO_2 reductions and all of the annual NO_x reductions. The imposition of the new emissions restrictions will have a clear effect on the costs and mix of energy resources used to generate electricity. Generally, the impact of the restrictions in the next 10 years is to increase the cost of electricity due to the use of more expensive low-sulfur coal and retrofitting many existing coal-burning facilities with scrubbers. By the year 2030, the differential effect of the restrictions will be somewhat reduced by the penetration of new clean-coal generating facilities that can use high-sulfur coal in compliance with the restrictions. The greatest impact of the restrictions on electricity costs and prices is forecast to be around the year 2000. The costs of compliance to the new emissions standards by electric utilities have been estimated to be in the range of $2.0 billion (discounted to 1992) or 2 mills per kilowatthour (1991 dollars) in the year 2000 (Table 23).

Tradable emissions permits or allowances are an innovative feature of how the restrictions are to be implemented. Often in the past, environmental restrictions would have been implemented by limiting each generating facility to the amount of emissions required for the average of all facilities. Since some facilities could comply with the restrictions at a lower cost than others, the incremental cost of compliance would vary from place to place. As a result, the total costs of compliance would not be minimized. With tradable permits, plants with a relatively low cost of reducing emissions can trade "excess compliance" for a fee to plants with a relatively high cost of reducing emissions. That is, some plants can reduce emissions to below the average level for all plants, and sell the difference to plants generating emissions above the average at a mutually advantageous price (i.e., a price above the incremental cost of the excess compliance, but below the incremental cost of the more expensive plant to operate at the average emission rate for all plants). In principle, the use of tradable permits should minimize the cost of reaching the program's goals for emission levels.

Conclusions

Examination of the Federal regulation of energy markets leads to two primary conclusions:

- The size of regulatory costs are not revealed by the size of associated Government outlays or tax concessions.

- Regulatory costs, when evaluated in dollar terms can rival, and often exceed, the level of expenditure of other Government energy programs.

In Table 1 the total outlay for all energy "subsidy" elements in Federal programs was $4.9 billion. Current and projected regulatory compliance costs given in Tables 22 and 23 amounted to over $25 billion when discounted to 1992. Moreover, the regulatory costs accounted for included only selected Federal regulations. Further, since only Federal regulations are considered, other costs due to State and local regulations are also omitted. Thus, the regulation of energy markets clearly leads to impacts which can change the level of energy costs and prices and consequently influences the consumption and production of various energy sources.

[154]The estimate of the effect on electricity prices of compliance with the Clean Air Act Amendments of 1990 is from Energy Information Administration, *Improving Technology: Modeling Energy Futures For The National Energy Strategy*, SR/NES/90-01 (Washington, DC, January 1991), pp. 52-62. The forecast of fossil fuel shares for electricity generation in the year 2000 is in Energy Information Administration, *Annual Energy Outlook 1992*, DOE/EIA-0383(92) (Washington, DC, January 1992), p. 68.

Appendix A

Previous Studies of Government Subsidies

Appendix A

Previous Studies of Government Subsidies

Past studies addressing the question of energy subsidies identify a host of programs of potential significance in affecting energy prices and uses. Specific quantitative findings of earlier studies are of limited current interest, given the manner in which energy policy has evolved. They are, however, instructive for at least three reasons:

- At any one point in time, large variations in estimates of subsidy values are possible, depending on the array of programs included when developing the valuation assessment.
- The potential for variations can be greatly compounded depending on the methodology used in calculating the subsidy value attributed to each program.
- A wide array of interventions may have only limited aggregate effects on the energy sector.

Ford Foundation Study

In 1971, the Ford Foundation promoted a comprehensive review of Federal energy policy. In that context, Gerard M. Brannon directed one of the earliest attempts to view subsidies in a comprehensive framework.[155] Though oil issues were of paramount concern, electricity policy, Government enterprise to promote substitute energy sources, and regulatory and tax options to reconcile energy and environmental concerns were also examined. The work was completed just after the 1973-1974 OPEC oil embargo and was one of the first energy economic analyses that sought to consider the implications of the embargo upon Government energy policies. Brannon concluded that the Government should remove or reduce subsidies that stimulate oil and gas production. In fact, many tax reforms adopted in the 1970's and 1980's had this effect. Additionally, he recommended an expansion of programs designed to stimulate the development of renewable energy sources and energy-conserving technologies.

EIA's Energy Policy Studies

At the end of the 1970's, the Energy Information Administration (EIA) of the Department of Energy (DOE) undertook a series of studies designed to identify and assess the consequences of Government policies and actions upon energy resource allocation. Many issues were addressed, including selected issues of regulation, the use of Federal lands, and energy taxation. Most studies were nonquantitative.[156] However, one examined the specific issue of Federal subsidies.[157] In doing this, a taxonomy of Government programs that provide subsidies was developed. Seven different forms for Federal subsidies were identified. These were:

- Grants
- Credit subsidies in the form of low-interest loans and loan guarantees
- The provision of goods and services at below-market prices
- The purchase of goods and services at above-market prices
- Guaranteed purchases at market price (reducing producer uncertainties)
- Joint Federal-private corporations
- Tax subsidies (here called tax expenditures).

[155]Gerard M. Brannon, *Energy Taxes and Subsidies* (Cambridge, MA: Ballinger, 1974).

[156]Energy Information Administration, *Energy Policy Studies*: *Selected Federal Tax and Non-Tax Subsidies for Energy Use and Production*, Volume 6, DOE/EIA-0201/6 (January 1980); *The Use of Federal Lands for Energy Development*, Volume 8, DOE/EIA-0201/8 (March 1980); *Nuclear Power Regulation*, Volume 10, DOE/EIA-0201/10 (May 1980); *Federal Pipeline Regulation*, Volume 11, DOE/EIA-0201/11 (August 1980).

[157]Energy Information Administration, *Energy Policy Study*: *Selected Federal Tax and Non-Tax Subsidies for Energy Use and Production*, Volume 6, DOE/EIA-0201/6 (January 1980).

Of these seven policy instruments, the study reviewed the effects of loan guarantees, grants, tax credits, and acquisition subsidies. Although the costs and benefits of each type of program were assessed, the net effects on energy prices and quantities of the programs in existence at that time were not estimated. However, a quantitative analysis of energy policy programs was attempted in a summary report on the results of all of the energy policy studies.[158] In this report, program impacts were evaluated through the development of two energy system scenarios for the year 1990 (then 10 years into the future). One was termed the "Current Program" case and embodied the assumption that a selected group of programs initiated after the 1973-1974 embargo would be kept in place through 1990. These programs included the Power Plant and Industrial Fuel Use Act, automobile efficiency standards, the Natural Gas Policy Act, depletion allowance severance taxes for coal, gasoline excise taxes, the tax-exempt status for public utilities, and the oil Windfall Profit Tax.[159] The second scenario, the "Reduced Intervention" case, assumed that the selected programs would be discontinued in 1980. The specific purpose of the comparative analysis was to assess the Government's programmatic effect on the forecast level of petroleum imports. Table A1 summarizes the results.

As noted at the time, the most striking comparative aspects of the two scenarios are the similarities in the results. At the level of gross summary, the net effects of the Government programs analyzed are quantitatively small reductions in both energy supply and demand.[160]

Petroleum imports are actually higher for the Current Programs case (although lower for this case when a lower world oil price was assumed). The results suggest that many Government programs can have off-setting effects. Further, market and programmatic effects can also be off-setting. For example, if conservation programs are removed but energy prices are also forecast to increase, then the "economic" conservation in response to higher prices to some degree replaces the mandated conservation. In the Reduced Intervention case the forecast fuel efficiency of automobiles was forecast to be larger (at the higher forecast gasoline price) than the mandated efficiency present in the Current Programs case. But the analyses

Table A1. Comparative Government Program Impacts for 1990
(Quadrillion Btu)

Item	Current Programs	Reduced Intervention
Domestic Production		
Oil	19.7	20.6
Gas	19.0	19.8
Coal	28.8	29.2
All Other	11.8	11.6
Total Domestic Supply	79.3	81.2
Net Imports	9.7	9.3
Total Supply (Losses)	(24.7)	(24.7)
Net Consumption	64.4	65.8
Average Price (dollars per quadrillion Btu)	14.64	14.78

[a]Quantities in the table are in quadrillion Btu (Quads), and the (end-use quantity-weighted) average price is in billion 1991 dollars per quadrillion Btu. The forecast values are from pages 53 and 54 of DOE/EIA-0201/16 (July 1980), cited above.

[158]Energy Information Administration, *Energy Policy Study*, DOE/EIA-201/16 (July 1980).

[159]Energy Information Administration, *Energy Policy Study*, DOE/EIA-201/16 (July 1980), Table 3.8, p. 59.

[160]Since both average end-use price and quantity are lower in the Current Programs case, the net program impacts result in a reduction in the aggregate demand for energy. If the prices and quantities were on the same aggregate energy supply schedule, then the apparent energy price elasticity of supply would be equal to 2, presumably too high. With the true supply elasticity smaller, the net program impact would also be a reduction in supply.

finding of greatest interest at that time was that the wide array of Government actions taken together largely offset one another and did not have large quantitative net impacts. In fact, the impacts that were found are within the range of forecasting error normally attributed to any projection.

DOE's Study of Federal Incentives for Energy Production

At about the same time as EIA's energy policy studies, DOE sponsored an analysis of Federal programs that provided incentives to energy production.[161] The purpose of this study was to determine the Federal programmatic influence on the *mix* of energy sources used. The specific concern was the degree to which Federal programs favored other energy sources compared to solar energy. It is entirely possible that Federal programs with a small net effect on aggregate energy supply, demand, and imports could nevertheless have a substantial effect on the mix of energy sources used to satisfy energy demand. Capital acquisition and new technology development can be very price-sensitive. At issue is the need to invest in technologies that cannot currently compete with alternative energy sources against the expectation that the technologies will eventually become competitive. For example, the cost of solar-based photovoltaic electric energy has been reduced by a factor of 3 since 1982; however, the cost of photovoltaic solar energy is still forecast to be $0.12 per kilowatthour in 1995 compared to a forecast average price of $0.067 per kilowatthour for other sources of electricity. By 2005 the cost of photovoltaic solar energy is forecast to be $0.06 per kilowatthour, which is competitive with the average price of $0.069 forecast for other sources.[162] The timing of when solar-based technologies will become economic is crucial to its current speed of development. To the degree that the prices of alternative nonsolar energy sources are differentially subsidized, the development and penetration of solar-based technologies could be significantly retarded.

The DOE production incentives study was comprehensive in its identification of Federal programs that could serve as energy production subsidies. Federal subsidies were organized with respect to eight different forms:

- Creation or prohibition of organizations that carry out actions
- Taxation: exemption, or reduction of existing taxes
- Collection of fees for delivery of a good or service
- Disbursements of money without requiring anything in return
- Requirements backed by criminal or civil sanctions
- Traditional services (e.g., regulating commerce)
- Nontraditional services (e.g., exploration, RD&D)
- Market activity under conditions similar to non-Government agents.

Taken together, subsidies in the amount of $25.83 billion (1991 dollars) were found for fiscal year 1978. Of this total, 76 percent was due to DOE, TVA, and the Army Corps of Engineers. An itemization of findings for fiscal year (FY) 1978 is given in Table A2.

Although the production incentives study provides a comprehensive catalogue of Federal programs that provide subsidies, no analysis was performed to determine the specific impact of the programs upon the current or future mix of energy sources. The basic conclusion of the study is that there is a substantial precedent for Federal programs providing incentives for energy production above market-determined amounts.

CBO Study: Carbon Emissions and Government Programs

Though the mix of Government energy policies changed significantly in the 1980's, the degree of programmatic influence on the mix of energy resources used, and the rate of development and penetration of new technologies, remained questionable. During the decade of the 1980's there was an increasing concern regarding the environmental effects of energy production and consumption associated with such issues as acid rain and global warming. Reflecting this shift in orientation, a study prepared by the Congressional Budget Office (CBO) in 1990 sought to

[161]Pacific Northwest Laboratory (operated by Battelle Memorial Institute), *An Analysis of Federal Incentives Used to Stimulate Energy Production*, PNL-2410 REV. II, prepared for DOE under contract EY-76-C-06-1830 (February 1980).

[162]The forecast prices for photovoltaic solar-based electricity are from page 66 of *U.S. Department of Energy Posture Statement and Fiscal Year 1993 Budget Overview* (January 1992). The forecast average price of electricity from other sources is given on page 68 of the *Annual Energy Outlook 1992*, DOE/EIA-0383(92).

Table A2. Comparative Federal Incentives for Energy Production in 1978
(Billion 1991 Dollars and Percentage Share)

Energy Source	All Federal Agencies in FY 1978[a]	Share of Total
Electricity	7.59	29.4
Nuclear	10.53	40.8
Fossil	6.79	26.3
Fusion	--	--
Solar	0.69	2.7
Other	0.23	0.9
Total	**25.83**	**100.0**

[a]The FY 1978 figures are from page 101 of the incentives study cited above, PNL-2410 REV. II. Expenditures for fusion are not broken out for FY 1978 and may be included in the figure given for "other."

assess the extent to which Federal policy might spur or deter fossil energy use, thereby impacting the rate of carbon emissions generated in the U.S. economy.[163]

The CBO study considered expenditure, credit, and tax programs that directly affect energy use. Two important classes of Federal programs were not considered, one of which was directly energy related. For example, the impacts of Government regulation, such as automobile fuel efficiency standards and electric utility regulation, were excluded. Other excluded programs were those whose impacts on energy were indirect even if potentially significant. An example is the effects on population density and transportation patterns of programs such as home mortgage interest tax deductions and Federal spending on highways.

The complexity of Government involvement in the energy sector is underscored by the CBO effort. Even while putting aside consideration of Federal regulatory activities, more than 10 forms of tax preferences, 13 forms of energy taxes, 5 key energy production and credit programs, and 6 major research and development initiatives were examined.

The report concluded that, for the programs considered (valued at about $28 billion), Federal impacts favoring fossil fuel use were small relative to those which favored non-fossil sources or taxed use of fossil fuels. Many caveats were attached to these findings, given the fact that a number of programs which could affect the level and composition of fuel use were not examined or were judged to have effects which were not readily quantifiable. Nonetheless, one finding should be underscored. Measurable tax, expenditure, and credit programs tend to be small relative to the size of the energy sectors they impact (Table A3).

Other Studies

In the mid-1980's, two reports were published asserting that Government energy subsidies impacting energy markets exceeded $50 billion (1991 dollars), more than $500 per household, and strongly favored fossil energy use over conservation and the use of renewable forms of energy. In the *Hidden Costs of Energy* report, estimates of tax subsidies, agency program outlays, and loans and loan guarantees were developed as of 1984.[164] Because of subsequent tax reform and reduced Government research and development spending, an updated estimate using the report's methodology would yield a substantially smaller total for Federal subsidies as of 1991. Nonetheless, the results would still differ from those presented in the CBO report, in part because of the treatment of Federal energy excise taxes (ignored by *Hidden Costs*) and in part because of differences in methodology used to measure the value of Government programs. The *Hidden Costs* study valued Government programs on a

[163]Congressional Budget Office, *Energy Use and Emissions of Carbon Dioxide: Federal Spending and Credit Programs and Tax Policies* (December 1990).

[164]Center for Renewable Resources, *The Hidden Costs of Energy* (Washington, DC, October 1985). A summary of estimates by Government agency and energy source is given on pages 26-27.

Table A3. Federal Programs That Affect Carbon Dioxide Emissions
(Billion 1991 Dollars)

Program	Expenditure
Programs that Reduce CO_2 Emissions	
Excise Taxes and Fees on Fossil Fuels	21.86
Promotion of Demand Conservation	0.42
Expansion of Nuclear Energy Supply	0.81
Expansion of Renewable Energy Supply	1.10
Total	**24.12**
Programs That Increase CO_2 Emissions	
R&D to Expand Use of Fossil	1.44
Tax Expenditures on Fossil	0.84
General Expansion of Energy Supply	1.27
Total	**3.55**

[a]The figures given are taken from Tables 6-12 of the CBO study. Some of the amounts provided are gross of compensating receipts. The table here is intended to reflect only net expenditures. As a result, the summary values in the table may differ slightly from the figures given in the CBO report.

gross rather than net basis, ignoring revenues collected as offsets to expenditures for various Government energy enterprises.

The second study, *Money to Burn? The High Cost of Energy Subsidies*, used an entirely different methodology to support its finding that U.S. energy use was subsidized at a rate of nearly $80 billion per year.[165] It did not develop an indepth review of the array of Government programs which might provide energy subsidies. Instead it focused on electricity pricing which through regulation is tied to average costs of electric power generation. The report claimed that the marginal cost of power generation was greater than average cost by nearly 75 percent. For pricing to be efficient in allocating energy resources, the report argues that all electricity should be priced at marginal cost. This not being the case, electricity consumers were found to be benefiting to the extent of $78 billion (1991 dollars) in 1984.[166] Failure to price at marginal cost, in the view of this report, favored continued use of conventional energy sources, mostly fossil, at the expense of improvements in efficiency in energy end-use applications.

[165]Mark Kosmo, *Money to Burn? The High Costs of Energy Subsidies* (Washington, DC: World Resources Institute, 1987).

[166]Mark Kosmo, *Money to Burn? The High Costs of Energy Subsidies* (Washington, DC: World Resources Institute, 1987). Estimates of the differences between electricity prices and long-run electricity marginal costs are given in Table 11, page 41.

Appendix B

Fact Sheets

Appendix B

Fact Sheets

Low Income Housing Energy Assistance Program

1. Description

The Low-Income Housing Assistance Program (LIHEAP) is administered by the Department of Health and Human Services. The program is carried out through grants administered to States and Indian tribal organizations to aid low-income households with high energy costs. Payments are made to households, energy suppliers, and building operators.

2. Revenue Loss/Outlay

Federal outlays amounted to $1,742.0 million (FY 1991) and an estimated $1,143.3 million (FY 1992).

3. Rationale

In the face of recurrent rapid rises in energy prices, this program was seen as a means of maintaining the standard of living and, in some cases, ensuring the survival of lower income Americans.

4. Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

No. 2 Fuel oil, natural gas, electricity and coal/End-use

5. Impact

Though it is not the express purpose of the program, the assistance has the potential of encouraging energy consumption and discouraging conservation.

Conservation Technical and Financial Assistance

1. Description

DOE provides conservation assistance in numerous areas. These program areas are: Institutional Conservation—provides 50 percent of the funding in grants to nonprofit schools and hospitals for energy conservation; State Energy Conservation Program and Energy Extension Service—20 percent cost sharing of State-funded energy efficiency programs; Municipal Energy Management—supports state technical and financial assistance to local governments in effective energy management; International Market Development—promotes U.S. energy efficiency and renewable energy products and services overseas and disseminates information on foreign technologies to U.S. manufacturers and companies.

2. Revenue Loss/Outlay

Federal outlays amounted to an estimated $262 million in FY 1992.

3. Rationale

These programs are designed to accelerate adoption of energy-efficient and renewable-energy technologies, and provide incentives to domestic manufacturers.

4. Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Renewables, oil, gas and electricity / End-use

5. Impact

Though often the technologies are cost effective on their own, cost-sharing with nonprofit and governmental agencies makes the first-cost barrier less inhibitive.

Rural Electrification Administration

1. Description

The Rural Electrification Administration (REA) was established by both Executive Order (1935) and by the Rural Electrification Act (1936). It became part of the U.S. Department of Agriculture in 1939. Residents of rural areas were invited to form electric power cooperatives, owned by their members. They were given access to low-cost power from Federal dam projects in their respective regions. The newer generation and transmission (G&T) cooperatives are usually owned by a group of distribution cooperatives that sell wholesale power partially from plants of which they have a fractional share) to their owners. The G&T cooperative has become the predominant form. The REA assists rural electricity (and telephone) suppliers by providing: (1) loans at rates below their costs to the Treasury and (2) loan guarantees to other lenders. The REA's direct loans are now made in a revolving fund format.

2. Revenue Loss/Outlay

There was a one-time loss when interest due on the outstanding debt borrowed from the Treasury to advance loans of $7.4 billion was forgiven in 1973. In 1990, rural cooperatives owed about $43 billion in long-term debt at an average interest rate of 6.7 percent. They owned approximately 30 gigawatts of capacity. They paid $2.09 billion in interest, which at investor-owned utilities rates would have been $4 billion. The difference could be considered a subsidy, but the revenue losses to the Treasury are the losses that occur because the REA charges less than the Federal Government's cost of borrowing, and when cooperatives default on guaranteed loans.

In FY 1992, outlays for direct loan subsidies are expected to amount to $25 million. Combined with outlays for administration, this brings Federal outlays up to $44 million.

3. Rationale

The REA was established as part of the general economic recovery programs of the Depression era. Federal support was thought required to provide electrification of rural areas because existing utilities tended to serve only heavily populated areas.

Not only would the provision of electricity enhance economic productivity, it would greatly improve the standard of living of people in those rural areas. Both of these were thought to improve the general welfare.

4. Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Electricity / Generation, transmission, and distribution

5. Impact

The major impact of this program has been the accelerated development of rural areas through electrification. The value in terms of economic value generated by increased production and consumption, as in the case of other subsidized power, is difficult to quantify.

Tennessee Valley Authority

1. Description

The Tennessee Valley Authority (TVA) is a Federally owned and chartered corporation, and the largest electric utility in the United States. It was created by the TVA Act of 1933 for the unified development of the Tennessee River basin, comprised of parts of seven States. The TVA runs several programs:

> The **Stewardship Program** includes maintaining a system of dams, reservoirs and navigational facilities, and, among other things, maintaining and managing 300,000 acres of public land and 11,000 miles of shoreline, efficiently and in an environmentally sound manner. The TVA operates and maintains the navigation channel from Paducah, Kentucky to Knoxville, Tennessee, operates a system of multipurpose reservoirs to retain excessive seasonal runoff and regulate discharges at flow rates that can be accommodated by downstream channels and reservoirs (resulting in the reduction of flood crests), performs dam safety modifications and maintenance activities, operates dewatering areas associated with TVA's reservoir system, manages Land Between the Lakes (170,000 acres, partly used for recreation and environmental education), and performs environmental cleanup and demolition at its Muscle Shoals Reservation.
>
> To further aid conservation, TVA operates, in its **Water and Land Program**, an air-quality monitoring network, monitors and seeks to improve water quality, promotes the wise use of forest resources in the region, and prepares maps for its own needs and to help the U.S. Geological Survey.
>
> The **Power Program** fulfills TVA's responsibility as the sole supplier of power to an area of 80,000 square miles in the seven Tennessee Valley states.

The TVA has a substantial mix of hydro, coal, and nuclear plants. In addition to the above functions, it also performs fertilizer research and general services.

2. Revenue Loss/Outlay

The TVA has a complicated financial structure, and is funded through a combination of power and nonpower revenues, borrowing, and direct Government appropriations. As noted in Chapter 6, consumers of public power can receive subsidies in the form of lower-than-private-utility costs that are passed on to them. These costs can be lower because public power providers pay lower interest rates on borrowing, do not need to conform to regulated (i.e., fair-market) rates-of-return, obtain power from low-cost sources such as hydro, and are tax-exempt. When compared with interest rates paid by investor-owned utilities (IOUs), the TVA is estimated to have benefitted from a subsidy of $231 million in FY 1990. Though unregulated, and though committed early on to hydropower, the TVA's venture into heavy borrowing at high interest rates for a massive nuclear program caused it to charge prices close to the average of nearby investor-owned utilities.[167]

Net Federal outlays for TVA in FY 1991 amounted to a negative $21.5 million, and are projected to be a positive $372 million in FY 1992.

3. Rationale

According to President Franklin Roosevelt's promotion of the TVA, "[The] potential usefulness of the Tennessee River . . . transcends mere power development; it enters the wide fields of flood control, soil erosion, afforestation, elimination from production use of marginal agricultural lands, and distribution and diversification of industry."[168]

[167]The investor-owned utilities considered are listed in Table 18. Financial data from Energy Information Administration, *Financial Statistics of Selected Investor-Owned Utilities*, DOE/EIA-0437(90)1 (Washington, DC, 1992).

[168]William U. Chandler, *The Myth of TVA* (Cambridge, MA: Ballinger, 1984), p. 26.

To many, this multidimensional development program would transform this depressed area into an economically viable region. That it should be a *public* corporation was presumably a defense against the apparent exercise of market power by the electric utility holding companies in the 1930's.

4. Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Hydro, coal-fired, and nuclear-fired electricity / Generation, transmission, and distribution

5. Impact

Since the TVA is such a complicated enterprise, it is difficult to identify and access the impacts of its operations. Its overall, long-term effect on the economy of the region is a matter of considerable controversy. Critics argue that most of the economic activity that occurred in the Valley was due to TVA's own construction and operations, rather than providing a large, secondary economic boost to the entire region. Supporters argue that the Valley would be quite backward without the TVA. Compared with TVA's scale of operations, Federal outlays are relatively small. In TVA's present financial condition, power prices are near those of IOUs. Hence, power is not as low-cost as its founders may have predicted, and consumption among its customers is not "excessively" encouraged. It is likely that the costs of compliance with the Clean Air Act Amendments of 1990 will not improve TVA's financial status, and power prices might rise more than they otherwise would have.

Tennessee Valley Authority Tax Subsidies

1. Description

The Tennessee Valley Authority (TVA) was established by Congress in 1933 to develop the Tennessee River system. The TVA is the largest electric utility in the United States. The preponderance of TVA's power is produced from coal- and nuclear-fired steam (86 percent in 1987), and hydroelectric accounts for almost the entire remainder. Historically, TVA was granted subsidies in the form of low-interest loans, debt forgiveness, and lower payments in lieu of taxation.

2. Revenue Loss/Outlay

The annual recurrent revenue losses are related to the difference between what TVA would pay in taxes and what it pays in lieu of taxes to State and local governments. The TVA paid $252.3 million in-lieu-of-tax payments in 1988. If TVA paid taxes at the approximate rate of private investor-owned utilities, then it should have paid $914.2 million. The difference of $661.9 million can be counted as revenue losses to all levels of government.

3. Rationale

The initial thrust of the TVA program was, among other things, the provision of low-cost Federal power to enhance the economic growth of the area. The TVA is a multipurpose, quasi-Government-owned corporation and is, therefore, exempt from taxation.

4. Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Electricity / Generation and transmission

5. Impact

The impacts can be divided into at least two categories. The first deals with the opportunity costs of the foregone Government revenues. These are difficult to determine, but are positive nonetheless. The second involves the decreased overall cost of operation for TVA. Depending on the pass-through mechanism, consumers of subsidized electric power benefit from prices that are lower than they otherwise might have been. It is difficult to determine if the same level of economic growth would have occurred if private sources developed the power in the region. The overall issue with Federal subsidies for regional power is that the burden of funding falls on society in general, but only certain regions benefit.

Tennessee Valley Authority Debt Issuance

1. Description

The Tennessee Valley Authority (TVA) is a quasi-government-owned corporation charged with the development of the Tennessee River area. Currently it receives no direct subsidies from the Federal Government and expenses are recovered from power operations. However, it sells a large portion of its debt to the Federal Financing Bank (FFB). As a result, it receives capital at lower interest rates than it otherwise would. Also, the direct cost of issuing debt and seeking capital is lowered.

2. Revenue Loss/Outlay

There are no associated budgetary costs.

3. Rationale

The Federal Financing Bank (FFB) as a coordinator of Federal borrowing seeks to lower the cost of debt to the Federal Government by pooling all Federal borrowing. The FFB then borrows from the Treasury.

4. Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Electricity / Generation, transmission, and distribution

5. Impact

Centralization of debt reduces costs. The TVA's ability to access the FFB acts as a subsidy in two ways. First, TVA does not incur any expenses to underwriters or marketing expense when it goes to the FFB. Second, it obtains financing at lower interest rates through the FFB. The impact discussion of the previous fact sheet applies here as well.

Power Marketing Administrations

1. Description

In the past, the Federal Government has sought to advance development in rural areas through its Power Marketing Administrations (PMAs): Alaska, Bonneville (BPA), Southeastern (SEPA), Southwestern (SWPA) and Western Area. Much of the activity of these administrations is the marketing of power produced by Corps of Engineers and Bureau of Land Management projects. Subsidies to the PMAs include: (1) low-interest loans; (2) preferential repayment schedules; (3) debt forgiveness; and (4) no primary taxation, such as property or income tax. The PMAs mainly distribute the electric power generated from Federally operated hydroelectric facilities.

Since BPA is by far the largest PMA, it will be used as an example to describe Federal subsidies. BPA was created by Congress as part of the New Deal. It was to sell the power generated by the Federal dams in the Columbia Basin. Publicly owned utilities were given preferential customer status with priority to power. The law calls for the PMAs to be self-supporting by offsetting their cost from the fees charged for power. If BPA always made repayment of its debt on time, and covered all of its other accounting (historical) costs, rates charged would still not cover the true cost of providing power. This arises because until 1974 BPA had access to special low-interest loans. In 1986, BPA had $6.5 billion in these special loans outstanding with an annual average interest rate of 3.5 percent. These subsidies do not appear in BPA's budget. There is another special aspect of these loans—they do not have a fixed payback period. BPA has a debt repayment schedule, but it does not have to meet that schedule. In fact, in the mid-1980's, it fell well behind in debt repayments. Also, PMAs are exempt from most Federal, State, and local taxes.

2. Revenue Loss/Outlay

According to the Department of Energy's *National Energy Strategy* (NES), these subsidies have cost the Treasury approximately $4 billion through 1991. If the BPA waits the full 50 years to make repayment on its low-cost loans, the costs to the Federal Government range from collecting 14.6 cents on each dollar loaned, to 2.89 cents. If the PMAs were obliged to pay taxes at a rate equivalent to private investor-owned utilities, then there was a loss, for example, of $1.1 billion in 1988 at all levels of government. In 1985 and 1986, BPA used a new marketing scheme termed "residential exchange," to sell $1 billion worth of power to investor-owned utilities at around $800 million. Another rate mechanism that BPA has used is to tie rates charged aluminum-producing customers to the price of aluminum.

3. Rationale

These subsidies were provided in part to promote economic development in areas where it was felt private enterprise would not offer electric power, and in part because of the nature of the regional economy. The flexible repayment approach was adopted due to the significant variability in revenues associated with hydroelectric power, a major source of power for some PMAs.

4. Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Electricity/Transmission, distribution, and end-use

5. Impact

Though different from TVA in that they generally do not produce power, the PMAs sell low-cost public power to regional customers. The impacts are the same as for TVA - Tax Subsidies above. However, in the FY 1993 U.S. Budget (*Department of Energy Fiscal Year 1993 Budget Overview*), the effort is continuing to make the PMAs pay for themselves. This will alleviate the equity problem involved when society in general is seen to subsidize particular groups of power consumers.

Corps of Engineers/Bureau of Reclamation Hydropower Projects

1. Description

The Department of the Interior's Bureau of Reclamation and the Army Corps of Engineers are both engaged directly and indirectly in hydroelectric power. Both of these agencies are charged with the maintenance, operation, and construction of Federal hydroelectric facilities. The direct cost of maintenance and operation is paid for by the PMAs which purchase and sell the power. Typically, construction of dams has been primarily for the benefits of irrigation and flood control, and only secondarily for the production of power. Thus, the costs of construction would need to be prorated to electric generation. Moreover, when the Corps dredges a waterway to facilitate navigation, and that waterway flows to a hydroelectric facility, silting at the dam is reduced. This increases the life of the dam and reduces maintenance costs. These costs will be registered not for hydroelectric but for navigation.

2. Revenue Loss/Outlay

The direct costs of power are covered by payments from the PMAs. The imputation of indirect costs would be a more complex problem.

3. Rationale

The rationale for the hydro plants was that the cost of adding hydroelectric capability to these dams was small compared to the perceived benefits of economic development.

4. Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Electricity / Generation

5. Impact

Essentially much of the fixed costs of developing the hydropower sites was paid by Government for other reasons. It may well have been that were it not for these other reasons, power would not have been available in these areas until later than the Government produced it. The value of the economic development, though difficult to estimate, can be seen as the impact of power availability.

Provision of Uranium Enrichment Services

1. Description

The Atomic Energy Act of 1946 essentially gave the U.S. Federal Government monopoly control over all operations of the U.S. nuclear industry. The 1954 Amendments allowed private firms into one stage of the nuclear fuel cycle - reactor development. In 1990, Congress passed the Solar, Wind, Waste and Geothermal Production Incentives Act. This Act allowed uranium enrichment facilities to be licensed under a section of the U.S. Code of Federal Regulations (CFR) different from that which is used to license reactors. This has opened the door to commercial enrichment, under Nuclear Regulatory Commission (NRC) license. The Government has traditionally been the sole provider of uranium dioxide, which is enriched to 2-3 percent U_{235}, pelletized, placed in fuel rods, and used to fuel fission reactors. The FY 1993 Federal enrichment program is divided into seven subprograms: (1) gaseous diffusion operations and support; (2) corrective actions; (3) environmental restoration; (4) waste management; (5) Uranium - Atomic Vapor Laser Isotope Separation (U-AVLIS); and (7) program direction. In addition to gaseous diffusion and laser experiments, centrifuge methods are used for enrichment.

2. Revenue Loss/Outlay

As noted in the data, a change in accounting technique allowed receipts for enrichment services to offset outlays starting in 1990. Since receipts have exceeded outlays in that and subsequent years, there is a *negative outlay*. For example, in FY 1991, revenues were $1,291 million and outlays were $1,176 million, yielding a $116 million (rounded) gain. Issues related to the amortization of up-front fixed costs will not be dealt with here.

3. Rationale

The goal of the Federal enrichment program is to meet domestic, foreign, and U.S. Government requirements for uranium enrichment services in the most economical, reliable, safe, secure, and environmentally acceptable manner possible. National security apparently was the main reason behind keeping this technology in Federal hands. However, enrichment is costly. As of the late 1980's, a diffusion enrichment plant could cost as much as $2-3 billion. The NRC is relaxing its security hold, and actual commercial ventures (e.g., Louisiana Energy Services's centrifuge plant) are challenging the economics. The NRC's action fits in with the general trend toward more competitive energy markets.

4. Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Nuclear power/Uranium enrichment

5. Impact

Since revenues are apparently covering costs, there is no subsidy from Government funds. (There is a subsidy in-so-far as these services could be acquired more cheaply outside the country. These services are produced domestically due to national security interests.) Economically, assuming that the efficiency of enrichment undertaken by the private sector would be the same, buyers of enriched UO_2 would not have the profit of the enrichment firm added to their costs of materials. This has an effect on the relative prices of fuels for electric power generation, and can influence utility planning in favor of nuclear. Depending on the pass-through mechanisms involved, this may benefit various groups of stakeholders, e.g., private utility stockholders and utility customers to varying degrees. It remains to be seen how the entry of commercial firms affects the market.

Nuclear Regulatory Commission

1. Description

The Nuclear Regulatory Commission (NRC) took over the regulatory activity of the Atomic Energy Commission as a result of the Energy Reorganization Act of 1974. It licenses and regulates activities at all stages of the nuclear fuel cycle.

2. Revenue Loss/Outlay

Net outlays for the NRC are $495 million in FY 1992 of which $115 million was for nuclear safety research.

3. Rationale

The potential health, environmental and national security dangers of nuclear materials has led to close regulation of every aspect of the industry.

4. Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Nuclear power / All stages

5. Impact

The NRC has, in recent years, developed a reputation as a rigorous regulatory body. It is probably accurate to say that the nuclear industry is cleaner and safer as a result of regulatory oversight. There has been an intensified concern for safety following the accident at Three Mile Island in 1979. As noted in Chapter 7, NRC is working on standardizing designs and streamlining plant licensing and plant license-renewal. It hopes to foster a new growth in the recently-dormant U.S. nuclear industry.

Energy and Minerals Management and the Minerals Management Service

1. Description

The Bureau of Land Management (BLM) of the Department of the Interior (DOI) is responsible for the conservation, management, and development of 270 million acres of public land. BLM also has full responsibility for mineral leasing and supervision of minerals operations on the public land and on some 300 million acres of Federal mineral estate underlying other agency jurisdictions and ownerships. The Energy and Minerals Management program within BLM provides for leasing of Federal minerals onshore, for Federal mineral resource and economic evaluation, and for the supervision of minerals development activities on Federal and Indian lands, including oil and gas, coal, geothermal, oil shale, and tar sands.

The Minerals Management Service (MMS) of the DOI supervises exploration for and the development and production of oil, gas, and other minerals on the Outer Continental Shelf (OCS), and collects royalties, rentals, and bonuses due to the Federal Government and Indian lessors from minerals produced on Federal, Indian, and OCS lands.

These agencies, along with the U.S. Geological Survey (USGS), assess the reserves in place, and/or the hydrocarbon and geothermal potential of these lands. This information is then available to the general public. In effect, this reduces private energy companies' search costs. It is important to note that private mineral owners leasing their lands do not typically provide such information.

2. Revenue Loss/Outlay

Federal outlays for the Energy and Minerals Management program were $69.7 million in FY 1991, and are estimated to be $84.2 million in FY 1992. Outlays for the Minerals Management Service were $181 million for FY 1991 and are estimated to be $208 million for FY 1992.

3. Rationale

The general role of these agencies is to protect the public lands from disruption and unreasonable exploitation. This activity is seen as an integral part of the stewardship role of these agencies. Taking a minerals inventory is an integral part of knowing the value of the lands.

4. Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Oil, geothermal, natural gas, and coal/Exploration

5. Impact

Much as the Bureau of Reclamation or the Corps of Engineers provide hydropower sites, the public provision of geological data subsidizes private companies through reduced search costs. Depending on the relative magnitude of the cost, and the possibility of pass-through to consumer prices, the result may be increased production and consumption of these resources.

Surface Mining Reclamation and Enforcement

1. Description

This Office within the Department of Interior (DOI) is responsible for carrying out the provisions of the Surface Mining Control and Reclamation Act (SMCRA) of 1977.

2. Revenue Loss/Outlay

Actual outlays for FY 1991 were $107 million. They are estimated to be $108 million for FY 1992.

3. Rationale

The rationale for the SMCRA was to induce operators of surface mines to attempt to leave the surface area as close to the state they found it in as possible. There was apparently little motivation by profit-seeking firms to internalize the external costs created by their activities. Civil penalties are assessed on violators.

4. Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Coal/Surface mining

5. Impact

The activities of the Office in enforcement of the SMCRA have the effect of raising the costs of operating surface mines—either through the additional costs of reclaiming the land, or the financial penalties of being found in violation.

Capital Gains Treatment of Royalties on Coal

1. Description

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 the lower individual capital gains tax rate of 28 percent rather than at the higher regular individual top tax rate of 31 percent. If the royalty owners are corporations, capital gains are taxed at the regular corporate tax rate of 34 percent. In order to claim capital gains treatment, the royalty owner must own the property for a minimum of 1 year and meet other simple requirements. If he elects the capital gains tax rate he cannot also elect percentage depletion.

2. Revenue Loss/Outlays

Estimated Revenue Loss and Outlay Equivalent

(Million Dollars)

Fiscal Year	Revenue Loss			Outlay Equivalent[a] (Total)
	Individuals	Corporations	Total	
1987	45	5	50	65
1988	b	b	b	b
1989	0	0	0	0
1990	0	0	0	0
1991	5	0	5	10
1992	10	0	10	10

[a]An outlay equivalent is the amount of outlay that would be required to provide the taxpayer the same after-tax income as would be received through the tax preference.

[b]$2.5 million or less.

Note: All estimates have been rounded to the nearest $5 million.

Source: Office of Management and Budget, *Budget of the United States Government, Fiscal Year 1993* (Washington, DC, 1992). Also earlier editions.

3. Rationale

The capital gains treatment of coal royalties was apparently adopted for three reasons: (1) to encourage additional production, (2) to place coal on the same tax footing as lumber, and (3) to provide a benefit to long-term lessors who might not benefit substantially from percentage depletion.

4. Major Form of Energy/Fuel Cycle Stage(s) Affected

Coal/Production

5. Impact

The capital gains treatment of royalties on coal causes Federal income tax payments by royalty owners to be lower than they otherwise would be, which encourages leasing and subsidizes production. However, those impacts are quite small because the capital gains provision cannot be used simultaneously with the percentage depletion provision. The latter provision is usually more beneficial, at least for corporations.

6. History

The capital gains treatment of coal royalties is provided for by law and has been in effect since the early 1950's.

7. Method Used to Estimate Revenue Loss

The “Revenue Loss” data in the tabulation above were generated by the U.S. Treasury Department. They are the difference between estimated Federal income tax payments in a reference case and estimated actual Federal income tax payments. The reference case assumes that royalties on coal are taxed at the regular rate. The actual case assumes that the royalties are taxed at the capital gains tax rate to the extent taxpayers so choose.

Expensing of Exploration and Development Costs: Oil, Gas, and Other Fuels

1. Description

Tax law allows energy producers, principally oil and gas producers, to write off (i.e., expense) certain exploration and development (E&D) expenditures rather than capitalizing them and depreciating them over time. The most important of these expenditures consist of intangible drilling costs (IDCs) associated with oil and gas investments. Integrated oil companies can expense 70 percent of their IDCs for successful domestic wells and 100 percent for unsuccessful domestic wells. The remaining 30 percent must be amortized over 5 years. Nonintegrated (independent) oil producers can expense 100 percent of their IDCs for all domestic wells. The 70-percent provision also applies to surface stripping and other selected expenditures for fuel minerals other than oil and gas (principally coal). The remainder must be amortized over 5 years.

2. Revenue Loss/Outlays

Estimated Revenue Loss and Outlay Equivalent

(Million Dollars)

	Revenue Loss						Outlay Equivalent[a] (Total)	
	Individuals		Corporations		Total			
Fiscal Year	Oil and Gas	Other Fuels	Oil and Gas	Other Fuels[b]	Oil and Gas	Other Fuels[b]	Oil and Gas	Other Fuels[b]
1987	425	0	-1,100	35	-675	35	-675	35
1988	455	0	-840	35	-385	35	-385	35
1989	560	0	-625	35	-65	35	-65	35
1990	-75	5	-425	40	-500	45	-500	45
1991	-100	5	-215	30	-315	35	-315	35
1992	-45	5	-45	30	-90	35	-90	35

[a]An outlay equivalent is the amount of outlay that would be required to provide the taxpayer the same after-tax income as would be received through the tax preference.

[b]Assumed to be primarily coal.

Note: All estimates have been rounded to the nearest $5 million.

Source: Office of Management and Budget, *Budget of the United States Government, Fiscal Year 1993* (Washington, DC, 1992). Also earlier editions.

3. Rationale

Intangible drilling costs were asserted by producers to be conventional operating expenses that therefore should be expensed. The provision is intended to encourage additional mineral exploration and development. It was explicitly codified to reduce uncertainty concerning its status in order to encourage further exploration and development.

4. Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Crude oil, natural gas, and coal/Production.

5. Impact

This tax deferral provision has historically been one of the most important for oil and gas producers. The rapid write-offs have added to other incentives to engage in exploration and development. As a result, domestic crude oil production has been greater than it otherwise would have been and capital has been diverted from more productive activities. The increased output has contributed to oil prices being lower than they otherwise would be, despite OPEC's price-controlling position, and to constrained growth for non-conventional forms of energy.

6. History

The option to expense IDCs (and dry hole costs) of oil and gas wells was originally based on regulations issued in 1916. A court invalidated the regulations in 1945 but Congress subsequently gave its approval to the treatment and it became law in 1954. The option to expense mine development expenditures and the option to expense mine exploration expenditures were formalized in law in 1951 and 1966, respectively.

Integrated oil companies were constrained to expensing only 85 percent of their IDCs by a 1982 tax law. The percentage was subsequently reduced to 80 percent by the Tax Reform Act of 1984 and to its present 70 percent by the Tax Reform Act of 1986.

7. Method Used to Estimate Revenue Loss

The "Revenue Loss" data in the tabulation above were generated by the U.S. Treasury Department. They are the difference between estimated Federal income tax payments in a reference case and estimated actual Federal income tax payments. The reference case assumes that relevant IDCs and certain other E&D expenditures are cost depleted. The actual case assumes that they are expensed.

The data in the table have been mostly negative since fiscal year 1987. The negative values imply a payment to the Government of funds that it had loaned (tax deferrals) to mostly oil companies in earlier periods. In a normal growth situation, the values would be positive. However, as a result of the sharp drop in oil E&D expenditures resulting from low oil prices during the past several years, repayments of old "loans" have swamped the receipt of new ones.

Expensing of Tertiary Injectants

1. Description

Taxpayers can write off (i.e., expense) certain chemical injectants that are used to enhance the process of recovering oil rather than capitalizing them and depreciating them over time.

2. Revenue Loss/Outlays

Estimated Revenue Loss and Outlay Equivalent
(Million Dollars)

Fiscal Year	Revenue Loss			Outlay Equivalent[a] (Total)[b]
	Individuals	Corporations	Total[b]	
1987	NA	NA	NA	NA
1988	NA	NA	NA	NA
1989	NA	NA	20	20
1990	NA	NA	20	20
1991	NA	NA	20	20
1992	NA	NA	20	20

[a]An outlay equivalent is the amount of outlay that would be required to provide the taxpayer the same after-tax income as would be received through the tax preference.
[b]Estimated by the Energy Information Administration based on data in source cited.
NA = Not available or not applicable.
Source: Joint Committee on Taxation (Staff), *Estimates of Federal Tax Expenditures for Fiscal Years 1992-1996* (Washington, DC, 1991). Also see earlier editions.

3. Rationale

The provision was, in part, intended to settle a long-standing controversy as to the proper treatment of tertiary injectants costs.

4. Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Oil and gas/Production.

5. Impact

Any effects to date have been minor. They consist of prolonging the lives of some wells, thus increasing the total volume of hydrocarbons recovered from those wells.

6. History

The provision has been in effect for more than a decade.

7. Method Used to Estimate Revenue Loss

The data were developed by the staff of the Joint Committee on Taxation with the assistance of Treasury Department Staff.

Exception from Passive Loss Limitation for Working Interests in Oil and Gas Properties

1. Description

Owners of working interests in oil and gas properties are exempt from the "passive income" limitations, which limit the ability of individuals to offset their losses from passive activities against active income. Passive losses remaining after being netted against passive incomes can only be carried over to future period passive incomes. The passive loss limitation provision and the oil and gas exception to it apply principally to partnerships and individuals rather than to corporations.

2. Revenue Loss/Outlays

Estimated Revenue Loss and Outlay Equivalent

(Million Dollars)

Fiscal Year	Revenue Loss			Outlay Equivalent[a] (Total)
	Individuals	Corporations	Total	
1987	NA	NA	NA	NA
1988	55	0	55	75
1989	135	0	135	135
1990	180	0	180	245
1991	80	0	80	100
1992	80	0	80	100

[a]An outlay equivalent is the amount of outlay that would be required to provide the taxpayer the same after-tax income as would be received through the tax preference.

NA = Not available or not applicable.

Note: All estimates have been rounded to the nearest $5 million.

Source: Office of Management and Budget, *Budget of the United States Government, Fiscal Year 1993* (Washington, DC, 1992). Also earlier editions.

3. Rationale

Working interests in oil and gas properties were exempted from the loss limitations in the Tax Reform Act of 1986. Factors that contributed to the adoption of the exemption included concern regarding availability of investible funds for oil and gas development given the collapse in oil prices that occurred during the same year the Act was passed.

4. Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Crude oil and natural gas/Production.

5. Impact

The major impact of the exception from the passive loss limitation is on forms of business organizations that develop oil and gas properties. A shift toward the unlimited liability partnership form is likely since the exception applies mainly to that form. Any shift is likely to be small because of the increased risk associated with unlimited liability. Nevertheless, some increase in exploration and development of oil and gas properties is likely as the subsidy attracts new capital.

6. History

Passive loss limitations were introduced by the Tax Reform Act of 1986. Owners of working interests in oil and gas properties were exempted from them.

7. Method Used to Estimate Revenue Loss

The “Revenue Loss” data in the tabulation above were generated by the U.S. Treasury Department. They are the difference between estimated Federal income tax payments in a reference case and estimated actual Federal income tax payments. The reference case assumes that there are no exceptions to the passive loss limitations. The actual case assumes that exceptions are granted principally to noncorporate taxpayers.

New Technology Credit

1. Description

Ten percent tax credits exist for investment in solar and geothermal energy facilities.

2. Revenue Loss/Outlays

Estimated Revenue Loss and Outlay Equivalent
(Million Dollars)

Fiscal Year	**Revenue Loss**			**Outlay Equivalent[a] (Total)**
	Individuals	Corporations	Total	
1987	10	140	150	180
1988	0	80	80	95
1989	0	80	80	110
1990	0	75	75	110
1991	0	75	75	110
1992	0	45	45	65

[a]An outlay equivalent is the amount of outlay that would be required to provide the taxpayer the same after-tax income as would be received through the tax preference.

Note: May include unknown amounts that apply to tax expenditure provisions that expired before January 1, 1992 and which were not new technology credits.

Note: All estimates have been rounded to the nearest $5 million.

Source: Office of Management and Budget, *Budget of the United States Government, Fiscal Year 1993* (Washington, DC, 1992). Also earlier editions.

3. Rationale

The rationale behind the tax credits that remain is to reduce dependence on oil and gas and to do so by increasing the use of solar and geothermal.

4. Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Solar and geothermal/Production.

5. Impact

The income tax credits for investing in solar and geothermal facilities have encouraged the production and consumption of energy from these two sources. The credit reduces the cost of developing new facilities and promotes the use of renewable resources for electricity generation. Production costs have declined over time. Nevertheless, production of solar and geothermal energy accounts for less than one-half of 1 percent of U.S. energy production. The scope of the solar provision has narrowed since the 1980's, which has further reduced the impact of the credit.

6. History

The Energy Tax Act of 1978 and the Crude Oil Windfall Profit Tax of 1980 provide the principal bases for the subsidies that at one time or another have been covered by this provision. The scope of the provision has narrowed considerably over the years. The provision included tax credits for equipment using energy from nonconventional sources, generally defined as sources other than oil and gas as traditionally produced. It also included credits for equipment used to extract oil and gas from unusual sources. Several other credits also existed, such as credits for investment in wind energy equipment. The tax credits for investment in solar and geothermal energy facilities are the only two credits that remain from the group that was intended to encourage conservation and the use of alternate energy sources, and even these credits expired on June 30, 1992.

7. Method Used to Estimate Revenue Loss

The "Revenue Loss" data in the tabulation above were generated by the U.S. Treasury Department. They are estimates based on an estimate of investment in solar and geothermal energy facilities and the estimated actual income tax credit for such investment.

Alternative Fuel Production Credit

1. Description

An alternative (or nonconventional) fuels income tax credit applies to qualified fuels from wells drilled or facilities placed in service between January 1, 1980, and December 31, 1992, and sold through the year 2002. The qualified fuels are: (1) oil produced from shale and tar sands; (2) gas from geopressurized brine, Devonian shale, coal seams, tight formations or biomass; (3) liquid, gaseous, or solid synthetic fuels produced from coal; (4) fuel from qualified processed wood; and (5) steam from solid agricultural byproducts.

The tax credit for these fuels is $3 per barrel of oil-equivalent produced. (Conversion factors are used to convert the various fuels into their crude oil equivalent for purposes of calculating the credit.) The credit is fully effective when the price of crude oil is $23.50 per barrel or less and phases out gradually as the price of oil rises to $29.50 per barrel. All prices as well as the credit are specified in 1979 dollars, but for actual use are indexed for inflation relative to that base. The credit is reduced if certain other energy subsidies, such as government grants and tax-exempt financing, are used.

2. Revenue Loss/Outlays

Estimated Revenue Loss and Outlay Equivalent
(Million Dollars)

Fiscal Year	Revenue Loss			Outlay Equivalent[a] (Total)
	Individuals	Corporations	Total	
1987	b	10	10	25
1988	b	10	10	15
1989	b	10	10	15
1990	b	10	10	15
1991	50	205	255	380
1992	50	360	450	670

[a]An outlay equivalent is the amount of outlay that would be required to provide the taxpayer the same after-tax income as would be received through the tax preference.
[b]$2.5 million or less.
Note: All estimates have been rounded to the nearest $5 million.
Source: Office of Management and Budget, *Budget of the United States Government, Fiscal Year 1993* (Washington, DC, 1992). Also earlier editions.

3. Rationale

The alternative fuel tax credit is one of several measures adopted in the early 1980's to encourage the development of synthetic fuels produced by nonconventional means or sources. The credit is designed to encourage capital investment in alternative fuel production by protecting producers of those fuels against the effects of oil price reductions.

4. Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Oil and gas/Production.

5. Impact

The tax credit provision has had a substantial impact on the production of alternative fuels. The fuel most affected has probably been gas produced from coal seams. The recent impact has been large both because it was expected that the credit would expire for wells and facilities not placed in service by a certain date and because crude oil prices have been low. The credit for qualified gas was about $0.86 per million Btu in 1990, or about one-half the wellhead price of U.S. produced natural gas in that year. The extent to which other non-conventional fuels have been affected is less certain. Generally, however, the credit has caused oil and gas supplies to increase beyond levels that would otherwise have been reached. The Department of Energy estimates that the increase could amount to 100,000 barrels a day of oil-equivalent production by 1995.

6. History

The alternative fuel production credit was established by the Windfall Profit Tax Act of 1980 and became operational in the same year. The principal additional changes that have occurred since the 1980 Act have been to extend the time limits by which wells or facilities must be placed in service and fuels sold in order to be eligible for the credit. In 1989, legislation allowed a 1-year extension of the time limits. The Omnibus Budget Reconciliation Act of 1990 provided an additional, 2-year, extension. The 1990 act also greatly eased the qualification for gas produced from tight sands after 1990. The qualification had been sharply constrained by executive branch rulings and judicial decisions.

7. Method Used to Estimate Revenue Loss

The “Revenue Loss” data in the tabulation above were generated by the U.S. Treasury Department. They are the difference between estimated Federal income tax payments in a reference case and estimated actual Federal income tax payments. The reference case assumes that the alternative fuels receive no production credit. The actual case assumes that the credit is granted.

Alcohol Fuel Credit

1. Description

Motor fuels composed of at least 10 percent alcohol are exempt from 5.4 cents of the per gallon Federal excise tax on gasoline, diesel fuel and other motor fuels. The income tax credit is 54 cents per gallon for alcohol used as motor fuel and can be used in lieu of the excise tax exemption. The income tax credit is granted to producers of alcohol fuels, that is, to distributors who blend the alcohol and motor fuels. The credit may differ from 54 cents depending on the proof of the alcohol. A new Federal income tax credit of 10 cents per gallon is also available to eligible small producers of ethanol. An eligible small producer of ethanol generally means a person who, at all times during a year, has a productive capacity for alcohol not in excess of 30 million gallons.

2. Revenue Loss/Outlays

Estimated Revenue Loss and Outlay Equivalent

(Million Dollars)

Fiscal Year	Revenue Loss			Outlay Equivalent[a] (Total)
	Individuals	Corporations	Total	
1987	b	5	5	10
1988	b	5	5	10
1989	0	b	b	b
1990	0	b	b	b
1991	0	0	0	0
1992	0	80	80	80

[a]An outlay equivalent is the amount of outlay that would be required to provide the taxpayer the same after-tax income as would be received through the tax preference.

[b]$2.5 million or less.

Note: All estimates have been rounded to the nearest $5 million.

Note: Gasohol is also partially exempt from the Federal excise tax on gasoline. The estimated revenue loss from that exemption has been: 1987: $475 million; 1988: $480 million; 1989: $485 million; 1990: $445 million; 1991: $465 million; and 1992: $460 million.

Source: Office of Management and Budget, *Budget of the United States Government, Fiscal Year 1993* (Washington, DC, 1992). Also earlier editions.

3. Rationale

The alcohol fuel income tax credit was created to encourage the production and use of alcohol as a substitute for petroleum-based gasoline. The basic objective was to reduce U.S. petroleum import dependence and to extend the supply of liquid fuels.

4. Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Alcohol as a motor fuel/Blending.

5. Impact

The alcohol fuels income tax credit is not generally used. The provision therefore has little impact. Instead, blenders use the excise tax exemption, which provides them with an immediate cash flow. Also, blenders can benefit from the excise tax exemption, even in the absence of profits. Also, the new Federal credit of 10 cents per gallon to small producers of ethanol will likely be used by them in the immediate future. However, any substantial impact with respect to credits is likely to continue to be from the excise tax credit rather than from the income tax credit.

6. History

The alcohol fuel income tax credit and its associated excise tax credit were initially implemented in the early 1980's. The income tax credit was initially 40 cents per gallon minus the amount of excise tax exemption, which was 4 cents per gallon. Some changes have been made since that time. The most recent resulted from the Omnibus Budget Reconciliation Act (OBRA) of 1990, which reduced the income tax credit from 60 cents per gallon to 54 cents per gallon. The excise tax credit was also reduced, from 6 cents per gallon to 5.4 cents per gallon. OBRA also introduced the small producer income tax credit of 10 cents per gallon.

7. Method Used to Estimate Revenue Loss

The "Revenue Loss" data in the tabulation above were generated by the U.S. Treasury Department. They are the difference between estimated Federal income tax payments in a reference case and estimated actual Federal income tax payments. The reference case assumes that no income tax credits are granted. The actual case assumes that the income tax credit exists and that the excise tax credit remains in effect.

Excess of Percentage Over Cost Depletion: Oil, Gas, and Other Fuels

1. Description

Independent oil and gas producers and royalty earners, and all producers and royalty owners of certain other natural resources, including mineral fuels, may take percentage depletion deductions rather than cost depletion deductions to recover their capital investment. Under cost depletion, the annual deduction is equal to the unrecovered 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 at rates of 10 percent for coal; 15 percent for oil, gas, oil shale and geothermal deposits; and 22 percent for uranium. However, two special provisions apply to oil and gas. First, percentage depletion for independent producers and royalty earners is limited to 1,000 barrels per day. Second, the 15 percent rate is increased by 1 percentage point for each dollar that the average wellhead price of domestically produced crude oil is less than $20 a barrel. The maximum increase allowed is 10 percentage points. This special provision applies only to oil and gas wells with marginal production, generally defined to include production from stripper wells and from wells substantially all of whose production is heavy oil. Marginal production eligible for the higher rate has a prior claim on the 1,000 barrel per day limitation.

The percentage depletion deductions based on gross income are subject to net income limitations. The annual deduction for oil and gas is limited to 100 percent of net income from the property, geothermal is limited to 65 percent and the other mineral fuels are limited to 50 percent. Since percentage depletion is based on gross income, the resultant allowances can exceed the actual acquisition and development costs for the property from which the resource is extracted.

2. Revenue Loss/Outlays

Estimated Revenue Loss and Outlay Equivalent

(Million Dollars)

	Revenue Loss						Outlay Equivalent[a] (Total)	
	Individuals		Corporations		Total			
Fiscal Year	Oil and Gas	Other Fuels	Oil and Gas	Other Fuels[b]	Oil and Gas	Other Fuels[b]	Oil and Gas	Other Fuels[b]
1987	580	15	145	200	725	215	1,030	330
1988	370	10	80	125	450	135	680	215
1989	310	10	80	125	390	135	530	210
1990	540	10	110	135	650	145	860	220
1991	460	10	95	150	555	160	735	240
1992	475	15	95	160	570	175	760	265

[a]An outlay equivalent is the amount of outlay that would be required to provide the taxpayer the same after-tax income as would be received through the tax preference.

[b]Assumed to be primarily coal.

Note: All estimates have been rounded to the nearest $5 million.

Source: Office of Management and Budget, *Budget of the United States Government, Fiscal Year 1993* (Washington, DC, 1992). Also earlier editions.

3. Rationale

Percentage depletion for oil and gas properties was introduced as a substitute for a related provision (discovery-value depletion) that had been adopted for a wide range of resources during World War I to stimulate production, but which was fraught with administrative problems. Discovery-value depletion was based on the market value of the deposit after discovery rather than on the cost of the property, as is done for cost depletion. Congress subsequently extended percentage depletion to a wide range of other minerals to be consistent with the treatment of oil and gas.

4. Major Energy Form/Fuel Cycle Stage(s) Affected

Crude oil, natural gas, and coal / Production
(Minor energy forms include uranium, oil shale, and geothermal.)

5. Impact

Percentage depletion had the effect of substantially increasing the development of existing property since the total depletion claimed could exceed the original investment. The increase in output benefitted producers (operators and royalty holders) through increased royalties and higher after-tax profits. Consumers also benefitted, a result of lower prices. The benefits to producers were considered so substantial that beginning in 1969 percentage depletion rates were reduced for oil and gas, major oil and gas companies were excluded from the percentage depletion provisions (1975), and other restrictive measures were adopted.

6. History

Percentage depletion for oil and gas properties became law in 1926. It was extended to most other minerals, including mineral fuels, in 1932. Whoever is eligible for percentage depletion must use it rather than cost depletion.

The oil and gas provisions have been changed several times since they were first introduced in 1926. The 27.5-percent depletion rate that prevailed from 1926 to 1969 was reduced to 22 percent at the end of that period. Between 1981 and 1984 it was gradually reduced to 15 percent where it has since remained, subject to the allowed increases mentioned above as the price of crude oil drops below $20 a barrel. Those allowed increases were enacted into law in 1990 but did not become operational until 1991. Not only has the oil and gas depletion rate generally declined over time, but producers have been increasingly restrained in the extent to which they can use percentage depletion. Integrated producers were prohibited from using percentage depletion beginning in 1975. At the same time, independent producers were constrained to 2,000 barrels a day or the equivalent for percentage depletion purposes, a level which was phased down to 1,000 barrels a day by 1980.

The depletion rates for mineral fuels other than oil and gas have not changed for at least a decade. The net income limitations for nearly all mineral fuels have also been essentially constant for the past decade. The most important exception was a 1991 increase in the limitation for oil and gas from 50 percent to 100 percent.

7. Method Used to Estimate Revenue Loss

The “Revenue Loss” data in the tabulation above were generated by the U.S. Treasury Department. They are the difference between estimated Federal income tax payments in a reference case and actual Federal income tax payments. The reference case assumes that cost depletion is used. The actual case assumes that percentage depletion is used.

Exclusion of Interest Income on Energy-Related State and Local Bonds

1. Description

The interest on industrial development bonds issued by State or local governments to finance certain energy facilities, such as municipal electric and gas utilities, may be exempt from Federal tax.

2. Revenue Loss/Outlays

Estimated Revenue Loss and Outlay Equivalent
(Million Dollars)

Fiscal Year	Revenue Loss			Outlay Equivalent[a] (Total)
	Individuals	Corporations	Total	
1987	0	305	305	360
1988	0	290	290	385
1989	0	315	315	380
1990	0	255	255	315
1991	0	125	125	185
1992	0	125	125	185

[a]An outlay equivalent is the amount of outlay that would be required to provide the taxpayer the same after-tax income as would be received through the tax preference.
Note: All estimates have been rounded to the nearest $5 million.
Source: Office of Management and Budget, *Budget of the United States Government, Fiscal Year 1993* (Washington, DC, 1992). Also earlier editions.

3. Rationale

To encourage the development of selected energy facilities.

4. Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Natural gas and electricity / Conversion.

5. Impact

The tax exempt feature of certain industrial development bonds for energy facilities encourages their construction. Investment in debt financed projects is encouraged relative to investments that are not so financed. The subsidy lowers utility financing costs and results in product prices that are lower and product consumption that is greater than they would be without a subsidy approach.

6. History

Interest on the obligations of State and local governments has been excluded from gross income for Federal income tax purposes since 1913. However, the interest on industrial development bonds issued by those governmental bodies has generally been subject to Federal tax, except for the interest on certain issues, including select energy issues. The general trend has been to reduce the scope of issues to which the tax-exempt status of industrial development bonds applies as well as the dollar magnitude of those issues. For example, the tax free status of small scale hydroelectric generating facilities and steam generating or alcohol production facilities expired during the 1980’s.

7. Method Used to Estimate Revenue Loss

The “Revenue Loss” data in the tabulation above were generated by the U.S. Treasury Department. Generally, they are the amount of estimated Federal income tax payments that would have been made on interest earnings on taxable bonds that are otherwise similar to those that are tax free.

Black Lung Disability Fund

1. Description

The Black Lung Disability Trust Fund consists of all moneys collected from the coal mine industry under the provisions of the Black Lung Benefits Revenue Act of 1981, as amended by the Consolidated Omnibus Budget Reconciliation Act of 1985, in the form of an excise tax on mined coal. In addition, the fund pays all administrative expenses incurred in the operation of the Black Lung program. The fund is administered jointly by the Secretaries of Labor, the Treasury, and Health and Human Services. The Benefits Revenue Act provides for repayable advances to the fund in the event resources will not be adequate to meet program obligations.

2. Revenue Loss/Outlay

Outlays for the fund were $935 million in FY 1991 and are expected to be $970 million in FY 1992. The fund's end-of-FY 1991 balance was $17 million and end-of-FY 1992 balance was $55 million.

3. Rationale

These monies are expended to pay compensation, medical and survivor benefits to eligible miners and their survivors, where mine employment terminated prior to 1970 or where no mine operator can be assigned liability.

4. Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Coal / Mining

5. Impact

The excise tax on coal is expected to put some upward pressure on the prices of mined coal. However, the latter is relatively low at this time, and a small increase will probably not affect demand very much.

Abandoned Mine Reclamation Fund

1. Description

This fund is designated for carrying out the provisions of Title IV of the Surface Mining Control and Reclamation Act (SMCRA) of 1977. There are three major programs. The first program is for State reclamation grants. Each State and Tribe with an approved reclamation program is entitled, subject to appropriation, to receive 50 percent of fund revenues derived from operating mines in that State or Tribal Land. With grants, States and Tribes assume primary responsibility for addressing problems such as subsidence, underground fires, open shafts, and acid drainage in accordance with SMCRA. States with approved reclamation plans are responsible for emergency reclamation. The second program covers Federal reclamation. This activity includes fee collection, and assistance to States in developing reclamation programs, abandoned mine lands reclamation projects undertaken directly by the Office of Surface Mining Reclamation and Enforcement for States lacking approved reclamation plans, and the Rural Abandoned Mine Program administered by the Department of Agriculture's Soil Conservation Service. The third program is for small operator assistance payments: This activity provides for payments for authorized services to eligible coal mine operators in preparing applications for mining permits under a permanent State or Federal regulatory program. These services include determining the probable hydrologic consequences of the proposed mining operation and analysis of test borings and core samples.

2. Revenue Loss/Outlay

Outlays for this fund were $216 million in FY 1991, and are expected to be $154 million in FY 1992. The fund's end-of-FY 1991 balance was $574 million and end-of-FY 1992 balance was $655 million.

3. Rationale

The rationale for the SMCRA was to induce operators of surface mines to attempt to leave the surface area as close to the state they found it in as possible. There was apparently little motivation by profit-seeking firms to internalize the external costs created by their activities. Civil penalties are assessed on violators.

4. Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Coal / Mining

5. Impact

To the extent that collections do not cover all expenses, the fund underwrites abandoned mine remediation. In actuality, the fund had an expected increased end-of-FY 1992 balance, so that the industry is paying in excess of claims on the fund. As the costs of coal are increased to the fund, coal prices may be increased.

Nuclear Waste Disposal Fund

1. Description

Monies from this fund administered by the Department of Energy are used to carry out the purposes of the Nuclear Waste Policy Act of 1982. The program consists of efforts related to the development, acquisition, and operation of facilities for the disposal of civilian and defense high-level nuclear waste. The fund is paid for by the users of the disposal service. Some of the monies are designated for the State of Nevada for oversight, and the University of Nevada for R&D as that State is the most likely location of a high-level waste repository.

2. Revenue Loss/Outlay

Outlays for this fund were $296 million in FY 1991, and are expected to be $264 million for FY 1992. The fund's end-of-FY 1991 balance was $2,831 million and end-of-FY 1992 balance was $3,302 million.

3. Rationale

As proper waste disposal is necessary for the public health and welfare, the Federal Government desires to be involved.

4. Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Nuclear power / Waste storage

5. Impact

To the extent that collections do not cover all expenses, the fund underwrites pipeline safety. In actuality, the fund has an increased end-of-FY 1992 balance, so that the industry is more than paying for the current costs of planning and building facilities for the program. As the costs of nuclear power are increased by the contributions to the fund, electricity prices may increase.

Oil Spill Liability Fund

1. Description

Though administered by the Department of the Interior, the monies in this fund are used to finance oil pollution prevention and cleanup responsibilities by various Federal Agencies. The Omnibus Budget Reconciliation Act of 1989 triggered the collection of a 5 cent tax on each barrel of oil entering U.S. ports to be deposited with the fund.

2. Revenue Loss/Outlay

Outlays for this fund were $41 million in 1991, and are estimated to be $66 million for FY 1992. The fund's end-of-FY 1991 balance was $647 million and end-of-FY 1992 balance was $894 million.

3. Rationale

To aid in the prevention or remediation of potentially damaging oil spill events.

4. Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Oil / Transportation

5. Impact

It is often the case that prevention is cheaper than remediation. To the extent that the fund wards off or minimizes oil-spill damages through its spending on prevention, the problem is solved in the lesser cost manner. The tax on imports tends to increase the prices of oil products and thereby reduce petroleum consumption.

Leaking Underground Storage Tank Fund

1. Description

The Leaking Underground Storage Tank Fund, authorized by the Superfund Amendments and Reconciliation Act of 1990 and administered by EPA, provides funds for responding to releases from leaking underground petroleum tanks. It is financed by a 0.1 cent/ gallon tax on motor fuels that became effective January 1, 1987.

2. Revenue Loss/Outlay

Outlays from this fund were $66 million in FY 1991 and are expected to be $87 million in FY 1992. The fund's end-of-FY 1991 balance was $468 million and end-of-FY 1992 balance was $573 million.

3. Rationale

The fund acts as insurance in the case of leakages. As the immediate potential damages are so great, a quick response is appropriate.

4. Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Oil/Storage

5. Impact

Consumers and producers of motor fuels are affected by the increased price implied by the tax.

Pipeline Safety Fund

1. Description

The Research and Special Programs Administration of the Department of the Interior is responsible for this fund. Monies in this fund are used to conduct the functions of the pipeline safety program and for grants-in-aid to carry out a pipeline safety program, as authorized by section 5 of the Natural Gas Safety Act of 1968 and the Hazardous Liquid Pipeline Safety Act of 1979. Activities include enforcement programs, R&D, and grants for State pipeline safety programs.

2. Revenue Loss/Outlay

Outlays for this fund were $9 million in FY 1991, and are expected to be $12 million in FY 1992. The fund's end-of-FY 1991 balance was $17 million and the end-of-FY 1992 balance was $18 million.

3. Rationale

The public interest in pipeline safety calls for Government intervention.

4. Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Oil and natural gas/Transportation

5. Impact

To the extent that collections do not cover all expenses, the fund underwrites pipeline safety. In actuality, the fund has a slightly increased end-of-FY 1992 balance, with no perceptible effect on energy prices.

Hazardous Substance Fund

1. Description

The Hazardous Substance Fund (Superfund) provides monies for the implementation of the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended. This Act provides authority for responding to and cleaning up hazardous substance emergencies and abandoned uncontrolled hazardous waste sites. There are three basic components of the Superfund program: site assessment and cleanup activities; enforcement; and support. Support includes facilities and management, R&D, and other nondirect site work. Financial responsibility for the program will be shared by the Federal and State Governments as well as industry. The Environmental Protection Administration will allocate funds from its appropriations to other Federal agencies to carry out the Act.

2. Revenue Loss/Outlay

Actual net outlays in FY 1991 were $1,417 million, and are estimated to be $1,486 million in FY 1992. The fund's end-of-FY 1991 balance was $1,249 million and the end-of-FY 1992 balance was $1,423 million.

3. Rationale

The fund acts as insurance in the case of spills and discoveries of sites left untended. As the immediate potential damages are so great, a quick response is appropriate. There can be no deliberations about liability, compliance with storage specifications, etc.

4. Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Oil, Chemical Feedstocks / Production, Refining, Storage, Distribution

5. Impact

To the extent that funds are not recovered under the Act, the Federal Government is expensing monies to mitigate the external costs of the operations of the related industries. Industries that do not pay the full costs of their negative externalities are, in effect, being subsidized in their activities. This allows them to operate at higher activity levels than society may desire.

Nuclear Fusion

1. Description

Fusion R&D is aimed at achieving a scientific understanding of the complex processes involved in fusion, and to use this understanding to design and operate an engineering test facility to develop fusion technology. The U.S. is supporting a world-wide effort to develop the engineering design of an International Thermonuclear Experimental Reactor (ITER). Other research includes the first deuterium-tritium experiments in the Tokamak Reactor, and conceptual design of a new experimental device to improve the current Tokamak machine performance and contribute to the ITER effort. In addition, support is provided to develop inertial confinement fusion by conducting R&D on a heavy-ion driver concept.

2. Revenue Loss/Outlay[169]

The fusion R&D program had outlays of $214 million in FY 1991 and $270 million in FY 1992.

3. Rationale

The potential for a virtually limitless, environmentally-friendly power source is the main motivation behind fusion research. The long-term goals of the R&D program are to have an operating power plant by 2025 and an operating commercial plant by 2040.

4. Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Nuclear Power / Production

5. Impact

In the long term, the expanded use of fusion energy could provide a low-cost, continuing supply of baseload electrical energy for the United States.

[169]The reader should note that to be consistent with other fact sheets, outlays are reported here, while Table 11 in Chapter 5 contains *appropriations*.

Other Basic Research

1. Description

The basic research at the Department of Energy involves three major thrusts: high energy physics, the superconducting supercollider (SSC) and nuclear physics. In the first program, research focuses on the fundamental constituents of matter, the fundamental forces in nature, and the transformations of matter and energy at the most elemental level. The second program involves research leading to the construction of an advanced accelerator. The third program is investigating, among other things, the role of quarks and the properties of neutrinos in atomic nuclei, as well as the mechanisms by which colliding nuclei exchange mass, energy and angular momentum.

2. Revenue Loss/Outlay[170]

Outlays for basic science were $1.1 billion (including the Super Colliding Super Conductor) in FY 1991 and are expected to be $1.5 billion in FY 1992. Basic energy science accounted for $0.9 billion in FY 1992. Environment, safety, and health was $0.5 billion in FY 1992.

3. Rationale

Government generally undertakes basic research. The commercial payoffs are uncertain, long-term, and "public." Therefore, private, for-profit organizations may invest "too little" in basic research. In DOE, the high energy physics program is aimed toward an increased knowledge of known particles, the discovery of new particle constituents, and ultimately a unified description of the four fundamental forces in nature. The SSC will aid in the pursuits of the first preceding program. The third program has a goal of understanding the interactions and structure of atomic nuclei. Ultimately, it is hoped that increased understanding of fundamental processes will reap applications that improve the energy sources and technologies that are in use today.

4. Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Nuclear and others / Pre-fuel cycle

5. Impact

If the results of basic research follow in the pattern of previous discoveries, then benefits of applied technological advances will be felt for decades to come. It is difficult, however, to assess these benefits in commensurate terms with the dollars allocated to the programs in the present.

[170]The reader should note that to be consistent with other fact sheets, outlays are reported here, while Table 11 in Chapter 5 contains *appropriations*.

Nuclear Fission Research and Development

1. Description

The Civilian Reactor Development program is proceeding on two parallel tracks. The "evolutionary" track refers to large, improved versions of current technology. The "advanced" track involves mid-sized (600 MW) plants with passive safety features. Industry-matched Department of Energy (DOE) funds are being allocated to an effort to assist in the certification of two evolutionary and two advanced Light Water Reactor designs. An important emphasis is in the "standardization" of designs. Other areas of concern are the Modular High-Temperature Gas Reactor, and the Integrated Fast Reactor / Advanced Liquid Metal Reactor. The latter holds particular promise, as it is expected to be able to recycle the actinides in the spent fuel.

2. Revenue Loss/Outlay[171]

Nuclear fission R&D program outlays were $225 million in FY 1991 and are expected to be $242 million in FY 1992.

3. Rationale

Besides the general improvement in nuclear power-generating systems, much of the research in the nuclear fission area is directed toward overcoming the obstacles that have stifled the orders for, and construction of, new nuclear facilities.

4. Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Nuclear power / Production

5. Impact

According to the DOE *National Energy Strategy*, a calculation of the combined benefits envisioned from achieving commercial standardization, simplified and modular design, improved construction management, and licensing reform indicates that the cost of fission-generated power could be reduced from the average of 9.9 cents / kWh for power plants brought into service since 1980 to 6.6 cents / kWh.

[171]The reader should note that to be consistent with other fact sheets, outlays are reported here, while Table 11 in Chapter 5 contains *appropriations*.

Clean Coal Technology Program

1. Description

Public Law 99-190 provided funds from the Energy Security Reserve in the Department of Treasury for a Clean Coal Technology (CCT) Program in the DOE. The program was authorized under the Clean Coal Technology Reserve proviso of PL 98-473. to subsidize the construction and operation of facilities to demonstrate the potential commercial feasibility of such technologies. Cost-shared (e.g., with the Electric Power Research Institute) Innovative CCT projects demonstrate technologies appropriate for replacing, retrofitting, or modernizing existing coal-fired facilities to provide significantly reduced emissions. The provisions of cost-sharing allow the Government to recoup investments if the technologies achieve commercialization.

2. Revenue Loss/Outlay

In FY 1991, outlays for CCT were $123.5 million, while in FY 1992 they are projected to be $162 million.

3. Rationale

To speed up the introduction of technologies that use low-cost coal, while ensuring that progress toward meeting air-quality goals is made.

4. Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Coal / Combustion

5. Impact

If successful, clean coal technologies may reduce the emissions of new coal-fired power plants in the post-1995 period, as well as reducing coal consumption, since the new technologies are projected to be as much as 20 percent more efficient than existing technologies (Energy Information Administration, *Assumptions for the Annual Energy Outlook 1992*, DOE / EIA-0527(92) (Washington, DC, 1992), p. 75.)

Other Coal Research and Development

1. Description

Other coal research and development (R&D) has three related facets—high-efficiency combustion, reduced emissions, and changing coal into gases or liquids. Advanced research is taking place on liquefaction, coal preparation, surface coal gasification, atmospheric fluidized-bed combustion systems, fuel cells, direct coal-fired turbines, and residential/commercial systems.

2. Revenue Loss/Outlay[172]

Other coal R&D received outlays of $301 million in FY 1991, with $293 million expected in FY 1992.

3. Rationale

The objective of coal R&D is to provide an adequate scientific and engineering knowledge base to foster technological advances by the private sector. Also, coal-burning power plants are at the center of the controversies involving acid rain and global warming. New technology may help alleviate these problems.

4. Major Form of Energy(s)/Fuel Cycle Stage(s) Affected

Coal/Mining, Combustion, Liquefaction, Gasification

5. Impact

If R&D is successful, improved coal technologies may benefit consumers through reduced electric power costs, and, perhaps, prices. In the 1992 *Annual Energy Outlook*, coal as a source is expected to provide 23.8 percent of total energy use in 2010 as compared to 22.5 percent with 1990.

[172]The reader should note that to be consistent with other fact sheets, outlays are reported here, while Table 11 in Chapter 5 contains *appropriations*.

Oil Research and Development

1. Description

The overall approach of oil R&D is first, to identify those types of oil deposits that have both the greatest potential for improved oil recovery and the greatest risk of abandonment within the next 5 to 10 years, and second, to apply available technologies. The technologies to be further investigated are called secondary and enhanced oil recovery. The first generally involves drilling and improved production methods based on sophisticated geological and geophysical interpretation. Enhanced oil recovery includes the injection of chemicals, gases, or heat to overcome physical barriers in the reservoir.

2. Revenue Loss/Outlay[173]

The oil, gas, and shale R&D program outlays were $51 million in FY 1991. They are expected to be $79 million in FY 1992.

3. Rationale

The enhanced oil recovery research is aimed at capturing a significant portion of the estimated 300 billion barrels left in the ground from past recovery rates and methods. The goal is to preserve access to these identified deposits while developing and testing technologies designed to overcome the specific problems that prevent increased oil recovery.

4. Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Crude Oil/Production

5. Impact

According to the Department of Energy *National Energy Strategy*, the proposed near-term R&D measures would result in additional oil production that would peak at 1.4 million barrels per day by 2005. They would add total oil reserves of 5 billion barrels (at oil prices of $20 per barrel) to more than 25 billion barrels (at $50 per barrel). Application of the near-term and longer term measures to 80 to 90 percent of the known remaining U.S. oil deposits would result in additional oil production of more than 3 million barrels per day by 2010. The R&D program would, if fully successful, increase the amount of economically recoverable reserves by between 20 (at $20 per barrel) and 65 (at $50 per barrel) billion barrels.

[173]The reader should note that to be consistent with other fact sheets, outlays are reported here, while Table 11 in Chapter 5 contains *appropriations*.

Natural Gas Research and Development

1. Description

Consistent with the objectives of the Department of Energy *National Energy Strategy*, the research program on natural gas has been redesigned. This program previously focused on unconventional gas recovery. It is now focused on developing better recovery technologies for the conventional natural gas resource base and broadening efforts to recover unconventional gas resources, such as tight formations and Devonian shale, improving secondary gas recovery from existing fields, and more economic development of speculative gas resources, such as gas hydrates, deep gas, and abiogenic gas. Storage technology, high-efficiency, low-NO_x turbines, coalbed methane, horizontal drilling, and fracturing technologies, seismic methods, and borehole gravimetry are among the additional research thrusts. Some of this research is co-sponsored with the Gas Research Institute.

2. Revenue Loss/Outlay[174]

The oil, gas and shale R&D program outlays were $51 million in FY 1991. They are expected to be $79 million in FY 1992.

3. Rationale

Natural gas has taken on additional attractiveness in light of the global warming controversy. Its combustion adds less CO_2 to the atmosphere than other fuels. Enhancing the technologically-secure reserve of this fuel, while the industry is made more competitive through regulatory changes, can add large potential benefits to the U.S. economy.

4. Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Natural gas/Exploration and production

5. Impact

According to the 1992 *Annual Energy Outlook*, the current excess capacity in the U.S. natural gas industry will diminish over time. Imports, however, are expected to increase. After reaching a peak of about 19 trillion cubic feet in the first decade of the 21st Century, U.S. gas production is expected to decline as imports grow and utilities and industry use less. The specific effects of the R&D program is uncertain.

[174]The reader should note that to be consistent with other fact sheets, outlays are reported here, while Table 11 in Chapter 5 contains *appropriations.*

Renewable Energy Research and Development

1. Description

The Solar and Renewable Energy research in the Department of Energy (DOE) is a multi-faceted effort. The Utility Technologies program is focusing primarily on photovoltaic (PV), solar thermal, and wind systems. In the first program, improved conversion efficiencies are sought through thin-film and concentrator materials. In the second, dish / Sterling systems and central receivers are receiving attention. In the third, utility-scale wind turbine research is proceeding. In the Building Technologies program, the search for cost-effective solar space and water heating goes on. In the Industrial Technologies program, concentrated solar energy is being investigated for use in the breakdown of toxic organics and for advanced materials processing. Finally, the Transportation Technologies program is looking into alternative, biomass-based fuels that can be used in new-generation vehicles to generate fewer pollutants than gasoline.

2. Revenue Loss/Outlay[175]

The total solar and renewable research outlays in FY 1991 were $147 million. The new multi-directed effort is expected to cost $193 million in FY 1992.

3. Rationale

The DOE Office of Conservation and Renewable Energy seeks to work with industry to strengthen the technology base leading to new products and processes for the commercial market. New technologies often suffer the chicken-or-egg dilemma, as suppliers hesitate to invest in a technology for fear of lack of demand. Consumers, meanwhile, hesitate to switch to the nascent technology, as the necessary complementary goods may not be available. The Government can help alleviate these problems on both sides of the market. Capturing renewable energy in a cost-effective manner will also help advance the *National Energy Strategy* to reduce dependence on foreign oil.

4. Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Solar, wind, biomass, etc. / Development and commercialization

5. Impact

In 1990, dispersed renewable applications generated 2.8 quadrillion Btu (quads) out of a total U.S. use of 85 quads. Renewable electricity generation replaced 3.6 quads. Combined, this is 7.5 percent of use, but is mainly hydro. The nonhydro portion, especially biofuels, is expected to increase. According to the 1992 *Annual Energy Outlook*, by 2010 the above numbers should be 5 quads and 5.25 quads out of a total of 106. This is 9.7 percent. The programs of research in renewables fuels may increase their penetration.

[175]The reader should note that to be consistent with other fact sheets, outlays are reported here, while Table 11 in Chapter 5 contains *appropriations*.

Energy End Use Research and Development

1. Description

Energy conservation is, in part, a program to discover or invent promising technologies for improving energy end-use efficiencies in the buildings, industry, transportation, and utility sectors of the economy. With respect to buildings, research is going forward on materials and structures, advanced lighting, heating and cooling equipment, indoor air quality, and building systems interactions. In the industrial area, process improvements which minimize waste materials, and which use wastes in production, are a major focus. Near-term demand-reduction technologies include advanced drying systems for textile and paper production, improved high-temperature heat pumps, improved steel-making processes, and advanced sensors for on-line process measurement. Research on long-term technologies includes corrosion-resistant, ultra high-temperature materials. In the transportation sector, advanced vehicle technologies are under scrutiny, including advanced batteries and hybrid vehicles. The major areas of utility-oriented research are integrated resource planning/least cost utility planning (including demand-side management) as well as district heating options.

2. Revenue Loss/Outlay[176]

The total R&D outlay for energy conservation was $171 million in FY 1991. For FY 1992, it is expected to be $232 million.

3. Rationale

It has been recently recognized that an important tool in reducing the U.S. dependence on foreign oil is the efficiency of the devices through which energy is used. An added bonus of using less energy is the set of positive environmental ramifications.

4. Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Oil, natural gas and electricity/End-use

5. Impact

The potential for saving energy through greater efficiency has been projected to be 20 to 30 percent.[177] Many of the electricity-saving options (e.g., the compact fluorescent light bulb) use much less energy than traditional technologies, and have payback periods of under 3 years. The impact on energy use of investments that are economically attractive, even in the short run, could be significant.

[176]The reader should note that to be consistent with other fact sheets, outlays are reported here, while Table 11 in Chapter 5 contains *appropriations*.

[177]Energy Information Administration, *Energy Consumption and Conservation Potential: Supporting Analysis for the National Energy Strategy*, SR/NES/90-02 (Washington, DC, 1990), p. 1.

Unleaded, Oxygenated and Reformulated Fuels

1. Description

In 1970, Congress initiated Federal regulation of fuel additives, in particular, lead. Implementation began in 1975, and was accelerated in 1986. Virtually all gasoline sold today in the United States is classified as unleaded, i.e., containing at most 0.1 gram lead/gallon.

The Clean Air Act Amendments of 1990 require that fuels sold in carbon monoxide nonattainment areas must contain a minimum percentage of oxygen by weight.[178] To reach this minimum, refiners will be blending manufactured gasoline with methyl/tertiary butyl/ether (MTBE), ethanol, and, perhaps, ethyl/tertiary butyl/ether (ETBE). MTBE will be the predominant blending agent in the long run.[179] Beginning in November 1992, only oxygenated gasoline with a minimum of 2.7 percent oxygen can be sold in 39 cities during winter months. These additives are currently more expensive than their refined product substitutes. Thus, there will be an increase in the costs for operating motor vehicles as a result of increased production costs.

Reformulation requirements will call for the blending of gasoline with a variety of additives, including oxygenates, and excluding highly volatile ingredients such as butane and benzene. Reformulated standards call for a minimum of 2 percent oxygen in nonwinter months beginning in 1995.

2. Revenue Loss/Outlay

There are no anticipated budgetary outlays resulting from these fuel-quality changes, other than increased costs of operating Federal vehicles. However, as refiners avail themselves of the Federal credit on 10-percent ethanol-blended gasoline, there may be a loss of Federal tax revenues.

3. Rationale

It has been claimed that the market prices of fuels do not represent all of the costs to society of their consumption and production. Therefore, society consumes more of these fuels than they would in the presence of the full costs of their use. Combustion of gasoline produces pollutants such as carbon monoxide, unburned hydrocarbons, and nitrous oxide. Reductions in carbon monoxide and the latter two ingredients of photochemical smog may improve public health.

4. Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Motor gasolines, ether-blended fuels/Refining and blending

5. Impact

These regulations will displace the use of less expensive motor gasoline blending agents in favor of higher cost ones. The transportation cost increases in 1992 that resulted from the reduction of lead in gasoline and associated environmental restrictions was estimated to be $9.2 billion (1991 dollars). Oxygenated fuels are expected to cost $540 million in 1992-1993, and reformulated fuels over $5 billion in the year 2000.

[178] Beginning in November 1992, only oxygenated gasoline with a minimum of 2.7 percent oxygen can be sold in 40 cities during winter months. Reformulated gasoline standards call for a minimum of 2 percent oxygen in nonwinter months beginning in 1995.

[179] Refiners will find it more economical to use surplus butanes (from lowering Reid vapor pressure) to create MTBE feedstock than to use ethanol or ETBE. This view has wide support in the industry trade press. See, for example, *Oil and Gas Journal*, May 27, 1992, page 69, or April 29, 1992, page 65.

Corporate Average Fuel Economy Standards

1. Description

Passed under President Ford in 1975, the Energy Policy and Conservation Act contained provisions regarding the average efficiency of the Nation's automobiles. U.S. automakers were directed, under threat of fines for violation, to achieve an average fleet fuel efficiency level of 27.5 miles per gallon by 1985.

2. Revenue Loss/Outlay

There are no anticipated budgetary outlays resulting from these standards other than the costs of checking for compliance and the costs of prosecuting violators.

3. Rationale

This program was intended to reduce U.S. dependence on imported oil.

4. Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Crude oil and gasoline/End use

5. Impact

Besides many engine improvements, autos have become smaller and lighter. It has been estimated (R. W. Crandall (1990)) that the costs of the mandated Corporate Average Fuel Economy (CAFE) standards averaged about $370 million (1991 dollars) per year from 1978 to 1989.

Underground Storage Tank Regulation

1. Description

Environmental damage associated with leaking underground storage tank systems led Congress to charge the Environmental Protection Agency (EPA) with regulating the nearly 2 million underground storage tanks in the United States. In September, 1988, EPA issued technical standards covering design, construction and installation of new tanks as well as requirements for mandatory upgrading of existing tanks. Regulations for existing tanks were to be phased in over 4 years. In October, 1988, EPA set forth financial responsibility regulations requiring owners of underground storage tanks to demonstrate the ability to cover costs of third party liability and corrective actions. These financial requirements were phased in over 2 years.

2. Revenue Loss/Outlay

There are no anticipated budgetary outlays resulting from these standards other than the costs of checking for compliance, and the costs of prosecuting violators. The Leaking Underground Storage Tank Fund was set up through a 0.1 cent tax per gallon tax on motor fuels to respond to situations created in the past by leaking tanks.

3. Rationale

The potential damage of oil-related products seeping into soil and groundwater is so great that Congress has decided to regulate the tanks themselves.

4. Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Oil-related products/Storage

5. Impact

EPA estimated that the costs of these regulations would be $3.6 billion per year over 30 years, with an expected 1 cent per gallon rise in gasoline prices.

Restrictions on Development

1. Description

Regulatory barriers prevent the development of domestic oil resources in discovered fields on the Alaskan North Slope (ANS), the Arctic National Wildlife Refuge, and certain areas of the Outer Continental Shelf (OCS).

2. Revenue Loss/Outlay

There are no anticipated budgetary outlays resulting from these standards other than the costs of checking for compliance, and the costs of prosecuting violators.

3. Rationale

Potential environmental disruption apparently has motivated the Congress to impose these restrictions on these ecosensitive areas.

4. Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Oil and natural gas/Exploration and development

5. Impact

Further development of ANS and OCS resources could add 4.1 billion barrels of oil and 9.4 trillion cubic feet of natural gas to the Nation's recoverable resources, if the environmental concerns could be successfully resolved. The costs of the restrictions can be construed as the foregone benefits of increased domestic supplies of oil and gas. On the other hand, not producing from them now will save supplies for the future.

Alaskan North Slope Oil Export Ban

1. Description

The Export Administration Act of 1979 effectively prohibits the export of Alaskan crude oil. The Act states that "no domestically produced crude oil transported through the Alaskan pipeline may be exported from the United States."

2. Revenue Loss/Outlay

The impact of the ANS export ban was estimated to diminish the later that the ban was eliminated. Without the ban, it has been estimated that 1.5 million barrels per day of ANS crude would have been exported in 1988 with a price increase of $2.25 per barrel; and that 0.4 million barrels per day would be expected in 1995 with a price increase of $0.225 per barrel.[180] Interpolating these estimates to 1992 gives ANS crude exports of 0.872 million barrels per day with a price increase of $1.09 per barrel. This amounts to a revenue differential for the ban on exports of $345.9 million in 1992.

3. Rationale

The explicit purpose of this ban was to prevent the export of U.S. oil, thought vital to the economy and to national security interests. Another consideration in the ban was the subsidization of U.S. maritime interests.

4. Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Crude oil/Producers and refiners

5. Impact

In principle, the export restriction on Alaskan oil prevents oil producers from (always) receiving the highest available price for their product.[181] In 1991, 24 percent of U.S. domestic crude production came from Alaska. The proportion of Alaskan production that would have been exported in the absence of the export restriction cannot be determined within the scope of this study (beyond the linear interpolation given on the page before this one. Whatever the amount would have been, since the United States is a net importer of crude oil, any oil exports from Alaska would probably require an increase in imports in a compensating amount. If the export ban actually makes a difference, then the price that could be received for the oil as exports would be greater than the price at which the oil actually trades. Presumably, if the oil were exported, then its replacement through additional imports would also be more expensive. The net result of these circumstances works to the advantage of consumers; however, the magnitude of the effects is unlikely to be very large.

[180]Energy Information Administration, *Implications of Lifting the Ban on the Export of Alaskan Crude Oil: Price and Trade Impacts*, SR/EMEU/90-3 (Washington, DC, 1990), p. 23.

[181]Pacific Rim refineries place a relatively higher value on ANS crude than the price of that crude on the West Coast (*ibid.*).

FERC Order 636

1. Description

Effective May 18, 1992, the Federal Energy Regulatory Commission (FERC) changed its regulations to require pipelines to separate their provision of transportation and related services from their vending of natural gas. The new order is intended to separate gas from its transportation in a fashion that eliminates the advantages of pipelines over other sellers of gas when they sell gas and its transportation as a composite commodity.

2. Revenue Loss/Outlay

There are no anticipated budget outlays or receipts due to this Order.

3. Rationale

The Order is intended to equalize the availability of gas from any supplier to any end-user. This increased competition should enable gas buyers to find the lowest available price and gas sellers to find the highest available price.

4. Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Natural gas/Producers and end-users

5. Impact

Over the past 5 years, pipeline gas prices have been on the order of $0.20 to $0.80 per thousand cubic feet higher than spot gas prices. This has lead many gas end-users to buy gas in the spot market, while paying pipeline demand charges for firm service. The Order should increase the efficiency of the mix of gas sources used to satisfy demand. The impact upon gas consumption versus other fuels is problematical (although presumably favors gas if the average supply price falls).

Regulatory Reform: NRC Streamlining Plant License Renewal

1. Description

The Nuclear Regulatory Commission (NRC) issued a proposed license extension rule which would eliminate much of the rigorous review process used for new operating licenses. It also would establish a "Generic Environmental Impact Statement."

2. Revenue Loss/Outlay

No expenditure on the part of Government is necessary beyond administrative costs.

3. Rationale

There is a power shortage projected for the late 1990's, and no new nuclear facilities are being built. NRC's rationale for streamlining is that most operating plants in the United States have adequate safety records, and should be allowed to continue to operate without additional extensive review. A "generic" environmental impact statement will help all plants comply with the National Environmental Policy Act.

4. Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Nuclear Power / Production

5. Impact

If the NRC is correct in waiving rigorous review of other-than-age-related areas, then the costs of license renewal should be lower. This could benefit electricity customers, and if demand is elastic, utilities as well by raising revenues. In addition, a uniform Environmental Impact Statement may provide better environmental information.

Price-Anderson Act

1. Description

The Nuclear Regulatory Commission limits liability in the form of the Price Anderson Act. The Act originally limited the liability of nuclear power plants to the level of $560 million. In 1988 amendments to the Act increased the potential liability limits to $7 billion per accident. This effectively controls the individual liability and provides a form of subsidized insurance. The Act also places limits on the amount of insurance required for accident cleanup and decontamination.

2. Revenue Loss/Outlay

There are no associated revenue losses or budgetary outlays at this time. However, Federal outlays could rise, if the Federal Government is forced to cleanup a nuclear incident in excess of individual liability limits.

3. Rationale

The purpose of this regulation was to promote nuclear energy by fixing the liability for a single nuclear incident, thereby reducing the uncertainty associated with future potential claims.

4. Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Nuclear power / Production

5. Impact

One estimate of the implied subsidy in the form of reduced insurance premiums per operating unit is $74.3 million per unit prior to the 1988 amendment increasing liability limits to over $7 billion, and $26.9 million thereafter.[182] For 110 operational units in 1991 the total amount of the subsidy for this estimate would be $3 billion per year. This estimate is based on pro-rata extrapolation of actual insurance premiums and estimates of accident value probability distribution.

[182]Dubin, J.A., and G.S. Rothwell, "Subsidy to Nuclear Power Through Price-Anderson Liability Limit," *Contemporary Policy Issues*, Vol. VIII (1990), pp. 73-79.

Reform of the Public Utility Holding Company Act of 1935 (PUHCA)

1. Description

There are 265 privately owned electric utilities that provide more 75 percent of U.S. electric power generating capacity. More than one-half of these utilities are organized using a holding company structure. The Public Utility Holding Company Act of 1935 (PUHCA) authorizes the Securities and Exchange Commission (SEC) to regulate the corporate and financial structure of public utility holding companies and their subsidiaries. Parallel to this, the Federal Power Act (1935) authorizes the Federal Energy Regulatory Commission to regulate the interstate transmission and sale of wholesale electricity. Generally, the purpose of PUHCA is to impose a structure on the electric power industry that allows State regulation of utility transactions. For this reason, a utility holding company that does not have significant multi-state operations is exempt from most SEC regulation under the Act. Since 1938, the SEC has reduced the number of nonexempt holding companies from over 200 to 13 (10 electric and 3 gas).

2. Revenue Loss/Outlay

No expenditure on the part of Government is necessary beyond administrative costs.

3. Rationale

The intent of Congress was to protect electricity and gas consumers and investors from abuses that had occurred through the use of holding company structures. These included: issuing securities without approval of states having jurisdiction over subsidiary companies; an absence of arm's-length bargaining with subsidiaries; allocation of charges among subsidiaries that States could not regulate; and the growth of holding companies in ways that are not related to the efficiency of subsidiary operations.

4. Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Electric power / Production

5. Impact

Since the time of passage (1935), the Nation's electricity supply system has been integrated beyond the local level into large, interconnected power grids. Since there can be significant regional differences in the costs of constructing and running power plants, one of the current impacts of PUHCA has been to constrain the ability of electricity suppliers to minimize the costs of power as viewed from the National level. Qualitatively, reform of PUHCA is expected to increase competition for providing electricity supply and as a result will reduce capital costs of new plants, enable the penetration of a wider range of generating technologies, improve generating efficiency, lower electricity prices, reduce risks of cost overruns, increase investment opportunities abroad, and increase electricity exports.

The Public Utility Regulatory Policies Act of 1978 (PURPA)

1. Description

The Public Utilities Regulatory Policies Act of 1978 (PURPA) was passed by Congress as part of the National Energy Act of 1978. The basic goal of PURPA is to improve the efficiency of electricity supply through enhanced competition. This is achieved by requiring utilities to purchase power from “nonutilities” at their avoided cost. For the purposes of the Act *nonutilities* are defined as: (1) cogenerators, usually large industrial consumers that produce steam and electricity for their own commercial purposes, but can sell the excess; and, (2) “small power producers” that are 80 megawatts or less and use renewable or waste resources for power generation. In addition, in recent years other electricity producers have appeared to sell wholesale power that do not qualify under PURPA’s fuel or technology requirements. These are termed “Independent Power Producers” (IPPs). IPPs are still considered to be utilities under PUHCA, and are therefore under SEC regulatory authority. However, consistent with the intent of PUHCA, the SEC is attempting to accommodate the development of IPPs. As of 1991, there are 5 operating IPPs and 38 are under development. Including IPPs, nonutilities provided 3.9 percent of the electric power sold in 1990.[183]

2. Revenue Loss/Outlay

No expenditure on the part of Government is necessary.

3. Rationale

PURPA and the development of IPPs represent initiatives to increase the competition among electricity suppliers. Nonutilities as a source of supply can reduce the risk in utilities’ capital acquisition with a resulting reduction in the cost of electric power.

4. Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Electric power / Wholesale supply

5. Impact

In 1984 it was estimated that nonutilities power sources filing for qualification under PURPA could provide around 2 percent of the electricity supplied in 1983. At that time it was estimated that as much as 5 to 20 percent of electricity supply could be from nonutilities by the year 2000.[184] With 3.9 percent of power from nonutilities supplied in 1990, it is currently projected that 10 to 15 percent of power supplied in 2010 will be from nonutilities (including power generated for their own use). For this forecast, it is estimated that from 25 to 30 percent of new generating capacity will be built by nonutility sources.

[183]The estimate of operating IPPs is given in General Accounting Office (GAO), “Electricity Supply: Regulating Utility Holding Companies in a Changing Electric Industry,” Report to the Chairman, Subcommittee in Telecommunications and Finance, Committee on Energy and Commerce, House of Representatives, GAO / RCED-92-98 (1990). Data and projections of nonutility electricity supply are given in EIA, *Annual Energy Outlook 1992*, DOE / EIA-0383(92) (Washington, DC, January 1992).

[184]Energy Information Administration, *Annual Energy Outlook 1992,* DOE / EIA-0383(92), pp. 152-153.

Emissions Restrictions on Electric Utilities

1. Description

Acid deposition control regulations in the Clean Air Act Amendments of 1990 are designed to reduce the emission of acidic compounds into the environment by 10 million tons of SO_2 and 2 million tons of NO_x compared with 1980 levels by the year 2010. Generators of electricity will be responsible for 87 percent of the annual SO_2 reductions and all of the NO_x reductions. Controls are achieved by setting standards for individual emission units and through the trading of annual emission allowances. The use of tradeable allowances is intended to minimize the total cost of conforming to the new environmental standards.

2. Revenue Loss/Outlay

There are no anticipated budgetary outlays resulting from these standards other than the costs of checking for compliance, and the costs of prosecuting violators.

3. Rationale

The purpose of this regulation is to reduce the deleterious effects of acid deposition and acid rain in the environment through reducing the emissions of sulfur dioxide and nitrogen oxides.

4. Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Renewables, natural gas, oil, and coal/Electric power generation

5. Impact

The impact of the restrictions in general will be to increase the cost of electricity. The basis for the cost increase will be primarily the costs of retrofitting existing facilities with pollution control devices and switching to the consumption of more expensive low-sulfur coal. As clean-coal technologies replace older facilities, the differential costs of the restrictions will be reduced. One estimate found the additional costs of compliance to be maximized around the year 2000 at 2 mills per kWh. Although difficult to make, one estimate of the value of damage due to acid disposition and acid rain is 68 mils per kilowatt-hour.[185] Although the restrictions will stimulate alternatives to high-sulfur coal, they should be viewed as an internalization of pollution costs rather than a "subsidy."

[185]The cost estimate is from Energy Information Administration, *Improving Technology: Modeling Energy Futures For The National Energy Strategy*, SR/NES/90-01 (Washington, DC, 1991), pp. 52-62. The damage valuation estimate is from Hall "Preliminary Estimates of Cumulative Private and External Costs of Energy," *Journal of Contemporary Policy Issues*, Vol. 8, No. 4 (1990), pp. 283-307.

Building and Appliance Standards

1. Description

The Department of Energy's home efficiency standards, developed in conjunction with the American Society of Heating, Refrigerating, and Air-Conditioning Engineers, are mandatory for all new Federally owned housing, including military housing. The Department of Housing and Urban Development's energy standards apply to new homes with Federal Housing Administration-insured loans. The Federal Government has mandated standard testing, energy-efficiency labeling, and minimum efficiency standards for all new residential appliances.

2. Revenue Loss/Outlay

There are no anticipated budgetary outlays resulting from these standards other than the costs of checking for compliance, and the costs of prosecuting violators.

3. Rationale

Efforts to constrain vulnerability to foreign energy sources, in the face of dwindling domestic supplies, led policymakers to seek options on the demand side. There are several significant barriers to achieving this increased efficiency through traditional market mechanisms.

4. Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Multi-fuels/End use

5. Impact

Households use approximately one-fifth of all primary energy consumed annually in the United States. Substantial opportunities for large energy savings through increased efficiency exist in the commercial and government sectors, as well as in the residential sector. It is estimated that new energy-efficient public housing and retrofitted public housing will save 0.2 quadrillion Btu of energy per year by 2010. Adoption by all state and local housing authorities of Federal guidelines could save an additional 0.2 quadrillion Btu by 2010.

Appendix C

Federal Energy Research and Development Appropriations

Appendix C

Federal Energy Research and Development Appropriations

The tables in this appendix (C1 through C5) document annual Federal energy research and development appropriations illustrated in Figures 8 through 12 in Chapter 5.

The tables also document the allocation of Department of Energy budget line items into the programmatic groupings discussed in Chapter 5.

Most of the data are taken from an internal appropriations tally maintained by the Comptroller's Office within the Department of Energy. This tally is considerably more detailed than the budget presentations made in the *Budget of the United States Government* and permits ascertaining, for example, how much money is appropriated for coal-fired power plant research and development versus coal liquefaction and gasification research.

As in any data set, however, it is best to know exactly what is being measured. Thus, users of this data set should be aware of the following considerations:

- Data are for appropriations and not for outlays. Outlays can vary considerably from appropriations, particularly for the Clean Coal Technology program. However, outlay data are not available at the same level of disaggregation.

- The appropriations shown are for final spending authority, after any subsequent reprogramming and supplemental appropriations have been made. Thus, the figures shown are not necessarily identical with the figures appropriated by the Congress in each year's budget. There were several instances of large-scale reprogramming of Departmental funds in the early 1980's.

- FY 1992 appropriations are estimated, and FY 1993 appropriations are from the President's budget request, rather than from the final FY 1993 appropriation.

- The term "unallocated" is used to describe budget items that cannot be attributed to particular fuels or energy types. Much of this spending is administrative "overhead" within the Department of Energy and capital and operating costs of the national laboratories. However, since overhead costs have not been treated uniformly over time, and are not treated uniformly by different offices within the Department of Energy, it is not possible to use these figures to ascertain what portion of research and development spending is actually devoted to overhead costs, nor to compare overhead spending across programs.

Table C1. Summary of U. S. Government Energy Research and Development Appropriations, FY 1978 - FY 1992
(Million Dollars)

Item	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993
Department of Energy																
Renewable Energy	604.9	769.8	832.7	824.0	400.9	304.0	256.8	241.6	200.7	173.6	147.8	149.2	140.6	200.0	243.6	249.8
Nuclear Power	1,151.9	1,092.3	1,081.1	1,050.5	1,085.8	1,034.9	758.8	610.2	599.9	562.5	523.3	524.1	555.8	667.4	889.5	981.0
Fossil Energy	765.3	838.6	847.4	818.5	567.0	311.0	330.9	349.5	340.4	299.2	351.3	378.3	406.1	447.8	428.1	306.7
Conservation/End Use	173.1	228.6	294.8	292.5	151.9	134.6	150.2	175.4	173.5	160.4	155.1	164.3	179.7	218.5	262.5	329.4
Total DOE R&D	**2,695.2**	**2,929.3**	**3,056.0**	**2,985.5**	**2,205.6**	**1,784.5**	**1,496.7**	**1,376.7**	**1,314.5**	**1,195.7**	**1,177.5**	**1,215.9**	**1,282.2**	**1,533.7**	**1,823.7**	**1,866.9**
Other Programs																
DOE Clean Coal	--	--	--	--	--	--	--	--	--	--	196.9	187.8	547.4	391.0	415.0	500.0
NRC Safety Research	140.0	163.5	190.4	227.3	220.3	207.3	190.7	149.6	123.8	122.5	104.0	115.0	103.4	103.8	115.0	121.4
USGS Oil Programs	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	42.0	54.0	54.0	26.0	26.0	26.0
Interagency NAPAP	--	--	10.0	12.0	17.0	22.0	32.7	65.0	81.0	85.0	81.0	82.0	62.0	25.3	31.1	--
Total Unallocated	**140.0**	**163.5**	**200.4**	**239.3**	**237.3**	**229.3**	**223.4**	**214.6**	**204.8**	**207.5**	**423.9**	**438.8**	**766.8**	**546.1**	**587.1**	**647.4**
Total	**2,835.2**	**3,092.8**	**3,256.4**	**3,224.8**	**2,442.9**	**2,013.8**	**1,720.1**	**1,591.3**	**1,519.3**	**1,403.2**	**1,601.4**	**1,654.7**	**2,049.0**	**2,079.8**	**2,410.8**	**2,514.3**

Notes: NA = Not available. DOE = Department of Energy. R&D = Research and development. NRC = Nuclear Regulatory Commission. USGS = U.S. Geological Survey. NAPAP = U.S. National Acid Precipitation Assessment Program. Data for FY 1978 through FY 1991 are actual data. FY 1992 data are estimated, and FY 1993 data reflect the President's initial request. Appropriations data for this and subsequent tables are "final" appropriations data, after subsequent reprogramming and supplemental appropriations. Therefore, they may not match initial appropriations. For example, initial appropriations for Clean Coal Technology were made by reprogramming prior year synfuels appropriations in FY 1985, and initial appropriations of new money were made in FY 1986. All FY 1987 and prior year money was, however, subsequently reprogrammed.

Sources: U.S. Department of Energy, Comptroller's Office, *Department of Energy Appropriation History Tables* (mimeo, March 29, 1991); and U.S. Department of Energy, *U.S. Department of Energy Posture Statement and Fiscal Year 1993 Budget Overview* (Washington, DC, March 1992). U.S. National Acid Precipitation Assessment Program, *Mission, Goals, and Program Plan Post 1990* (Washington, DC, November 1991).

Table C2. U.S. Department of Energy Nuclear Power Research and Development Appropriations, FY 1978 - FY 1993
(Million Dollars)

Item	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993
New Nuclear Reactors																
Light Water Reactors	28.1	10.3	--	--	--	--	--	--	47.6	33.6	31.6	26.5	24.1	38.3	62.5	58.7
Advanced Reactors	--	--	--	--	--	--	--	--	126.8	75.1	91.5	78.5	58.0	56.7	59.5	50.0
Advanced Systems	75.0	54.3	39.6	40.5	37.6	38.9	33.9	36.2	19.5	20.4	20.8	26.6	--	--	--	--
Conventional Reactors	105.9	70.9	60.3	82.9	105.3	78.5	90.1	87.1	--	--	--	--	--	--	--	--
Fast Breeder Reactors	735.2	733.1	747.7	610.8	675.7	552.0	467.1	289.3	18.7	13.6	--	--	--	--	--	--
Total New Plants	**944.2**	**868.7**	**847.6**	**734.2**	**818.6**	**669.4**	**591.1**	**412.6**	**212.6**	**142.7**	**143.9**	**131.6**	**82.1**	**95.0**	**122.0**	**108.7**
Waste/Fuel/Safety																
Nuclear Fuel Cycle	--	--	--	82.8	--	52.4	41.8	--	--	--	--	--	--	--	--	--
Spent Fuel Research	5.3	11.4	18.5	--	7.3	--	--	--	--	--	--	--	--	--	--	--
Commercial Waste	184.1	212.2	215.1	188.8	207.4	--	2.8	25.9	16.0	6.5	5.0	2.5	1.0	0.7	4.7	0.7
Waste Treatment	--	--	--	--	--	249.6	22.5	12.9	--	--	--	--	--	--	--	--
Nuclear Safety	--	--	--	--	--	--	--	--	--	--	--	--	--	6.0	12.5	20.5
Restoration & Waste Treatment	18.3	--	--	43.1	52.5	62.9	98.7	157.5	230.0	277.1	246.7	254.7	293.1	431.4	602.5	707.0
Total	**207.7**	**223.6**	**233.5**	**314.6**	**267.2**	**364.9**	**165.8**	**196.3**	**246.0**	**283.5**	**251.7**	**257.2**	**294.1**	**438.0**	**619.7**	**728.2**
Unallocated																
Facilities	--	--	--	--	--	--	--	--	131.2	126.9	117.0	124.7	168.8	92.0	97.8	95.1
Program Direction	--	--	--	--	--	--	--	--	8.3	7.6	8.5	8.5	8.7	9.7	16.1	14.0
NE Policy & Management	--	--	--	1.7	--	0.6	1.9	1.3	1.7	1.8	2.2	2.2	2.2	32.7	33.8	35.1
Total Unallocated	**--**	**--**	**--**	**1.7**	**--**	**0.6**	**1.9**	**1.3**	**141.3**	**136.3**	**127.7**	**135.3**	**179.6**	**134.4**	**147.8**	**144.1**
Total Nuclear Power	**1,151.9**	**1,092.3**	**1,081.1**	**1,050.5**	**1,085.8**	**1,034.9**	**758.8**	**610.2**	**599.9**	**562.5**	**523.3**	**524.1**	**555.8**	**667.4**	**889.5**	**981.0**

Note: Data for FY 1978 through FY 1991 are actual data. FY 1992 data are estimated, and FY 1993 data reflect the President's initial request.

Sources: U.S. Department of Energy, Comptroller's Office, *Department of Energy Appropriation History Tables* (mimeo, March 29, 1991); and U.S. Department of Energy, *U.S. Department of Energy Posture Statement and Fiscal Year 1993 Budget Overview* (Washington, DC, March 1992).

Table C3. U.S. Department of Energy Fossil Energy Research and Development Appropriations, FY 1978 - FY 1993
(Million Dollars)

Item	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993
Coal Mining/Preparation																
Mining R&D	62.8	68.6	59.1	33.9	14.2	--	--	--	--	--	--	--	--	--	--	--
Coal Preparation	--	7.0	45.7	40.8	22.0	27.9	25.6	34.8	32.0	37.8	41.6	48.9	57.8	55.7	51.1	32.4
Advanced Research	37.0	46.5	42.5	58.4	56.3	36.0	45.5	39.7	33.8	32.4	31.9	25.6	26.5	31.4	30.2	21.5
Other Coal Programs	9.5	11.2	18.2	10.8	--	--	--	--	--	--	--	--	--	--	--	--
Total Coal Mining/Prep.	**109.3**	**133.3**	**165.5**	**143.9**	**92.5**	**63.9**	**71.1**	**74.5**	**65.8**	**70.2**	**73.5**	**74.4**	**84.3**	**87.1**	**81.3**	**53.9**
Coal Conversion																
Liquefaction	126.5	217.9	248.6	339.7	228.4	37.6	28.8	25.6	31.6	24.0	27.1	32.4	34.7	42.7	39.5	23.5
In situ Gasification	12.6	15.0	9.9	10.1	8.3	6.0	6.0	5.7	4.1	2.4	2.8	1.4	0.8	0.8	--	--
Surface Gasification	195.6	112.4	124.8	70.1	54.2	38.8	36.5	31.8	41.3	24.7	23.0	21.6	23.5	15.0	11.1	14.5
Total Conversion	**334.7**	**345.3**	**383.3**	**419.9**	**290.9**	**82.4**	**71.3**	**63.1**	**77.0**	**51.1**	**52.9**	**55.4**	**59.0**	**58.5**	**50.6**	**38.0**
Coal Power Generation																
Combustion	66.1	52.1	50.9	37.7	41.0	24.2	18.1	30.1	29.1	15.1	21.8	26.7	33.4	36.9	37.7	21.0
Fuel Cells	35.4	41.1	26.0	32.0	34.5	29.9	42.3	40.5	34.1	28.1	32.7	26.5	38.0	42.9	51.3	35.0
Heat Engines	42.3	52.1	50.3	29.2	15.4	5.1	6.5	11.9	12.3	12.1	17.9	22.3	21.1	23.6	18.2	6.0
Magnetohydrodynamics	71.5	80.0	79.0	67.0	27.8	29.0	29.9	30.7	27.7	26.5	35.0	37.0	40.4	40.0	40.3	--
Total Power Generation	**215.3**	**225.3**	**206.2**	**165.9**	**118.7**	**88.2**	**96.8**	**113.2**	**103.2**	**81.8**	**107.4**	**112.5**	**132.9**	**143.4**	**147.5**	**62.0**
Total Coal	**659.3**	**703.9**	**755.0**	**729.7**	**502.1**	**234.5**	**239.2**	**250.8**	**246.0**	**203.1**	**233.8**	**242.3**	**276.2**	**289.0**	**279.4**	**157.9**
Other Fossil																
Unconventional Gas	27.4	33.8	30.7	31.0	11.7	13.7	15.4	10.1	8.5	8.0	10.5	11.4	14.4	15.9	12.6	40.0
Oil Shale	28.8	48.6	27.0	32.2	19.2	12.3	16.1	14.6	12.1	10.9	9.5	10.5	9.0	17.2	5.9	2.5
Oil-Related R&D	49.8	52.3	34.7	25.6	20.2	11.5	14.2	17.1	17.0	15.0	20.0	27.8	30.0	41.8	51.4	54.5
FE Unallocated	--	--	--	--	13.8	39.0	46.1	56.9	56.8	62.2	77.5	86.3	76.5	83.9	78.8	55.8
Total Other Fossil	**106.0**	**134.7**	**92.4**	**88.8**	**64.9**	**76.5**	**91.7**	**98.7**	**94.4**	**96.1**	**117.5**	**136.0**	**129.9**	**158.8**	**148.7**	**152.8**
Total Fossil Energy	**765.3**	**838.6**	**847.4**	**818.5**	**567.0**	**311.0**	**330.9**	**349.5**	**340.4**	**299.2**	**351.3**	**378.3**	**406.1**	**447.8**	**428.1**	**306.7**

Note: Data for FY 1978 through FY 1991 are actual data. FY 1992 data are estimated, and FY 1993 data reflect the President's initial request.

Sources: U.S. Department of Energy, Comptroller's Office, *Department of Energy Appropriation History Tables* (mimeo, March 29, 1991); and U.S. Department of Energy, *U.S. Department of Energy Posture Statement and Fiscal Year 1993 Budget Overview* (Washington, DC, March 1992).

Table C4. U.S. Department of Energy Renewable Energy Research and Development Appropriations, FY 1978 - FY 1993
(Million Dollars)

Item	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993
Solar Energy																
Photovoltaics	63.5	103.8	150.0	151.6	74.0	57.9	50.2	54.6	40.3	40.3	34.7	35.1	34.3	46.3	60.4	63.5
Solar Thermal	104.1	98.3	151.2	138.3	56.0	49.4	43.7	33.9	25.5	22.8	16.9	14.8	16.0	19.3	29.1	27.0
Wind Energy	36.7	59.6	60.6	77.5	34.4	31.4	26.4	28.4	24.8	16.6	8.5	8.8	8.7	11.1	39.3	48.4
Biofuels/Alcohol	21.2	42.4	55.0	49.7	30.5	20.9	28.3	30.0	27.0	23.9	16.9	13.2	17.3	33.1	21.4	22.0
Ocean Thermal	36.0	41.1	43.0	34.6	20.8	10.5	5.5	4.0	4.8	4.5	4.0	4.1	3.9	2.7	2.0	--
Solar Building	123.5	127.0	84.9	76.4	22.1	11.6	16.4	9.2	8.2	5.9	5.4	5.3	3.9	2.0	2.0	2.0
International	--	--	--	10.8	4.0	10.0	0.5	0.5	1.0	0.8	0.8	1.0	1.0	1.5	2.0	2.0
Technology Transfer	--	--	--	--	6.7	3.0	3.3	5.1	3.0	2.5	2.6	2.4	1.8	2.2	1.0	2.0
Resource Assessment	--	--	--	--	--	--	--	--	1.0	0.6	0.7	0.8	0.7	1.0	1.2	1.2
Solar Energy Research Institute	--	3.0	10.0	5.0	--	--	--	--	2.2	0.5	0.6	0.6	0.6	5.1	11.5	6.6
Program Support	--	--	--	--	3.5	1.0	0.8	1.0	1.3	0.7	0.9	1.0	0.9	0.9	0.9	0.9
Program Direction	8.6	10.1	4.6	8.2	16.3	5.9	6.0	4.9	4.5	4.1	4.2	4.4	4.1	4.3	4.7	5.9
Total Solar Energy	**393.5**	**485.3**	**559.3**	**552.0**	**268.3**	**201.7**	**180.9**	**171.6**	**143.6**	**123.1**	**96.1**	**91.5**	**93.3**	**129.4**	**175.5**	**181.5**
Other Renewable Energy																
Geothermal	107.9	146.2	149.2	156.0	69.9	57.6	30.3	29.7	26.5	20.7	20.7	19.3	17.2	27.3	27.2	24.4
Hydropower	10.4	39.2	20.9	3.2	3.0	2.0	0.8	0.4	0.5	0.5	--	--	--	1.0	1.0	1.1
Electricity	41.6	40.8	37.1	39.9	21.3	17.1	18.4	19.7	11.4	11.2	15.1	23.6	16.9	28.0	30.8	33.8
Energy Storage	51.4	58.4	66.3	71.8	38.5	25.7	25.6	18.6	17.1	16.6	14.5	13.2	11.7	12.7	7.2	6.3
Total Other Renewable	**211.3**	**284.6**	**273.5**	**270.9**	**132.7**	**102.4**	**75.1**	**68.4**	**55.5**	**49.0**	**50.3**	**56.1**	**45.8**	**69.0**	**66.2**	**65.6**
Total	**604.9**	**769.8**	**832.7**	**824.0**	**400.9**	**304.0**	**256.8**	**241.6**	**200.7**	**173.6**	**147.8**	**149.2**	**140.6**	**200.0**	**243.6**	**249.8**

Note: Data for FY 1978 through FY 1991 are actual data. FY 1992 data are estimated, and FY 1993 data reflect the President's initial request.

Sources: U.S. Department of Energy, Comptroller's Office, *Department of Energy Appropriation History Tables* (mimeo, March 29, 1991); and U.S. Department of Energy, *U.S. Department of Energy Posture Statement and Fiscal Year 1993 Budget Overview* (Washington, DC, March 1992).

Table C5. U.S. Department of Energy Conservation Research and Development Appropriations, FY 1978 - FY 1993
(Million Dollars)

Item	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993
Conservation/End Use																
Transportation	67.3	99.1	113.4	105.1	58.9	53.8	64.7	61.3	57.5	55.4	51.4	54.3	68.4	83.8	110.2	162.4
Industry	31.9	40.0	60.2	69.6	28.8	27.9	33.5	31.7	40.7	34.5	32.8	30.3	75.8	83.5	97.5	105.2
Buildings	63.4	79.3	104.4	91.3	47.7	39.0	37.2	41.0	37.9	30.2	34.4	32.6	30.0	43.1	47.4	52.5
Utility	--	--	--	--	--	--	--	--	--	--	--	--	3.4	4.2	4.7	6.0
Multi-Fuel	10.5	10.2	16.8	26.5	16.5	12.7	12.7	23.8	25.9	28.4	28.8	32.3	--	--	--	--
Total Conservation	**173.1**	**228.6**	**294.8**	**292.5**	**151.9**	**133.4**	**148.1**	**157.8**	**162.0**	**148.5**	**147.4**	**149.5**	**177.6**	**214.6**	**259.8**	**326.1**
Unallocated																
Policy & Management	--	--	--	--	--	1.2	1.3	1.7	1.7	1.9	1.7	1.8	2.1	3.9	2.7	3.3
Facilities	--	--	--	--	--	--	--	15.7	9.8	10.0	6.0	13.0	--	--	--	--
Policy Analysis	--	--	--	--	--	--	0.8	0.2	--	--	--	--	--	--	--	--
Total Unallocated	**--**	**--**	**--**	**--**	**--**	**1.2**	**2.1**	**17.6**	**11.5**	**11.9**	**7.7**	**14.8**	**2.1**	**3.9**	**2.7**	**3.3**
Total	**173.1**	**228.6**	**294.8**	**292.5**	**151.9**	**134.6**	**150.2**	**175.4**	**173.5**	**160.4**	**155.1**	**164.3**	**179.7**	**218.5**	**262.5**	**329.4**

Note: Data for FY 1978 through FY 1991 are actual data. FY 1992 data are estimated, and FY 1993 data reflect the President's initial request.

Sources: U.S. Department of Energy, Comptroller's Office, *Department of Energy Appropriation History Tables* (mimeo, March 29, 1991); and U.S. Department of Energy, *U.S. Department of Energy Posture Statement and Fiscal Year 1993 Budget Overview* (Washington, DC, March 1992).

Appendix D

Bibliography

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Bibliography

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