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Volume 1

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The Honorable John R. Kasich
Chairman
Committee on the Budget
House of Representatives

The Honorable John T. Doolittle
Chairman, Subcommittee on Water
and Power Resources
Committee on Resources
House of Representatives

This two-volume report responds to your December 13, 1996, and January 13, 1997, requests expressing concern about the significant ongoing expenses incurred by the federal government to support the electricity-related activities of the power marketing administrations (PMAS)[1] and the Rural Utilities Service (RUS). The report also responds to your concerns regarding potential future losses from these activities, as well as those of the Tennessee Valley Authority (TVA), given the move toward deregulation and increased competition in the electricity industry. Accordingly, this report estimates the federal government's net recurring cost[2] from the electricity-related activities at the Department of Agriculture's RUS, the Department of Energy's PMAS, and TVA for fiscal year 1996 and, where possible, the cumulative net cost for fiscal years 1992 through 1996 (in constant 1996 dollars).[3] As agreed with your offices, we estimated the net cost to the federal government on the accrual[4] basis of accounting. These net costs already have had or will have an impact on the federal budget.

[1]In this report, we discuss four of the five PMAs: Bonneville Power Administration (BPA), Southeastern Power Administration (Southeastern), Southwestern Power Administration (Southwestern), and Western Area Power Administration (Western). Because BPA had more than twice the revenue of the other three PMAs combined in fiscal year 1995 and faces different operating risks, we frequently discuss BPA separately. The fifth PMA, the Alaska Power Administration, is excluded from our analysis because legislation has been enacted to sell it to nonfederal entities.

[2]We define net recurring cost ("net cost") as the difference between the total expenses the federal government incurs and the total revenue it receives from its electricity-related activities in a given year.

[3]RUS provides loans and loan guarantees primarily to rural electric cooperatives that generate, transmit, and/or distribute wholesale and retail power, the PMAs market wholesale power, and TVA generates and transmits wholesale power.

[4]Accrual basis accounting recognizes the impact of revenue and expense transactions on the financial statements in the time periods when they occur, rather than when they result in cash receipts or disbursements.

You also asked that we assess the likelihood of future losses beyond the net recurring costs to the federal government from these entities. Based on risk criteria similar to those used by major bond rating agencies, we determined whether the likelihood of future losses to the federal government from its direct and indirect involvement in the electricity-related activities of RUS, the PMAs, and TVA was (1) remote, (2) reasonably possible, or (3) probable, as defined in federal accounting standards.[5]

The net costs and exposure to future financial losses result from the federal government's direct and indirect financial involvement in the electricity-related activities of these entities. For this report, we defined direct involvement as loans or loan guarantees made by the federal government directly to RUS borrowers, the PMAS, and TVA, and appropriated debt[6] owed by the PMAS and TVA. As of September 30, 1996, the federal government had over $53 billion of direct financial involvement in electricity-related activities. The federal government would have financial losses from its direct involvement if the RUS borrowers or the federal entity were unable to repay debt owed to or explicitly guaranteed by the federal government.

As of September 30, 1996, the federal government had indirect financial involvement of over $31 billion—primarily BPA's nonfederal debt[7] and bonds issued by TVA. Although BPA's nonfederal debt and the TVA bonds are not explicitly guaranteed by the federal government, the financial community generally views them as having an implicit federal guarantee. The federal government would have financial losses from its indirect involvement if it incurred unreimbursed costs as a result of actions it took to prevent default or breach of contract by the federal entity on nonfederal debt.

[5]Statement of Federal Financial Accounting Standards No. 5, Accounting for Liabilities of the Federal Government (SFFAS No. 5), indicates that if the chance that a contingent loss will occur is more likely than not, then the loss is considered *probable*; if the chance of loss is more than remote but less than probable, then the loss is considered *reasonably possible*; and if the chance of the loss occurring is slight, then the loss is considered *remote*.

[6]We use the term "appropriated debt" because PMAs and TVA are required to repay appropriations used for capital investments, with interest. However, these reimbursable appropriations are not technically considered lending by the Department of the Treasury.

[7]BPA refers to this as "nonfederal project debt." BPA used its contracting authority to acquire all or part of the generating capability of power projects of other entities. Under these agreements, BPA contracts to pay all or part of the annual project budgets, including debt service, whether or not the projects are completed. BPA does not have the authority to borrow from nonfederal sources. See appendix VIII of volume 2 for additional discussion.

Deregulation of the electricity industry has led to wholesale (sales for resale) competition, which, combined with factors such as surplus power and reduced production costs for gas-fired generation, has caused wholesale electricity prices to fall in many parts of the country. The increasingly competitive wholesale market and the financial vulnerability of the RUS borrowers, the PMAS, and TVA have increased, in varying degrees, the risk of future losses the federal government faces. Retail competition is also expected to have a future impact on the electricity industry. However, it is uncertain whether this will increase or decrease the likelihood of future losses related to the federal government's involvement in electricity-related activities.

The overall results of our review are summarized in volume 1 of this report. Volume 2 contains additional background information; details of our objectives, scope, and methodology; additional details on our risk analyses and the entities' net cost to the federal government; written agency comments, and major contributors to this report.

Results in Brief

The federal government incurs net costs of over a billion dollars annually in supporting the electricity-related activities of RUS and the PMAS. Additionally, the financial difficulties faced by RUS borrowers, BPA, TVA, and one or a few projects at each of the three PMAS result in risk to the federal government of future losses from these entities. The risk of loss from these entities is heightened by the onset of competition in the electricity industry.

The federal government is incurring substantial net costs annually from the electricity-related activities of RUS and the PMAS, but generally does not incur similar net costs from TVA. Although the PMAS are generally required to recover all costs, favorable financing terms and the lack of specific requirements to recover certain costs have resulted in net costs to the federal government. Because RUS, on the other hand, is not legislatively required or intended to recover all of its financing or other costs, interest charges to its borrowers cover only a portion of the federal government's cost for that program. Additionally, RUS has recently experienced loan write-offs.

We estimate that the net costs to the federal government for fiscal year 1996 totaled about \$2.5 billion—\$0.4 billion for BPA, \$0.2 billion for the three PMAS, and about \$1.9 billion for RUS, including about \$982 million in RUS loan write-offs. Cumulatively, for fiscal years 1992 through 1996, we estimate that the government's net cost of operating these entities has been about $8.6 billion in constant 1996 dollars, including over $1 billion in RUS loan write-offs. Under current operating policies and law, the federal government will likely continue to incur many of the same types of costs. However, for RUS, future loan write-offs cannot be accurately predicted. It is important to note that these entities were generally following applicable laws and regulations regarding recovery of costs.

The federal government is exposed to additional future losses beyond the recurring net costs resulting from the government's more than $84 billion in direct and indirect financial involvement in the electricity-related activities of RUS, the PMAS, and TVA as of September 30, 1996. These potential future losses relate to the possibility that RUS borrowers, the PMAS, or TVA would be unable to repay the full $53 billion in debt owed to the federal government or that the federal government would incur unreimbursed costs as a result of actions it took to prevent default or breach of contract on the $31 billion in nonfederal debt.

This risk exists because certain RUS borrowers, the PMAS (to varying degrees), and TVA are financially vulnerable primarily as a result of uneconomical construction projects and the accumulation of substantial debt, which have resulted in high fixed costs. For example, in fiscal year 1996, RUS wrote off almost $1 billion in loans to a borrower that incurred significant debt as a minority-share owner of an uneconomical nuclear plant. It is probable that the federal government will continue to incur substantial losses from loan write-offs relating to RUS borrowers that are currently classified by RUS as "financially stressed."[8] It is also probable that future losses will arise from other RUS borrowers with high costs who are unable to raise rates because of regulatory and/or market constraints.

Southeastern, Southwestern, and Western (referred to in this report as the three PMAS) generally market wholesale power that consistently costs at least 40 percent less than power sold by nonfederal utilities and are therefore currently competitively sound overall. However, the three PMAS maintain this overall soundness in part because they do not recover all power-related costs. If they were required to recover some or all of these power-related costs, which we estimate totaled about $0.2 billion for fiscal year 1996, their ability to remain competitive might be impaired and the risk of future financial loss to the federal government increased. Also, each has one or a few projects or rate-setting systems with problems that,

[8]Borrowers classified by RUS as financially stressed have defaulted on their loans, had their loans restructured but are still experiencing financial difficulty, declared bankruptcy, or have formally requested financial assistance from RUS.

taken as a whole, make the risk of some loss to the federal government probable.

For BPA, customer contracts, a memorandum of agreement limiting fish mitigation costs,[9] and high current financial reserves[10] make the risk of any significant loss to the federal government remote through fiscal year 2001. However, the expiration of nearly all customer contracts, market uncertainties, high fixed costs, and substantial upward pressure on operating expenses make it reasonably possible that the federal government will incur some losses after fiscal year 2001 from BPA. This risk will begin to decline after 2012, all else being equal, if BPA pays off its nonfederal debt as scheduled.

For TVA, the risk that the federal government will incur losses is remote as long as TVA retains a position similar to a traditional regulated utility monopoly[11] in its service area. However, if this position changes and TVA is required to compete when wholesale prices are expected to fall, its high level of fixed costs and deferred assets compared to neighboring utilities make it reasonably possible that the federal government would incur future financial losses.

Background

Historically, electric utilities operated as regulated monopolies and were thus required to provide electricity service to all customers within their power service areas in exchange for exclusive service territories. Two key laws—the Public Utilities Regulatory Policies Act of 1978 (PURPA) and the Energy Policy Act of 1992—have resulted in an increasingly competitive wholesale electricity market. PURPA authorized operation of electric power-generating entities that were exempt from many federal regulations. Called “independent power producers” (IPPS),[12] these entities typically use new technologies, such as natural gas-fired generation units,

[9]These costs are incurred by BPA to protect and enhance fish and wildlife affected by federal hydro systems.

[10]BPA’s financial reserves consist of cash and deferred federal borrowing authority. At the end of fiscal year 1996, BPA had a $278 million cash and deferred federal borrowing authority balance. In addition, credits from a $325 million contingency fund are available to BPA to fund fish-related costs incurred under specified circumstances.

[11]Regulated monopolies are permitted by the government when unregulated market forces (e.g., economies of scale) would naturally drive the market from competition to monopoly. In such situations, the government designates a single seller of a well-defined product and regulates it to ensure delivery at acceptable prices.

[12]IPPs, which are firms that produce electric power to be sold at wholesale rates, are not considered utilities because they do not produce power for a service area and do not engage in transmitting or distributing power.

to produce power. The Energy Policy Act of 1992 required that a utility make its transmission lines accessible to other utilities (called "open transmission access"). This open access has enabled wholesale customers to obtain electricity from a variety of competing suppliers, even if that power must be transmitted over lines owned by another utility—referred to as the "wheeling" of power. This ability to wheel power has resulted in increasing wholesale competition in the electricity industry across the United States, with competition becoming intense in some areas. As a result, wholesale electricity rates have decreased in many parts of the country over the last several years, which has impacted, to varying degrees, the PMAS, TVA, and RUS borrowers. On a retail basis, the traditional regulated utility monopoly still exists in most states. However, issues relating to retail open access are being addressed on a state-by-state basis and in the Congress, with end-use customer choice expected to result.

Electricity generation, transmission, and distribution in the United States involves several government entities, including the following:

- RUS, an entity within the Department of Agriculture (USDA), provides direct or guaranteed loans primarily to rural electric cooperatives that market power on a wholesale and retail basis.
- Federal PMAS within the Department of Energy (DOE) market wholesale power generated primarily at federal water projects.
- The U.S. Army Corps of Engineers (Corps) in the Department of Defense and the Bureau of Reclamation (Bureau) in the Department of the Interior both operate multipurpose water projects, many of which generate electric power. Other multipurpose project purposes include flood control, navigation, irrigation, and recreation. The Corps and Bureau allocate power-related costs and some irrigation and other nonpower costs for repayment through the PMAS' power revenues. The Corps and the Bureau are referred to as the operating agencies.
- TVA, a multipurpose, independent government corporation generates and transmits electricity, primarily on a wholesale basis, to distributors.

To some extent, these entities interact with each other in the electricity market. For example, the PMAS sell power to some rural electric cooperatives financed by RUS, and Southeastern sells power to TVA. TVA also sells power to rural electric cooperatives. In aggregate terms, federal power generation represents about 10 percent, and rural electric cooperative generation represents about 4 percent, of all generating capability in the United States.

In this report, we focus our discussions on the PMAS rather than the operating agencies. This is because the PMAS are responsible for marketing power produced at federal facilities and setting rates to recover the federal government's costs associated with the power production.

For a more detailed discussion of competition in the electricity market and the federal entities involved, see appendix I in volume 2 of this report.

RUS and PMA Activities Result in Recurring Net Costs to the Federal Government

For fiscal year 1996, we estimate that the federal government incurred $2.5 billion in net costs, including about $982 million in RUS loan write-offs,[13] from the electricity-related activities of RUS and the PMAS. We estimate that cumulative net costs for fiscal years 1992 through 1996 were about $8.6 billion in constant 1996 dollars. Currently, the revenues earned by these entities do not cover the full cost of their operations. As a result, the federal government rather than RUS borrowers and PMA ratepayers bears these costs. TVA generally recovers all power-related costs from its ratepayers.

To define the full cost to the PMAS and TVA of generating, transmitting, and/or marketing federal power and to RUS of providing loans and loan guarantees to its electricity borrowers, we referred to Office of Management and Budget (OMB) Circular A-25, User Fees, industry practice and federal accounting standards. Applying the definitions used in these contexts, the full cost of generating, transmitting, and marketing power or providing loans and loan guarantees would include all direct and indirect costs incurred by RUS, the PMAS, TVA, and other entities directly involved in supporting RUS, PMA, and TVA operations.

We estimated cumulative net costs for fiscal years 1992 through 1996 because information for these years was readily available. These cumulative net cost calculations as well as those for fiscal year 1996 were intended to measure the net cost to the federal government, on an accrual basis, of the electricity-related activities of RUS, the PMAS, and TVA. It is important to note that RUS, the PMAS, and TVA were generally following applicable laws and regulations regarding recovery of costs.

Table 1 summarizes the net costs by type for each entity for fiscal year 1996 and cumulatively for the 5 years ending with fiscal year 1996 (in

[13]Loan write-offs are considered to be a typical part of lending operations. However, RUS has not experienced loan write-offs on a regular basis.

constant 1996 dollars). Each of the listed costs is discussed in detail following the table.

Table 1: The Federal Government's Estimated Net Costs for Fiscal Year 1996 and Cumulatively for Fiscal Years 1992 Through 1996 for RUS, the Three PMAs, BPA, and TVA

Dollars in millions

	RUS		3 PMAs		BPA		TVA		Total	
Net Cost	**1996**	**1992-96[a]**	**1996**	**1992-96[a]**	**1996**	**1992-96[a]**	**1996**	**1992-96[a]**	**1996**	**1992-1996[a]**
Financing	$874	$3,812	$208	$1,155	$377	$1,974			**$1,459**	**$6,941**
Loan write-offs	982	1,049							**982**	**1,049**
Benefits[b]	1	3	16	82	21	110	$1	$4	**39**	**199**
Construction			30	138		1			**30**	**139**
Other	21	112	(69)[c]	157					**(48)**	**269**
Total	**$1,878**	**$4,976**	**$185[d]**	**$1,532[d]**	**$398**	**$2,085**	**$1**	**$4**	**$2,462**	**$8,597**

Notes: Numbers may not add due to rounding. See appendix IV of volume 2 for a specific breakdown of net costs among the three PMAs and a discussion of the components of other net costs. Also, see appendix V of volume 2 for additional discussion of RUS' net financing cost.

[a]Cumulative net costs for fiscal years 1992 through 1996 are shown in constant 1996 dollars.

[b]Benefits refers to pensions and postretirement health benefits.

[c]This negative number results from Western's fiscal year 1996 repayments of interest and operations and maintenance (O&M) expenses, which had been deferred in prior years.

[d]About 23 percent of the fiscal year 1996 net costs and 9 percent of the cumulative net costs are potentially recoverable through future PMA rate charges.

Source: GAO estimates based on entity annual reports and other data.

Rural Utilities Service

Net Financing Cost

A net financing cost to the federal government exists in the RUS electric program because the annual interest income received from RUS borrowers is substantially less than the federal government's annual interest expense on funds provided to the borrowers. Interest income is affected by favorable rates and terms given to some borrowers and also by financially troubled RUS borrowers that have missed scheduled loan payments. According to RUS reports, about $10.5 billion is owed by 13 financially stressed wholesale producers that we refer to as Generation and

Transmission Cooperatives (G&T) borrowers.[14] We estimate that the net financing cost (interest expense minus interest income) to the federal government for the RUS electric program for fiscal year 1996 was about $874 million. Cumulatively over the last 5 years, we estimate that the net financing costs totaled about $3.8 billion (in constant 1996 dollars).[15]

Financially stressed borrowers' failure to make scheduled payments has had a significant impact on the federal government's interest income. For example, one G&T borrower, Cajun Electric, has not been required to make interest payments on its $4.2 billion debt since filing for bankruptcy in December 1994. In addition, Cajun made total principal payments of only about $19 million from December 1994 through the end of fiscal year 1996. Based on Cajun's contractual interest rate of about 8.6 percent, the federal government has forgone interest income of about $30 million per month, or about $1 million per day, since December 1994. In the meantime, the federal government continues to incur interest expense on financing related to this borrower. A detailed discussion of the net financing costs related to RUS is presented in appendix V of volume 2.

Loan Write-offs

RUS has recently written off, under Department of Justice (DOJ) authority, a substantial dollar amount of loans to rural electric cooperatives. The most significant loan write-offs are related to two G&T borrowers. In fiscal year 1996, about $982 million of one G&T borrower's loans was written off and forgiven because the G&T was unable to sell its electricity at a price sufficient to service its RUS loans due to an investment in an uneconomical nuclear plant. In the early part of fiscal year 1997, loans to another G&T borrower were written off and forgiven for a loss of about $502 million because the borrower was unable to recover costs for a coal-fired generating plant built to satisfy anticipated demand that did not materialize. The total amount of write-offs during fiscal years 1992 through 1996 was about $1.05 billion (in constant 1996 dollars)—with $0.5 billion of additional write-offs in the early part of fiscal year 1997.[16]

[14]In our previous report, Rural Development: Financial Condition of the Rural Utilities Service's Loan Portfolio (GAO/RCED-97-82, April 11, 1997), we noted 12 borrowers that were delinquent or in financial distress. However, in this report, we discuss 13 financially stressed G&T borrowers identified by RUS management. The primary difference between the two is that RUS management includes borrowers that have officially requested financial assistance.

[15]As these net financing costs reflect net interest expense incurred by Treasury in providing the funding for RUS electricity loans, they do not correspond to RUS' appropriations for those years.

[16]According to RUS officials, as these amounts were forgiven, the borrowers were relieved of their legal obligations; therefore, the federal government will make no further attempts to recover any of these funds.

Pension and Postretirement Health Benefits and Other Net Costs

The federal government also incurs costs for the electricity-related portion of RUS' appropriation for administrative expenses and for RUS employee pension and postretirement health benefits. In addition, attorneys at DOJ spend substantial amounts of time litigating on behalf of RUS during loan restructuring or bankruptcy proceedings. These estimated net costs amounted to $1 million for benefits and $22 million in other charges for fiscal year 1996 and $3 million and $112 million, respectively, for fiscal years 1992 through 1996 (in constant 1996 dollars). These other net costs are discussed in appendix IV of volume 2 to this report.

Power Marketing Administrations

Net Financing Cost

The net financing cost for the PMAs results primarily from appropriated debt provided by the federal government at low interest rates with favorable repayment terms. Appropriated debt carries a fixed interest rate with no ability for Treasury to call[17] the debt. Although PMAs are generally required[18] to pay off highest interest rate debt first, they cannot refinance the debt. Thus, Treasury bears the risk of increases in interest rates and PMAs, to some degree, bear the risk of decreases in interest rates. The interest rates on outstanding PMA appropriated debt are substantially below the rates Treasury incurs to provide funding to the PMAs and other federal programs. Thus, interest income earned by Treasury on the appropriated debt is less than Treasury's interest expense, which it incurs to finance this debt. The PMAs have accumulated substantial amounts of appropriated debt at low interest rates primarily because, in accordance with applicable guidance, they repay high interest rate debt first and because PMA appropriated debt incurred prior to 1983[19] was generally at below-market interest rates in effect at the time. We estimate that the net financing cost for the three PMAs' appropriated debt for fiscal year 1996 was $208 million and for BPA, $377 million. Cumulatively, for fiscal years 1992 through 1996, we estimate that the net financing cost in constant 1996 dollars has been over $1.1 billion for the three PMAs and nearly $2 billion

[17]The term "call" refers to the legal right of the lender to require the borrower to pay back the debt before its maturity date.

[18]DOE order RA6120.2, "Power Marketing Administration Financial Reporting," generally requires the PMAs to repay the highest interest rate debt first, while still complying with repayment periods and unless otherwise indicated by legislation.

[19]In 1983, DOE required that in the absence of specific legislation to the contrary, appropriations for capital expenditures made after September 30, 1983, be financed at interest rates equal to the average yield during the preceding fiscal year on interest-bearing marketable securities of the United States, which, at the time the computation is made, have terms of 15 years or more remaining to maturity.

for BPA. Table 2 shows the differences in the interest rates paid by the PMAs, Treasury's cost of funds, and the components of our estimates.

Table 2: Estimated PMA Net Financing Costs for Fiscal Year 1996 and Cumulatively for Fiscal Years 1992 Through 1996

Dollars in millions

PMA	Outstanding appropriated debt as of September 30, 1996[a]	Weighted average interest rate (percent)[a]	Treasury average interest rate (percent)[b]	Fiscal year 1996 net financing costs	Fiscal years 1992-1996 net financing costs[c]
Southeastern	$1,491	4.4	9.0	$68	$363
Southwestern	686	2.9	9.0	42	244
Western	3,217	6.0	9.0	98	548
Total—Three PMAs	**$5,394**			**$208**	**$1,155**
BPA	**$6,848**	**3.5**	**9.0**	**$377**	**$1,974**

Note: For a discussion of our methodology for the above calculations, see appendix II of volume 2.

[a]Because audited fiscal year 1996 data were not available for Southeastern and Southwestern at the time of our fieldwork, we used fiscal year 1995 appropriated debt and weighted average interest rates. According to the PMAs, the appropriated debt balances did not change significantly in fiscal year 1996. We then calculated the fiscal year 1996 net financing cost using the 1996 Treasury average interest rate.

[b]This rate represents the weighted average interest rate on Treasury's entire outstanding bond portfolio (10- to 30-year maturities). We used this interest rate because it reflects Treasury's average interest rate on outstanding long-term debt and most closely matches the terms of the PMAs' appropriated debt.

[c]In constant 1996 dollars.

Source: GAO estimates based on PMA annual reports and information from the Bureau of the Public Debt, Department of the Treasury.

As a result of legislation passed in 1996,[20] BPA's appropriated debt was restructured from $6.85 billion, with an average interest rate of 3.5 percent, to $4.29 billion, with an average interest rate of 7.1 percent. According to BPA's 1996 final rate proposal, the restructuring "is intended to permanently eliminate subsidy criticisms directed at the relatively low interest rates assigned to historic Federal Columbia River Power System (FCRPS)[21] appropriations."

[20]The Omnibus Consolidated Rescissions and Appropriations Act of 1996 (Public Law 104-134, April 26, 1996, 110 Stat. 1321-350) called for a "refinancing" of BPA's appropriated debt.

[21]BPA is part of FCRPS, which also includes the power-related operations of the Corps and the Bureau. BPA is responsible for marketing power from FCRPS.

The legislation required that the present value of the new principal balance equal the present value of the principal and interest payments that would have been made if restructuring had not occurred, plus an additional $100 million. The legislation also required that the interest rate applicable to the new principal balance (including the additional $100 million) be set to approximate the prevailing interest rate on Treasury debt of comparable maturity issued at the time of the restructuring. The dates at which the segments of appropriated debt become due are not changed by the legislation. As was the case before the restructuring, the due dates extend through the year 2046 and average about 26 years remaining.

Because the restructuring was not effective for fiscal year 1996, this transaction did not change the $377 million estimated net financing cost on BPA appropriated debt for fiscal year 1996. In the future, with the exception of the $100 million, if BPA repays appropriated debt at maturity, the net present value of future financing costs to the federal government will also remain unchanged.[22]

BPA also had $2.5 billion of medium- and long-term debt held by Treasury in the form of BPA bonds. Interest rates on this debt are set based on debt with similar terms issued by U.S. government corporations. This debt matures in fiscal years 1997 through 2034, with $346.2 million maturing by the year 2000. Based on our review of the terms of this debt, we believe there is no net cost to the federal government.

Pension and Postretirement Health Benefits

The federal government incurs a portion of the cost for Civil Service Retirement System (CSRS) pensions and substantially all of the cost for postretirement health benefits for current[23] PMA and operating agency employees. For fiscal year 1996, we estimate that the net cost to the federal government of providing these benefits was about $16 million for the three PMAS and almost $21 million for BPA. Cumulatively, for fiscal years 1992 through 1996, we estimate that the net cost in constant 1996 dollars was $82 million for the three PMAS and $110 million for BPA.

Recovery of the full annual cost of pension and postretirement health benefits is planned by Southeastern, Southwestern, and Western starting in fiscal year 1998. BPA plans to begin recovering some of these costs in

[22]However, if BPA repays principal before it is due, and the federal government's cost of money has declined, the federal government will experience a decrease in cash flow and a resultant increase in net cost.

[23]We did not calculate the cost of benefits provided to retired employees because the information was not available from the Office of Personnel Management (OPM).

1998, with full recovery planned beginning in 2002. Consistent with current policies and law, the PMAS do not plan to recover pre-fiscal year 1998 net costs.

Construction Costs

We found that all of the PMAS had incurred costs and/or had costs allocated to them by the operating agencies for projects that were completed, under construction, or cancelled, for which the full costs were not being recovered. In some cases, this was because the power-generating projects had never operated as designed. In accordance with DOE guidance, the PMAS set rates that exclude the costs of nonoperational parts of power projects, including capitalized interest. For example, at the Russell Project, partially on line since 1985, litigation over excessive fish kills has kept four of the eight turbines from becoming operational. As a result, over one-half of the project's construction costs—about $500 million—have been excluded from Southeastern's rates.

The net costs relating to these construction projects for fiscal year 1996 represent capitalized or unpaid interest incurred in that year. We estimate that for fiscal year 1996, the net cost to the federal government for the projects we identified is $30 million for the three PMAS and $0.2 million for BPA. Cumulatively, from fiscal years 1992 through 1996, we estimate that the net cost in constant 1996 dollars is about $138 million for the three PMAS and $1.2 million for BPA.[24] The PMAS have stated that in most of these instances, including Russell, these net costs will be recovered in future years.

Other

The PMAS incur a number of other net costs including environmental mitigation, irrigation, deferred payments, and interest expense on store supplies totaling approximately $157 million cumulatively for fiscal years 1992 through 1996 in constant 1996 dollars. A net recovery totaling approximately $69 million existed for fiscal year 1996 resulting from Western's repayments of interest and O&M expenses which had been deferred in prior years. These other net costs are discussed in appendix IV of volume 2 of this report.

[24]These amounts do not include the actual construction and capitalized interest costs that were incurred prior to fiscal year 1992. These costs are further discussed in appendix VII of volume 2 in connection with our risk assessment of the three PMAs.

Tennessee Valley Authority

TVA's Federal Financing Results in No Net Cost to the Federal Government

Unlike the PMAS' appropriated debt, TVA's appropriated debt has terms that provide Treasury full reimbursement for its related financing costs. Substantially all of TVA's appropriated debt was incurred prior to the 1959 self-financing amendments to the TVA Act. The Tennessee Valley Authority Act of 1933, as amended, requires TVA to make fixed annual payments of principal to Treasury and pay interest at an annually calculated Treasury interest rate on the outstanding balance. In accordance with the TVA Act, the interest rate is what Treasury pays on its total marketable public obligations issued—6.87 percent for fiscal year 1996.[25] The terms of this debt include resetting of the interest rate annually, which is a short-term debt feature, and a principal repayment term of over 50 years, which is characteristic of long-term debt. Consequently, we believe that the terms of this debt, including the use of Treasury's total average interest rate for all debt, result in no net cost to the federal government.

As of September 30, 1996, TVA also had $3.2 billion of long-term debt that was held by the Federal Financing Bank (FFB).[26] This debt matures at various dates from fiscal years 2003 through 2016 and bears interest rates ranging from about 8.5 percent to 11.7 percent. Because the interest rate on TVA's FFB debt is based on the rate Treasury pays plus a one-eighth of 1 percent administrative fee, we believe there was no net financing cost to the federal government for this debt in fiscal years 1992 through 1996.

Recently, TVA asked the FFB to allow it to repay this debt before its maturity dates. However, TVA was not willing to incur the prepayment premiums required under the terms of the existing loan contracts with FFB. In 1995, the Congressional Budget Office (CBO) was asked to review proposed legislation that would have authorized TVA to prepay $3.2 billion

[25]Total marketable obligations include all outstanding short-term and long-term marketable Treasury securities, including Treasury bills, notes, bonds, and Federal Financing Bank securities.

[26]TVA's FFB debt was issued from fiscal years 1985 through 1989 with terms ranging from 14 to 30 years. Interest rates ranged from 11.7 percent for the 30-year bonds issued in 1985 to 8.5 percent for 16-year bonds issued in 1988. These bonds do not have any call provisions, but TVA has the option of repurchasing the FFB bonds under standard FFB repayment provisions. FFB obtains the funds provided to TVA by borrowing from the Department of the Treasury. FFB charges TVA the interest it incurs on its Treasury borrowing, plus a fee of at least one-eighth of 1 percent to cover administrative costs.

in loans made by the FFB without paying the prepayment premiums.[27] CBO estimated that enacting such legislation in 1996 would have increased federal outlays by about $120 million per year through 2002 with declining amounts thereafter until the last notes matured in the year 2016. The estimated cost reflects the net effect of the refinancing on both Treasury and TVA. This proposed legislation was never introduced.

Pension and Postretirement Health Benefits

TVA has its own pension and postretirement health benefit plans, which are funded through TVA's electricity rate charges. TVA's postretirement health plan covers all TVA employees while its pension plan covers all employees except for a small number covered by federal plans. As of September 30, 1996, TVA had about 163 staff employed in its power program that were part of the federal government's pension plans.[28] As with most other federal agencies, TVA does not currently reimburse the federal government for the full cost of the benefits of employees covered by the CSRS. We estimate that the net cost to the federal government for these benefits was about $0.7 million in fiscal year 1996 and about $4 million for fiscal years 1992 through 1996 in constant 1996 dollars.

Federal Government Faces Risk of Future Losses Due to Financial Vulnerability of Electricity-Related Entities

The federal government has financial exposure stemming from its over $84 billion of direct and indirect financial involvement in the electricity-related activities of RUS, the PMAS, and TVA. Comparatively high debt and fixed costs resulting from factors such as investments in uneconomical construction projects have left federal electricity-related entities vulnerable, in varying degrees, and results in risk of future losses to the federal government. The federal government's risk of future losses is directly related to the ability of the RUS borrowers, the PMAS, and TVA to set their rates in a competitive and/or regulated market at a level sufficient to recover all of their costs.

[27]The prepayment premium is charged by FFB in order to protect FFB from incurring an economic loss on the prepayment. This premium is calculated based on the difference between the book (face) value and Treasury's market value of the loan. The loan's market value is calculated based on the net present value of the future stream of principal and interest payments the government gives up when FFB accepts prepayment of a loan.

[28]These employees transferred to TVA from other federal agencies. Under OPM's implementation of the Civil Service Retirement Act, federal employees who transfer from one federal entity to another, including TVA, have the right to retain their federal pension benefits if there has not been a break in service of more than 3 days. TVA employees are not covered by the same postretirement health benefits plan as other federal employees.

Federal Government Has Substantial Financial Involvement in Electricity-Related Activities

The federal government faces financial exposure because of direct and indirect financial involvement in the electricity-related activities of RUS, the PMAS, and TVA. As of September 30, 1996, the federal government had over $53 billion of primarily direct lending to RUS borrowers, the PMAS, and TVA and appropriated debt owed by the PMAS and TVA. The federal government would incur a future loss on this direct involvement to the extent that RUS borrowers, the PMAS, or TVA failed to make payments on federal debt.

As of September 30, 1996, the federal government also had indirect financial involvement of over $31 billion—primarily TVA bonds and BPA's nonfederal debt. Although the TVA bonds and BPA's nonfederal debt are not explicitly guaranteed by the federal government, the financial community generally views them as having an implicit federal guarantee. For this indirect involvement, the federal government would incur future losses if it incurred unreimbursed costs as a result of actions it took to prevent default or breach of contract by the federal entity on nonfederal debt. Table 3 shows the federal government's direct and indirect financial involvement in RUS, the three PMAS, BPA, and TVA.

Table 3: The Federal Government's Financial Involvement in Electricity-Related Activities as of September 30, 1996

Dollars in billions

	Financial involvement[a]		
Entity	**Direct**	**Indirect**	**Total**
RUS	$32.3		**$32.3**
Three PMAs	7.0	$0.2[b]	**$7.2**
BPA	10.1	7.1[c]	**$17.2**
TVA	3.8	24.1	**$27.9**
Total	**$53.2**	**$31.4**	**$84.6**

Note: See appendixes VI through IX in volume 2 for a detailed discussion of the components of the financial involvement for each entity.

[a]Financial involvement represents these entities' total outstanding debt for which the federal government is either directly or indirectly at risk. The federal government could sell the power-related assets of RUS' borrowers, the PMAs, and TVA to offset some or all of any actual losses the federal government incurred as a result of its financial involvement with these entities.

[b]For the three PMAs, indirect involvement refers to capital provided by Western's customers (primarily through the issuance of bonds) to finance capital improvement projects (nonfederal debt). The customers pay the debt service cost, and Western records the proceeds as a liability and records interest expense. Western then bills the customers for the production costs of electricity, including the debt service, and credits the customers for the debt service costs. Essentially, this arrangement results in customers directly paying for capital improvements rather than paying for them indirectly through rates.

[c]For BPA, indirect involvement refers primarily to BPA's nonfederal debt, which was previously noted.

Source: GAO analysis of information contained in entity annual reports and other data.

Risk Hinges on Probability of Loss

In assessing risk to the federal government, we used the criteria for contingencies from Statement of Federal Financial Accounting Standards (SFFAS) No. 5, Accounting for Liabilities of the Federal Government. According to SFFAS No. 5, "A contingency is an existing condition, situation, or set of circumstances involving uncertainty as to possible gain or loss to an entity. The uncertainty will ultimately be resolved when one or more future events occur or fail to occur." When a loss contingency exists, the likelihood that the future event or events will confirm the loss or the incurrence of a liability can range from probable to remote:

- *Probable*: The future confirming event or events are more likely than not to occur.
- *Reasonably possible*: The chance of the future confirming event or events occurring is more than remote but less than probable.
- *Remote*: The chance of the future event or events occurring is slight.

We assessed risk of loss for RUS, which is essentially a lending operation, based on a review of the loan portfolio, an assessment of the production costs of key borrowers relative to their respective markets, and consideration of state regulatory actions. For the three PMAS, BPA, and TVA, we considered the cost of electricity production and rates, key financial ratios, generating mix, competitive environment, management actions, and legislative and other factors. The risk factors we used to assess risk of loss to the federal government from its electricity-related activities are consistent with those used by the bond rating services to assess credit risk for nonfederal utilities.[29]

Average Revenue Per Kilowatthour Is a Key Determinant of Competitive Position

In a competitive market for a relatively homogeneous product like electricity, being among the lowest cost producers is generally the most important factor in determining competitive position. As discussed below, average revenue per kilowatthour (kWh) is a reasonable indicator of power production costs.[30] Thus, because RUS borrowers and the PMAS are subject to some wholesale competition, one of the key factors we looked at in assessing the risk described in this section of the report was these entities' average revenue per kWh for wholesale sales compared to nonfederal utilities. The average revenue per kilowatthour for wholesale

[29]We consulted Fitch Investors Service, Inc., New York, New York, and Moody's Investors Service, New York, New York, regarding the criteria they use to assess risk when preparing bond ratings for electric utilities.

[30]This assumes that the entity's competitive position is such that it can charge sufficiently high rates to recover all costs from customers.

sales (sales for resale) is referred to in this report as average revenue per kWh.

This average is calculated by dividing total revenue from the sale of wholesale electricity by the total wholesale kWhs sold. Because the PMAS, publicly-owned generating utilities (POGS), and rural electric cooperatives generally recover costs through rates with no profit, average revenue per kWh should reflect the PMAS', POGS', and rural electric cooperatives' power production costs. For investor-owned utilities (IOUS), average revenue per kWh should reflect power production cost plus the regulated rate of return. Given that a large portion—an average of 79 percent over the last 5 years—of IOU rate of return (net income) is paid out in common stock dividends, which is a financing cost, average revenue per kWh also approximates power production costs for IOUS.

Continuing Losses From RUS Loan Portfolio Are Probable

During fiscal year 1996 through July 31, 1997, RUS has written off about $1.5 billion in electricity loans. As of September 30, 1996, $10.5 billion of the $32.3 billion total electricity portfolio relates to loans to G&TS that are in bankruptcy or otherwise financially stressed. The total principal outstanding on G&T loans is approximately $22.5 billion, or about 70 percent of the RUS electric loan portfolio. Distribution borrowers make up the remaining 30 percent of the electric loan portfolio. At the time of our review, there were 55 G&T borrowers and 782 distribution borrowers. Our review focused on the G&T loans since they make up the majority of the portfolio in terms of dollars and generally pose the greatest risk of loss to the federal government. It is probable that the federal government will continue to incur substantial losses on the loans to financially stressed G&T borrowers. It is also probable that additional future losses will be incurred on loans to G&T borrowers that are not currently troubled but will become financially stressed due to high production costs and competitive and/or regulatory pressures.

Substantial Loan Write-offs Occurred in Recent Years

Under DOJ authority, RUS has recently written off a substantial dollar amount of loans to rural electric cooperatives. The most significant write-offs related to G&T loans. In fiscal year 1996, one G&T made a lump sum payment of $237 million to RUS in exchange for RUS writing off and forgiving the remaining $982 million of its RUS loan balance. This borrower's financial problems stemmed from its participation in a nuclear plant construction project that experienced lengthy delays as well as severe cost escalation. When construction of the plant began in 1976, its total cost was projected to be $430 million. However, according to the

Congressional Research Service, the accrued expenditures by 1988 were $3.9 billion as measured in nominal terms (1988 dollars). These cost increases are due primarily to changes in Nuclear Regulatory Commission (NRC) health and safety regulations after the Three Mile Island accident. The remaining increases are generally due to inflation over time and capitalization of interest during the delays.

In the early part of fiscal year 1997, another G&T borrower made a lump sum payment of approximately $238.5 million in exchange for forgiveness of its remaining $502 million loan balance. The G&T and its six distribution cooperatives borrowed the $238.5 million from a private lender, the National Rural Utilities Cooperative Finance Corporation. The G&T had originally borrowed from RUS to build a two-unit coal-fired generating plant and to finance a coal mine that would supply fuel for the generating plant. The plant was built in anticipation of industrial development from the emerging shale oil industry. However, the growth in demand did not materialize and there was no market for the power. Although the borrower had its debt restructured in 1989, it still experienced financial difficulties due to a depressed power market. RUS and DOJ decided that the best way to resolve the matter was to accept a partial lump sum payment on the debt rather than force the borrower into bankruptcy. The total amount of debt written off for the entire RUS electricity loan portfolio between fiscal years 1992 and 1996 was about $1.05 billion (in constant 1996 dollars)—with $0.5 billion in additional write-offs in the early part of fiscal year 1997.

Additional Losses From Financially Stressed G&T Borrowers Are Probable in the Short Term

It is probable that RUS will have additional loan write-offs and therefore that the federal government will incur further losses in the short term from borrowers that RUS management has identified as financially stressed. According to RUS reports, about $10.5 billion of the $22.5 billion in G&T debt is owed by 13 financially stressed G&T borrowers. Of these, 4 borrowers with about $7 billion in outstanding debt are in bankruptcy. The remaining 9 borrowers have investments in uneconomical generating plants and/or have formally requested financial assistance in the form of debt forgiveness from RUS. According to RUS officials, these plant investments became uneconomical because of cost overruns, continuing changes in regulations, and soaring interest rates. These investments resulted in high levels of debt and debt-servicing requirements, making power produced from these plants expensive.

Since cooperatives are nonprofit organizations, little or no profit is built into their rate structure, which helps keep electricity rates as low as possible. However, the lack of retained profits generally means the cooperatives have little or no cash reserves to draw upon. Thus, when cash flow is insufficient to service debt, cooperatives must raise electricity rates and/or cut other costs enough to service debt obligations, or default on government loans.

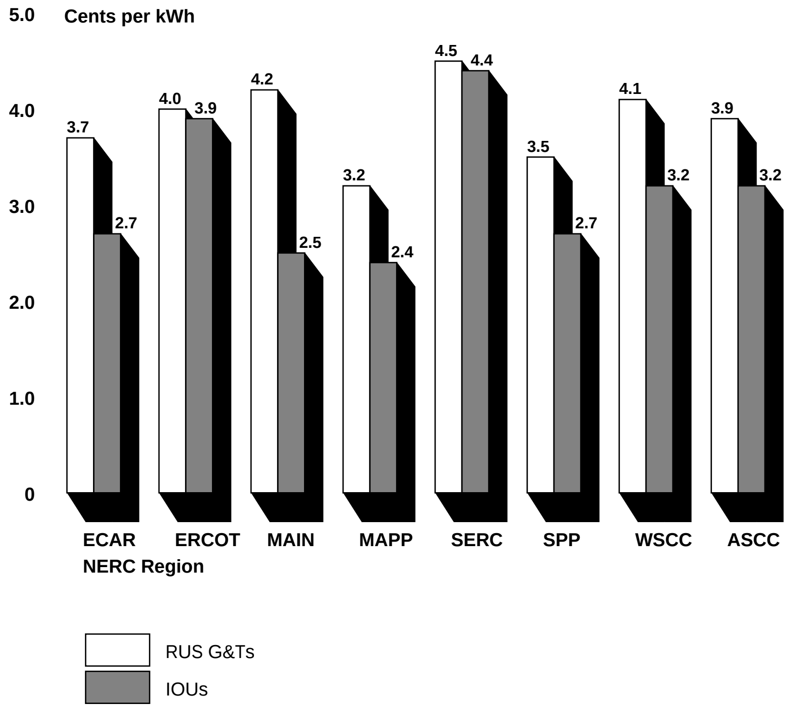
This was the scenario for the previously discussed write-offs in fiscal year 1996 and through July 31, 1997. Additional write-offs are expected to occur. For example, according to RUS officials, the agency may write off as much as $3 billion of the total $4.2 billion debt owed by Cajun Electric, a RUS borrower that has been in bankruptcy since December 1994. Cajun Electric filed for bankruptcy protection after the Louisiana Public Service Commission disapproved a requested rate increase and instead lowered rates to a level that reduced the amount of revenues available to Cajun to make annual debt service payments. Several factors contributed to Cajun's heavy debt, including its investment in a nuclear facility which experienced construction cost overruns and its excess electricity generation capacity resulting from overestimation of the demand for electricity in Louisiana during the 1980s.

Some Losses From Loans Currently Considered Viable Are Probable in the Future

In addition to the loans to financially stressed borrowers, RUS has loans outstanding to G&T borrowers that are currently considered viable by RUS but may become stressed in the future due to high production costs and competitive or regulatory pressures. We believe it is probable that the federal government will incur losses eventually on some of these G&T loans.

We believe the future viability of these G&T loans will be determined based in part on the RUS cooperatives' ability to be competitive in a deregulated market. To assess the ability of RUS cooperatives to withstand competitive pressures, we focused on the average revenue per kWh of 33 of the 55 G&T borrowers with about $11.7 billion of loans outstanding as of September 30, 1996. We excluded 9 G&Ts that only transmit electricity and the 13 financially stressed borrowers. Our analysis shows that for 27 of the 33 G&T borrowers, average revenue per kWh was higher in their respective regions than IOUs, and 17 of the 33 were higher than POGs. Additionally, as shown in figure 1, in 1995, RUS cooperatives' average revenue per kWh was higher than IOUs in all of the eight primary North American Electric Reliability Council (NERC) regions in which the cooperatives operate. The relatively high average production costs indicate that the majority of G&Ts may have difficulty competing in a deregulated market. RUS officials told us that several borrowers have already asked RUS to renegotiate or write off their debt because they do not expect to be competitive due to high costs. However, RUS officials stated that they will not write off debt solely to make borrowers more competitive.

Figure 1: Average Revenue per kWh for Wholesale Power Sold in 1995 for RUS G&T Borrowers Compared to IOUs in Their Regional Markets



Legend

ECAR = East Central Area Reliability Coordination Agreement
ERCOT = Electric Reliability Council of Texas
MAIN = Mid-America Interconnected Network
MAPP = Mid-Continent Area Power Pool
SERC = Southeastern Electric Reliability Council
SPP = Southwest Power Pool
WSCC = Western Systems Coordinating Council
ASCC = Alaska Systems Coordinating Council

Note: We compared Alaskan cooperatives to POG data since IOU data were unavailable. See appendix III of volume 2 for a map of the above regional markets.

Source: GAO analysis of data from the RUS fiscal year 1995 annual report, preliminary (unaudited) 1995 IOU data from the Energy Information Administration, and POG data from the American Public Power Association (APPA).

As with the financially stressed borrowers, some of the G&T borrowers currently considered viable have high debt costs because of investments in uneconomical plants. In addition, according to RUS officials, two unique factors cause cost disparity between the G&Ts and IOUs. One factor is the sparser customer density per mile for cooperatives and the corresponding high cost of providing service to the rural areas. A second factor has been the general inability to refinance higher cost FFB debt when lower interest rates have prevailed. However, RUS officials said that recent legislative changes that enable cooperatives to refinance FFB debt with a penalty may help align G&T interest rates with those of the IOUs.

In the short term, G&Ts will likely be shielded from competition because of the all-requirements wholesale power contracts between the G&T and their member distribution cooperatives. With rare exceptions, long-term contracts obligate the distribution cooperatives to purchase all of their respective power needs from the G&T. In fact, RUS requires the terms of the contracts to be at least as long as the G&T loan repayment period. However, wholesale power contracts have been challenged recently in the courts by several distribution cooperatives because of the obligation to purchase expensive G&T power. According to RUS officials, one bankrupt G&T's member cooperatives are currently challenging their wholesale power contracts in court in order to obtain less expensive power. RUS officials believe that the long-term contracts will come under increased scrutiny and potential renegotiation or court challenges as other sources of less expensive power become available.

Wholesale rates under these contracts are currently set by a G&T's board of directors with approval from RUS. In states whose commissions regulate cooperatives, the cooperative must file a request with the commission for a rate increase or decrease. Several of the currently bankrupt borrowers were denied requests for rate increases from state commissions. However, RUS officials indicated they do not expect G&Ts to pursue rate increases as a means to recover their costs because of the recognition of declining rates in a competitive environment. RUS officials also acknowledge that borrowers with high costs are likely to request debt forgiveness as a means to reduce costs in order to be competitive in the future.

As discussed above, denials of requested rate increases by state commissions culminated in several G&Ts filing for bankruptcy. Eighteen of the RUS G&T borrowers operate in states where regulatory commissions must approve rate increases. These commissions may deny a request for a rate increase if they believe such an increase will have a negative impact on the region. According to RUS officials, some commissions have denied a rate increase to cover the costs of projects that the commission had previously approved for construction. Therefore, G&Ts with high costs may be likely candidates to default on their RUS loans, even without direct competitive pressures.

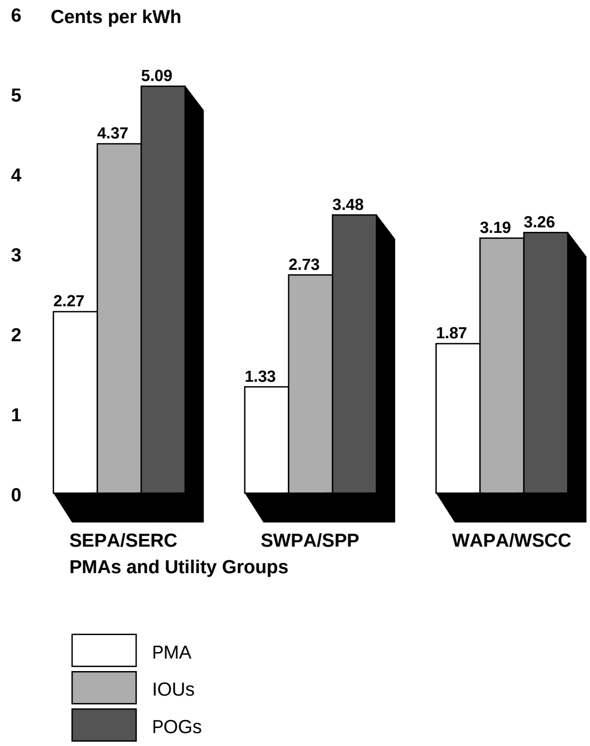
Three PMAs Are Competitively Sound Overall, but Risk of Loss for Certain Projects Is Probable

At September 30, 1996, the three PMAs had $5.4 billion of appropriated debt, and Western had an additional $1.6 billion of irrigation debt[31] and about $165 million of nonfederal debt. The three PMAs market power that is substantially lower in cost than nonfederal utilities and thus, in the current operating environment, are competitively sound overall. However, all three PMAs have one or a few projects or rate-setting systems with problems that, taken as a whole, make risk of some loss to the federal government probable.

As shown in figure 2, Southeastern, Southwestern, and Western have production costs that average more than 40 percent below IOUs and POGs in the primary NERC regions in which the PMAs operate.

[31]Aid to Irrigation (which we refer to as irrigation debt) is the legal obligation to repay costs incurred to construct federal irrigation projects that are determined by law to be beyond the irrigators' ability to repay.

Figure 2: Average Revenue per kWh for Wholesale Power Sold in 1995 for the Three PMAs Compared to IOUs and POGs in Their Respective Regions



Legend

SEPA/SERC = Southeastern/Southeastern Electric Reliability Council
SWPA/SPP = Southwestern/Southwest Power Pool
WAPA/WSCC = Western/Western Systems Coordinating Council

Source: GAO analysis of data from the PMAs' 1995 annual reports, preliminary (unaudited) 1995 IOU data from EIA, and POG data from APPA.

The three PMAs are low-cost marketers of power for several key reasons. First, the three PMAs market power produced primarily at hydropower dams built 30 to 60 years ago and run primarily by the operating agencies. These hydropower dams are currently a low cost energy source compared to coal and nuclear fuels, which are the primary energy sources used by other utilities.

Another key advantage for the three PMAs is that as federal agencies, they generally do not pay taxes. In contrast, IOUs do pay taxes. According to the

Energy Information Administration (EIA),[32] IOUs paid taxes averaging about 14 percent of operating revenues in 1995. POGs, as publicly owned utilities, typically do not pay income taxes because they are units of state or local governments. However, many POGs do make payments in lieu of taxes to local governments. A study[33] of 670 public distribution utilities showed that the POGs' median net payments and contributions as a percent of electric operating revenue were 5.8 percent.

Finally, as previously mentioned, the three PMAs did not recover nearly $185 million of costs in fiscal year 1996 associated with producing and marketing federal power. If Congress were to require the three PMAs to begin recovery of the net costs described earlier, or if competition drives electricity prices down significantly, the three PMAs' competitive position could deteriorate.

Because the three PMAs market power at prices that are substantially below those of other utilities, they generally have had little difficulty in selling all of the power that they produce. However, as discussed in detail in appendix VII of volume 2, each of the three PMAs has one or a few projects or rate-setting systems with problems that, taken as a whole, make the risk of some future losses to the federal government probable. In aggregate, these problem projects and rate-setting systems represent about $1.4 billion,[34] or 19 percent of the federal government's financial involvement in the three PMAs.

Risk of Loss From BPA Is Remote Through Fiscal Year 2001 but Increases Thereafter

BPA had over $17 billion of debt and over $766 million of interest expense as of and for the year ended September 30, 1996. These high fixed costs limited BPA's flexibility to lower rates and contributed significantly to BPA's loss of customers in recent years. However, as a result of existing customer contracts, a memorandum of agreement (MOA) limiting fish mitigation costs, and currently large financial reserves, we believe that the risk of any significant loss to the federal government from BPA is remote through fiscal year 2001. After 2001, expiration of customer contracts, significant risks from market uncertainties, BPA's high fixed costs, and substantial upward pressure on operating expenses increase the risk of loss to the federal government. Despite a number of factors that mitigate this risk, we believe it is reasonably possible that the federal government

[32]EIA is a statistical and analytical agency in the Department of Energy.

[33]1994 Payments and Contributions by Public Power Distribution Systems to State and Local Government, American Public Power Association, March 1996.

[34]Of the problem projects, about $518 million relates to Southeastern, $839 million to Western, and $31 million to Southwestern.

will incur losses from BPA after fiscal year 2001. This risk will begin to decline after 2012, all else being equal, if BPA pays off its nonfederal debt as scheduled. In addition, one small project that serves BPA represents a probable loss to the federal government (see appendix VIII of volume 2).

Key Factors Stabilize BPA Through Fiscal Year 2001

Three key factors have stabilized the government's risk of loss relative to BPA through fiscal year 2001 and, in our view, make risk remote for this timeframe. First, in 1995-96, BPA signed its customers to contracts to purchase a substantial amount of power through fiscal year 2001. BPA projects that firm power sales to these customers will secure $1.14 billion annually through fiscal year 2001, or 63 percent of each year's total projected power revenues. Second, BPA management entered into a MOA with various federal agencies that has limited its fish mitigation costs through fiscal year 2001. This agreement also created a contingency fund of $325 million comprised of past BPA nonpower fish mitigation expenditures.[35] Finally, BPA has had strong water years in 1996 and so far in 1997 and estimates that it will have financial reserves of about $400 million at the end of fiscal year 1997.[36] In addition, the $325 million fish cost contingency fund is available under specified circumstances.

Risk Increases After Fiscal Year 2001

After fiscal year 2001, BPA faces the expiration of customer contracts, significant market uncertainties, high fixed costs, and significant upward pressure on operating expenses. Nearly all of BPA's power contracts with customers expire at the end of fiscal year 2001. If these customers can find power cheaper than BPA can offer, they might opt to leave BPA. One of the key market uncertainties that will determine whether cheaper power will be available is the future production cost of gas-fired generation plants. This generation source has become increasingly competitive due to low natural gas prices and improving gas turbine technology. Natural gas prices in the Pacific Northwest are low due to several factors, including a large supply coming from Canada. Also, recent technology advances have

[35]BPA is required by the Northwest Power Act to protect, mitigate, and enhance fish and wildlife resources to the extent these resources are affected by federal hydroelectric projects. Section 4(h)(10)(C) of this act directs BPA to allocate fish and wildlife costs to the various project purposes, for example, power, irrigation, and flood control. The reserve represents the portion of BPA's expenditures that are related to nonpower uses of the projects. It is important to note that to the extent BPA uses the $325 million reserve, the federal government will incur these costs because the MOA allows BPA to apply the $325 million, under specified circumstances, as a credit against BPA's Treasury payment.

[36]BPA financial reserves of about $400 million include cash and deferred Treasury borrowing authority. Deferred borrowing authority is created when BPA uses operating revenues to finance capital expenditures in lieu of borrowing. This temporary use of cash on hand instead of borrowed funds creates the ability in future years to borrow money, when fiscally prudent, to liquidate revenue funded activities. The deferred Treasury borrowing authority is similar to an unused line of credit. While this may be useful in the short term to provide liquidity, its use results in additional debt; thus, deferred borrowing authority is not a long-term solution to financial difficulty.

improved the efficiency of gas turbines by more than 50 percent. According to BPA, natural gas-generated power has driven down the price of wholesale electricity and resulted in customers leaving or obtaining some of their power at rates well below BPA's current rate.

According to BPA, a surplus of power on the west coast is also driving down the price of wholesale power. Because utilities are still able to pass on fixed costs to captive retail customers, surplus wholesale power is being sold on a marginal cost basis. According to BPA, other utilities and power marketers[37] are offering wholesale power at as low as 1.5 cents per kWh, which is lower than BPA's price for sales of comparable products of 2.14 cents per kWh. It is uncertain whether surplus power and low cost natural gas generation will continue to drive down wholesale power prices after fiscal year 2001.

It is also uncertain what impact retail open access will have on BPA's competitive position. Retail open access—which would provide retail consumers freedom to choose among suppliers—could result in BPA's wholesale customers being uncertain about the size of their own future power needs. These power needs will be directly impacted by retail customers being able to choose their supplier. BPA's customers may be hesitant to sign long-term contracts to purchase power from BPA to the extent they face uncertainty about future power needs. However, even without long-term contracts, BPA is likely to remain a major supplier. Most states and the Congress are considering various proposals regarding the approach to retail open access.

BPA's substantial fixed costs will continue to inhibit its flexibility to lower its rates and meet competitive pressures. For example, 32 percent of BPA's revenue went to pay financing costs in fiscal year 1996—substantially more than the nationwide average of 14 percent for IOUs and 18 percent for POGs. BPA will continue to face high fixed costs after fiscal year 2001 relating to its $17 billion of debt.

BPA will also face upward pressure on its operating expenses after fiscal year 2001. The most significant of these operating expenses is fish mitigation. It is uncertain whether an agreement similar to the current MOA will be possible after expiration of the present one. Without this agreement, BPA is at risk of escalating costs after fiscal year 2001 if additional funds for fish measures beyond those planned at this time are

[37]Power marketers are subsidiaries of IOUs or independent companies that buy and sell power, typically on a wholesale basis.

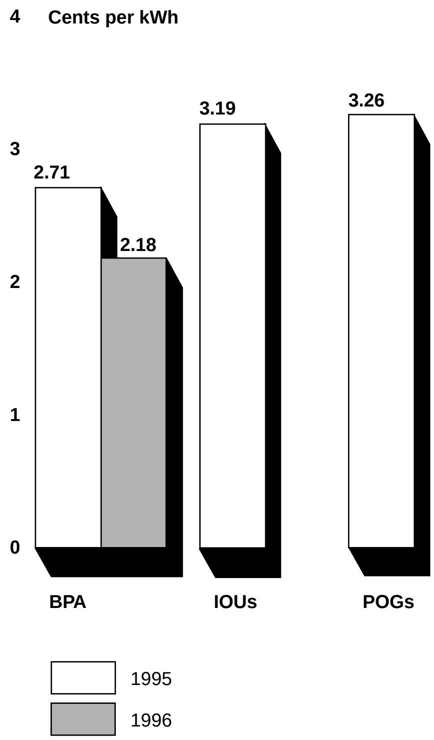
needed.[38] BPA also faces new or additional costs after 2001. First, it plans to implement a phased-in approach to recover the full cost of pension and postretirement health benefits in fiscal year 1998 but will defer full recovery until fiscal year 2002, when $55 million will be due. To completely recover obligations for fiscal years 1998 through 2001, an additional $35 million will be due in fiscal year 2003. Other new or additional costs that will be incurred after fiscal year 2001 include $806 million of irrigation debt payments and $396 million in payments to the Confederated Tribes of the Colville Reservation for their share of Grand Coulee Dam revenues. These costs, which are discussed further in appendix VIII of volume 2, will be paid out over several decades.

Mitigating Factors Reduce Probability of Loss

Several factors mitigate the federal government's risk of future losses relative to BPA. These factors include certain inherent cost advantages, management actions to reduce operating costs, and an extensive transmission system. We believe that these factors reduce the risk of loss to the federal government after 2001, but that the risk of loss is still reasonably possible. Additionally, BPA is scheduled to have nearly all of its nonfederal debt paid off by 2019, with a substantial decrease in debt service beginning in 2013. If BPA is able to make these payments as scheduled, all else being equal, its fixed financing costs would be more in line with those of its competitors. This would reduce the risk to the federal government. As shown in figure 3, BPA's 1995 average revenue per kWh was more than 15 percent lower than IOUs and POGs in the primary NERC region (Western Systems Coordinating Council) in which BPA operates.

[38]If total federal mitigation costs increase and BPA reduces or caps its fish mitigation expenses after 2001, the federal government may have to bear additional costs.

Figure 3: Average Revenue per kWh for Wholesale Power Sold in 1995 for BPA Compared to IOUs and POGs in the Western Systems Coordinating Council Region



Note: 1995 data are the latest available for IOUs and POGs. We included BPA's 1996 average revenue per kWh to show its almost 20 percent decrease from 1995 to 1996.

Source: GAO analysis of BPA annual reports, preliminary (unaudited) 1995 IOU data from EIA, and POG data from APPA.

As previously mentioned, BPA is facing significant competition today. However, BPA believes that its average production costs are less than others in the Pacific Northwest, as shown in figure 3. If the supply of surplus power dries up and gas generation costs rise, which BPA believes will happen, BPA's low average production costs should improve its long-term competitive position. This long-term position will be further improved after 2012, if BPA repays its nonfederal debt as scheduled.

BPA has comparatively low average production costs because of certain inherent cost advantages over nonfederal utilities. As previously mentioned, BPA did not recover nearly $400 million of costs associated with producing and marketing federal power. In addition, the hydroelectric plants that generate the power marketed by all the PMAS have cost advantages over coal and nuclear generating plants, which generate over 81 percent of the electricity in the United States. BPA's hydroelectric plants, which were built decades ago, had relatively low construction costs compared to the newer construction of nonfederal utilities. Another key advantage for BPA is that like the other three PMAS, it generally does not pay taxes. Furthermore, interest income to bondholders from BPA's nonfederal debt is exempt from federal personal income tax and some state income taxes.

BPA management has taken significant steps in the last several years to react to the intense wholesale electricity competition in the Pacific Northwest. According to BPA, it reduced its staff from about 3,755 in March 1994 to 3,160 by the end of fiscal year 1996. An additional reduction to 2,755 is planned by fiscal year 1999. In addition, over the last several years, BPA has refinanced much of its Treasury bonds and nonfederal debt to keep its interest expense as low as possible. According to BPA, these staffing and other cost savings will reduce planned expenses by an average of $600 million per year during fiscal years 1997 through 2001 and allow for a 13 percent rate decrease for those years.

BPA also has an extensive transmission system that comprises about 75 percent of the bulk power transmission capacity in the Pacific Northwest. BPA has advised us that in the event of BPA being unable to sell its power at a level that recovers all costs, it might be able to use its massive transmission system to help recover stranded costs.[39] This could involve allocating stranded generation costs, in whole or in part, to transmission charges.

Risk From TVA Is Remote Under Current Structure but Is Reasonably Possible in a Competitive Environment

At September 30, 1996, TVA had $27.9 billion of debt and $6.3 billion of deferred assets, which leaves TVA with far more financing costs and deferred assets than its potential competitors. However, we believe that as long as TVA remains in a protected position similar to a traditional regulated utility monopoly, the risk of loss to the federal government is remote. If this position changes and TVA is required to compete when wholesale prices are expected to be falling, its high level of fixed costs and deferred assets compared to neighboring utilities increase the risk that the federal government would incur future losses. Despite a number of factors

[39]As defined by the Federal Energy Regulatory Commission (FERC), a stranded cost is any legitimate, prudent, and verifiable cost incurred by a public or transmitting utility that is no longer economically viable in a competitive wholesale environment.

that mitigate this risk, it is reasonably possible under this scenario that the federal government would incur future losses related to TVA.

TVA has two key items that protect it from competition and result in TVA operating like a traditional regulated utility monopoly in its service area. First, contracts with TVA's distributors (except for Bristol, Virginia) automatically renew each year and require that at least 10 or 15 years' notice be given before they can switch to another power company. Second, TVA is exempt from the wheeling provisions of the Energy Policy Act of 1992. This exemption generally prevents other utilities from using TVA's transmission system to sell power to customers inside TVA's service area.

High Fixed Costs Would Limit Flexibility in a Competitive Environment

TVA's regulated monopoly-type position enables it to set its rates at whatever price is necessary to recover its costs. However, TVA has chosen to defer costs related to its substantial nuclear investment to future years rather than currently including them among the costs being recovered from ratepayers. As a result, TVA had accumulated about $28 billion of debt as of September 30, 1996, which resulted in over $2 billion of interest expense in fiscal year 1996. By not recovering these costs from ratepayers and using the cash to pay off debt in prior years, TVA has developed a high level of fixed costs and deferred assets which will leave it vulnerable to future competition if it loses its protections. This is similar to the situation BPA faced when its high fixed costs limited its flexibility to meet competitive challenges when electricity prices fell sharply in the Pacific Northwest. However, unlike TVA, BPA has no deferred nuclear assets.

Our analysis shows that for fiscal year 1996, TVA's ratio of financing costs to revenue[40] was more than twice the average for 11 neighboring utilities and its ratio of fixed financing costs to revenue[41] was almost five times higher. These two ratios clearly show that because of high financing costs, TVA does not have the same level of flexibility as neighboring IOUs to lower prices to meet price competition. Additionally, as TVA's debt matures, the portion that is not repaid will likely need to be refinanced, thus exposing TVA to the risk of rising interest rates and even higher financing costs. However, if interest rates decline, TVA's financing costs would decrease.

[40]The ratio of financing costs to revenue was calculated by dividing financing costs by operating revenue for fiscal year 1996. The financing costs include interest expense and, for IOUs, also include preferred and common stock dividends to reflect the difference in the capital structures of these entities and TVA.

[41]The ratio of fixed financing costs to revenue is the same as the financing cost to revenue ratio except that common stock dividends for IOUs are excluded. These dividends are excluded from the IOUs' financing costs because they are not contractual obligations.

TVA has deferred $6.3 billion in costs associated with its Bellefonte units 1 and 2, and Watts Bar unit 2 that are currently in "mothballed" status. TVA is treating these assets similar to construction work-in-progress, with the costs not being recovered from ratepayers.[42] In aggregate, TVA has spent over $26 billion on nuclear plants, which were primarily debt financed. Most of these costs have not yet been recovered from ratepayers. Other utilities have been preparing for competition by writing-down their uneconomical assets at a much faster rate than TVA. As a result, these utilities have been recovering costs at a much greater pace than TVA and thus will have greater financial flexibility in the future.

To demonstrate the magnitude of TVA's deferral of costs, we compared TVA's rate of depreciation and its cost deferral to neighboring utilities. First, TVA's ratio of accumulated depreciation and amortization to gross property, plant, and equipment (PP&E) was about 18 percent as of September 30, 1996, compared to about 36 percent for the 11 neighboring utilities. This ratio shows that other utilities have already recovered twice as much of their capital investments percentagewise as TVA. Second, TVA's deferred assets as of September 30, 1996 were nearly 20 percent of its gross PP&E compared to about 3 percent for the IOUs. This ratio clearly shows that TVA's deferral of $6.3 billion of costs is unique and out of line with neighboring utilities. TVA's ability to recover its substantial capital costs in a competitive environment is uncertain.

TVA's vulnerability to wholesale competition without protections was recently demonstrated when one of its customers, the Bristol Virginia Utilities Board, announced that it will leave the TVA system for Cinergy, Inc., in January 1998. Cinergy offered firm wholesale power at 2.59 cents per kWh for 7 years, 40 percent lower than TVA's comparable wholesale rate of 4.3 cents per kWh. Bristol, which is on the border of TVA's service area, was able to purchase this power because it had given TVA written notice of its intent to cancel its power contract and had received a unique exemption in the Energy Policy Act of 1992,[43] which allows other utilities to transmit (wheel) electricity to Bristol over TVA's power lines. While we recognize that Cinergy may have offered this power to Bristol at a price representing its marginal costs, TVA could face this type of competitive situation regularly if it were to lose its protections from competition.

[42]TVA believes this accounting treatment is justified because there is still a possibility the plants will be completed. However, given that there has been no construction on these plants for 9 years, we believe TVA should be recovering these costs from ratepayers. See appendix IX of volume 2 for further discussion.

[43]As a result of Bristol's exemption, TVA is required, for a fee, to wheel Cinergy's power to Bristol.

Mitigating Factors Reduce Probability of Loss

Several factors mitigate the government's risk of future loss relative to TVA. These factors include certain inherent cost advantages; management actions to increase revenue, cut operating expenses, and reduce debt; and an extensive transmission system. We believe these factors reduce the risk of loss to the federal government, but the risk of loss is still reasonably possible.

TVA has several inherent cost advantages because it is a federal government corporation. First, TVA's debt receives the highest possible rating from the bond rating services. According to these services, TVA's creditworthiness is based primarily on its links to the federal government rather than on the criteria applied to a stand-alone corporation.[44] As a result, the private lending market has provided TVA with access to billions of dollars of financing at favorable interest rates. One of the major bond rating services believes, and we concur, that without the links to the federal government, TVA would have a lower bond rating and higher cost of funds. Additionally, interest income for TVA's bondholders is generally exempt from state income taxes, which further lowers TVA's cost of funds.

TVA is exempt from paying income taxes, unlike its neighboring IOUs. Therefore TVA, as a nonprofit entity, does not have to generate the net income that an IOU would need to cover income taxes and provide for an expected rate of return. However, the TVA Act requires TVA to make payments in lieu of taxes to state and local governments where power operations are conducted. The base amount TVA is required to pay is 5 percent of gross revenues from the sale of power to other than federal agencies during the preceding year. This amounted to about $256 million in fiscal year 1996. In addition, according to TVA, its distributors are required to pay various state and local taxes that amounted to about $125 million, or about 2 percent of the total fiscal year 1995 operating revenues of TVA and the distributors. According to EIA, IOUs pay about 14 percent of gross revenues for taxes.

Another cost advantage is that TVA generates significantly more hydroelectric power than other utilities in the region and purchases hydropower from Southeastern at less than 1 cent per kWh. TVA's hydropower dams generate about 11 percent of TVA's power with a relatively low capital investment of about $1.3 billion; on the average, other utilities nationwide generate only about 6 percent of their electricity with hydropower.

[44]In assessing stand-alone corporations, the rating services also consider the strength of parent companies in making debt ratings. Because TVA's "parent" is the federal government, it has the benefit of the highest bond ratings—Aaa (Moody's).

TVA management has taken significant steps to reduce its expenses. According to TVA, it reduced its staff from about 34,000 in 1988 to about 16,000 in 1996 and plans further reductions in 1997. In addition, TVA has refinanced its debt to keep its interest expense as low as possible. The completion of TVA's Watts Bar 1 and restarting of its Browns Ferry 3 nuclear power units—a major reason for TVA's increasing debt in recent years—is another important step. According to TVA, it has internally capped its debt at about $28 billion and plans to finance its future capital expenditures from operations. These plans and actions are consistent with those of IOUs in preparation for competition.

On July 22, 1997, TVA released a 10-year business plan that identifies actions it plans to take to position its power operations to meet the challenges from the coming restructured marketplace. This plan calls for TVA to (1) increase power rates enough to increase annual revenues by about 5.5 percent ($325 million), (2) limit annual capital expenditures to $595 million, (3) reduce debt by about 50 percent from $27.9 billion as of September 30, 1996, to $13.8 billion by fiscal year 2007, and (4) reduce its total cost of power by about 16 percent by fiscal year 2007. To the extent TVA is able to use the cash generated from increasing rates, reducing expenses, and capping future capital expenditures to pay down debt, the risk of loss to the federal government will be reduced. In addition to the above planned actions, the plan calls for TVA to change the length of the wholesale power contracts with its distributors from a rolling 10-year term to a rolling 5-year term beginning 5 years after the amendment. However, reducing the length of the wholesale contracts with its distributors could increase the risk of loss to the federal government.

A final mitigating factor is TVA's extensive transmission system, which covers nearly 100 percent of the transmission service available in its service area. If TVA is exposed to competition and is unable to sell its power at a level that recovers all costs, it may be able to use its transmission system to recover some stranded costs.

Objectives, Scope, and Methodology

As agreed with your offices, we did not

- estimate the forgone revenue for federal, state, or local governments resulting from the tax-exempt status of the RUS borrowers, the PMAS, or TVA;
- estimate the forgone revenue for federal and state governments resulting from tax-exempt debt instruments issued by TVA or related to Western or BPA's nonfederal debt;

- assess the reasonableness of the methodologies used by the operating agencies to allocate power-related costs to the PMAs for recovery; or
- quantify the amount of potential future losses to the federal government.

A detailed discussion of our objectives, scope, and methodology, including additional items not included in the scope of our review, is contained in appendix II of volume 2 to this report. Appendix II also includes detailed explanations of the calculations of various estimates used in the report and the criteria we used to assess cost recovery and the likelihood that the federal government will incur future losses relating to RUS, the PMAS, and TVA.

When appropriate, we used audited numbers from RUS, RUS' borrowers, PMA, and TVA fiscal years 1996, 1995, and earlier financial statements included in their annual reports. We conducted our review from January 1997 through July 1997 in accordance with generally accepted government auditing standards. We received written comments on a draft of this report from USDA, the three PMAS, BPA, and TVA. These comments are discussed in the following section and are reprinted in volume 2, appendixes X through XIII. We also received technical oral comments from the Corps of Engineers and the Bureau of Reclamation. We evaluated their comments and incorporated changes, where appropriate, into volumes 1 and 2 of our final report.

Agency Comments and Our Evaluation

The comments from USDA, the three PMAS, BPA and TVA generally focused on our analysis of net financing costs and the federal government's risk of future financial losses related to the electricity-related activities of these entities. All of these entities generally disagreed with our estimates of their net financing costs. In addition, they also disagreed with our assessment of the federal government's risk of future financial losses related to their electricity-related activities.

Net Financing Costs

USDA, the three PMAS, and BPA took issue, for varying reasons, with our estimate of net financing costs.

Department of Agriculture

USDA disagreed with our use of the portfolio methodology[45] in estimating net financing costs on RUS outstanding federal debt. It noted that our analysis resulted in larger estimates of net financing costs to the federal government than the estimates obtained in USDA's application of the credit

[45]See appendix II of volume 2 of this report for a description of the portfolio methodology.

reform methodology that were discussed in our April 1997 report.[46] As we stated in our current report, the majority of outstanding RUS electricity loans and guarantees, approximately 90 percent, were made prior to 1991 and therefore are not required to be reported under credit reform. Additionally, because the USDA Inspector General deemed the RUS credit reform estimates unreliable, we chose to use actual costs incurred rather than any credit reform estimates for our analysis.

The Power Marketing Administrations

The three PMAS and BPA disagreed with our estimate of the net financing costs. While the comments regarding the net financing cost estimates were not consistent and in one instance contradictory, two broad common issues were raised: (1) disagreement with our use of the portfolio methodology for estimating the net financing costs to the federal government for appropriated debt, including the use of the weighted average interest rate on outstanding long-term Treasury bonds, and (2) the assertion that the PMAS' appropriated debt is analogous to a mortgage loan.

Disagreement With the Use of the Portfolio Methodology to Estimate Net Financing Costs

The three PMAS stated that they believe the use of the portfolio methodology assumes that both the PMA interest rate and Treasury's cost of funds are variable, so the cost difference on any individual investment varies from year to year. They stated that this is equivalent to assuming that the PMA appropriated debt should be refinanced annually. The three PMAS stated that comparing the interest rates assigned to PMA financings to Treasury rates in the years the financings were provided (loan-by-loan methodology) would be a more accurate way of determining the net financing cost. BPA also suggested a loan-by-loan approach, stating that determining the cost to Treasury of providing BPA's financing should be done "on the basis of an assessment of each loan incrementally, as a commercial lender would do." Finally, the three PMAS and BPA disagreed with our using the interest rate on Treasury's outstanding bond portfolio to estimate net financing costs on outstanding appropriated debt.

As discussed in appendix II of volume 2 of this report, we defined the net financing cost to the federal government as the difference between Treasury's borrowing cost or interest expense and the interest income received from RUS borrowers, the PMAS, and TVA. Our basic methodology was to determine whether the federal government received a return sufficient to cover its borrowing costs and, if not, to estimate the net financing cost. RUS, the PMAS, and TVA had several forms of federal debt

[46] Rural Development: Financial Condition of the Rural Utilities Service's Loan Portfolio (GAO/RCED-97-82, April 11, 1997). As stated in this report, we did not assess the accuracy of RUS' reported subsidy cost estimates or the accuracy of the system used by RUS to derive such estimates under credit reform.

outstanding at September 30, 1996. Each of these forms of federal debt had different terms and thus required us to apply variations of our basic methodology in assessing whether there was a net financing cost and, if so, estimating the amount.

For the PMAS' appropriated debt, the portfolio methodology best captures the combined impact of the four distinct aspects of the net financing cost that we identified: (1) the difference between the PMAS' borrowing rate and Treasury's borrowing rate for securities of similar maturity at the time the appropriation was made (interest rate spread), (2) the PMAS' ability to repay the highest interest rate debt first (prepayment option), (3) the interest rate risk arising from Treasury's general inability to refinance or prepay outstanding debt in times of falling interest rates (Treasury borrowing practices), and (4) the difference in the maturities of the three PMAS' and BPA's appropriated debt and Treasury's bonds (maturity differential). The loan-by-loan methodology suggested by the three PMAS and BPA is limited in that it captures only that portion of the net financing cost arising from the interest rate spread and not the other three aspects of that cost.

We noted in appendix II of volume 2 of this report that as a comparison to our portfolio analyses, we did perform loan-by-loan assessments to estimate the net financing cost to the federal government for one of the three PMAS—Southwestern—as well as for BPA and RUS. In our loan-by-loan analyses, we attempted to match the PMAS' appropriated debt and RUS federal debt with Treasury borrowing. In these analyses, we assumed that to provide financing for up to 50 years for a PMA project and 40 years for RUS debt, Treasury had to borrow an equivalent amount via the sale of long-term bonds. Because Treasury does not generally borrow for more than 30-year terms, in the loan-by-loan analyses, we also assumed that Treasury had to refinance each borrowing to extend the financing to the PMAS or RUS borrowers for the remainder of the terms of the debt.

Our loan-by-loan analyses resulted in a net financing cost for fiscal year 1996 that was higher than under the portfolio methodology for two of the three entities (BPA and Southwestern) and the same for the third (RUS). For BPA, the net financing cost for fiscal year 1996 was about $445 million under the loan-by-loan analysis (versus $377 million under the portfolio analysis), for Southwestern it was about $54 million (versus $42 million under the portfolio analysis), and for RUS it was about $874 million (the same as under the portfolio analysis).

The criticism of our use of the portfolio methodology is also inconsistent with another BPA comment asserting that a portfolio methodology estimate of net financing costs using a lower Treasury interest rate—the rate on Treasury's entire portfolio of outstanding marketable securities, including short-term securities—would be appropriate. BPA stated that in using only long-term Treasury debt to gauge Treasury's cost of funds for appropriated debt, our report inflates Treasury's true cost of funds and, therefore, the net cost to the government of BPA's operations. BPA stated that a more appropriate measure of Treasury's cost of carrying this debt is Treasury's composite rate for all marketable interest-bearing debt, which was about 6.7 percent at the end of fiscal year 1996.

The composite interest rate that BPA proposed includes recently issued short-term Treasury bills and some notes with maturities of only several months. Using this composite interest rate that includes short-term securities is inappropriate because it would match short-term Treasury borrowing costs with long-term PMA appropriated debt. Because Treasury's bond portfolio includes debt issued over the last several decades, the average interest rate on this portfolio is a reasonable approximation of the federal government's cost of funds relating to the PMAS' appropriated debt, which also was incurred over the last several decades.

Moreover, the interest rate BPA is to pay on its appropriated debt under the Omnibus Consolidated Rescissions and Appropriations Act of 1996 supports our position that a long-term Treasury rate is the correct rate to use in our portfolio analysis. Under this act, that interest rate is based on long-term Treasury bond interest rates.

Assertion That Financings Provided by Treasury Are Analogous to Mortgage Loans

The three PMAS and BPA also asserted that appropriated debt is analogous to fixed-rate mortgage loans issued by a commercial lender. The three PMAS stated that their concern over our estimate of net financing costs might be best explained by using a mortgage loan example. They stated that a fixed interest rate is assigned to each investment that the PMAS' customers are required to repay, just as a homeowner receives a fixed rate mortgage from a lender. They further stated that to assert that the PMAS impose a net cost to Treasury in a year in which market interest rates have risen above the interest rates on the PMAS' appropriated debt is equivalent to saying that the homeowner imposes a net cost on a lender whenever market rates for home loans rise above the homeowner's fixed mortgage rate. Similarly, BPA stated that a 30-year fixed rate mortgage entered into in a year with low interest rates would not result in a cost to the lender simply because interest rates increased over time.

We do not agree that the PMAS' financing is analogous to a mortgage lending situation for several reasons. First, in a mortgage-type lending arrangement, if the lender wants to remain in business, it establishes a spread between the rate charged the borrower and the rate it must pay for the capital it lends. In the case of the PMAS' appropriated debt, the PMAS do not pay higher interest rates than the interest rates Treasury pays on its bonds. On the contrary, in most instances the rates the PMAS paid on currently outstanding appropriated debt were significantly lower than the rates Treasury paid when the financings were provided. In addition, the PMAS do not pay any transaction fees (for example, points or closing costs) associated with the financings, which homeowners generally pay. The highest interest rate the PMAS are subject to for new financing is based on the rates on long-term Treasury securities issued the previous year, which generally have maturities of 30 years or less even though the repayment periods for the PMAS' appropriated debt are up to 50 years. No attempt is made to charge a differential or take into account the greater risk of having appropriated debt outstanding for 50 years; in contrast, 30-year mortgages have higher interest rates than 15-year mortgages. Also, the PMAS are able to receive interest rates based on Treasury bonds that are "risk-free." If the PMAS were required to obtain financing in the private market, without any implicit or explicit federal guarantee, they would likely pay interest rates higher than the risk-free Treasury rate.

Furthermore, a mortgage lender typically requires that borrowers repay their loans, including principal and interest payments, on a fixed schedule, while the PMAS are not required to make fixed principal payments. Instead, the PMAS' appropriated debt is similar to a balloon loan that is due in full at the end of the term—up to 50 years for the PMAS. The PMAS are required to repay debt with the highest interest rate first to minimize interest expense. Since the PMAS' interest expense is minimized, this requirement minimizes interest income to Treasury and maximizes Treasury's interest rate risk. The PMAS currently have debt outstanding from decades ago at extremely low and outdated interest rates and upon which no principal has been paid. If the PMAS' appropriated debt had been paid back like a mortgage, their current weighted-average interest rates would be far higher. The result of this type of arrangement, along with Treasury's general inability to call its outstanding bonds, is that the interest income Treasury receives on the PMAS' appropriated debt is considerably less than the interest Treasury pays to bondholders on a comparable amount of Treasury debt. We are not aware of any mortgage lender who would be able to remain in business over the long term if it operated similarly.

Additional Net Financing Cost Comments by BPA

BPA stated that our draft report disregards the fact that the interest charges BPA pays on its appropriated debt were determined years ago using interest rates prevailing at that time. While the interest rates assigned to some Federal Columbia River Power System (FCRPS) appropriations approximated Treasury's long-term interest rate, BPA's statement is not factually accurate. Over the last 4 decades, BPA has incurred substantial debt at below-Treasury interest rates, as shown by the following examples:

- BPA incurred over $250 million in appropriated debt in 1969 at an interest rate of 2.5 percent when Treasury's long-term bond rate was 6.67 percent; less than 1 percent of this has been repaid.
- BPA incurred over $250 million in appropriated debt at 2.5 percent in 1975 when Treasury's long-term bond rate was 7.99 percent; less than 1 percent of this has been repaid.
- BPA incurred over $399 million in appropriated debt at 3.25 percent in 1982 when Treasury's long-term bond rate was 12.76 percent; none of this has been repaid.
- BPA currently has outstanding appropriated debt bearing interest at 2.5 percent that was borrowed as recently as 1992 when Treasury's long-term bond rate was 7.67 percent, and 3.125 and 3.25 percent debt incurred as recently as 1990 when long-term Treasury bond rates were 8.61 percent.

In addition, BPA stated that we were inconsistent in assessing the net financing cost for BPA and TVA appropriated debt because we used a 9.0 percent interest rate to assess BPA's net financing cost but used a 6.87 percent interest rate to determine the federal government's net cost of providing financing to TVA. We disagree with BPA's assessment. Since the terms of BPA's and TVA's appropriated debt differ markedly, it is reasonable to reflect this in assessing the net financing cost to the federal government. TVA is generally required to make payments on its outstanding principal balance every year, whereas BPA is required to pay outstanding principal only in the year of maturity. Also, the interest rate on TVA's appropriated debt is revised annually to reflect the cost to Treasury of providing the financing. In contrast, BPA is allowed to repay appropriated debt with the highest interest rate first and keep appropriated debt with a low interest rate on the books for decades.

Since TVA appropriated debt is in effect refinanced annually, it can reasonably be assigned an interest rate based on Treasury's composite interest rate on all outstanding marketable securities, which includes short-term securities. Moreover, the different terms result in different exposures to interest rate risk. TVA bears interest rate risk in that if Treasury's interest rates rise, TVA's interest expense rises. In contrast, once BPA's interest rates are assigned, they remain the same over the life of the debt. As a result, BPA bears interest rate risk only in the unlikely event that Treasury rates fall below BPA's weighted-average interest rate of 3.5 percent. For example, in 1982 (because of high inflation and resultant high interest rates), TVA's weighted-average interest rate on its appropriated debt was over 12 percent while BPA's was approximately 3.3 percent. Moreover, TVA's appropriated debt currently carries a weighted-average interest rate of 6.87 percent, while BPA's weighted-average rate is 3.5 percent.

BPA also stated that we inadequately addressed the restructuring of BPA's appropriated debt and that we "hint" that BPA has an imbedded interest rate advantage that the Congress has ignored. In making this observation, BPA appears to be suggesting that the restructuring of its appropriated debt has permanently eliminated any net financing cost to the federal government.

We do not agree. Under the terms of BPA's appropriated debt restructuring, more than $2.5 billion of appropriated debt will be written off in exchange for increasing the interest rates on BPA's revised appropriated debt balance to market interest rates. BPA will also pay an additional $100 million over the remaining terms of the debt. Other than this $100 million, the net cash flow to Treasury is essentially unchanged as a result of the restructuring. We acknowledge that Treasury will receive $100 million more under the restructured repayment plan than under the existing arrangement if BPA pays off the debt when it matures. However, this $100 million is less than one-third of the $377 million net financing cost we estimate that Treasury incurred in 1996 alone. This net negative cash flow to the federal government will continue as long as the appropriated debt and the corresponding Treasury debt are outstanding.

Additional Net Financing Cost Comments by TVA

TVA suggested that our report include an income item of approximately $100 million in our presentation of "annual costs to the government." It contends that this amount represents what TVA pays Treasury each year in excess of the government's current cost of financing TVA's Federal Financing Bank (FFB) loans. We disagree. Treasury's current interest rate is not an appropriate measure of its cost of financing loans issued in the past. Rather, the interest rates in effect at the time the loans were issued represents Treasury's cost. Because FFB is charging TVA the long-term borrowing rate of similar Treasury debt at the time the loan was made, the federal government is receiving a return sufficient to cover its borrowing costs.

If TVA is permitted to refinance these loans without penalty, the federal government will suffer a significant loss. This loss represents the difference between the interest rate at the time of the borrowing and the interest rate on current debt Treasury could avoid incurring today. In 1995, the Congressional Budget Office (CBO) was asked to review proposed legislation that would have authorized TVA to prepay the $3.2 billion in loans made by FFB without paying the prepayment premiums. CBO estimated that enacting such legislation in 1996 would increase federal outlays by about $120 million per year through 2002 with amounts declining thereafter until the last notes matured in the year 2016. This proposed legislation was never introduced.

Risk Assessment

Several of the entities commented on our use of average revenues per kWh as an indicator of cost competitiveness and risk. In addition, each entity commented on our assessment of the risk of future financial losses.

Disagreement With the Use of Average Revenue per Kilowatthour to Compare Utilities' Competitiveness

The three PMAS and USDA disagreed with our use of average revenue per kWh to compare utilities' competitiveness.[47] The three PMAS stated that the use of average revenue per kWh is overly simplistic and may mislead the report's readers about the magnitude and causes of the difference in costs between the PMAS and other utilities. The three PMAS stated that they do not believe that average revenue per kWh takes into account the differences in the types of power being sold by different utilities. They stated that a more accurate measure would be to compare similar products being offered by different utilities. USDA officials stated that many variables not addressed in our analysis could significantly alter any comparison.

We believe that average revenue per kWh is a strong indicator of the relative power production costs of the PMAS, TVA, and RUS G&T borrowers compared to IOUS and POGS. For the three PMAS, RUS G&T borrowers, and POGS, average revenue per kWh should equal cost over time because each operates as a nonprofit organization that recovers costs through revenues. This assumes that the entity's competitive position is such that it can charge sufficiently high rates to recover all costs from customers. For IOUS, average revenue per kWh should represent cost plus the regulated rate of return. Given that a large portion of an IOU's rate of return (net income) is

[47]BPA also had a technical comment on our use of average revenues per kWh, which we address in appendix XII of volume 2 of this report.

used to pay common stock dividends,[48] which is a financing cost, average revenue per kWh, while somewhat higher because it includes a profit, is a reasonable approximation of IOUs' power production costs. In addition, analysts and bond rating agencies commonly use average revenue per kWh in assessing the competitiveness of power rates.

We do recognize, however, that using average revenue per kWh as an analytical tool has some limitations. We clearly state in appendix III of volume 2 of this report that the price that any one utility charges another for wholesale energy comprises numerous transaction-specific factors, including fees charged for reserving a portion of capacity, consumption during peak and off-peak periods, and the use of the facilities. In appendix III, we have also clarified our discussion of the current electricity market, in which utilities are generally able to recover their fixed costs from retail customers. Thus, when competing for new wholesale customers, utilities with excess capacity and the ability to recover fixed costs from retail customers are able to sell surplus power at less than full production cost (that is, marginal cost). However, despite these limitations, average revenue per kWh is a good indicator of production costs since, over time, utilities must recover all costs to remain in business.

The PMAs also stated that because of the variability in output of certain hydropower projects, our use of average revenue per kWh to indicate competitiveness could result in wide variations in a PMA's competitive position from year to year. To address this concern, in this report and our September 1996 report, we compared the overall average revenue per kWh for the three PMAs, IOUs, and POGs from 1990 through 1995.[49] In each year, the overall average revenue per kWh for each of the three PMAs were lower than IOUs and POGs by at least 40 percent. This 6-year comparison shows that the use of average revenue per kWh does not result in wide fluctuations in assessing the PMAs' competitiveness from year to year.

Additional Risk Assessment Comments

Each entity commented on our assessment of the risk to the federal government of future financial losses related to that entity. USDA did not agree with our assessment that it is probable that some RUS borrowers who are not currently financially distressed will require loan write-offs in the future. The three PMAs asserted that our assessment of risk of future

[48]The amount of IOUs' net income paid out in common stock dividends averaged 79 percent over the last 5 years.

[49]In appendix VII of volume 2 of this report and appendix V of our September 1996 report, we also compared individual rate-setting systems of the three PMAs to IOUs and POGs in their respective regions. See Power Marketing Administrations: Cost Recovery, Financing, and Comparison to Nonfederal Utilities (GAO/AIMD-96-145, September 19, 1996).

losses is overstated. BPA stated that our risk assessment did not adequately take into account changes which will occur in the year 2012, when BPA asserts that the price of its wholesale power should be well below market. TVA stated that our assessment of the federal government's risk of loss is more negative than is warranted.

Department of Agriculture

USDA agreed that in the near future, some write-offs of loans related to old investments by borrowers that are currently financially stressed are probable. However, USDA disagreed that it is probable that other borrowers that are not currently financially stressed will also require write-offs of their loans. USDA stated that it does not believe that the past history of power plant investment is useful in projecting the future in a new competitive, restructured, unbundled infrastructure. We disagree. Because past investments must be recovered and directly impact current production costs, these investments will be key factors in the ability of RUS G&Ts to compete in a deregulated environment. Our analysis shows that 27 of the 33 G&T borrowers (82 percent) had higher production costs than the IOUs in their regions. For this and other reasons discussed in our report, it is probable that the federal government will eventually incur losses on some of these G&T borrowers. In a May 1995 report, Moody's Investors Service reported, "In a more competitive environment, a G&T's production costs relative to those of IOUs will become increasingly important. Competitively priced power resulting from low generation and purchased power costs is essential for co-ops to maintain their place in the electric utility industry of the future."

The Three Power Marketing Administrations

The three PMAs asserted that our assessment of risk of future losses is overstated and that the risks of future financial losses from four projects (Russell, Truman, Mead-Phoenix, and Washoe) are not "probable." We disagree. As discussed in our report, each of these projects faces operational and/or financial difficulties. Increasing competition in the electricity industry is expected to lead to falling prices, which will put even more competitive pressure on these projects and could result in financial difficulties at others. For the reasons detailed in our report, these four projects all meet the probable loss criteria if they do not become fully operational (Russell and Truman) or certain proposals to mitigate the risk are not implemented or are not successful (Mead-Phoenix and Washoe). Because the likelihood that all four projects can be successfully turned around is, in our opinion, remote, a probable risk assessment overall is appropriate.

Bonneville Power Administration

BPA stated that by concluding that it is "reasonably possible" that the federal government will incur a loss from BPA's operations after fiscal year 2001, we did not describe the limited, transitional nature of the risk. BPA asserted that the risk is confined to the approximately 10 years after 2001, following which BPA's costs and the price of its wholesale power should be well below market and the risk to the government "remote." We agree that, all else being equal, if BPA pays off its nonfederal debt as planned, the federal government's risk begins to decrease after 2012. After that year, nuclear project debt service costs are expected to decrease from an average of about $570 million (about 29 percent of BPA's total operating expenses for fiscal year 1996) annually to an average of about $304 million annually for the period from 2013 through 2018. However, the risk of future financial loss to the federal government would not become remote until 2019, when BPA's scheduled debt service payments drop to less than $3 million and decrease further in the following years.

Tennessee Valley Authority

TVA stated that our long-term assessment of the federal government's risk of loss due to its involvement in TVA is more negative than is warranted. TVA stated that although there are many uncertainties about the future of the utility industry, it believes that the steps it has taken over the past 10 years and future plans to improve TVA's competitiveness will allow it to be successful in a restructured electric utility marketplace.

We disagree. As also discussed in our August 1995 report,[50] if TVA is required to compete when wholesale prices are expected to be falling, its high level of fixed costs and deferred assets compared to neighboring utilities make it reasonably possible that the government would incur future losses. The following facts, among others, support our position.

- At September 30, 1996, TVA had $27.9 billion of debt and $6.3 billion of deferred assets, which leaves TVA with far more financing and deferred costs than its potential competitors. For fiscal year 1996, we found that TVA's ratio of financing costs to revenue was more than twice the average of 11 neighboring utilities. In addition, TVA's deferred assets at September 30, 1996, were nearly 20 percent of its gross PP&E, compared to about 3 percent for the IOUs.
- TVA's vulnerability to future competition, without protections, was recently demonstrated when one of its customers, the Bristol Virginia Utilities Board, announced that it will leave the TVA system for Cinergy, Inc. beginning on January 1, 1998. Cinergy offered Bristol firm, delivered

[50] Tennessee Valley Authority: Financial Problems Raise Questions About Long-term Viability (GAO/AIMD/RCED-95-134, August 17, 1995).

wholesale power at 2.59 cents per kWh for 7 years—40 percent lower than TVA's comparable wholesale rate of 4.3 cents per kWh.

- Through the third quarter of fiscal year 1997, TVA reported a net loss of about $176 million.
- In May, 1997, the Board of a second TVA distributor—Paducah, Kentucky—voted to give TVA its 10-year notice to cancel its power contract.
- TVA's five largest distributors, which currently buy about one-third of TVA's power, have indicated that they plan to negotiate changes to their contracts with TVA.

In addition, as discussed in our current report, on July 22, 1997, TVA released a 10-year business plan that identifies actions it plans to take to position its power operations to meet the challenges of the restructured marketplace. TVA's planned actions support the position we have taken in this and our August 1995 report about the impact TVA's high level of financing costs and deferred assets will have on its ability to compete in a deregulated marketplace. In announcing the 10-year plan, TVA stated that the actions described in the plan were "deemed critical for TVA to provide power at projected market prices of the future." TVA's Chief Financial Officer also stated "To remain competitive in the changing electrical-utility market, we must reduce our total cost of power and become more financially flexible to respond quickly to changing customer demands." We agree with these recent TVA statements.

As agreed with your offices, unless you publicly announce its contents earlier, we plan no further distribution of this report until 30 days from the date of this report. At that time, we will send copies to appropriate House and Senate committees; the Ranking Minority Members of the House Committee on the Budget and the Subcommittee on Water and Power Resources, House Committee on Resources; interested Members of the Congress; the Secretary of Agriculture; the Secretary of the Interior; the Secretary of Energy; the Secretary of Defense; the Director, Office of Management and Budget; the Chairman of the Board of Directors of the Tennessee Valley Authority; and other interested parties. We will make copies available to others upon request.

Please call me at (202) 512-8341 or Gregory Kutz, Associate Director for Governmentwide Audits, at (202) 512-9505 if you or your staffs have any questions. Major contributors to this report are listed in appendix XIV of volume 2.

Linda M. Calbom
Director, Civil Audits

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