4. Federal Electricity Programs

Introduction

This chapter looks at support provided by the Federal Government to certain electric power customers. This support differs in some notable respects from the subsidies provided to other energy sectors described in Chapters 2 and 3. For one, the Federal support outlined in the following discussion does not include any direct expenditures provided to electricity producers by the Federal Government, as was the case for other programs (such as the LIHEAP expenditures discussed in Chapter 2). The support provided to electricity producers is not measured by the U.S. Treasury, and it is not reported in Federal budget documents.

In the following discussion, Federal support to the electricity generation sector is estimated from data published by the Federal Energy Regulatory Commission (FERC), the North American Electricity Reliability Council (NERC), bond rating agencies, and various company financial documents. The values provided in this chapter should be treated as estimates of support, not given to the same precision as the values provided in earlier chapters, which were generally taken directly from budget documents. The methodology used to estimate the support provided by the Federal Government to particular segments of the electric power industry includes two measures—market price support and interest rate support—that are commonly used in subsidy studies.[47] A third measure is used to estimate the value of Federal revenues forgone when returns on Federal electricity assets fall short of the returns on similar assets held by investor-owned utilities (IOUs). This measure is comparable to the standard method used by electricity regulatory bodies to determine the appropriate ratebase in reviews of IOU rate filings.

Background

The electric power industry in the United States is composed of approximately 3,200 electric utilities and 2,100 nonutility power producers.[48] Electric utilities are generally classified as either investor-owned, rural cooperative, publicly owned, or Federal utilities. The classes operate under different legal, financial, and tax environments. The main focus of this chapter is on the Federal utilities, which consist of four Power Marketing Administrations (PMAs) and the Tennessee Valley Authority (TVA). A discussion of Federal financial assistance through the Rural Utilities Service (RUS) is also included at the end of the chapter. Support to the Federal utilities is emphasized over RUS support to rural electric cooperatives, because much of the support directed at the Federal utilities is related to their Federal ownership. Hence, the Federally owned utilities are—precisely due to their ownership status—provided both price and asset advantages. In contrast, although RUS-supported entities derive support from the Federal Government in the form of interest subsidies, their non-Federal ownership status means that no direct Federal price or asset support is provided to them. Hence, this study details three means by which the Federal Government

[47]See, for example, Congressional Budget Office, *Should the Federal Government Sell Electricity?* (Washington, DC, November 1997). Appendix A provides brief summaries of this study and others produced by the General Accounting Office and the Office of Management and Budget.

[48]Energy Information Administration, *Electric Power Annual 1998*, Volume 2, DOE/EIA-0348(98/2) (Washington, DC, December 1999), p. 1.

provides support to the Federal utilities (price, interest, and asset) and the one means by which the Federal Government provides support to RUS loan recipients.

Federal electric utilities are primarily producers and wholesalers of electric power. As required by law, they are nonprofit and provide certain classes of customers preference in purchasing their power. In general, preference customers include municipal utilities, cooperatives, State utilities, and irrigation districts. For some PMAs, they may also include State governments and Federal agencies. After meeting commitments for electricity to preference customers, the Federal utilities can and do sell their excess electricity to IOUs or directly to industry. Only about 16 percent of Federal power (in megawatthours) is sold to ultimate consumers, accounting for about 1.4 percent of all electricity sales to ultimate consumers.[49]

The ownership and operation of Federal electricity generation facilities fall under the responsibilities of the U.S. Department of the Interior's Bureau of Reclamation, the Army Corps of Engineers, and the International Boundary and Water Commission.[50] Most of the electricity produced by these Federal agencies is marketed by the four PMAs: Bonneville Power Administration (BPA), Southeastern Power Administration (SEPA), Southwestern Power Administration (SWPA), and Western Area Power Administration (WAPA). The Tennessee Valley Authority (TVA), the largest producer of Federal power, markets its own electricity.

Rural cooperative electric utilities are privately owned by their members (customers) and are established in rural areas to provide electricity to those members. Cooperatives, incorporated under State law, usually are directed by an elected board of directors. Cooperatives generally are nonprofit and tax-exempt, with access to low-cost Federal Government loans. Cooperatives accounted for almost 9 percent of electricity sales to ultimate consumers in 1998.[51]

Publicly owned electric utilities are State and local government agencies established to serve their communities and nearby consumers. Publicly owned electric utilities include municipals, public power districts, State authorities, irrigation districts, and other State organizations. Publicly owned electric utilities are tax-exempt and nonprofit, returning excess funds to the consumers in the form of community contributions and/or reduced rates. There are more than 2,000 publicly owned electric utilities in the United States, which in 1998 accounted for 17 percent of U.S. electricity sales for resale and 15 percent of sales to ultimate consumers.[52] Publicly owned utilities can borrow through the issuance of bonds whose interest is exempt from Federal taxation, but because the same exemption is available to all State and local government agencies (electric and otherwise) it does not meet the definition of subsidy used in this report. In addition to income tax exemptions on their bonds, publicly owned utilities are themselves exempt from Federal income taxes; however, both exemptions are also available to providers of municipal services, such as water and sewage, and hence are excluded from this report. Furthermore, as nonprofit enterprises, these companies would not, on average, realize positive income, and their tax liabilities would be minimal.

Some aspects of government support for electricity providers are not addressed in this chapter. For example, many States and localities provide various types of support to electricity producers within their jurisdictions, and some rural electricity companies and public power companies derive benefits from State and local governments similar

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[49]Energy Information Administration, *Financial Statistics of Major U.S. Publicly Owned Electric Utilities 1998*, DOE/EIA-0437(98) (Washington, DC, December 1999), p. 3.

[50]Federal utilities provide consolidated financial and operational data for their own operations as well as the operations of related Bureau of Reclamation and Army Corps of Engineers power facilities.

[51]Energy Information Administration, *Financial Statistics of Major U.S. Publicly Owned Electric Utilities 1998*, DOE/EIA-0437(98) (Washington, DC, December 1999), p. 3.

[52]Energy Information Administration, *Financial Statistics of Major U.S. Publicly Owned Electric Utilities 1998*, DOE/EIA-0437(98) (Washington, DC, December 1999), p. 3.

to those derived by Federal utilities from the U.S. Government. By definition, however, such subsidies do not constitute support from the Federal Government, which is the subject of this report.

IOUs also receive some types of Federal Government support. For instance, Federal tax advantages provided to IOUs include such items as the ability to apply accelerated depreciation to assets. These advantages, however, are available not only to IOUs but also to other industries, and as such they fall outside the scope of this report, which is limited to the study of Federal interventions directed solely at a particular form of energy, or a particular energy producer or consumer. IOUs also benefit from tax exemptions applied to bonds funding certain forms of pollution abatement, but similar tax-free bonds are also used to fund a variety of traditional municipality-provided non-energy activities, such as water and sewage. Because the Federal tax exemption for interest on these industrial development bonds is available to non-electric utilities in addition to IOUs, it is not included in this analysis.

In a number of instances, this chapter compares the operating environment of the Federal utilities and rural cooperatives with that of IOUs. IOUs are privately owned but publicly regulated electric utilities. Like all private businesses, they seek to produce a return (profit) on investment to their investors. IOUs are granted service monopolies. In return, they are obligated to serve all customers in their service areas. Although the electric power industry is undergoing deregulation, most sales by IOUs still are regulated. The Federal Government regulates wholesale transactions (sales among utilities), and State agencies regulate retail sales (sales to ultimate consumers) within each State. The 239 IOUs accounted for 75 percent of all U.S. electric utility retail sales in 1998.[53]

Historically, the structure of the electric utility industry has been predicated on the concept that the industry was a natural monopoly. The result was traditional ratebase regulation for IOUs, designed to protect consumers by ensuring reliability and a fair revenue requirement to the electric utility. The revenue requirement was based on operating costs and a reasonable return on the ratebase (invested capital) of the utility. Rate schedules were based on the cost of service for different customer classes and projected sales in each customer class to capture the revenue requirement.

The issue of what constitutes a government benefit is not without controversy. It should be noted that the intention of this analysis is not to assess all the cost differences faced by Federal utilities and the IOUs. Nor is it to assess the desirability of publicly provided power versus privately provided power. Rather, the purpose is to measure any advantage conferred to consumers of electricity as a result of specific Federal Government interventions. According to this criterion, the actions must be directly targeted to a particular group of energy consumers or producers and not conferred to others. Interventions that affect not only certain electricity producers but also a host of other companies or industries (even if they may disproportionately affect electricity companies) are not covered in this report.

[53]Energy Information Administration, *Electric Sales and Revenue 1998*, DOE/EIA-0540(98) (Washington, DC, October 1999), pp. 4 and 9.

Federal Policies Affecting Power Costs and Pricing

Programs

The prices charged by Federal utilities are in general lower than those charged by IOUs. Federal utilities and rural cooperatives are affected by their legal status and the benefits derived from the following long-established Federal programs:

- **Access to Low-Cost Generation.** Federal utilities are required to sell their electricity preferentially to certain users. By law, PMA electricity is sold "at the lowest possible rates consistent with sound business principles,"[54] which today are typically less than the cost of alternative supplies. The "lowest possible rates" require Federal utilities to price electricity so as not to earn a profit. Essentially, taxpayers are forgoing returns they might receive if these entities were operated as competitive businesses, in exchange for lower electricity prices to particular classes of customers and economic benefits to particular regions.

- **Access to Low-Cost Credits.** As a result of a number of Federal Government programs (some of which date back to the inception of Federal power), in some instances, Federal utilities have been able to borrow funds at interest rates below prevailing Treasury rates; in some instances, their interest rates are closely tied to the Treasury's own rates; and in other instances, Federal utilities borrow at private-sector interest rates, but their creditworthiness is enhanced by an implicit Federal guarantee that they will not default on their borrowings. All these interest rate advantages constitute Federal support to the Federal utilities. Rural electrification cooperatives, under a program dating from 1935, are eligible for low-interest long-term loans from the Federal Government, which were made at a 2-percent interest rate through 1973. Loans made between 1973 and 1993 carry a 5-percent interest rate, with loan periods up to 35 years.[55] In 1993, the 5-percent interest rate was replaced with a new interest rate structure tied to the interest rates on municipal bonds. At the end of 1998, some $33 billion (1999 dollars) in Federal loans and guarantees were outstanding to cooperatives.[56]

Measuring the Support

Three frameworks were chosen for the valuation of support conferred to Federally supported power as a result of the programs cited above. The first method is based on a comparison between the prices charged for electricity under Federal programs and an estimate of relevant "market" prices—a price advantage that is, in turn, conferred to the utilities' preference customers. The second method quantifies the benefits of favorable borrowing rates that are made available to Federal utilities and RUS borrowers. The third method answers the following question: if Federal utilities were required to achieve a competitive rate of return (similar to IOUs), how much higher would their revenues (and associated electricity prices) have to be in order to achieve that return? Of the three, the second measure of support is the most direct, because favorable interest rates directly reduce the utilities' borrowings costs.

Each of the valuation approaches has strengths and weaknesses. For example, the market price approach assumes that a fully competitive market price for wholesale power exists when, in fact, fully competitive prices do not exist

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[54] U.S. General Accounting Office, *Federal Electricity Activities: The Federal Government's Net Cost and Potential for Future Losses*, GAO-AIMD-97-110A (Washington, DC, September 1997), Vol. 2, p. 18.

[55] U.S. Department of Agriculture, Rural Utilities Service, *1998 Statistical Report, Rural Electric Borrowers*, IP 201-1 (Washington, DC, August 1999), Preface and pp. 9-13.

[56] U.S. Department of Agriculture, Rural Utilities Service, *1998 Statistical Report, Rural Electric Borrowers*, IP 201-1 (Washington, DC, August 1999), pp. 9 and 13.

today. The interest rate approach assumes that Federal utilities and RUS borrowing practices can be fairly compared with the practices of private-sector borrowers when, in fact, there are substantial differences between the two. Knowing exactly which benchmark interest rate to compare with the Federal utility rate is largely a matter of judgment. The return on asset measure assumes that taxpayers (or the owners of these facilities) are entitled to a market rate of return on their assets,[57] comparing the IOU rate of return against the Federal utility rate of return; however, the Federal utility assets in place today were not developed under fully competitive market conditions. Only the interest rate measure is applied to RUS borrowers, which, because they are not Federally owned, receive no Federal support in the areas of prices or returns on assets.

Market Price Support

There are a number of different measures of wholesale electricity prices. The one used in this analysis, "sales for resale," was the only available measure that could be readily derived from published data.[58]

In a competitive market the prices charged by different companies for the same commodity would be similar, with some variation resulting from such factors as transportation costs. Competitive forces would not allow significant price differences to persist over time. Where well-functioning markets exist, market prices can be observed directly. If Federal utilities sell power at below-market prices, the value of their preferential rates is the difference between the revenues that would be earned by selling electricity at the market price and the actual revenues of the utility. For several reasons, however, caution should be exercised in estimating competitive market prices for electricity. First, although U.S. electricity markets are becoming more competitive, they still are heavily regulated. Because the prices charged by IOUs for wholesale transactions are often based on their embedded costs, a true competitive price cannot be derived. Currently, Federal utilities are required to sell electricity at rates that cover both power and nonpower costs.

In addition, electricity is not entirely a commodity. The data available for wholesale power sales do not specify all the terms of each transaction. In some cases, a utility may be selling on the spot market power it does not need to serve its own customers. In other cases, a utility may have a contract to provide all the power generation capacity and other services (spinning reserves, reactive power support, etc.) essential to wholesale customers. Essentially, these two transactions involve different goods, and the prices for them are not directly comparable. The market price approach implicitly assumes that Federal utility wholesale power sales are directly comparable to private utility power sales within the same regions; however, this may not always be the case. Because of the large degree of uncertainty associated with this effort, the values derived using this methodology are labeled in this chapter as "support" rather than subsidies. Further, EIA has elected not to include them in the summary tables for national energy subsidies in this report. Nevertheless, they are an important aspect of Federal intervention in energy markets and, consequently, are considered here.

Apart from any government support discussed in this chapter, Federal power today is often low-price power because much of it comes from relatively cheap hydroelectricity. In a purely rate-regulated environment, conventional ratemaking policy allows low-cost producers to pass on the benefits of cheap power to their customer base. In a regulated environment, selling relatively cheap power at below-market prices does not involve a form of government

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[57]Although there is some overlap between the ownership and the beneficiaries of Federal utility power, many taxpayers do not benefit from low-cost Federal utility power. For instance, most of the Midwest and all of New England derive no benefit from low-price Federal utility power sales, even though as citizens of the United States they are in part owners of the power. It should be noted, however, that not all Federal power is low cost, as explained later in this chapter.

[58]Compiled from data provided by the Federal Energy Regulatory Commission, FERC Form 1.

support, as long as the power is sold without preference. Thus, one could argue that it is the preference, not the price, that is the conveyance of Federal Government support. However, this conveyance has a value in any environment, whether rate-regulated or free market, but it can more readily be estimated in a market where prices are freely set by supply and demand.

As electricity markets make the transition to full competition (a transition that has been in effect for a number of years), market forces play a greater role. In contrast to the rate-regulated environment, in a pure market-based environment, low-cost power producers become profit maximizers. Whatever cost advantage these producers possess relative to their competitors could be captured in the form of rents. Low-cost producers would have little incentive to price their power at anything other than market clearing rates, which in a competitive environment would be equal to the industry's marginal cost of power. Moreover, in a pure market environment, producers would be free to sell their electricity to the highest bidders without the constraints of a preference customer class. In a purely competitive environment the extent to which Federal power prices fell below the prices charged for similar power by competing utilities would constitute Federal support to the buyers of Federal power. Current efforts to deregulate U.S. electricity markets should work to further reduce the spread between Federal power prices and IOU power prices.

A comparison is made in this chapter between wholesale power prices charged by the four PMAs (along with the TVA) and wholesale prices charged by nearby IOUs[59] (see box below). The intent of the comparison is to ascertain whether Federal utilities provide power at rates below those charged by neighboring IOUs, thus providing their customers with an advantage unavailable to other consumers. However, although industry regulators have become increasingly inclined to approve rates that reflect contemporaneous market conditions, U.S. wholesale electricity prices remain regulated to a significant degree. Accordingly, the value of the price differential between rates charged by Federal utilities and those charged by neighboring IOUs should be seen as only a rough estimate of any price advantage enjoyed by the customers of Federal utilities. Still, it should also be noted that the value of the price differential has fallen since the Energy Information Administration (EIA) prepared its 1992 report on Federal energy subsidies. The narrowing of the wholesale price gap reflects two related developments: first, electricity markets have grown more competitive over the past decade; and second, as IOU prices have fallen, the measured value of Federal support received by utility customers has also fallen.

Electricity Markets

The electricity market has two distinct segments—wholesale and retail power markets. Wholesale markets comprise the resale and purchase of electricity among utilities and nonutility power producers for sale to ultimate consumers. Wholesale trade transactions are categorized by the service provided: full or partial requirements, firm or non-firm, etc. Generally, different services have different associated costs of service and, under cost-of-service regulation, have different prices. Prices of wholesale electricity sales are subject to approval by the Federal Energy Regulatory Commission, with the exception of the TVA.[a]

[a]The TVA and its regulatory exception are discussed later in this chapter.

[59]The comparison prices are the average prices of utilities operating in nearby States. For TVA, a comparison was made against prices of utilities operating in all the States in the SERC region. For BPA, the comparison States were Idaho, Oregon, and Washington. For the Southeastern Power Administration, the comparison States were Alabama, Florida, Georgia, Kentucky, Missouri, North Carolina, South Carolina, Tennessee, and Virginia. For the Southwestern Power Administration, the comparison States were Arkansas, Kansas, Louisiana, Missouri, Oklahoma, and Texas. For the Western Area Power Administration, the comparison States were Arizona, California, Colorado, Iowa, Minnesota, North Dakota, Nebraska, New Mexico, South Dakota, Utah, and Wyoming.

Federal utilities as a group have only 347 end-use customers, none of which is classified as residential or commercial.[60] In general, their end-use customers are bulk purchasers, such as the U.S. Department of Energy's national laboratories and aluminum smelters in the Pacific Northwest.

Interest Rate Support

One element of Federal aid to public power is low-cost credit. Rural cooperatives receive RUS loans, and some Federal utilities receive appropriations to be repaid at the 30-year Treasury bond rate. Even when Federal utilities borrow through publicly issued debt, the debt receives much higher credit ratings than would be attained if it were not for the widely held view in the financial community that this debt carries an implicit U.S. Treasury guarantee to prevent any default. This form of support is more direct than the price-based support measure just discussed. The magnitude of the resulting support can be computed by comparing the actual interest rates paid with various market interest rates. When Federal utilities are able to raise funds in capital markets at interest rates lower than those at which they could borrow were it not for their Federal Government status, a measure of support is conferred.

Although some Federal power producers borrow at various rates under various legal authorities, on balance they pay lower rates than privately owned utilities and, in some cases, lower than the Treasury itself. Credit markets view Federal utility debt as having an implicit Treasury guarantee, although no guarantee in fact exists. In its appraisal of a 1998 TVA bond underwriting, Standard and Poor's assigned the debt a AAA rating. In doing so, Standard and Poor's noted that "the rating reflects the implicit support of the U.S. Government and Standard & Poor's view that, without a binding legal obligation, the Federal Government will support principal and interest payments on certain debt issued by entities created by Congress. The rating does not reflect TVA's underlying business or financial condition."[61]

As a result, Federal utilities are able to float debt at rates well below those paid by all but the most highly rated of IOUs. The three smaller PMAs (SEPA, SWPA, and WAPA) have average financing costs below that of the U.S. Treasury itself, because DOE requires them to repay higher cost debt early whenever possible, a privilege not held by the Treasury.[62] Moreover, before 1983, the three smaller PMAs were allowed to finance capital projects at rates actually lower than the Treasury's rate.[63]

This analysis uses both public-sector and private-sector interest rates as benchmarks against which to measure the value of interest rate support. The public-sector benchmark is the U.S. Treasury's cost of funds for 30-year borrowings. For the private-sector rates, the benchmarks used are the rates paid by utilities using various utility bond ratings ranging from Aaa down to Baa. These ratings indicate two different measures of support. When Federal agencies achieve lower borrowing costs than the U.S. Treasury itself, the underlying advantage can be viewed as support provided directly to the borrower by the U.S. Treasury or by the public at large. The second measure of support assumes that Federal utilities are advantaged to the extent that their borrowing costs are less than they would be if they were private entities. This may be viewed as a form of indirect support from the Treasury. This measure of support compares the borrowing costs of the Federal utilities with the cost of funds realized by select

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[60]Energy Information Administration, *Financial Statistics of Major U.S. Publicly Owned Electric Utilities 1998*, DOE/EIA-0437(98) (Washington, DC, December 1999), Table 36.

[61]"S&P Rates Tennessee Valley Authority $1 Billion Global Power Bonds AAA," *Business Wire* (November 2, 1998).

[62]The Treasury can decide, and recently has decided, to retire high-priced debt early; however, it must pay the market value of the debt and not its face value.

[63]U.S. General Accounting Office, *Power Marketing Administrations: Cost Recovery, Financing, and Comparison to Nonfederal Utilities*, GAO/AIMD-96-145 (Washington, DC, September 1996), p. 7.

groups of private utilities. The comparison rate (e.g., the A utility rating) may or may not be appropriate, depending on the presumed creditworthiness a Federal utility would command were it to lose the borrowing benefits derived from Federal ownership or its implicit financial backing from the U.S. Treasury.

Table 5 shows the 30-year Treasury bond rate and various utility bond rates for 1990 and 1998. The intent of the presentation is to illustrate that the level of estimated support varies directly with the benchmark interest rate chosen. In 1998, the average yield on 30-year Treasury bonds was 5.58 percent, and the average yield on Baa-rated utility bonds was 7.26 percent. The estimate will be higher when the Aaa IOU rate is used than when the Treasury rate is used for comparison and will increase as the comparison is graduated downward to the IOU Baa rate. The average interest rate spread between the 30-year Treasury bond and IOU Aaa bonds was 119 basis points over the 1980-1998 period, and the average spread between the 30-year Treasury bond and the Baa IOU bond rates was 168 basis points.[64]

Table 5. Interest Rates Used for Comparisons with Federal Utility Borrowing Costs, 1990 and 1998

Rate	1990	1998
30-Year Treasury	8.61	5.58
Investor-Owned Aaa	9.45	6.77
Investor-Owned Aa	9.66	6.91
Investor-Owned A	9.87	7.04
Investor-Owned Baa	10.06	7.26
Municipal Aaa	6.97	4.92
Municipal Aa	7.07	4.99
Municipal A	7.16	5.08
Municipal Baa	7.30	5.15

Note: Municipal bond yields are significantly lower than similar maturity IOU yields because of the Federal income tax exemption for municipal bonds. Municipal bonds also usually have an exemption from State and local taxes in the jurisdictions in which they are issued. BPA's cost of funds on its appropriated and long-term debt were estimated at 78 basis points above the Treasury's own cost of funds in 1998, as explained later in this chapter.

Source: Moody's Investor Service, *Utility Manual 1998*, and Federal Reserve, Form H-15.

Because the financial accounts of the four PMAs, TVA, and cooperatives borrowing from the RUS differ considerably, different calculations of Federal interest rate support are used in this analysis. One method is to measure the interest paid by Federally supported power entities against the interest paid on similar debt issued by the Treasury or by IOUs in the same year. However, several difficulties are involved. One problem is that debt maturities cannot always be matched. For instance, TVA has issued debt with maturities as great as 50 years, for which there are no similar Treasury or IOU issues. Another difficulty is that some debt is callable, which means it may never be held to maturity and therefore commands a different interest rate than debt which is not. Still another problem is lack of data. Although some of the debt on the books of the PMAs date back to the 1940s, there is little in the way of comparative interest rate data available. For instance, the U.S. Treasury did not start to issue 30-year debt until 1978. Further, much of the information provided to EIA by the Federal utilities and the RUS on their respective loan portfolios was insufficient to reconstruct their debt at market rates.

Interest rate support for BPA and TVA can be directly tied to market interest rates; therefore, a simplified calculation was used in their cases. BPA borrows at a premium to the Treasury rate for its long-term debt and appropriated

[64]A basis point is one-hundredth of a percentage point.

debt. For its non-Federal debt, BPA borrowed essentially at the Aa municipal rate in 1998. TVA, as explained later, is currently borrowing at the Aaa IOU rate. In measuring the interest rate support provided by the Federal Government to TVA and BPA, these rates are measured against other private-sector borrowing rates. For instance, TVA's Aaa-rated borrowings are compared to what the company would have to pay in interest if it borrowed at the Aa, A, or Baa rate. The difference in borrowing costs constitutes the level of support. To calculate the difference in borrowing costs that involves moving from the Aaa rating down through the Aa, A, and Baa ratings, the average spread was calculated between interest rates on these debt instruments between the years 1980 and 1998. As an example, the average spread over this period between the Aaa and Aa rates was 33 basis points. An average spread was calculated over several years to abstract from year-to-year variations in interest rate differentials.

The three smaller PMAs have average interest rates that fall below the 30-year Treasury rate. Although currently all new debt issued by the three smaller PMAs is at the Treasury rate, much of their unretired old debt bears interest well below that of similar Treasury issues. Further, unlike TVA, the three smaller PMAs have an advantage unavailable to the Treasury in that DOE requires them to retire high-interest debt first whenever possible. As such, a different approach to measuring Federal interest rate support was taken for the three smaller PMAs. This approach attempted to compare the loan portfolio of the three smaller PMAs against a similar portfolio of Treasury and utility debt instruments. More specifically, a loan-by-loan comparison was made, going back to debt issued in the early 1940s. All debt that is currently on the books of the three smaller PMAs was compared to similar debt (i.e., debt having the same or similar maturity) issued by the U.S. Treasury or by IOUs. Where similar Treasury or IOU debt was unavailable for comparison, estimates were based on the average spread between Treasury and private-sector securities. An estimate of Federal support to RUS borrowers was undertaken in a similar fashion.

Return on Asset Support

Over the long term, in competitive markets IOUs must earn a sufficient return on invested capital to satisfy their shareholders. Historically, U.S. regulators have taken this into account when setting the price of electricity for private utilities. Regulators have set the price of electricity at a level that would allow IOUs to recover operating costs and earn a market-based return on the assets they have invested to meet their customers needs. If sales of services provided by Government-owned assets provide a below-market return on the assets, a preferential benefit is being conferred to customers. This approach measures the value of forgone Federal utility revenue that would have been needed for the Federal utilities to realize a market rate of return on their assets.

A typical textbook definition of cost for a private-sector electric utility is operating cost plus depreciation of capital assets plus some allowance for cost of capital. The extent to which actual Federal utility earnings from electricity sales fall below what they would have earned charging market rates constitutes a support to the purchasers of Federal power, with the amount of the support equal to the difference between revenues sufficient to recover costs and revenues at the actual selling price.

Like the estimates of market price and interest rate support, estimates of return on asset support are not perfect measures of the support provided to the preferred customers of Federal utilities. As stated above, U.S. electricity markets are heavily regulated, and the assets utilities have in place today were not fully developed under competitive market conditions.

Federal Power Programs

Federal power producers are themselves not the intended recipients of the advantages the Federal Government confers to this group of electricity suppliers. Their preference customers are the primary target of low-cost Federal power. Those preference customers that are electricity providers, in turn, sell their power to households, businesses, and other customers. Federal utilities themselves have no residential or commercial customers, and their direct sales of electricity in 1998 accounted for only 16 percent of their total sales.[65]

In the early years of Federal power, its proponents asserted that publicly supported electricity was essential in order to provide electrification to large parts of rural America that were then not connected to the grid. Critics at the time argued that Federal power was a subsidy from urban to rural areas.[66] Federal power producers are mandated by law to provide power preferentially to public power entities such as State and municipal providers and consumer-owned cooperatives.[67] The remainder may, however, be sold to privately owned entities such as IOUs and industrial customers. TVA, for instance, sold 76 percent of its power to municipalities and cooperatives, 13 percent to Federal agencies and others, and 11 percent directly to industrial customers in 1998.[68] WAPA sold 46 percent of its power to municipalities and cooperatives, 26 percent to State agencies, 11 percent to IOUs, 10 percent to public utility districts, 5 percent to Federal agencies, and the remaining 2 percent to others.[69] Roughly half of BPA's power is sold to public utility districts, city light departments, and rural electric cooperatives, another 15 percent is sold to IOUs, and roughly one-quarter is sold to aluminum companies and other large industrial concerns.[70] RUS electricity distribution borrowers provided 58 percent of their electricity to farm and non-farm residences, 21 percent to large commercial and industrial customers, 18 percent to small commercial and industrial customers, 2 percent to irrigation users, and another 2 percent to other users.[71]

Tennessee Valley Authority

TVA was established in 1933 under the Tennessee Valley Act. Its original purpose was to promote economic development in the Tennessee Valley, to improve navigation, and to aid in flood control. TVA is far and away the largest of the Federal utilities, having an asset base greater than that of the four PMAs combined. TVA is operated as an independent Government-owned corporation. Its three-member board of directors is solely responsible for setting rates and for policymaking. The board is appointed by the President of the United States.

TVA's service territory covers nearly all of Tennessee and parts of Alabama, Kentucky, North Carolina, Mississippi, Georgia, and Virginia. Its wholesale customers include 159 municipal and cooperative distributors. The company's retail customers include 63 large industrial concerns and Federal agencies.[72] It operates 17,000 miles of transmission

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[65]Energy Information Administration, *Financial Statistics of Major U.S. Publicly Owned Electric Utilities 1998*, DOE/EIA-0437(98) (Washington, DC, December 1999), p. 457.

[66]D. Shapiro, "Public Power Policy: The Controversial Origins," in *Generating Failure* (New York, NY: University Press of America, 1989).

[67]U.S. General Accounting Office, *Power Marketing Administrations: Cost Recovery, Financing, and Comparison to Nonfederal Utilities*, GAO/AIMD-96-145 (Washington, DC, September 1996).

[68]Tennessee Valley Authority, *Annual Report 1999* (2000), p. 42.

[69]Western Area Power Administration, *Annual Report 1998* (1999), Appendix, p. 23. Excludes project use and interdepartmental and interproject exchanges.

[70]Bonneville Power Administration, web site www.bpa.gov/corporate/kc/who/watsbpax.shtml.

[71]U.S. Department of Agriculture, Rural Utilities Service, *1998 Statistical Report, Rural Electric Borrowers*, IP 201-1 (Washington, DC, August 1999), Table 3.

[72]U.S. House of Representatives, Subcommittee on Water Resources and Environment, "TVA: Electricity Restructuring and General Oversight," web site www.house.gov/transportation/water/09-22-99/09-22-99memo.html.

lines and 29 hydropower dams and provides electricity to 8 million customers.[73] TVA has 28,498 megawatts of generating capacity and is the Nation's largest wholesaler of electricity, with sales of 163 billion kilowatthours in 1998.[74]

A number of explicit and implicit benefits are conferred upon TVA by the Federal Government. For example, TVA receives implicit interest rate support. The debt rating service, Moody's, assigns TVA its highest credit rating, Aaa.[75] Standard and Poor's assigns TVA a similar AAA credit rating. If TVA borrowed funds in capital markets without the Treasury's implicit guarantee, it undoubtedly would pay higher interest rates. As noted earlier, according to Standard and Poor's, its TVA rating "reflects the implicit support of the U.S. Government and Standard & Poor's view that, without a binding legal obligation, the Federal Government will support principal and interest payments on certain debt issued by entities created by Congress. The rating does not reflect TVA's underlying business or financial condition."[76] In general, TVA borrows at rates comparable to those for other U.S. Government agencies.

TVA also benefits from a captive market. Its customers are required to provide 10 years notice before they are allowed to switch their service to another utility.[77] It is also exempt from antitrust laws and exempt from the wheeling provisions required by the Energy Policy Act of 1992.[78] Its rates are not regulated by the FERC or by State utility commissions. These benefits are, however, regulatory in nature.[79]

In 1959, the U.S. Congress placed restrictions on TVA's ability to sell power outside its prescribed territory and, in addition, established a debt ceiling for the TVA at $750 million. This ceiling has been raised four times since then and was capped at $30 billion in 1979.[80]

TVA's Prices Relative to Neighboring IOUs

TVA is unique among the Federal utilities in that its electricity prices generally exceed those of neighboring utilities. In 1998, TVA's average wholesale revenues were 4.6 cents per kilowatthour, compared with an average of 4.0 cents for nearby utilities operating in the SERC (Southeastern Electric Reliability Council) region as a whole.[81] As a result, there is no explicit Federal price support provided to TVA's electricity customers. Even though the TVA has not brought deferred assets and terminated nuclear assets of $8.3 billion (1999 dollars) into its ratebase,[82] interest payments on the underlying borrowings are passed on to ratepayers and thus serve to elevate TVA's electricity prices. In 1990, however, TVA's average wholesale revenues fell beneath those of surrounding utilities, providing $440 million (1999 dollars) in Federal support to its customers.

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[73]Tennessee Valley Authority, *Annual Report 1998* (1999), p. 3.

[74]Tennessee Valley Authority, *Annual Report 1998* (1999), p. 42.

[75]According to Moody's: "Bonds which are rated Aaa are judged to be of the best quality. They carry the smallest degree of investment risk and are generally referred to as "gilt edged." Interest payments are protected by a large or by an exceptionally stable margin and principal is secure. While the various protective elements are likely to change, such changes as can be visualized are most unlikely to impair the fundamentally strong position of such issues." Source: Moody's Investors Service Ratings and Ratings Action, web site www.moodys.com/ratings/ratdefs.htm.

[76]"S&P Rates Tennessee Valley Authority $1 Billion Global Power Bonds AAA," *Business Wire* (November 2, 1998).

[77]U.S. General Accounting Office, *Tennessee Valley Authority: Financial Problems Raise Questions About Long-Term Viability*, GAO/AIMD/RCED-95-134 (Washington, DC, August 1995), p. 57.

[78]As long as the power is to be consumed inside TVA's territory.

[79]Federal regulatory support lies outside the framework of this report's analysis.

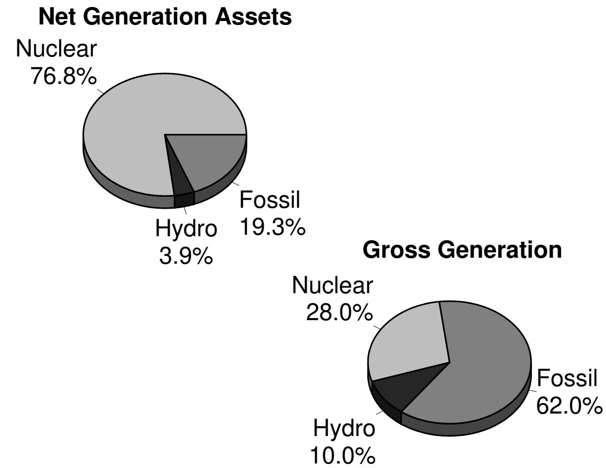
[80]U.S. General Accounting Office, *Tennessee Valley Authority: Financial Problems Raise Questions About Long-Term Viability*, GAO/AIMD/RCED-95-134 (Washington, DC, August 1995), pp. 17 and 18.

[81]Compiled from data provided by the Federal Energy Regulatory Commission, FERC Form 1.

[82]Tennessee Valley Authority, *Annual Report 1998* (1999), p. 26.

Nuclear power accounted for 77 percent of TVA's investment in generating assets in 1998, while nuclear power plants provided 28 percent of its gross generation in 1998 (Figure 4). In contrast, fossil fuels and hydropower, which account for 23 percent of the utility's generation assets, provided 72 percent of its generation.

Figure 4. Tennessee Valley Authority Net Generation Assets and Power Generation by Fuel Type, 1998



Note: Nuclear assets include $11.9 billion in completed plant and $6.4 billion in deferred assets.

Source: Tennessee Valley Authority, *Annual Report 1998* (1999), pp. 33, 34, and 42.

TVA's Borrowing Costs

TVA has a much higher concentration of nonperforming assets and debt than do the IOUs on average. TVA's ratio of debt to capital is 68 percent, and its interest payments take up 29 percent of its revenue.[83] For IOUs as a whole, the debt/assets and interest payment/revenue ratios in 1998 were 30 percent and 6 percent, respectively.[84] However, TVA's bonds are given the highest credit rating available from Moody's and Standard and Poor's.[85] Although the U.S. Government is not required to provide TVA support in the event of default, the investment community views TVA's debt as having an implicit Federal guarantee (see box on pages 31 and 32). This allows the TVA an advantage in raising capital in financial markets over any private-sector utility with a comparable financial condition. As stated earlier, rating agencies' appraisal of TVA's debt is contingent on the belief that the Federal Government would prevent any default.

TVA currently pays interest on deferred debt underlying assets that have yet to be brought into its ratebase. Most of the deferred assets and debt were accumulated by investing in a large-scale nuclear power program. During the 1950s, TVA moved from building dams to building coal-fired power plants. In 1966, it launched what became the largest nuclear power program in the United States, announcing plans to build 17 nuclear power units. By 1984, 8 of the proposed units had been canceled, despite investments that totaled $4.6 billion at the time of their cancellation.[86] Of the 9 remaining units, 5 are currently in operation, 3 are listed as deferred, and 1 is listed as inoperative.[87] About one-third of the value of TVA's utility plant is in currently completed nuclear assets. Unlike the dams, these projects were largely funded during the 1970s and 1980s when interest rates were relatively high, and those high interest charges have been passed on to TVA's customers.

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[83]Tennessee Valley Authority, *Annual Report 1998* (1999), p. 1.

[84]Energy Information Administration, *Electric Power Annual 1998*, Volume 2, DOE/EIA-0348(98/2) (Washington, DC, December 1999), p. 26.

[85]According to Moody's: "Although TVA's debt is not an obligation of the U.S. government, the company's status as an agency and the fact that the government is TVA's only shareholder, indicates strong 'implied support' [that] would afford assistance in times of difficulty."

[86]Moody's Investor Service, *Utility Manual 1998*, p. 4665.

[87]Tennessee Valley Authority, *Annual Report 1998* (1999), p. 33.

The Issue of Implicit Support

A longstanding issue in financial markets has been the degree to which the U.S. Government would prevent a default of the debt of Government agencies, such as the TVA, and government-sponsored entities (GSEs), such as the Federal National Mortgage Association (FNMA) and the Farm Credit System (FCS). The debt of these agencies carries no explicit guarantee by the U.S. Treasury. In fact, TVA bonds explicitly state that their debt is not a legal obligation of the U.S. Government.[a] However, financial markets have strongly assumed otherwise, believing that the U.S. Government would not (and could not) allow any of this unbacked debt to ever default. Although the financial community's assumptions are subject to debate, there is evidence suggesting that their view is correct.

For example, according to a study completed by the Federal Reserve Bank of Richmond, Virginia,[b] during the 1980s the U.S. Treasury twice initiated actions that were designed to provide support to two GSEs—the FNMA and the FCS—during times of financial difficulty. The Federal Reserve Bank study noted that in both cases action was undertaken because the GSEs saw a sharp widening of the spread on their debt instruments against similar Treasury debt, thus significantly raising their cost of funds. In both cases, the Treasury made the "implicit guarantee explicit by providing Federal Government loans to the GSEs. Once the loans were made, the interest spread of the GSE securities and comparable U.S. Treasury securities narrowed."

When rating TVA's debt, major credit agencies assume that the government would provide support if needed. According to Moody's Credit Service: "Although TVA's debt is not an obligation of the U.S. government, the company's status as an agency and the fact that the government is TVA's only shareholder, indicates strong 'implied support' [that] would afford assistance in times of difficulty . . . . This implied support provides important bondholder protection." Similarly, according to Standard and Poor's: "The [AAA] rating reflects the U.S. government's implicit support of TVA and Standard and Poor's view that, without a binding legal obligation, the federal government will support principal and interest payments on certain debt issued by entities created by Congress. The rating does not reflect TVA's underlying business or financial conditions." Standard financial texts also describe Federal agency debt as carrying a "de facto backing from the federal government."[c]

In addition, TVA's chairman has also made note of the implicit guarantee arising from potential pressure on the Treasury to prevent any agency default. According to a quote appearing in a March 5, 1997, *Wall Street Journal* article, TVA chairman Craven Crowell stated: "If Congress does anything that devalues us, you always have the potential for the Treasury having to get involved."[d]

Were the Federal government to allow a default on one agency's (or one GSE's) debt, the ability of *all* Federal agencies and GSEs to borrow money at favorable rates could be affected. An unchallenged default could cause financial markets to downgrade the value of all agency and GSE debt, an action that could greatly affect their borrowing costs and their ability to carry out their government mandates. In all likelihood this potential hazard weighs heavily on the U.S. Government to prevent even one default. TVA may have an even closer relationship with the U.S. Government than do the GSEs, which may increase whatever implicit support its debt derives. For instance, unlike the GSEs, the U.S. Treasury carries TVA debt as gross Federal debt. In fact, TVA's borrowings accounted for 92 percent of $24 billion in U.S. Government agency debt outstanding in 1998.[e] GSEs had, however, $2.0 trillion in debt (1999 dollars) outstanding at the end of 1998, which makes them a considerable component of total U.S. credit markets.[f] Total U.S. Treasury debt, for instance, equaled $5.5 trillion in 1998.

(continued on page 32)

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[a] U.S. General Accounting Office, *Tennessee Valley Authority: Financial Problems Raise Questions About Long-Term Viability*, GAO/AIMD/RCED-95-134 (Washington, DC, August 1995), p. 29.
[b] T.Q. Cook and R.K. Laroche, eds., *Instruments of the Money Market* (Richmond, VA: Federal Reserve Bank, 1993).
[c] M. Stigum, *The Money Markets: Myth, Reality, and Practice* (Homewood, IL: Dow Jones-Irwin, 1978), p. 161.
[d] J. Ball, "TVA Plan Seen by Critics as Unfair Grab for Power," *Wall Street Journal* (March 5, 1997), p. 1.
[e] Office of Management and Budget, *Analytical Perspectives, 2000* (Washington, DC, 1999), p. 264.
[f] Office of Management and Budget, *Analytical Perspectives, 2000* (Washington, DC, 1999), p. 202.

The Issue of Implicit Support (Continued)

In this report, "implicit support" is included in the estimates of total support provided by the Federal Government to TVA and the PMAs, because the ratings and yields on their debt instruments would be different if the Federal Government did not support them.

Alternative viewpoints on the issue of implicit interest support may exist. These viewpoints question whether a support without any binding legal basis is really a support. According to these views, market expectations that the Federal Government would act to prevent a default, should that possibility ever arise, are just expectations and not necessarily a reality. Although the market views a TVA debt default as "highly unlikely," there is no absolute guarantee that the market view is infallible. On the other hand, the U.S. Government remains the sole equity owner of the TVA, and the fact that TVA's government ownership status has a substantial impact on the utility's borrowing costs is an advantage that EIA believes constitutes support.

In 1998, TVA had outstanding long-term debt of almost $24 billion (Table 6), which consisted of $20 billion in public bonds and $3 billion in borrowings from the Federal Financing Bank (FFB).[88] Although the $3 billion in FFB debt is unrated, for reasons described below this analysis assumes that it carried the same degree of Federal support as the $20 billion in bonds that were publicly traded. TVA's FFB debt carried a much higher interest rate in 1998 than prevailing market rates. The presence of this high-price debt on TVA's books stems from the fact that the TVA issued several billion dollars of noncallable debt during the late 1980s when interest rates were exceptionally high (see box on page 33). The noncallable debt was refinanced in late 1998, and in 1999 all of TVA's debt was publicly held and carried the AAA rating.[89] Had TVA's noncallable debt been refinanced before 1998, it is reasonable to assume that all of its debt in 1998 would have carried the AAA rate, as did its non-FFB debt.

Table 6. Computation of Implied Interest Rate Support to the Tennessee Valley Authority

Item	TVA	Aa IOU Rate	A IOU Rate	Baa IOU Rate
Outstanding Debt (Million 1999 Dollars)	23,717	23,717	23,717	23,717
Interest Paid/Implied (Million 1999 Dollars)	1,605.6	1,682.7	1,759.1	1,853.2
Average Rate Differential, 1980-1998 (Percent)	—	0.325	0.647	1.044
Implied Support (Million 1999 Dollars)	—	77.1	153.4	247.6

Note: Most of the dollar values appearing in this report have been converted to 1999 dollars using the Gross Domestic Product (GDP) deflator. The GDP deflator was applied to companies' prior year loan and interest data. Although the values on the companies' balance sheets and income statements do not change from year to year, the purpose of the calculation was to estimate Federal Government support in a consistent framework. The framework chosen was the value of Federal Government support in terms of its 1999 purchasing power. The 1999 GDP deflator was 22 percent higher than the 1990 value and 1 percent higher than the 1998 value.

Sources: Tennessee Valley Authority, *Annual Report 1998* (1999), and Moody's Investor Service, *Utility Manual 1998*.

One method of calculating the value underlying TVA's high credit rating would be to compare TVA's total interest costs (assuming a rate on its FFB debt similar to the rate on its publicly held debt) against what TVA would pay if it had an inferior credit rating. To determine the different levels of borrowing costs under various credit ratings, an estimate of the spread between different interest rates was calculated. The spread is the average difference in yield on these rates against the Aaa rate between 1980 and 1998.[90] The average spreads were calculated over a number

[88]Tennessee Valley Authority, *Annual Report 1998* (1999), p. 27. TVA's Federal Finance Bank loans were not rated.

[89]Tennessee Valley Authority, *Annual Report 1999* (2000), p. 36.

[90]For this period, the average spread between the Aaa rate and the Aa rate equaled 33 basis points. Source: Standard and Poor's *DRI* database. This spreadsheet can be made available from EIA upon request.

of years to abstract from year-to-year vicissitudes in interest rate differentials. The spread between TVA's borrowing costs and alternative borrowing costs presents a measure of the value of TVA's subsidy. In other words, if TVA borrowed money at the Aa rate rather than the Aaa rate, its borrowing costs in 1998 would be 33 basis points, or $77 million, higher (Table 6). This $77 million is one measure of Federal support. The A rating would raise TVA's 1998 borrowing costs by $153 million and the Baa rating by $248 million.

TVA's 1998 Debt Cost Reduction

Interest on TVA's Federal Financing Bank debt was unusually high relative to market rates in 1998, when it had an outstanding $3.2 billion (nominal dollars) in relatively high-priced debt held by the Federal Financing Bank.[a] From 1985 to 1989, TVA issued a nominal $6.2 billion in noncallable debt to the Federal Financing Bank[b] at rates between 8.5 percent and 11.7 percent, or an average interest rate of 9.7 percent. As a result of the sharp decline in interest rates since the late 1980s, those rates were significantly higher than TVA's average 1998 borrowing costs. Market interest rates in 1998 reached their lowest level since at least the mid-1970s. The Treasury's 30-year bond, for instance, averaged 5.58 percent in 1998, its lowest level since the instruments were first introduced by the Treasury in 1978. In 1998, passage of the Fiscal Year 1999 Omnibus Appropriations Bill (H.R. 4328) allowed TVA to refinance its $3.2 billion in high-interest debt at par value. The yield on the newly issued debt averaged 6 percent. As a result of the refinancing, TVA expects to save $1.6 billion in borrowing costs out to the year 2016.[c] TVA estimates that its savings from the refinancing in the first year will save the utility $117 million.[d] This saving can be viewed as Federal support to the TVA to the extent that it reduced the interest on TVA's overall indebtedness to the U.S. Treasury.

[a]Tennessee Valley Authority, *Annual Report 1998* (1999), p. 35.

[b]The Federal Financing Bank is an agency under the supervision of the U.S. Treasury. Its role is to provide financing assistance to selected Federal agencies (such as TVA) in order to lower their borrowing costs. In essence, the Bank raises money through the sale of Treasury securities and then lends the money to Federal agencies.

[c]A General Accounting Office study estimated that TVA's $14 billion of nonproductive nuclear assets accounted for $833 million of its $1.9 billion in annual interest expense in 1994. See U.S. General Accounting Office, *Tennessee Valley Authority: Financial Problems Raise Questions About Long-Term Viability*, GAO/AIMD/RCED-95-134 (Washington, DC, August 1995).

[d]Tennessee Valley Authority, "TVA Pays Off $3.2 Billion in High Interest Debt, Savings Begin Immediately," Press Release (October 23, 1998).

TVA's Return on Capital

Measuring operating costs and depreciation is straightforward, as the relevant information can be extracted from Federal utility financial statements; however, deciding what the appropriate rate of return on assets for a Federal utility ought to be is not so obvious. This report uses several simplified measures of comparative financial performance to measure TVA's return on capital against the return on capital realized by IOUs. The first measure is net income before interest and taxes divided by net utility assets, without consideration of deferred assets. For the comparative IOUs, this rate equaled 11.63 percent, compared with a 9.65-percent return for TVA (Table 7).[91] The next two measures incorporate the deferred assets of IOUs into the denominator. One uses IOU returns on capital before taxes, and the other uses the returns after taxes. (The before-tax measure is used because Federal utilities do not pay Federal income taxes.)

[91]The operating return on assets measures were chosen, rather than the more familiar net income or return on equity, in order to abstract from the differing roles of debt for public-sector versus private-sector utilities. Public-sector utilities sometimes have debt that equals or exceeds their assets, and they set prices so that there is little or no net income remaining after interest payments.

Many utilities carry substantial sums of deferred assets on their books. In 1998, the IOUs listed a total of $84 billion in regulatory assets as deferred.[92] When those deferred assets are included, IOUs as a group earned a 6.79-percent operating rate of return on an after-tax basis and a 9.45-percent rate of return before taxes (Table 7). In contrast, TVA, including its deferred assets, earned a 7.55-percent rate of return in 1998. In the case of TVA, the utility carried on its books $8.3 billion (1999 dollars) in terminated nuclear facilities and deferred regulatory assets, which were not a part of its ratebase.[93] TVA's rate of return was also calculated both with and without its deferred nuclear power and regulatory assets.

Table 7. Tennessee Valley Authority Return on Assets Compared with Hypothetical Equivalent Investor-Owned Utility Returns, 1990 and 1998

IOU Comparison	Net Plant and Equipment (Million 1999 Dollars)	Actual Revenue (Million 1999 Dollars)	Operating Income (Million 1999 Dollars)	Average Return (Percent)	Adjusted Revenue (Million 1999 Dollars)	Implied IOU Rate of Return (Percent)	Federal Government Support (Million 1999 Dollars)
			1990				
No Deferred Assets	23,882.5	6,502.9	1,193.6	5.00	7,759.6	10.26	1,256.7
Deferred Assets Before Taxes	31,056.6	6,502.9	1,193.6	3.84	8,495.7	10.26	1,992.8
Deferred Assets After Taxes	31,056.6	6,502.9	1,193.6	3.84	7,765.8	7.91	1,262.9
			1998				
No Deferred Assets	20,935.4	6,812.1	2,206.9	10.54	7,040.0	11.63	227.9
Deferred Assets Before Taxes	29,247.8	6,812.1	2,206.9	7.55	7,369.1	9.45	557.0
Deferred Assets After Taxes	29,247.8	6,812.1	2,206.9	7.55	6,591.1	6.79	—

Notes: Because TVA does not pay Federal taxes, the after-tax and pre-tax net income values are the same. Calculated values may differ slightly from the values shown due to independent rounding. Most of the dollar values appearing in this report have been converted to 1999 dollars using the Gross Domestic Product (GDP) deflator. The GDP deflator was applied to companies' prior year loan and interest data. Although the values on the companies' balance sheets and income statements do not change from year to year, the purpose of the calculation was to estimate Federal Government support in a consistent framework. The framework chosen was the value of Federal Government support in terms of its 1999 purchasing power. The 1999 GDP deflator was 22 percent higher than the 1990 value and 1 percent higher than the 1998 value.

Source: Tennessee Valley Authority, *Annual Report 1990* (1991) and *Annual Report 1998* (1999).

Generating revenues sufficient to earn an 11.63-percent operating return for TVA would require that TVA increase its average price by 5 percent, implying a revenue gain of $227.9 million (Table 7).[94] To generate a before-tax rate of return equal to the 9.45-percent return for IOUs (including their regulatory utility assets), TVA would have to raise its prices by 7 percent and increase revenues by $557 million. This calculation indicates that TVA is more heavily affected by its deferred regulatory costs than is the IOU industry. On an after-tax basis, however, the IOU rate of return on assets (including deferred regulatory assets) falls short of the TVA rate of return, in part because TVA is not required to pay Federal taxes. By this measure, there is no government support to the TVA.

Table 7 indicates that the value of Federal support to TVA underlying the historic cost differential has declined since 1990. In 1990, the three measures of return on plant and equipment provided TVA with respective gains of $1.3 billion, $2.0 billion, and $1.3 billion.

[92]Compiled from data provided by the Federal Energy Regulatory Commission, FERC Form 1. Note: Regulatory assets are mainly deferred expenses that appear as assets on the balance sheet in return for the regulatory promise that the utilities will be allowed to recover them in the future. See Energy Information Administration, *The Changing Structure of the Electric Power Industry: An Update*, DOE/EIA-0562(96) (Washington, DC, December 1996), p. 78.

[93]Tennessee Valley Authority, *Annual Report 1998* (1999), p. 24.

[94]Assuming that no loss of sales resulted from the increase in prices.

Bonneville Power Administration

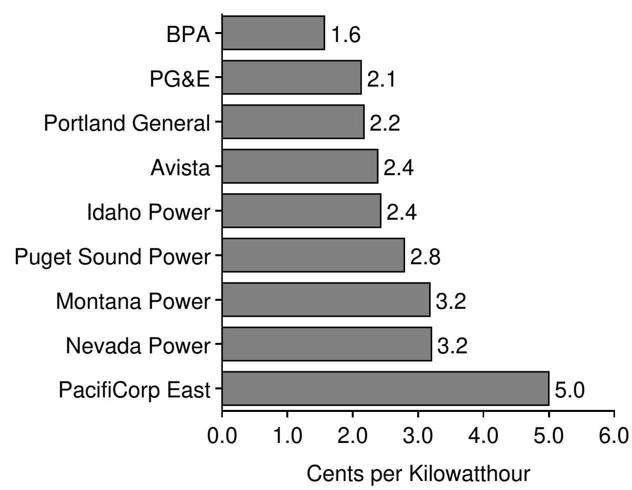
BPA is the largest of the Federal PMAs and the second largest Federal utility in terms of assets after TVA. BPA serves 3 million customers and supplies about half of all power in the Northwest.[95] Its transmission network accounts for 75 percent of the bulk transmission system in the Northwest.[96] BPA markets power from 29 dams and 1 nuclear power plant, which in 1998 produced a total of 90 billion kilowatthours of electricity.[97] Its service territory includes Oregon, Washington, Idaho, Western Montana, and small parts of California, Eastern Montana, Nevada, Utah, and Wyoming.[98]

BPA was created by the Bonneville Project Act of 1937. The purpose of the Act was to market power produced in the Columbia River basin and promote economic development in the Pacific Northwest. Currently a part of the U.S. Department of Energy, BPA is responsible for the Federal Columbia River Power System. BPA receives no direct payment from the U.S. Treasury, although the operating agencies do. Rather, the support it receives from the U.S. Government is embodied in the prices it charges its customers for electricity, the interest it pays on its debt, and the lack of return it realizes on its assets.

BPA's Prices Relative to Neighboring Investor-Owned Utilities

More than 90 percent of the electricity sold by BPA is produced from Federal hydropower facilities, and the remainder comes from one nuclear power plant. The average revenues derived from BPA's wholesale electricity sales are, in general, lower than those of competing utilities in BPA's operating region and much lower than those of IOUs operating outside the Pacific Northwest. Figure 5 shows that BPA has the lowest wholesale average revenue of utilities operating in the Pacific Northwest region. Clearly, BPA's lower average revenue is due to its heavy dependence on relatively inexpensive hydroelectric power. No other major utility in the Pacific Northwest region sold as much hydroelectricity as BPA, although in general other utilities in the region also tend to be heavily dependent on hydropower (Table 8). The ample hydroelectric resources in the Pacific Northwest also allow neighboring utilities to charge rates substantially lower than those in the rest of the Nation. Although BPA sells power mainly in the wholesale market, end users (industrial, commercial, and residential) benefit substantially from its lower cost power (Table 9).

Figure 5. Average Wholesale Electricity Revenues for the Bonneville Power Administration and for Investor-Owned Utilities Operating in the Pacific Northwest Region, 1998



Source: Federal Energy Regulatory Commission, FERC Form 1; and Energy Information Administration, *Financial Statistics of Major U.S. Publicly Owned Electric Utilities 1998*, DOE/EIA-0437(98) (Washington, DC, December 1999), p. 457.

[95]Bonneville Power Administration, web site www.bpa.gov/corporate/kc/who/watsbpax.shtml.
[96]Bonneville Power Administration, web site www.bpa.gov/corporate/kc/who/watsbpax.shtml.
[97]BPA's 1998 power production was obtained via a phone conversation with BPA's Accounting Department.
[98]Bonneville Power Administration, *Annual Report 1998* (1999), p. 52.

Table 8. Hydroelectric Share of Net Power Generation for Utilities in the Pacific Northwest, 1996
(Percent)

Utility	Hydropower Generation as a Percentage of Net Power Generation
Bonneville Power Administration	91.0
PG&E	30.6
Portland General	37.5
Avista[a]	64.6
Idaho Power	69.1
Puget Sound Power	24.1
Montana Power	43.2
PacifiCorp	9.7
Nevada Power	0.0

[a]Formerly, Washington Water Power.

Note: BPA's 91-percent share equals the utility's share of sustained peak capacity coming from hydroelectricity.

Sources: Bonneville Power Administration and Energy Information Administration, *Financial Statistics of Major U.S. Investor-Owned Electric Utilities 1996*, Volume 1, DOE/EIA-0437(96/1) (Washington, DC, December 1997), Table 43.

Table 9. Average Revenue per Kilowatthour for U.S. Electric Utilities by State and End-Use Sector, 1998
(1999 Dollars)

State	All Sectors	Residential	Commercial	Industrial	Other
Washington	4.08	5.09	4.87	2.67	3.65
Oregon	4.96	5.89	5.06	3.54	6.75
Idaho	4.07	5.35	4.39	2.80	4.65
Nationwide	6.82	8.36	7.50	4.54	6.71

Note: Most of the dollar values appearing in this report have been converted to 1999 dollars using the Gross Domestic Product (GDP) deflator. The GDP deflator was applied to companies' prior year loan and interest data. Although the values on the companies' balance sheets and income statements do not change from year to year, the purpose of the calculation was to estimate Federal Government support in a consistent framework. The framework chosen was the value of Federal Government support in terms of its 1999 purchasing power. The 1999 GDP deflator was 22 percent higher than the 1990 value and 1 percent higher than the 1998 value.

Source: Energy Information Administration, *Electric Power Annual 1998*, Volume 2, DOE/EIA-0348(98/2) (Washington, DC, December 1999), p. 22.

As electricity reform continues, an increasing portion of the wholesale market is becoming deregulated. In a fully competitive environment, the extent to which BPA's nonregulated sales into the wholesale market reflect the utility's cost advantage (related to its low-cost hydropower assets) could be viewed as a measure of Federal support to the recipients of its power. In 1998, electricity revenues averaged 6.82 cents per kilowatthour for the United States as a whole, 4.07 cents per kilowatthour in Idaho, 4.08 cents per kilowatthour in Washington, and 4.96 cents per kilowatthour in Oregon (Table 9). Kentucky and Wyoming were the only other States with comparably low electricity rates.

Residential users in the Pacific Northwest are also among the beneficiaries of BPA's low-cost hydropower production. Residential electricity prices in Washington State averaged 5.09 cents per kilowatthour in 1998, lower than in any other State. In contrast, the average revenue per kilowatthour for residential users in the United States as a whole was 8.36 cents. Similar price benefits were realized by commercial and industrial electricity consumers in the Pacific Northwest.

To measure the value of BPA's relative price advantage, a comparison can be made between BPA's average wholesale revenue per kilowatthour and those of nearby utilities. In 1998, BPA's average revenue per wholesale kilowatthour was 1.6 cents (1999 dollars), as compared with 2.6 cents for surrounding utilities (Table 10). If the BPA were able to sell its electricity at the same prices as surrounding utilities, its revenues would increase by $732 million. The difference in revenue provides a measure of the price support provided to the recipients of BPA's low-cost Federal power. In 1990, BPA's average wholesale revenue was only 0.6 cents lower per kilowatthour than those of neighboring utilities, resulting in $357 million in Federal support (Table 10).

Table 10. Computation of Implied Support for the Bonneville Power Administration on a Market Price Basis, 1990 and 1998

Year	Wholesale Revenues (Million 1999 Dollars)	Revenues at Implied Market Prices (Million 1999 Dollars)	Implied Revenue Loss (Million 1999 Dollars)	Revenues from Wholesale Electricity Sales (1999 Cents per Kilowatthour)		Revenue Loss per Unit of Electricity Sold (1999 Cents per Kilowatthour)
				WSCC Regional Average	BPA Average	
1990	1,556.9	1,914.3	357.4	3.4	2.8	0.6
1998	1,098.1	1,829.6	731.5	2.6	1.6	1.1

Notes: Totals may not equal sum of components due to independent rounding. Most of the dollar values appearing in this report have been converted to 1999 dollars using the Gross Domestic Product (GDP) deflator. The GDP deflator was applied to companies' prior year loan and interest data. Although the values on the companies' balance sheets and income statements do not change from year to year, the purpose of the calculation was to estimate Federal Government support in a consistent framework. The framework chosen was the value of Federal Government support in terms of its 1999 purchasing power. The 1999 GDP deflator was 22 percent higher than the 1990 value and 1 percent higher than the 1998 value.

Source: Form EIA-861, "Annual Utility Report," and Bonneville Power Administration, *Annual Report 1998* (1999).

BPA's price advantage is in large measure due to its low-cost hydroelectric power plants, which were built with relatively cheap Federal Government financing. Although its prices are among the lowest in the region, the utility has a high concentration of nonperforming assets and debt, which elevates its prices. For the most part, BPA's nonproductive assets and debt, like those of TVA, were accumulated in the pursuit of a large-scale nuclear power program. BPA guaranteed much of the debt of the Washington Public Power Supply System (WPPSS), which was owned by a group of municipal utilities in Washington State. WPPSS began construction of five nuclear power plants in the mid-1970s, but the projects were beset with cost overruns, schedule delays, and mudslides. BPA is currently financing debt on three of the five nuclear power plants. In 1998, BPA carried $4.2 billion in partially completed nuclear power plants on its balance sheet.[99]

BPA's Borrowing Costs

Although in large measure BPA's lower prices are the result of its access to low-cost generation from Federal hydropower facilities, artificially low borrowing costs add to its price advantage. BPA has, since its inception, benefitted from substantial Federal intervention in the way of interest support. The size of BPA's estimated Federal interest support is a function of the interest rate chosen to reflect the appropriate "market" interest rate. Table 11 illustrates a computation of Federal utility interest support, making alternative assumptions about the appropriate market interest rate. In one case it is assumed that the appropriate "unsupported rate," for comparison with the rate

[99]Bonneville Power Administration, *Annual Report 1991* (1992), pp. 26-32. BPA did not guarantee the debt issued to pay for two plants (WNP-4 and WNP-5), and bondholders lost their investments in those plants.

actually paid, is the 1998 average Federal long-term bond rate of 5.58 percent. In the other case it is assumed that if Federal utilities were independent entities, then the unsupported rate would be a "private sector" borrowing rate, which would include a greater allowance for default risk. The comparison rate in this case is the rate paid by IOUs with credit ratings running from Aaa to Baa.

Table 11. Assumed Additional Borrowing Costs for the Bonneville Power Administration Under Different Credit Ratings, 1998

Type of Debt and Support Values Underlying Interest Rate Differentials	Assumed Additional Borrowing Costs (Thousand 1999 Dollars)			
Appropriated Debt				
Treasury(+)/Aaa Utility Rate	5,399.4	—	—	—
Treasury(+)/Aa Utility Rate	—	20,022.6	—	—
Treasury(+)/A Utility Rate	—	—	34,465.8	—
Treasury(+)/Baa Utility Rate	—	—	—	52,373.7
Long-Term Debt				
Treasury(+)/Aaa Utility Rate	3,034.8	—	—	—
Treasury(+)/Aa Utility Rate	—	11,254.0	—	—
Treasury(+)/A Utility Rate	—	—	19,372.1	—
Treasury(+)/Baa Utility Rate	—	—	—	29,437.4
Non-Federal Projects Debt				
Municipal Aa/Municipal A	15,682.3	—	—	—
Municipal Aa/Municipal Baa	—	—	—	34,458.8
Total	**24,116.5**	**31,276.6**	**53,837.9**	**116,269.9**

Notes: Most of the dollar values appearing in this report have been converted to 1999 dollars using the Gross Domestic Product (GDP) deflator. The GDP deflator was applied to companies' prior year loan and interest data. Although the values on the companies' balance sheets and income statements do not change from year to year, the purpose of the calculation was to estimate Federal Government support in a consistent framework. The framework chosen was the value of Federal Government support in terms of its 1999 purchasing power. The 1999 GDP deflator was 22 percent higher than the 1990 value and 1 percent higher than the 1998 value. The Treasury(+) rate includes BPA's 78 basis point premium over the corresponding Treasury securities in 1998.

Sources: Bonneville Power Administration, *Annual Report 1998* (1999); Moody's Investor Service, *Utility Manual 1998*; and Federal Reserve, Form H-15.

BPA carries three forms of debt on its books. In 1998 its debt consisted of:

- **Appropriated Debt.** What BPA calls its appropriated debt was, before 1992, extended by the Congress to fund the construction and replacement of Army Corps of Engineers generation facilities. Since passage of the National Energy Policy Act, BPA has been required to fund these operations directly. BPA's appropriated debt was restructured in 1996. The utility's compliance with the BPA Appropriations Refinancing Act (16 U.S.C. 8381) reduced the principal of the debt by $2.5 billion and required that a portion of the debt be reset and assigned prevailing market rates as of September 1996.[100] The prevailing market rates, however, were based on rates corresponding to the prevailing Treasury yield curve plus the average spread between BPA's outstanding long-term debt and treasuries of similar maturity—not the rates of private-sector utilities.[101] Still, this led to a significant reduction of support on BPA's appropriated debt. Before 1996, the interest rate on BPA's debt was a

[100]Bonneville Power Administration, *Annual Report 1998* (1999), p. 38.

[101]BPA borrows at a rate on its appropriated debt that is slightly above the Treasury rate. BPA's *Annual Report 1998*, p. 37, lists its outstanding long-term debt and respective interest rates. A spread was calculated between those rates and the corresponding Treasury rates to provide an estimate of BPA's Treasury premium, which was estimated at 78 basis points in 1998.

weighted average of 3.5 percent.[102] The Act also required the BPA to pay the Treasury an additional $100 million, prorated over the course of the appropriations. This value was incorporated by BPA into its interest payment on appropriated debt and captured in the interest support estimated in this chapter.[103] In 1998, BPA's appropriated debt stood at $4.5 billion (1999 dollars).

- **Long-Term Debt.** BPA's long-term debt primarily funds its transmission system. In 1974, the Congress allowed BPA an amount limited to a nominal $3.75 billion in direct borrowing authority from the Treasury to fund the utility's capital program. Of the total, $1.2 billion was earmarked for conservation and renewable energy investments, and $2.5 billion was earmarked for transmission and other capital investments.[104] The appropriations are to be repaid to the Treasury by BPA. This long-term debt is actually of medium- as well as long-term maturity. The debt is held by the Treasury at interest rates set by the Treasury, which approximate the interest rates paid by Government agencies. The rates are adjusted to reflect the cost of specific features of BPA's bonds. In 1998, BPA's long-term debt equaled approximately $2.5 billion (1999 dollars).[105]

- **Non-Federal Projects Debt.** Non-Federal projects debt stems from BPA's financing of the three WPPSS nuclear projects and several smaller generation and conservation investments.[106] Approximately $4.2 billion of BPA's debt is devoted to nuclear power assets that have never been brought into service. Although the Federal Government does not guarantee BPA's non-Federal debt, the financial community treats the debt as though it did. BPA is a Federally owned utility, and Standard and Poor's assigns the company's bonds their AA- rating and Moody's Aa1 rating.[107] Non-Federal projects debt is not actually issued by BPA but rather is issued under the name of WPPSS. The value of BPA's non-Federal projects debt was roughly $7.0 billion (1999 dollars) in 1998.[108]

Table 11 compares BPA's current interest costs at its 78 basis point spread over the 30-year Treasury rate with what the utility might have paid if its borrowings had been priced at various IOU rates or municipal utility rates. BPA's appropriated long-term debts are essentially borrowings from the Treasury at rates which averaged 78 basis points above the Treasury's own cost of funds. For comparison, this analysis measures what BPA's cost of capital on its appropriations or long term debt would be if BPA had raised the funds in private capital markets rather than through the Treasury. The spread between the adjusted 30-year Treasury rate (including BPA's 78 basis point spread) and the Aaa IOU rate averaged 13 basis points between 1990 and 1998.[109] Had BPA borrowed its appropriated debt and long-term debt at Aaa rates in 1998 (or at 13 basis points higher), its cost of funds would have been $8 million higher ($3.0 million for long-term debt and $5.4 million for appropriated debt). Had BPA borrowed the same funds at the Baa rate, its cost of funds would have been $82 million.

BPA also raises funds in private capital markets through its WPPSS bonds, which are used to fund BPA's non-Federal power projects. BPA's non-Federal power project borrowing was roughly $7 billion in 1998. These borrowings are equivalent to tax-free municipal debt. In 1998, BPA maintained a Moody's credit rating of Aa1 on its non-Federal

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[102] U.S. General Accounting Office, *Federal Electricity Activities, The Federal Government's Net Cost and Potential for Future Losses*, GAO/AIMD-97-110 (Washington, DC, September 1997), p. 108.

[103] Bonneville Power Administration, *Annual Report 1998* (1999), p. 36.

[104] U.S. General Accounting Office, *Federal Electricity Activities, The Federal Government's Net Cost and Potential for Future Losses*, GAO/AIMD-97-110 (Washington, DC, September 1997), p. 109.

[105] Bonneville Power Administration, *Annual Report 1998* (1999), p. 29.

[106] Bonneville Power Administration, *Annual Report 1998* (1999), p. 22.

[107] Bonneville Power Administration, *Annual Report 1998* (1999), p. 22.

[108] Bonneville Power Administration, *Annual Report 1998* (1999), p. 29.

[109] A basis point is one-hundredth of a percentage point. Source: Compiled from data appearing in Federal Reserve, Form H15, and Standard and Poor's *DRI* database.

projects debt, very close to this report's comparison Aa municipal utility rating. Table 11 illustrates how BPA's borrowing costs would rise if the utility carried the A or Baa municipal utility rating. At the A rate, BPA's borrowing costs on its non-Federal project debt would be $16 million higher; at the Baa rate, its costs would be $34 million higher. For BPA's total debt, the borrowing costs at less desirable interest rates would be anywhere from $24 million to $116 million higher.

It should be kept in mind that were it not for the implicit backing of the Federal Government, BPA's interest costs would be substantially higher. BPA's non-Federal debt receives Moody's rating of Aa1.[110] In all likelihood, BPA's credit rating would be negatively affected in the event of a loss of the Federal implicit guarantee. Further, BPA's almost entire reliance on debt financing would also detrimentally affect its creditworthiness were it to raise funds in private capital markets. In 1998, BPA's debt accounted for 79 percent of its total assets.[111] Average IOU debt, in contrast, accounted for 30 percent of total assets.[112]

BPA's Return on Capital

The final measure of Federal Government support to the Federal utilities concerns the forgone rate of return to the owners of the utilities' assets. To determine the relevant ratebase for IOUs, for instance, regulators assume an appropriate return on assets. For illustrative purposes, an assumption is being made here that if BPA were to realize the same rate of return on assets as IOUs, then an appropriate adjustment to its prices, revenues, and operating income would be needed. Like the other Federal utilities, BPA is not expected, on average, to realize a positive rate of return. Rather, its rates are expected to cover costs and no more. A positive rate of return is possible, however, given unforeseen changes in the operating environment. For instance, all the PMAs are hydropower-intensive electricity producers. With rates set in advance, income can vary considerably with annual precipitation.

The first measure of operating rate of return uses net income before interest and taxes divided by net utility assets.[113] The IOUs realized an 11.63-percent rate of return in 1998, as compared with a 7.6-percent rate for BPA (Table 12). The second measure includes deferred regulatory assets as plant and equipment. For the IOUs, roughly $84 billion in assets were listed as deferred in 1998.[114] Using this measure, the comparative IOU group realized a 9.45-percent return on investment in 1998 before taxes, against a 7.6-percent rate for BPA. Because, as stated earlier, Federal utilities do not pay Federal income taxes, the second comparison measure uses the IOU pre-tax rate of return. The third measure also includes deferred regulatory assets but on an after-tax basis. For the comparative IOU group, this rate equaled 6.79 percent after taxes versus a 5.6 percent rate for BPA. In the case of BPA, the utility carried $4.2 billion (1999 dollars) in terminated nuclear facilities on its books in 1998. Although a part of BPA's ratebase, these facilities provide limited if not negative value to the utility's asset base. Therefore, BPA's rate of return was also calculated both with and without its non-operating nuclear power assets.

[110]Bonneville Power Administration, *Annual Report 1998* (1999), p. 22.

[111]Bonneville Power Administration, *Annual Report 1998* (1999), p. 29. Debt equals Federal appropriations, long-term debt, and non-Federal projects debt.

[112]Energy Information Administration, *Electric Power Annual 1998*, Volume 2, DOE/EIA-0348(98/2) (Washington, DC, December 1999), p. 27.

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

[114]Compiled from data appearing in Federal Energy Regulatory Commission, FERC Form 1.

Table 12. Bonneville Power Administration Return on Assets Compared with Hypothetical Equivalent Investor-Owned Utility Returns, 1990 and 1998

IOU Comparison	Net Plant and Equipment (Million 1999 Dollars)	Actual Revenue (Million 1999 Dollars)	Operating Income (Million 1990 Dollars)	Average Return (Percent)	Adjusted Revenue (Million 1999 Dollars)	Implied IOU Rate of Return (Percent)	Federal Government Support (Million 1999 Dollars)
			1990				
No Deferred Assets	12,135.1	2,534.4	764.4	6.3	3,015.0	10.26	480.6
Deferred Assets Before Taxes . .	12,135.1	2,534.4	764.4	6.3	3,015.0	10.26	480.6
Deferred Assets After Taxes . . .	18,142.8	2,534.4	764.4	4.2	3,205.0	7.91	670.7
			1998				
No Deferred Assets	11,607.6	2,080.8	883.6	7.6	2,547.0	11.63	466.3
Deferred Assets Before Taxes . .	11,607.6	2,080.8	883.6	7.6	2,294.0	9.45	213.3
Deferred Assets After Taxes . . .	15,810.1	2,080.8	883.6	5.6	2,270.6	6.79	190.0

Notes: EIA's *Financial Statistics of Major U.S. Investor-Owned Utilities* did not report any deferred regulatory assets in 1990. Most of the dollar values appearing in this report have been converted to 1999 dollars using the Gross Domestic Product (GDP) deflator. The GDP deflator was applied to companies' prior year loan and interest data. Although the values on the companies' balance sheets and income statements do not change from year to year, the purpose of the calculation was to estimate Federal Government support in a consistent framework. The framework chosen was the value of Federal Government support in terms of its 1999 purchasing power. The 1999 GDP deflator was 22 percent higher than the 1990 value and 1 percent higher than the 1998 value.

Sources: Bonneville Power Administration, *Annual Report 1990* (1991) and *Annual Report 1998* (1999); Energy Information Administration, *Financial Statistics of Major U.S. Investor-Owned Electric Utilities 1992*, Volume 1, DOE/EIA-0347(92/1) (Washington, DC, December 1993), Tables 6 and 8; *Financial Statistics of Major U.S. Investor-Owned Electric Utilities 1996*, Volume 1, DOE/EIA-0347(96/1) (Washington, DC, December 1997), Tables 6 and 8; and FERC Form 1.

Generating revenues sufficient to earn an 11.63-percent return on operating income for BPA would require that BPA increase its average price by 22 percent, implying a revenue gain of $466 million (Table 12). For BPA to realize a 9.45-percent rate of return on its combined assets (i.e., including the deferred assets) it would need to increase its prices by 10 percent, suggesting a revenue increase of $213 million. On an after-tax basis, BPA would need to raise prices by 9 percent to achieve a rate of return comparable to the 6.79-percent rate for IOUs (assuming that their deferred assets are also incorporated into their ratebase), suggesting a level of Federal support to the BPA of $190 million.

Table 12 also shows that the real value of Federal support to BPA underlying the three historic cost measures has fallen since 1990. In 1990, the three measures of return on plant and equipment provided BPA with respective gains of $481 million, $481 million, and $671 million.

The Smaller Power Marketing Administrations

The three smaller PMAs are the Southeastern Power Administration (SEPA), the Southwestern Power Administration (SWPA), and the Western Area Power Administration (WAPA). Each is headed by a single administrator appointed by the Secretary of Energy. More so than either BPA or TVA, the three smaller PMAs benefit from low-cost hydropower dams that were built as long as 60 years ago. For instance, WAPA's Hoover Dam came on line in 1936.[115] Perhaps more importantly, their only non-hydro generation assets consist of one thermal plant. The PMAs receive appropriations from the U.S. Treasury for most of their operations and maintenance expenses as well as for capital expenses. The former is expected to be paid off in the year it was received; the latter can be paid back with interest over the service life of the investment, for a period not to exceed 50 years.

[115]Western Area Power Administration, *Annual Report 1998* (1999), p. 9.

Before 1983, the three smaller PMAs were allowed interest rates below prevailing Treasury rates. In 1983, the U.S. Department of Energy modified the interest rates available for new projects requiring the PMAs to pay a rate equal to the average Treasury yield during the previous fiscal year. In addition, DOE requires the PMAs to retire their high-price debt first whenever possible (an advantage unavailable to the Treasury itself). As a result, over time, they can realize an average cost of funds below that of the Treasury itself.

Southeastern Power Administration

SEPA was created in 1950 in response to the Flood Control Act of 1944,[116] and in 1977 it was transferred to the Department of Energy. SEPA markets electricity in 11 States: Alabama, Florida, Georgia, Illinois, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee, Virginia, and West Virginia. In 1998, the utility had 3,092 megawatts of generating capacity,[117] almost entirely hydropower, and sold 8.8 billion kilowatthours of electricity.[118] It provides electricity to 127 electric cooperatives, 1 Federal utility, 176 public bodies, and 2 IOUs. SEPA markets power from 23 hydroelectric power stations, all of which are operated by the Army Corps of Engineers.[119]

Southwestern Power Administration

SWPA markets power from 24 hydroelectric power plants operated by the Army Corps of Engineers to customers in Arkansas, Kansas, Louisiana, Missouri, Oklahoma, and Texas. SWPA has 2,158 megawatts of generation capacity and operates 1,380 miles of transmission lines. In 1998 it sold 6.7 billion kilowatthours of electricity, 70 percent of which went to electric cooperatives, 27 percent to municipalities, 2 percent to Federal agencies, and 1 percent to utilities and others.[120]

Western Area Power Administration

WAPA was established by the Congress in the 1977 Department of Energy Organization Act to manage power marketing and transmission operations that previously were under the responsibility of the U.S. Department of Interior's Bureau of Reclamation. WAPA markets power in Arizona, California, Colorado, Iowa, Kansas, Montana, Minnesota, Nebraska, Nevada, New Mexico, North Dakota, South Dakota, Texas, Wyoming, and Utah. It operates 17,000 miles of transmission lines and sells power from 55 hydroelectric generation facilities and 1 thermal plant. In 1998, WAPA sold 45 billion kilowatthours of electricity, 26 percent of which went to State agencies, 25 percent to municipalities, 21 percent to cooperatives, 11 percent to IOUs, 10 percent to public utility districts, 5 percent to Federal agencies, and the remaining 2 percent to power marketers, irrigation districts, and other users.[121]

WAPA derives about 24 percent of its electricity revenues from municipalities, 22 percent from cooperatives, 22 percent from State agencies, 12 percent from public utility districts, 11 percent from IOUs, and 5 percent from Federal agencies. The remaining 4 percent is derived from a variety of users. The utility receives annual appropriations from

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[116]Southeastern Power Administration, *Annual Report 1998* (1999), p. 6.
[117]Southeastern Power Administration, *Annual Report 1998* (1999), p. 18.
[118]Southeastern Power Administration, *Annual Report 1998* (1999), p. 17.
[119]Southeastern Power Administration, *Annual Report 1998* (1999), p. 1.
[120]Southwestern Power Administration, *Annual Report 1998* (1999), pp. 24 and 25. Excludes losses, interchange, and contract exchange.
[121]Western Area Power Administration, *Annual Report 1998* (1999), p. 23. Excludes project use and interdepartmental and interproject exchanges.

the Congress to cover all expenses associated with its power and other activities. Its power rates are set to recover those costs, along with all costs associated with debt servicing.

PMA Prices Relative to Neighboring Investor-Owned Utilities

The prices charged by the three smaller PMAs are among the lowest available in the United States. The legislation that created the three smaller PMAs[122] requires them to charge rates that adequately cover costs, but it does not fully explain which costs should be recovered in the ratebase. In 1944, the Congress established SEPA and SWPA and mandated that their power be sold at the "lowest possible rates consistent with sound business principles."[123] Like BPA and TVA, the three smaller PMAs are required to provide certain classes of customers with preference power.

Average wholesale revenues charged by the three smaller PMAs are considerably below those charged by nearby IOUs. The average revenue realized by SEPA in 1998 was 1.9 cents per kilowatthour, compared with 3.6 cents for surrounding IOUs (Table 13). For SWPA, the average wholesale revenue was 1.4 cents per kilowatthour, compared with 3.0 cents for neighboring IOUs. For WAPA, average wholesale revenues equaled 1.6 cents per kilowatthour, compared with 2.6 cents for neighboring IOUs. If the three smaller PMAs could charge the same prices as those of competing IOUs, their combined average wholesale revenues would climb by $666 million or 1.2 cents per kilowatthour. These differences in revenue and price can be viewed as a form of Federal support to the customers of the three smaller PMAs. Since 1990, the differentials between the average wholesale revenues of the three smaller PMAs and those of their surrounding IOUs have fallen considerably. As a result, the calculated Federal price support for the three entities has fallen from $1,115 million in 1990 to $666 million in 1998 (Table 13).

PMA Borrowing Costs

Because the three smaller PMAs have historically borrowed at rates considerably lower than the Treasury's own cost of funds, the calculations used to measure the value of the interest rate support provided to TVA and BPA are not appropriate. Instead, hypothetical interest rate payments for the three PMAs were estimated in the following manner. Power repayment schedules record the timetables for recovering the costs of each power project and report the annual investment incurred for each project through 1998. SWPA's earliest project began in 1936, SEPA's in 1949, and WAPA's in 1944. Cumulative investment in power projects was allocated on an annual basis. A weighted average cost of capital for total investment was developed by applying annual benchmark rates to the annual incremental investment, summing over the project history, and then dividing by total cumulative interest. The range of interest rates is provided because it is unclear what rates similar private enterprises would pay. Any outstanding debt not scheduled for repayment was assigned an average rate for the appropriate period. The reported subsidy, then, is the difference between a hypothetical interest payment based on this weighted average and the actual interest payment reported by the PMA. An inverse relationship between principal investment levels and interest rates would yield the lowest level of support, so to the extent that debt was incurred during the late 1970s and 1980s, the methodology indicates a higher level of support. Table 14 shows the implied yield curves for outstanding debt for each of the PMAs. Depending on the comparative interest rate benchmarks, the three smaller PMAs received Federal support ranging from $80 million to $224 million in 1998.

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[122]The Reclamation Project Act of 1939, the Flood Control Act of 1944, and the Department of Energy Reorganization Act of 1977.
[123]Southwestern Power Administration, *Annual Report 1998* (1999), p. 6.

Table 13. Computation of Implied Support for the Three Smaller Federal Power Marketing Administrations on a Market Price Basis, 1990 and 1998

Federal Utility	Wholesale Revenues (Million 1999 Dollars)	Revenues at Implied Market Prices (Million 1999 Dollars)	Implied Revenue Loss (Million 1999 Dollars)	Revenues from Wholesale Electricity Sales (1999 Cents per Kilowatthour)		Revenue Loss per Unit of Electricity Sold (1999 Cents per Kilowatthour)
				Nearby NERC Regional Average[a]	Federal PMA Average	
			1990			
Southeastern	166.3	426.7	260.3	4.1	1.6	2.5
Southwestern	104.6	254.9	150.3	3.1	1.3	1.9
Western Area	517.0	1,221.2	704.2	3.6	1.5	2.1
			1998			
Southeastern	171.1	323.2	152.2	3.6	1.9	1.7
Southwestern	93.0	199.4	106.4	3.0	1.4	1.6
Western Area	634.0	1,041.3	407.3	2.6	1.6	1.0

[a]The nearby NERC regions used for the comparison are SERC (for SEPA), SPP (for SWPA), and WSCC (for WAPA).

Notes: Totals may not equal sum of components due to independent rounding. Most of the dollar values appearing in this report have been converted to 1999 dollars using the Gross Domestic Product (GDP) deflator. The GDP deflator was applied to companies' prior year loan and interest data. Although the values on the companies' balance sheets and income statements do not change from year to year, the purpose of the calculation was to estimate Federal Government support in a consistent framework. The framework chosen was the value of Federal Government support in terms of its 1999 purchasing power. The 1999 GDP deflator was 22 percent higher than the 1990 value and 1 percent higher than the 1998 value.

Sources: Form EIA-861, "Annual Utility Report," and company annual reports, income statements, and balance sheets.

Table 14. Computation of Implied Interest Rate Support to the Three Smaller Federal Power Marketing Administrations, 1998
(Thousand 1999 Dollars)

Item	30-Year Treasury Rate	Aaa IOU Rate	Aa IOU Rate	A IOU Rate	Baa IOU Rate
Outstanding Debt	5,814,071	5,814,071	5,814,071	5,814,071	5,814,071
Interest Paid/Implied	324,425	344,746	354,760	366,181	388,853
Implied Support	80,257	172,168	186,380	199,638	224,189

Note: Most of the dollar values appearing in this report have been converted to 1999 dollars using the Gross Domestic Product (GDP) deflator. The GDP deflator was applied to companies' prior year loan and interest data. Although the values on the companies' balance sheets and income statements do not change from year to year, the purpose of the calculation was to estimate Federal Government support in a consistent framework. The framework chosen was the value of Federal Government support in terms of its 1999 purchasing power. The 1999 GDP deflator was 22 percent higher than the 1990 value and 1 percent higher than the 1998 value.

Sources: Company annual reports and balance sheets and Moody's Investor Service, *Utility Manual 1998*.

PMA Returns on Capital

The method used to measure the difference between the returns on assets for the three smaller PMAs and those for the IOU comparison group is exactly the same as used for BPA and TVA. The first measure of operating rate of return uses net income before interest and taxes divided by net utility assets. For the comparative IOUs this rate equaled 11.63 percent, compared with 2.9 percent for the three smaller PMAs (Table 15). The two other measures incorporate the deferred assets of the IOUs—largely involving unfinished nuclear power plants—into a before-tax and after-tax basis.

Table 15. Returns on Assets for the Western Area Power Administration, Southwestern Power Administration, and Southeastern Power Administration Compared with Hypothetical Equivalent Investor-Owned Utility Returns, 1990 and 1998

IOU Comparison	Net Plant and Equipment (Million 1999 Dollars)	Actual Revenue (Million 1999 Dollars)	Operating Income (Million 1999 Dollars)	Average Return (Percent)	Adjusted Revenue (Million 1999 Dollars)	Implied IOU Rate of Return (Percent)	Federal Government Support (Million 1999 Dollars)
			1990				
No Deferred Assets	7,875.6	901.1	181.2	2.3	1,527.9	10.26	626.8
Deferred Assets Before Taxes . .	7,875.6	901.1	181.2	2.3	1,527.9	10.26	626.8
Deferred Assets After Taxes . . .	7,875.6	901.1	181.2	2.3	1,342.8	7.91	441.7
			1998				
No Deferred Assets	6,047.0	1,074.6	173.6	2.9	1,604.3	11.63	529.7
Deferred Assets Before Taxes . .	6,047.0	1,074.6	173.6	2.9	1,472.4	9.45	397.9
Deferred Assets After Taxes . . .	6,047.0	1,074.6	173.6	2.9	1,311.6	6.79	237.0

Notes: EIA's *Financial Statistics of Major U.S. Investor-Owned Utilities* did not report any deferred regulatory assets in 1990. Most of the dollar values appearing in this report have been converted to 1999 dollars using the Gross Domestic Product (GDP) deflator. The GDP deflator was applied to companies' prior year loan and interest data. Although the values on the companies' balance sheets and income statements do not change from year to year, the purpose of the calculation was to estimate Federal Government support in a consistent framework. The framework chosen was the value of Federal Government support in terms of its 1999 purchasing power. The 1999 GDP deflator was 22 percent higher than the 1990 value and 1 percent higher than the 1998 value.

Sources: Company annual reports, income statements, and balance sheets; Energy Information Administration, *Financial Statistics of Major U.S. Investor-Owned Electric Utilities 1992*, Volume 1, DOE/EIA-0347(92/1) (Washington, DC, December 1993), Tables 6 and 8; *Financial Statistics of Major U.S. Investor-Owned Electric Utilities 1996*, Volume 1, DOE/EIA-0347(96/1) (Washington, DC, December 1997), Tables 6 and 8; and FERC Form 1.

Generating revenues sufficient to earn an 11.63-percent operating return for three smaller PMAs would require that they increase their average prices by 48 percent, implying a revenue gain of $530 million (Table 15). To generate a before-tax rate of return equal to the IOUs' 9.45-percent rate (including their deferred utility assets), the three smaller PMAs would have to raise prices by 37 percent and increase revenues by $398 million. On an after-tax basis, the three smaller PMAs would have to raise their prices by 22 percent and their total revenues by $237 million in order to realize the IOU 6.79-percent rate of return. Table 15 indicates that the real value of Federal support to the three smaller PMAs underlying the historic cost differential has declined since 1990. In 1990, the three measures of return on plant and equipment provided the three smaller PMAs with respective gains of $627 million, $627 million, and $442 million.

Rural Utilities Service

Background

The Rural Utilities Service (RUS) is an agency of the U.S. Department of Agriculture (USDA) that provides support to rural communities for the development and improvement of water, telecommunications, and electricity services. It is part of a broader set of programs within the USDA whose goal is to assist in the development of rural America. As stated on USDA's web site,

> "USDA Rural Development is committed to helping improve the economy and quality of life in all of rural America. Through our programs, we touch rural America in many ways . . . . Our financial programs support such essential public facilities and services as water and sewer systems, housing, health clinics, emergency

service facilities and electric and telephone service. We promote economic development by supporting loans to businesses through banks and community-managed lending pools. We offer technical assistance and information to help agricultural and other cooperatives get started and improve the effectiveness of their member services. And we provide technical assistance to help communities undertake community empowerment programs."[124]

The RUS was established in October 1994 when the USDA was reorganized and the functions of the Rural Electrification Administration (REA), the Rural Development Administration (RDA) and the Rural Telephone Bank (RTB) were assigned to it. The former REA programs, the focus of the rest of this section, began in May 1935, and were codified into law with the passage of the Rural Electrification Act of 1936 (7 U.S.C. 901). In 1998 RUS electricity borrowers accounted for 6.7 percent of total U.S. retail electricity sales and 4.3 percent of net utility generation (Table 16).

Table 16. Key Statistics for the Rural Utilities Service Electricity Program, 1998

Statistic	Quantity	Percent of National Total
Consumers Served	10,858,441	8.8
Generation (Megawatthours)	157,896,742	4.3
End-Use Sales (Megawatthours)		
Residential	125,210,030	11.1
Commercial/Industrial	84,268,848	4.2
Other	8,165,832	7.9
Total	**217,644,698**	**6.7**

Sources: **Rural Utilities Service:** U.S. Department of Agriculture, Rural Utilities Service, *1998 Statistical Report, Rural Electric Borrowers*, IP 201-1 (Washington, DC, August 1999), pp. 10 and 14. **National:** Energy Information Administration, *Electric Power Annual 1998*, Volume 2, DOE/EIA-0348(98/2) (Washington, DC, December 1999).

RUS Electricity Loan Programs

The RUS electricity program provides support by issuing direct loans to electricity providers to build and maintain distribution facilities and by guaranteeing loans made by others for the construction of new power plants and transmission facilities. The loans fall into three general categories—direct 5-percent "hardship" loans, direct loans with interest rates tied to municipal borrowing rates (referred to in the rest of this section as direct municipal rate loans), and guaranteed loans. In 1998, the RUS electricity program had advanced loans of nearly $21 billion (both hardship and direct municipal rate loans) and had guaranteed loans of nearly $26 billion. In 1998, RUS borrowers had outstanding long-term debt approaching $33 billion.

Hardship loans are made at an interest rate of 5 percent[125] to borrowers that serve financially distressed rural areas. Municipal rate loans fall into two categories—capped and uncapped. Capped municipal rate loans, with rates no higher than 7 percent, are made to borrowers who meet a consumer density test—less than 5.5 consumers per line mile—or the combination of a rate disparity test and a consumer income test. To meet the rate disparity test, the borrower's average revenue per kilowatthour must be higher than the average for the State in which it operates. To meet the income test the consumers served by the borrower must have average per capita incomes or household

[124]Rural Utilities Service, web site www.rurdev.usda.gov/rd/index.html.

[125]Before the amendment of the Rural Electrification Act in 1973, hardship loans were made at an interest rate of 2 percent and had maturities up to 35 years.

incomes below the averages for the State in which it operates. If these tests are not met, the rate on direct municipal loans can exceed 7 percent. The interest rates for uncapped municipal rate loans are set at competitive market rates for similar types of loans. Guaranteed loans are generally made to support the development of power generation facilities. If the money is borrowed from the Federal Financing Bank (FFB) the rate is set at one-eighth percent above the Treasury's cost of money, and the RUS guarantees 100 percent of the loan. If the money is borrowed from a commercial lender, both the interest rate and degree of RUS guarantee vary.[126]

Cost of Loan Support Provided to RUS Electricity Borrowers

The RUS programs do provide cost savings to its borrowers. Enumerating the savings that flow to RUS borrowers requires assessing the administrative costs of running the RUS programs, the costs RUS incurs by loaning money to its borrowers at interest rates below its Treasury borrowing costs (interest rate buydown costs), the costs RUS incurs when it covers defaults on loans it has guaranteed, and measuring the benefit RUS borrowers receive from being able to borrow money below competitive market interest rates. If the RUS did not exist, many of these costs would be borne by the borrowers in the form of higher fees and interest rates.

The amount of loan support provided by RUS is dependent on the market interest rates at the time of issuance. When market interest rates are low the RUS support may be relatively low, but when rates are high—as they were through most of the 1980s—the support can be quite large. An aggregate measure of the total support to RUS electricity borrowers could be derived by comparing the interest rate on all outstanding RUS electricity loans in 1998 to the interest rates on treasury and utility bonds with similar characteristics (i.e., date of issuance, maturity, whether the loan is callable or not, etc.). The difference in interest rates would show the benefit RUS electricity borrowers received in 1998. However, the data needed for such a comparison are not readily available.[127]

As a surrogate measure, the average interest rate faced by RUS borrowers is compared with the 1998 average 30-year Treasury bond rate, the 1998 average IOU 30-year bond rate, a weighted average 30-year Treasury bond rate, and weighted average IOU 30-year bond rates for Aaa, Aa, A, and Baa rated companies.[128] The range is provided because it is unclear what rate RUS electricity borrowers would face in private markets without RUS guarantees. The weighted rates are derived by amortizing the amount of RUS electricity loans advanced each year over the past 30 years (it is assumed that most of the loans are for 30 years), determining the remaining balance on them in 1998, and multiplying this balance by the appropriate rate for the year of issuance. For example, if it is estimated that 10 percent of the outstanding balance of loans in 1998 were issued in 1985, then the 1985 rates for each instrument would receive a 10-percent weight in the average rate. This approach makes numerous simplifying assumptions, but absent actual data it provides a rough estimate of the potential support. It does not address the likelihood that many loans may be shorter than 30 years and that some loans probably have been refinanced. Given that it is likely that non-RUS borrowers have refinanced higher cost loans in recent years, this approach likely overstates the support in 1998. However, the outstanding balance derived using this approach with the weighted Treasury rate is just under $14.3 billion,[129] very close to the $14.0 billion in outstanding distribution system loans shown in Table 17 (distribution loans are the majority of RUS electricity loans advanced).

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[126]For more information on the specifics of RUS electricity program loan conditions see Code of Federal Regulations, 7 CFR 1714.

[127]This information was requested from the RUS but was not provided in time to be used in this report.

[128]The RUS provided EIA with the total quantity of debt issued each year for the past 30 years. The weighted average rates were derived by calculating the average rate on the remaining balance of 30-year Treasury bonds and 30-year utility bonds issued at the same time as the RUS electricity loans.

[129]This 1998 balance value was calculated by assuming that the loans advanced by RUS each year over the past 30 years were issued at the 30-year Treasury rate. The data on loans advanced each year come from the statistical yearbook for rural electric borrowers published annually by the U.S. Department of Agriculture.

Table 17. Rural Utilities Service Electricity Loan Statistics, 1998

Number of Active Borrowers		**Long-Term Debt (Thousands 1999 Dollars)**	
Distribution	699	Distribution	14,038,371
Power Supply	59	Power Supply	18,529,076
Total	**758**	**Total**	**32,567,447**
Funds Advanced (Thousands 1999 Dollars)		**Interest on Long-Term Debt (Thousand 1999 Dollars)**	
Distribution	17,047,980	Distribution	719,632
Power Supply	3,675,429	Power Supply	1,202,044
Total	**20,723,409**	**Total**	**1,921,676**
Loan Guarantees (Thousand 1999 Dollars)			
Power Supply	26,128,863		

Notes: Long-term debt includes RUS long-term debt and other long-term debt advanced by others. Long-term debt values include only information from borrowers reporting detailed information to RUS (686 out of 699 distribution borrowers and 48 out of 59 power supply borrowers). Most of the dollar values appearing in this report have been converted to 1999 dollars using the Gross Domestic Product (GDP) deflator. The GDP deflator was applied to companies' prior year loan and interest data. Although the values on the companies' balance sheets and income statements do not change from year to year, the purpose of the calculation was to estimate Federal Government support in a consistent framework. The framework chosen was the value of Federal Government support in terms of its 1999 purchasing power. The 1999 GDP deflator was 22 percent higher than the 1990 value and 1 percent higher than the 1998 value.

Source: U.S. Department of Agriculture, Rural Utilities Service, *1998 Statistical Report, Rural Electric Borrowers*, IP 201-1 (Washington, DC, August 1999), Tables 1 through 5.

The average interest rate paid on the outstanding debt of RUS electricity borrowers in 1998 is actually slightly above the average 30-year Treasury rate for a bond issued in 1998 (Table 18). This comparison reflects the historically low interest rates that prevailed in 1998, rather than negative support from the RUS. When compared to a weighted Treasury rate—which captures the effect of the high interest rates of the 1980s, when many of the outstanding RUS electricity loans were issued—the support to RUS electricity borrowers in 1998 is estimated at $965 million. The estimated support value, using weighted borrowing rates, ranges from $965 million to $1,557 million. Again, the larger value captures the value of access to RUS electricity loans in the 1980s when others faced much higher interest rates.

Table 18. Computation of Implied Interest Rate Support to Rural Utilities Service Electricity Borrowers, 1998

Item	1998 Rates			Weighted Rates				
	RUS Electricity	30-Year Treasury	IOU	30-Year Treasury	Aaa IOU	Aa IOU	A IOU	Baa IOU
Outstanding Debt (Million 1999 Dollars)	32,567	32,567	32,567	32,567	32,567	32,567	32,567	32,567
Interest Paid/Implied (Million 1999 Dollars)	1,922	1,817	2,065	2,886	3,101	3,208	3,315	3,478
Average Rate (Percent)	5.90	5.58	6.34	8.86	9.52	9.85	10.18	10.68
Implied Support (Million 1999 Dollars)	—	—	144	965	1,179	1,287	1,394	1,557

Note: Most of the dollar values appearing in this report have been converted to 1999 dollars using the Gross Domestic Product (GDP) deflator. The GDP deflator was applied to companies' prior year loan and interest data. Although the values on the companies' balance sheets and income statements do not change from year to year, the purpose of the calculation was to estimate Federal Government support in a consistent framework. The framework chosen was the value of Federal Government support in terms of its 1999 purchasing power. The 1999 GDP deflator was 22 percent higher than the 1990 value and 1 percent higher than the 1998 value.

Sources: U.S. Department of Agriculture, Rural Utilities Service, *1998 Statistical Report, Rural Electric Borrowers*, IP 201-1 (Washington, DC, August 1999), and Moody's Investor Service, *Utility Manual 1998*.

The values shown in Table 18 do not fully capture the support provided by the RUS in the form of loan guarantees to power plant developers. Several analyses have concluded that the RUS faces a significant risk of large loan defaults. For example, in 1997 the U.S. General Accounting Office found that $618 million of the outstanding electricity loan portfolio was owed by borrowers who were delinquent in their payments and that $7.4 billion of the outstanding debt was owed by borrowers who were in financial distress.[130] At that time the outstanding RUS electricity debt totaled $32.3 billion, of which approximately 25 percent was at risk of not being fully repaid. Much of the problem debt resulted from investments made in expensive nuclear plants many years ago. For example, the *Wall Street Journal* reported that more than $1.5 billion in debt was written down for two borrowers in 1996.[131]

Summary

In total, it is estimated that Federal utilities received market price support equal to $1.4 billion (1999 dollars) in 1998 and return on asset support equal to $655 million to $1.6 billion (Table 19). Federal utilities and RUS borrowers received interest rate support ranging from $325 million to $2.1 billion. These estimates differ from the estimated support for 1990, when the Federal utilities received $1.9 billion in market price support and $2.2 billion to $3.3 billion in return on asset support (Table 19). The spread between the average revenues per kilowatthour charged

Table 19. Summary Estimates of Electricity Market Price, Interest Rate, and Return on Asset Supports, 1990 and 1998
(Million 1999 Dollars)

Utility/Program	Market Price Support	Interest Rate Support		Return on Asset Support	
		Low Estimate	High Estimate	Low Estimate	High Estimate
1990					
Tennessee Valley Authority	440.0	—	—	1,256.7	1,992.8
Bonneville Power Administration	357.4	—	—	480.6	670.7
SEPA, SWPA, and WAPA	1,114.8	—	—	441.7	626.8
Rural Utilities Service	—	—	—	—	—
Total	**1,912.2**	**—**	**—**	**2,179.0**	**3,290.3**
1998					
Tennessee Valley Authority	—	77.1	247.6	227.9	557.0
Bonneville Power Administration	731.5	24.1	116.3	190.0	466.3
SEPA, SWPA, and WAPA	665.9	80.3	224.2	237.0	529.7
Rural Utilities Service	—	143.8	1,557.0	—	—
Total	**1,397.4**	**325.3**	**2,145.1**	**654.9**	**1,553.0**

Notes: SEPA, SWPA, and WAPA designate the Southeastern Power Administration, the Southwestern Power Administration, and the Western Area Power Administration, respectively. Most of the dollar values appearing in this report have been converted to 1999 dollars using the Gross Domestic Product (GDP) deflator. The GDP deflator was applied to companies' prior year loan and interest data. Although the values on the companies' balance sheets and income statements do not change from year to year, the purpose of the calculation was to estimate Federal Government support in a consistent framework. The framework chosen was the value of Federal Government support in terms of its 1999 purchasing power. The 1999 GDP deflator was 22 percent higher than the 1990 value and 1 percent higher than the 1998 value.

Source: Tables 6, 7, 10, 11, 12, 13, 14, 15, and 18 in this chapter.

[130]U.S. General Accounting Office, *Rural Development: Financial Condition of the Rural Utilities Service's Loan Portfolio*, GAO/RCED-97-82 (Washington, DC, April 1997).

[131]*Wall Street Journal* (October 3, 1996), p. A3.

by the Federal utilities and those charged by competing utilities has narrowed since 1990, bringing the price-based measure of support down. Although the interest differential for 1990 was not measured, it probably was higher than the 1998 differential. Since 1990, the four PMAs have lost some (but not all) of their borrowing advantages, although that change is offset to some degree by TVA's refinancing of its high-interest 1998 Federal Financing Bank debt at lower market rates. In contrast, asset support has fallen since 1990.

A Note on Data Sources

Comparable financial data on public power agencies are not easily obtained. The primary data sources for this chapter are data collected on Form EIA-861, "Annual Electric Utility Report"; Form EIA-412, "Annual Report of Public Electric Utilities"; FERC Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others"; Standard and Poor's; and Federal Reserve, Form H-15, The data in those reports create certain ambiguities that should be noted:

- EIA publishes data only for "major" IOUs. EIA identified 239 IOUs as of 1998; however, only 179 were sufficiently large to be required to file FERC Form 1. Those 179 "major" utilities account for 99 percent of the electricity sold by IOUs to ultimate consumers; thus, the data lost by ignoring the missing 60 small IOUs are not of great importance. IOU data are on a calendar-year basis.

- Similarly, EIA publishes data only for "major" publicly owned utilities. In this case, EIA has identified 2,009 publicly owned utilities in 1998.

For rural electric cooperatives, data were obtained from U.S. Department of Agriculture, Rural Utilities Service, *1998 Statistical Report, Rural Electric Borrowers*, IP 201-1 (Washington, DC, August 1999). Cooperative data were collected on a uniform basis for calendar year 1998.

Federal utilities file Form EIA-412, and their financial results are published in EIA's *Financial Statistics of Major U.S. 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. Some of this lower price debt remains on the PMAs' books, which accounts for their much lower interest costs. For the PMAs, the 1998 annual report of each agency was used. All Federal utility data are for fiscal year 1998.