GAO

United States General Accounting Office

Report to the Chairman, Subcommittee on Water, Power, and Offshore Energy Resources, Committee on Interior and Insular Affairs, House of Representatives

February 1990

FEDERAL ELECTRIC POWER

Bonneville's Residential Exchange Program

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Resources, Community, and
Economic Development Division

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February 6, 1990

The Honorable George Miller
Chairman, Subcommittee on Water,
Power, and Offshore Energy Resources
Committee on Interior and Insular Affairs
House of Representatives

Dear Mr. Chairman:

In accordance with your request, this report provides our evaluation of the Bonneville Power Administration's implementation of the Residential Exchange Program—a program designed to reduce the disparity in power rates charged to residential consumers of Pacific Northwest interties—including the program's benefits and costs and Bonneville's efforts to monitor the pass-through of program benefits to utility customers.

Unless you publicly announce its contents earlier, we plan no further distribution of this report until 30 days from the date of this letter. At that time we will provide copies of the report to the Secretary of Energy; the Administrator, Bonneville Power Administration; and the Director, Office of Management and Budget. We will also make copies available to other interested parties upon request.

This work was performed under the direction of Victor S. Rezendes, Director, Energy Issues, (202) 275-1441. Major contributors to this report are listed in appendix IV.

Sincerely yours,

J. Dexter Peach

J. Dexter Peach
Assistant Comptroller General

Executive Summary

Purpose

The Bonneville Power Administration, one of five Department of Energy (DOE) power-marketing administrations, wholesales nearly half of the electric power used in the Pacific Northwest. Since 1981, Bonneville has also participated in a power exchange with certain Northwest utilities, as authorized by the Northwest Power Act. The purpose of this exchange is to reduce the disparity in electric rates paid by residential and small farm customers of the region's utilities by having Bonneville "exchange" its relatively low-cost power with Northwest utilities that have higher-cost power.

As requested by the Chairman, Subcommittee on Water, Power, and Offshore Energy Resources, House Committee on Interior and Insular Affairs, GAO assessed the significance of the residential exchange program and Bonneville's efforts to ensure that program benefits are being received by the utilities' residential and small farm customers.

Background

During the 1970s, residential and small farm customers of Northwest investor-owned utilities were paying up to three times more for electricity than similar customers of the region's public utilities. Some of the region's public utilities were able to charge lower power rates primarily because they were being supplied with low-cost power from Bonneville. The power Bonneville markets is from 30 federal dams and 3 thermal-generating facilities.

In 1980, the Congress enacted the Northwest Power Act, in part, to address this disparity. The act authorizes Northwest utilities to exchange their higher-cost power for an equivalent amount of Bonneville's lower-cost power. The power exchange is limited to the amounts utilities need to supply their residential and small farm customers' requirements and is accomplished through a "paper transaction" rather than an actual exchange of power. Under the act, cost savings resulting from the exchange are to be passed along to residential and small farm customers.

Results in Brief

The disparity in electric power rates paid by residential and small farm customers in the Northwest has decreased over the past decade. The $1.37 billion in exchange program benefits that Bonneville provided to Northwest utilities through fiscal year 1988 has contributed to this decrease. However, a more important factor in reducing the rate disparity was the fact that Bonneville's costs—and, consequently, its power rates—increased significantly more than did those of the regional utilities.

Bonneville has not been conducting the reviews needed to ensure that utilities are passing program benefits through to their residential and small farm customers, although the Northwest Power Act does not specifically direct Bonneville to do so. Given the dollar value of the benefits that have been provided to regional utilities, GAO believes Bonneville should perform such reviews.

Principal Findings

Significance of Program Benefits

The residential exchange program has provided benefits to Northwest utilities that had higher power costs than Bonneville. Three investor-owned and two public utilities received about $1.2 billion, or about 88 percent, of the $1.37 billion in program benefits paid through fiscal year 1988. The remaining benefits were shared by other Northwest utilities. According to Bonneville data, exchange program benefits are expected to total about $1.3 billion for fiscal years 1989-1995.

The program benefits have reduced the cost of the electricity provided to residential and small farm customers of these utilities. For example, on the basis of data GAO obtained from the five utilities that were major program beneficiaries, their residential customers paid between 10 and 25 percent less for electricity in 1988 than they would have absent program benefits. These data indicate that the program has contributed to reducing the disparity in the region's power rates.

GAO also found other indications that the disparity between the electricity rates charged to residential customers by investor-owned utilities and the rates charged by public utilities has been reduced. For example, the 1978 average monthly residential electricity bill was $14 in Washington, which is primarily served by public utilities, compared with $25 in Oregon, which is primarily served by investor-owned utilities. By 1988, the average monthly residential bills in these two states were $42 and $48, respectively.

In GAO's view, the significant increase in Bonneville's rates is a more important reason than the residential exchange program for the reduced disparity in Northwest power rates. Between 1981 and 1987, Bonneville's rates have more than tripled, thus increasing the cost of Bonneville's power relative to the costs of utilities' power.

Significance of Program Costs

GAO found that about 9 percent of Bonneville's operating revenues were needed to cover the $1.37 billion program cost through fiscal year 1988. These costs have been passed on to Bonneville's power customers through the rates Bonneville charges to its various customer classes. More specifically, GAO estimated that about 45 percent of program costs are reflected in rates Bonneville charges its industrial customers and 29 percent are reflected in rates charged to investor-owned utilities in the Northwest and California. Most of the remaining costs are reflected in rates charged by Bonneville to public utilities. GAO obtained these estimates from data Bonneville used to establish its power rates.

Bonneville Has Not Determined Whether Program Benefits Reached Customers

Although the act provides that benefits are to be passed through to residential and small farm customers, GAO found that Bonneville has not been routinely determining whether utilities receiving program benefits have passed through these benefits. Bonneville officials told GAO that Bonneville has relied on state utility regulatory commissions and public utility boards to make this determination.

State utility regulatory commissions are reviewing whether program benefits are being passed through by the investor-owned utilities they regulate, but the depth of these reviews varies among states. According to utility commission staff, benefits, overall, are being passed through to residential customers, and, when problems are identified, utilities take corrective action. Yet GAO also found that there are no independent reviews covering public utility districts, municipal utilities, and electric cooperatives, since they are outside the regulatory purview of the state utility commissions.

Bonneville did conduct a pilot review of the benefit pass-through actions of two public utilities in 1987. According to Bonneville's preliminary review results, the utilities either had not passed through sufficient benefit amounts or had passed benefits through to customers other than residential customers. However, Bonneville did not follow up with these utilities to discuss its findings.

GAO believes that Bonneville needs to initiate reviews to determine whether residential exchange program benefits are being received by utilities' customers. Such reviews should include examining the timeliness of benefit payments and, if warranted, testing customer bills to ensure that actual benefit amounts are correct. Bonneville should also coordinate its reviews with state public utility commissions.

Recommendations

GAO recommends that the Administrator, Bonneville, initiate reviews to determine whether residential exchange program benefits are appropriately passed on by utilities to residential and small farm customers. GAO also recommends that the Administrator resolve the problems identified in Bonneville's 1987 reviews of two public utilities.

Agency Comments

In commenting on GAO's draft report, DOE stated that it agreed with the thrust of the report that benefit pass-throughs should be monitored. DOE stated that Bonneville is developing and implementing benefit pass-through reviews that will help ensure the timely and accurate pass-through of benefits to eligible residential and small farm customers. DOE also stated that Bonneville will take action to ensure that the problems identified in its 1987 reviews of two public utilities are resolved.

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Abbreviations

ASC	Average System Cost
DOE	Department of Energy
GAO	General Accounting Office

Introduction

The Bonneville Power Administration (Bonneville), created by an act of Congress in 1937, markets electric power to utilities and industries located primarily in a 300,000-square-mile area that encompasses Oregon, Washington, Idaho, western Montana, and small portions of Nevada, Utah, and Wyoming. Bonneville markets electric power generated at 30 federal hydroelectric projects and several nonfederal hydro- and thermal-generating facilities in the region. Its customers include public utility districts, municipal utilities, rural electric cooperatives, investor-owned utilities, and a number of industrial customers, primarily aluminum companies. In addition, Bonneville markets and exchanges electric power with Southwest utilities over the Pacific Northwest-Pacific Southwest Intertie[1] and, through other interconnections, with utilities in British Columbia.

In 1973, Bonneville ceased providing power to investor-owned utilities in order to meet the growing power demands of public utilities. Public utilities have priority over investor-owned utilities for Bonneville's power under the Bonneville Project Act of 1937. Over the next several years, investor-owned utilities increased their rates to resiential and small farm customers by as much as 300 percent because the power generated or purchased to replace the power previously acquired from Bonneville was so much higher in cost.

As a result, congressional reviews of the late 1970s found that customers of some Pacific Northwest utilities were paying substantially higher electric rates than others within the region. For example, in 1980 the House Committee on Interior and Insular Affairs found that the retail rates of the region's investor-owned utilities were as much as 300 percent higher than the rates charged by the region's public utilities that purchased power from Bonneville. A central factor in these rate differences was the access some utilities had to low-cost power from Bonneville.

Although the substantial rate increases during the period primarily affected customers of investor-owned utilities, customers of some public utilities were also affected. In the case of public utilities, substantial rate increases stemmed from high transmission system costs or from their own generation facilities that produced electric power at a higher cost than Bonneville charged. Taken together, the higher electric rates at investor-owned and publicly owned utilities were affecting about 2.5 million residential and small farm customers in the Pacific Northwest.

[1] A major electricity transmission interconnection between the Pacific Northwest and California.

The Congress intended to reduce this rate disparity when it passed the Pacific Northwest Electric Power Planning and Conservation Act in 1980. Section 5(c) of the Northwest Power Act (16 U.S.C. 839c(c)) provides for a residential power exchange. The exchange, which is explained in more detail in chapter 2, provides a means for Pacific Northwest utilities with higher resource costs to have access to Bonneville's lower-cost power by exchanging it for their own higher-cost power. Section 5(c) requires the utilities to pass on the cost savings to their residential and small farm customers. Bonneville's cost of purchasing the utilities' higher-cost power is in turn to be passed on in the rates Bonneville charges its customers for power.

While the act does not specifically call for a "program," Bonneville refers to the exchange activities as a program. We, likewise, refer to the exchange as a program.

Objectives, Scope, and Methodology

In March 1988 discussions with the office of the Chairman of the Subcommittee on Water, Power, and Offshore Energy Resources, House Committee on Interior and Insular Affairs, we were asked to review the exchange program. We focused our review on the following:

- the significance of the exchange program to utilities participating in the program, to the utilities' residential and small farm customers, and to Bonneville and its customers, and
- Bonneville's efforts to ensure that utilities participating in the program pass on the exchange energy cost savings they receive to their residential and small farm customers.

To address the significance issue, we developed data to determine (1) whether utilities participating in the exchange program have realized cost savings, (2) to what extent the program's rate relief benefits have affected the electric bills of the residential and small farm customers of participating utilities, and (3) which of Bonneville's customer classes have paid the cost of the exchange program. We also developed data to determine whether Bonneville expects the exchange program to provide future cost savings to participating utilities. In addition, we developed data to determine whether the electric power rate disparity that existed in the Pacific Northwest before the Northwest Power Act has been reduced. The information we used to develop these data was obtained from Bonneville, utilities participating in the exchange program, and Department of Energy reports.

To address the rate relief benefit pass-through issue, we (1) determined the extent to which Bonneville has ensured that utilities participating in the exchange program have passed rate relief benefits through to their residential and small farm customers; (2) reviewed the efforts of other organizations, and the significance of their findings, to ensure that participating utilities pass rate relief benefits through to their residential and small farm customers; and (3) reviewed the draft procedures Bonneville developed for conducting rate relief benefit pass-through reviews. We did not attempt to conduct any benefit pass-through reviews, but we did review the procedures that four utilities participating in the exchange program established for passing rate relief benefits through to their residential and small farm customers.

To develop general information about the exchange program, we reviewed the legislative history of the Northwest Power Act to determine why the program was established, who was to benefit from the program, and who is to pay program costs. In addition, we interviewed officials and reviewed exchange program files at Bonneville headquarters in Portland, Oregon, and contacted individuals from 11 utilities, 3 state regulatory agencies, and 14 organizations. These utilities, state regulatory agencies, and organizations were selected because they (1) received significant exchange energy cost savings from Bonneville, (2) were involved in reviews to determine whether rate relief benefits had been passed through to customers, (3) represented major Bonneville customers, or (4) represented utilities. Appendix I shows the utilities, state regulatory agencies, and organizations from which we obtained information.

Our review was conducted between December 1988 and mid-July 1989 in accordance with generally accepted government auditing standards.

Exchange Program Overview

The exchange program provides rate relief to residential and small farm customers of participating Pacific Northwest utilities. During the first 7 years of the program, the amount of rate relief provided was about $1.37 billion. This amount was also a net cost for Bonneville. Bonneville recovers its costs through the power rates it charges its customers.

Exchange Program—How It Works

Under the exchange program, which began in October 1981, whenever a Pacific Northwest utility offers to sell electric power to Bonneville, the Bonneville Administrator acquires and, in exchange, offers to sell an equivalent amount of power to the utility for resale to its residential and small farm[1] customers. Utilities that participate in the program sell power to Bonneville at a price higher than what they pay to buy it back. The exchange is essentially a paper transaction in that no power is actually transferred between Bonneville and the participating utilities. However, the difference between the utilities' higher-cost power and Bonneville's lower-cost power results in exchange energy cost savings to the utilities.

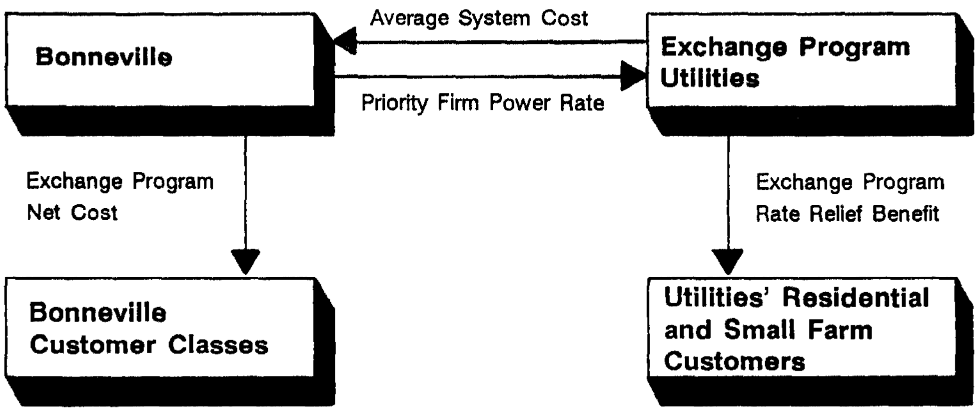
The steps in the exchange program can be described as follows:

- A utility sells Bonneville the amount of electric power the utility needs to serve its residential and small farm customers. Bonneville purchases this power at the utility's average system cost (ASC)—a calculation based on the utility's expenses for power generation and transmission.
- In return, Bonneville sells the same amount of electric power back to the utility at Bonneville's "priority firm power rate"—the basic rate paid by public utilities for guaranteed electric power from Bonneville. Because these sales occur when the priority firm power rate is lower than the utility's ASC, the net effect is that the utility receives exchange energy cost savings.
- The utility passes the cost savings on to their customers as rate relief benefits, in the form of reduced electric power rates, credits on monthly power bills, or checks distributed to their customers monthly or annually.
- The net cost of the exchange program—the difference between Bonneville's high purchase price and low sale price is recovered through the power rates Bonneville charges its customer classes.

[1]The Northwest Power Act defines residential and small farm as all usual residential, apartment, seasonal dwelling, and farm electrical uses within certain limits.

Figure 2.1 depicts the relationship between Bonneville, the utilities that participate in the exchange program, and Bonneville's customer classes that pay the program's net cost.

Figure 2.1: Basic Relationship Between Parties in the Residential Exchange Program



During the program's first 7 years (fiscal years 1982-88), Bonneville purchased $5.83 billion in residential and small farm power and sold an equivalent amount of power for $4.46 billion, as table 2.1 shows. Thus, the total rate relief benefits from the first 7 years of the exchange program—equal to the net costs of the program—were $1.37 billion.

Table 2.1: Rate Relief Benefits of Exchange Program to Participating Utilities' Residential and Small Farm Customers

Dollars in millions[a]

Fiscal year	Cost of power purchased by Bonneville	Revenue from power sold by Bonneville	Value of benefit to residential and small farm customers
1982	$428.4	$211.8	$216.6
1983	551.3	400.1	151.2
1984	836.8	651.0	185.8
1985	1,008.8	801.0	207.8
1986	1,046.4	838.1	208.3
1987	1,010.1	796.7	213.4
1988	949.7	761.7	188.0
Total	**$5,831.5**	**$4,460.4**	**$1,371.1**

[a]Nominal dollars not adjusted for inflation.

Source: Bonneville's Exchange Program Branch.

Activities Affecting Exchange Program Implementation and Operation

During the first 7 years of the exchange program, Bonneville made several important decisions affecting the utilities that participate in the program. Bonneville

- developed a method that keeps utilities from paying Bonneville if their ASCs fall below Bonneville's priority firm power rate;
- revised its method of determining utilities' ASC to exclude unauthorized costs and became more active in reviewing the utilities' ASC computations; and
- suspended, terminated, or bought out the exchange program contracts for 18 of the 40 utilities participating in the program because the utilities considered it no longer advantageous to participate.

These key decisions are explained in greater detail below.

"Deemer Clause" and Benefit Offset

An issue of concern in 1980-81, as decisions were being made by Bonneville to implement the program, was whether utilities should pay Bonneville when their ASCs drop below Bonneville's power rate. This issue anticipated a reverse of the power cost situation that the program was designed to address and that generally existed at that time. According to Bonneville officials, neither the Northwest Power Act nor its legislative history contains specific provisions on this point.

After several meetings between Bonneville and participating utilities, the parties negotiated in 1981 to include a clause in exchange program contracts specifying that if a utility's ASC dropped below Bonneville's priority firm power rate, the utility may deem its ASC to be equal to Bonneville's priority firm power rate. The effect of this "deemer clause" is that a utility would not be required to pay Bonneville for the difference between its ASC and Bonneville's priority firm power rate.

According to Bonneville, the deemer provision represents a contractual compromise by limiting the extent to which the exchange program should disadvantage residential and small farm customers of utilities whose ASCs are lower than Bonneville's priority firm power rate. Specifically, the deemer clause keeps a utility from immediately paying Bonneville. Instead, Bonneville maintains a benefit offset balance, which accrues interest, to record how much the utility would have paid Bonneville if it was not in deemer status. Bonneville offsets this debit balance against positive benefits the utility receives once its ASC again exceeds Bonneville's priority firm power rate. In order for a utility to come out of deemer status, a condition it would logically elect only if its ASC was greater than Bonneville's priority firm power rate, the utility would have to either pay Bonneville the benefit offset balance or wait until its now-positive benefits reduced the offset balance to zero. Thus, a utility in deemer status will not receive exchange program rate relief benefits until its benefit offset balance is liquidated.

Since the beginning of the exchange program, four participating utilities have accrued a total benefit offset balance of approximately $115 million. Table 2.2 identifies those four utilities and their April 1989 benefit offset balances.

Table 2.2: Utilities in Deemer Status and Benefit Offset Balances as of April 1989

Dollars in millions

Utility	Benefit offset balance[a]
Idaho Power Company	$53.2
Washington Water and Power Company	44.0
Puget Sound Power and Light Company	14.6
Montana Power Company	3.2
Total	**$115.0**

[a]These amounts are estimates and do not reflect all final ASC adjustments, interest on deemer balances, or final invoices.

Source: Bonneville's Exchange Program Branch.

Revised Average System Cost Method

Since the beginning of the exchange program, there have been continual discussions between Bonneville, its customers, state regulatory agencies, and utilities participating in the program concerning what costs should be included in the method for determining a utility's ASC. The ASC method is used to determine the level of exchange energy cost savings Bonneville should pay to utilities participating in the program.

In accordance with section 5(c)(7) of the Northwest Power Act, the Bonneville Administrator developed, in consultation with others, a method for determining a utility's ASC. The method, developed in 1981, relied on state regulatory agencies to determine what costs would be included in the ASC filings of utilities participating in the exchange program. Under this approach—called a jurisdictional costing approach—retail rate orders of regulatory agencies were used as the primary source of data for computing the ASC. According to the Bonneville Administrator's Record of Decision for the 1981 ASC method, the jurisdictional costing approach was used to determine a utility's ASC because costs allowed or established for rate-making purposes should be used in calculating ASCs and intrusion by Bonneville into jurisdictional rate issues should be avoided.

According to Bonneville's July 1985 legal brief, one investor-owned utility seriously abused the 1981 ASC method by attempting to recover $79 million in nuclear plant termination costs through the exchange program. Bonneville disallowed the inclusion of the $79 million cost from the utility's ASC filing. Although section 5(c)(7) of the Northwest Power Act expressly prohibits the inclusion of plant termination costs in ASC calculations, the regulatory agency for the state in which the investor-owned utility is located did not exclude that amount.

Subsequent to the situation described above, Bonneville specifically identified the costs that could not be included in ASC calculations and issued a revised ASC method in June 1984. The 1984 method retained the basic jurisdictional costing approach included in the 1981 method. However, Bonneville now determines independently, through a complex review process, the validity of data submitted in ASC filings to ensure the appropriateness of the ASC calculations. This independent determination may require Bonneville to monitor the retail rate-setting processes of utilities participating in the exchange program.

In spite of the changes made earlier, the ASC methodology issue continues to concern Bonneville. For example, in a June 1987 letter to Bonneville's customers, the Bonneville Administrator said that he is concerned that utilities participating in the exchange program, or contemplating participation, may take potential exchange energy cost savings into account when evaluating the costs associated with the acquisition of future electric power-generating facilities. He said that including these costs in a participating utility's ASC could quickly drive up Bonneville's costs and inappropriately increase Bonneville's rates to all customers.

Contract Suspension, Termination, and Buy-Out

According to Bonneville officials, 99 utilities signed exchange program contracts with the assumption they would begin active participation once their ASCs were greater than Bonneville's priority firm power rate. Only 40 of the utilities (see app. II) participated in the exchange program during the first 7 years of the program. However, 18 of the 40 participating utilities have had their contracts suspended, terminated, or bought out by Bonneville.

Five utilities have suspended their contracts with Bonneville on the basis of mutually agreeable suspension periods—generally for the length of time the utilities estimate it will take for their ASCs to rise above Bonneville's priority firm power rate. For example, the Washington Water Power Company, an investor-owned utility, negotiated an agreement with Bonneville to suspend its exchange program contract from June 30, 1987, until September 30, 1990. According to the agreement, Washington Water Power and Bonneville agreed to suspend the contract because the utility had incurred and would continue to incur substantial costs in connection with the preparation and review of its ASC submissions and because its ASC was consistently below Bonneville's priority firm power rate, thereby resulting in no likely future rate relief benefits.

Two utilities have terminated their exchange program contracts with Bonneville. According to Bonneville, the residential and small farm customers of the two utilities were likely to receive limited rate relief benefits. According to Bonneville officials, utilities that have terminated their contracts have foregone their contract rights to participate further in the exchange program until after June 30, 2001, when the current contracts expire.

Eleven utilities asked Bonneville to buy out their contracts. A buy-out is the same as a termination except that Bonneville pays the utility a negotiated amount based on the discounted net present value of the program's exchange energy cost savings that the utility expects to receive during the remaining life of the contract. The total cost of the buy-outs has been about $68.3 million.

Bonneville purchased the exchange program contracts from 9 of the 11 utilities in a negotiated settlement totaling $11.0 million. According to a Bonneville exchange program fact sheet, these nine utilities had their contracts bought out to eliminate the administrative burden associated with participation in the program. The contracts of the other two utilities—Snohomish County Public Utility District and Clark County Public Utility District, both in Washington State—were bought out at a cost of $43.3 million and $14 million, respectively. According to the buy-out agreements, the two public utility districts wanted Bonneville to purchase their exchange program contracts because of disagreements in the interpretation and implementation of the ASC method.

According to Bonneville, the contract buy-out amounts were negotiated between Bonneville and the utilities. The amounts were based on the discounted net present value of the exchange energy cost savings that utilities expect to receive during the remaining life of the contracts. The negotiated buy-out amounts took into consideration such variables as projected costs, estimated amounts of residential and small farm electric power to be exchanged, past ASC filings, prior allowances for certain costs, and uncertainties about future exchange energy cost savings.

According to Bonneville officials, the details behind the negotiated buy-outs are proprietary information, which the utilities do not want released. We reviewed the negotiated settlement process for the Snohomish County buy-out—the largest of the 11 settlements—and found no reason to take exception with the negotiation process followed by Bonneville.

Conclusions

During the first 7 years of the exchange program, Bonneville purchased $5.83 billion in residential and small farm power and sold an equivalent amount of power for $4.46 billion. The difference between these two amounts—$1.37 billion—is both the total amount of rate relief benefits and the net cost of the exchange program.

Bonneville and utilities participating in the program have made several significant decisions that have affected program costs.

- Bonneville and the utilities agreed to contracts providing that future benefits would be offset when the utilities' present costs exceeded Bonneville's priority firm power rate. As a result, as of May 1989, four utilities had accrued offset balances of $115 million, which were to be applied to offset future benefits.
- Bonneville decided to revise the method used for preparing ASC filings to better ensure that the utilities do not include prohibited costs and thus realize inappropriate rate relief benefits. This decision resulted, in part, because one investor-owned utility had attempted to include a prohibited $79 million in plant termination costs in its ASC filing under the initial method.
- The number of utilities participating in the exchange program has been reduced from 40 to 22 because 18 utilities considered it no longer in their benefit to participate. The contracts of 11 of the 18 were bought out at a cost of $68.3 million.

Significance of the Exchange Program's Rate Relief Benefits and Costs

During the first 7 years of the exchange program, residential and small farm customers of the 40 utilities that participated in the program were entitled to receive about $1.37 billion in rate relief benefits. Exchange program benefits have varied from utility to utility, with more than 86 percent, or about $1.18 billion, of the benefits passed through to the residential and small farm customers of investor-owned utilities. The two largest investor-owned utilities have received $941 million, or nearly 69 percent, of the exchange program's total rate relief benefits. Bonneville projections indicate that over the next 7 years the exchange program may result in cost savings of about $1.3 billion to participating utilities.

During its rate-setting process, Bonneville allocates the projected gross costs of the exchange program to its firm power rate classes. The largest portion of the projected gross costs of the exchange program—about $2.36 billion, or 45 percent—has been allocated to Bonneville's direct service industry rate class. Customers who purchase firm power—including utilities Bonneville serves directly, publicly owned and cooperative utilities that have priority for Bonneville power, and investor-owned and public utilities in the Pacific Northwest and California—pay the net costs of the program. However, Bonneville has not analyzed how much of the exchange program's net costs its firm power customers have paid.

During the past decade, the disparity has narrowed between the power rates paid by Pacific Northwest residential and small farm customers of investor-owned utilities participating in the exchange program and the rates paid by customers of public utilities with access to Bonneville power. Since 1981, for example, Bonneville has increased its power rates by more than 300 percent. The narrowing rate disparity can be attributed, in part, to the exchange program. However, numerous other factors have also affected retail rates in the Pacific Northwest since 1980.

Significance of the Exchange Program's Benefits

We assessed the significance of the exchange program's benefits in terms of (1) the total exchange energy cost savings for participating utilities and (2) the savings realized by residential and small farm customers of five participating utilities. The benefits varied greatly from utility to utility, but for those utilities and their customers receiving the greatest benefits, the amounts were substantial.

Significance of Benefits to Participating Utilities

Through the end of fiscal year 1988, Bonneville paid utilities participating in the exchange program more than $5.83 billion for their residential and small farm electric power and sold the utilities an equivalent amount of power for about $4.46 billion. The difference between the two amounts—about $1.37 billion—was the cost savings to the participating utilities. In essence, during this 7-year period, for every $1 Bonneville paid participating utilities for their exchange energy, the utilities saved almost 24 cents in costs because they bought the energy back from Bonneville for only 76 cents.

The total cost savings realized by participating utilities in any 1 year ranged from about $151 million to almost $217 million, as shown in table 3.1. The table also shows that since fiscal year 1984, the annual cost savings, as a percentage of the cost of energy exchanged, has ranged from 20 to 22 percent.

Table 3.1: Cost Savings Realized by Utilities Participating in the Exchange Program

Dollars in millions

Fiscal year	Cost of exchange energy purchased by Bonneville at ASC	Exchange energy cost savings realized by participating utilities	Exchange energy cost savings as percentage of cost of exchange energy
1982	$428.4	$216.6	51
1983	551.3	151.2	27
1984	836.8	185.8	22
1985	1,008.8	207.8	21
1986	1,046.4	208.3	20
1987	1,010.1	213.4	21
1988	949.7	188.0	20
Total	**$5,831.5**	**$1,371.1**	**24**

Source: Bonneville's Exchange Program Branch.

Annual fluctuations in the amount of cost savings have resulted from several factors, according to Bonneville officials. These factors include (1) changes in the level of Bonneville's priority firm power rate, (2) changes in the level of utilities' ASCs, (3) modification of the ASC method in 1984, (4) changes in the amount of electric power exchanged between Bonneville and the participating utilities, (5) termination and suspension of several exchange program contracts, and (6) the gradual phase-in of the exchange program. With regard to the last factor, the Northwest Power Act required a gradual phase-in of the amount of power exchanged under the program, initially limiting utilities to exchanging

50 percent of qualified residential and small farm power, and increasing the amount of power exchanged to 100 percent beginning July 1985.

The energy cost savings varied considerably from utility to utility. Investor-owned utilities, which generally have higher ASCs than publicly owned utilities, received most of the cost savings. In all, investor-owned utilities received about $1.18 billion, or about 86 percent, of the total cost savings. In particular, the two largest investor-owned utilities of the region —Portland General Electric Company and Pacific Power and Light Company—received the largest share of the cost savings. Nearly 69 percent of the total cost savings, or about $941 million, went to these two utilities, which serve about 954,000 residential and small farm customers.

Significance of Benefits to Residential and Small Farm Customers

To illustrate the significance of the rate relief benefits provided for residential and small farm customers, we compared the benefits received in calendar year 1988 by an average residential customer and an average small farm customer[1] of five participating utilities. Together, these five utilities—three investor-owned utilities, one cooperative utility, and one public utility district—accounted for about $1.18 billion, or more than 86 percent, of the program's total cost savings. The highest residential benefit among the five utilities went to Utah Power and Light Company's customers living in Idaho (see table 3.2). Without rate relief, the average Idaho residential customer would have paid an annual electric bill of about $1,137. However, after subtracting a rate relief credit of almost $286 for the year, the average Idaho residential customer had an annual power bill of approximately $851. In essence, the rate relief benefit received by an average Idaho residential customer of Utah Power and Light was the equivalent of receiving 3 months of power usage at no cost.

[1] An average residential and small farm customer for each of the five utilities is defined by the average annual amount of power purchased by a residential customer and small farm customer from each utility. The average annual residential power purchased was different for each utility and ranged from a low of 12,049 kilowatt-hours for Pacific Power and Light Company to a high of 16,334 kilowatt-hours for Snohomish County Public Utility District.

Table 3.2: Exchange Program Rate Relief Benefits Received by Average Residential Customer, Calendar Year 1988

Utility	Average residential customer's electric bill before rate relief benefit	Rate relief benefit per average residential customer	Electric bill paid by average residential customer
Investor-owned utilities			
Portland General Electric Company	$699.81	$104.46	$595.35
Pacific Power and Light Company	710.00	74.00	636.00
Utah Power and Light Company	1,136.92	285.61	851.31
Cooperative			
Central Electric Cooperative, Inc.	986.28	141.84	844.44
Public utility district			
Snohomish County	825.03	115.97	709.06

In addition to affecting residential electric bills, the exchange program had a significant effect on power bills paid by small farm customers, according to officials for three of these five utilities. Specifically, during the May-September 1988 irrigation season:

- The power bills for small farm irrigators served by Utah Power and Light Company in Idaho were reduced on average from $10,751 to $6,043. This $4,708 rate relief was an average reduction of almost 44 percent.
- The average power bills for small farm irrigators served by Pacific Power and Light Company in Oregon were reduced from $1,336 to $1,010. This was an average reduction of $326, or more than 24 percent.
- The average power bills for small farm irrigators served by Central Electric Cooperative, Inc., in Oregon were reduced from $988 to $654. This was an average reduction of $334, or almost 34 percent.

Significance of the Exchange Program's Costs

Bonneville recovers the cost of the exchange program through the rates it charges its customer classes. Assessing the significance of this cost for Bonneville's customer classes is more difficult than assessing the significance of the program's exchange energy cost savings on participating utilities and their customers. This difficulty stems from the fact that Bonneville allocates the gross costs of its exchange program to its rate classes prior to setting rates, but does not record the actual net costs paid by each of its customer classes. Nonetheless, these allocations of gross costs can provide several indications of the significance of the exchange program's costs. We assessed this significance in two ways: (1) in terms of the relationship between the exchange program's gross costs and Bonneville's total operating gross costs and (2) in terms of the allocation of the exchange program's gross costs among Bonneville's rate classes.

Significance of Costs to Bonneville's Total Operations

As part of its rate-setting process, Bonneville projects the gross costs for all aspects of its operations, including the exchange program. For our purposes in assessing the significance of the program, the cost to be recovered is best expressed as a net cost—that is, as the dollar difference between the power Bonneville buys from participating utilities and the power it sells back to them. During the first 7 years of the exchange program, the program's total net cost of $1.37 billion was approximately 9.2 percent of Bonneville's total operating revenue of $14.98 billion.

For rate-setting purposes, however, Bonneville does not directly use this net amount. The gross cost of the exchange program used for rate-setting takes into account the cost of the exchange energy Bonneville expects to purchase. Bonneville's revenue estimate for the rate test period includes the amount Bonneville expects to sell in return.

Table 3.3 compares Bonneville's total projected gross operating costs with the projected gross costs of the exchange program for the four rate-setting processes covering fiscal years 1983-89.[2] For those four rate-setting processes, the projected annual gross costs of the exchange program ranged from almost $671 million to about $2.3 billion. This amount ranged from 30 to 39 percent of Bonneville's total projected gross costs for all aspects of its operations. For the four rate-setting processes, the projected gross cost of the program averaged 37 percent of Bonneville's total projected gross costs.

[2]Bonneville did not project the gross cost of the exchange program in its rate-setting process for fiscal year 1982 because the program was too new for a projection to be developed. The four rate-setting processes for fiscal years 1983-89 took place in 1982, 1983, 1985, and 1987.

Table 3.3: Projected Gross Costs for the Exchange Program Versus Projected Gross Costs for All Bonneville Operations in 1982, 1983, 1985, and 1987 Rate-Setting Processes

Dollars in millions

Year of rate-setting process	Projected exchange program gross costs	Projected gross operating costs	Projected exchange program gross costs as percentage of projected gross operating costs
1982	$670.9	$2,225.2	30
1983	1,108.5	2,927.1	38
1985	1,107.4	2,929.4	38
1987	2,304.5	5,874.9	39
Total	**$5,191.3**	**$13,956.6**	**37**

Source: Bonneville's Exchange Program Branch.

It is important to remember that the gross costs reflected in table 3.3 are projections for rate-setting purposes, not actual amounts. A comparison of the exchange program's total gross costs that were allocated (table 3.3) with the actual gross costs of energy purchased by Bonneville (table 3.1) will show considerable differences. For example, table 3.3 shows that in the 1983 and 1985 rate-setting processes, Bonneville's projected gross costs for the exchange program totaled about $2.2 billion. However, the actual gross cost of exchange energy purchased by Bonneville for fiscal years 1984-87, the 4 fiscal years covered by the 1983 and 1985 rate-setting processes, amounted to $3.9 billion—a difference of approximately $1.7 billion. Bonneville officials pointed out that before the 1987 rate-setting period, projections were based on 1-year test periods rather than on the full-period rates that were expected to be in effect. (In its 1987 rate-setting process for fiscal years 1988-89, Bonneville used a 2-year test period.)

Estimated Distribution of Costs Among Bonneville's Customers

During its rate-setting processes, Bonneville has generally allocated the exchange program's projected gross costs to its firm power rate customers.[3] Bonneville has classified its firm power rate customers as follows:

[3]In its rate-setting process for fiscal years 1986-87, Bonneville also allocated the exchange program's gross costs to its non-firm power rate classes—the only time Bonneville did so during the first 7 years of the program. According to the Bonneville Administrator's Record of Decision for the 1987 Final Rate Proposal, inclusion of the exchange costs made the 1986 non-firm power rates uneconomical and forced Bonneville to an emergency rate reduction. The inclusion of exchange program costs in Bonneville's non-firm power rates for fiscal years 1986-87 is an issue waiting final resolution by the Federal Energy Regulatory Commission.

- Direct service industry rate class: This rate class consists of industries—primarily aluminum companies—that purchase power directly from Bonneville.
- Preference rate class: This rate class consists of publicly owned utilities, cooperatives, federal agencies, and municipalities, which have priority for Bonneville power under federal law, and utilities participating in the exchange program.
- Surplus firm power rate class: This rate class consists of investor-owned utilities in the Pacific Northwest and utilities in California that have signed contracts with Bonneville for firm power surplus to Bonneville's preference customer requirements.
- "Other" rate class: This rate class consists of a variety of utilities that purchase small amounts of firm power.

Table 3.4 shows how Bonneville allocated the projected gross costs for the exchange program among its customer classes. The largest portion—about $2.36 billion, or 45 percent—was allocated to the direct service industry rate class. The surplus firm power rate class and preference rate class had the next largest shares, with 29 and 24 percent, respectively.

Table 3.4: Allocation of the Exchange Program's Projected Gross Costs for Bonneville's Rate-Setting Processes

Dollars in millions

	Cost allocated to each rate class				
Year of rate-setting process	Direct service industry	Surplus firm power	Preference	Other	Total allocated gross cost
1982	$511.9	$99.6	$54.0	$5.5	$671.0
1983	522.6	286.7	269.4	29.7	1,108.4
1985	459.6	416.5	214.0	17.3	1,107.4
1987	861.8	690.7	706.9	45.1	2,304.5
Total	**$2,355.9**	**$1,493.5**	**$1,244.3**	**$97.6**	**$5,191.3**

Source: Bonneville's Exchange Program Branch.

According to Bonneville, after allocating costs among the rate classes, Bonneville adjusts the allocated costs to set rates. One adjustment accounts for the difference between the costs allocated to the surplus firm power rate class and the revenues Bonneville expects to receive from the sale of that power. Market conditions have historically compelled Bonneville to sell surplus firm power either in the open (economy energy) market or under contract for less than fully allocated costs. The adjustment allocates costs in the amount of the deficiency from the surplus firm power rate class to all other firm power rate classes. Because of this reallocation, the amount of the exchange program's costs that remains in surplus firm power rates is less than the original amount allocated.

Once rates are set, Bonneville is able to negotiate sales for surplus firm power under the rate schedules. The negotiated contract rates reflect market conditions perceived by each party to the negotiated sale. Bonneville attempts to recover fully allocated costs from each sale of surplus firm power, but it uses its opportunity cost—the revenue that Bonneville would receive from selling surplus firm power in the short-term economy energy market—as its lower limit for negotiating a surplus firm power sale price.

The actual amount of program costs paid by each Bonneville customer class has not been determined, since the actual revenues received from a customer class may differ substantially from those forecast for rate-making. For example, in fiscal year 1988, Bonneville's revenues from its direct service industrial customers were over $200 million more than forecast in the 1987 rate-setting process. Also, revenues from surplus firm power customers were about $150 million less than forecast in that rate-setting process.

To illustrate the difficulty in determining which customer classes pay actual program costs, we developed information about a 20-year power sale and exchange agreement between Bonneville and Southern California Edison, a surplus firm power customer. Beginning July 1, 1989, Southern California Edison agreed to purchase surplus firm power from Bonneville. Southern California Edison will initially pay 2.85 cents per kilowatt-hour for electric power purchased and as much as 3.69 cents per kilowatt-hour, based on annual increases in oil and gas prices. Under Bonneville's gross cost allocation, approximately 26 percent of Southern California Edison's power costs under the agreement would go toward the exchange program's gross costs.

According to Bonneville, however, revenues have differed substantially from those projected in Bonneville's 1987 rate-setting process, when the gross cost allocation was made. In addition, because Bonneville and Southern California Edison agreed to rates for this sale that are below Bonneville's fully allocated cost rate, less than 26 percent of Southern California Edison's power costs will be attributable to the exchange program.

The Exchange Program's Future Benefits and Costs

Utilities participating in the exchange program may continue to receive significant cost savings. However, three of the utilities participating in the exchange program are currently involved in either wholesale electric power marketing or merger activities, which could affect the net costs of the exchange program.

The Exchange Program's Future Energy Cost Savings

According to data compiled by Bonneville's Exchange Program Branch in preparation for the 1989 rate-setting process,[4] the cost savings to be realized by utilities participating in the exchange program for fiscal years 1989-95 may range from $142 million to about $228 million annually (see table 3.5). The projected total cost savings of about $1.3 billion is almost 18 percent of the projected $7.3 billion Bonneville expects to pay utilities for their exchange energy.

Table 3.5: Projected Exchange Energy Cost Savings for Utilities Participating in the Exchange Program, Fiscal Years 1989-95

Dollars in millions

Fiscal year	Projected cost of exchange energy to be purchased by Bonneville at utilities' ASCs	Projected exchange energy cost savings for participating utilities	Projected exchange energy cost savings as percentage of projected cost of exchange energy
1989[a]	$870.2	$142.0	16
1990	887.3	143.1	16
1991	925.1	175.8	19
1992	1,080.3	186.2	17
1993	1,126.6	202.2	18
1994	1,181.5	214.2	18
1995	1,243.6	228.3	18
Total	**$7,314.6**	**$1,291.8**	**18**

[a]Excludes $22.1 million for buyouts of the Clark and Snohomish County public utility districts that were expensed in 1989 but obligated in 1988.

Note: Amounts adjusted by Bonneville for inflation.

Source: Bonneville's Exchange Program Branch.

[4]Because Bonneville extended the rates established for fiscal years 1988-89 to fiscal years 1990-91, it did not undertake a full rate adjustment process in 1989. Until Bonneville conducts another rate-setting process, the most current allocations of exchange program gross costs are those used for setting rates in 1987.

Activities That Could Affect Exchange Program Costs

Wholesale electric power marketing and merger activities involving three utilities participating in the exchange program could affect the net costs of the program. The activities in which the three utilities are involved and the potential impacts of the activities on the exchange program's net costs are described below. The residential and small farm customers of the three utilities were entitled to more than $1 billion, or almost 79 percent, of the exchange program's total energy cost savings paid by Bonneville during the first 7 years of the program.

Portland General Electric

The Portland General Electric Company, a subsidiary of the Portland General Corporation, received almost $65 million in exchange energy cost savings in fiscal year 1988. In addition, Portland General Electric has received the most exchange energy cost savings—approximately $502 million—of any utility participating in the program.

Portland General Electric Company sells electric power to customers in northwestern Oregon and to utilities in California. Revenue from the California sales offsets the cost to Portland General Electric, reduces its ASC, and reduces the cost savings the utility receives from the exchange program. According to Bonneville officials, a net revenue of $60 million from electric power sales to California utilities would reduce Portland General Electric's annual exchange energy cost savings by approximately $12 million.

In February 1988, the Portland General Corporation established the Portland General Exchange to operate in the wholesale power market. According to Portland General Electric officials, Portland General Exchange would be able to purchase power from any source; however, if it purchased any power from Portland General Electric, it would be under a Power Services Agreement filed with the Federal Energy Regulatory Commission. Portland General Exchange may sell to any utility on a long-term basis and is not confined to any geographical area.

Bonneville estimates that if Portland General Exchange's power sales should undercut Portland General Electric's sales to California utilities, Portland General Electric's ASC would increase. According to Bonneville officials, this potential increase in Portland General Electric's ASC could increase the exchange program's net costs by about $151 million through June 2001.

Bonneville does not want any unwarranted reductions of Portland General Electric's revenues, and corresponding increases in the utility's ASC, to result from Portland General Exchange's efforts to capture electric power sales to California utilities. Bonneville officials said they may participate in Federal Energy Regulatory Commission and state regulatory proceedings to ensure that there is no unwarranted reduction in Portland General Electric's off-system revenues that would result in an ASC increase and exchange energy cost savings paid by Bonneville. Bonneville does not consider a change to the ASC method necessary at this time.

Utah Power and Light Merger With Pacific Power and Light

On January 9, 1989, Pacific Power and Light Company, a subsidiary of PacifiCorp, and Utah Power and Light Company conditionally merged through a stock exchange worth approximately $1.9 billion. Utah Power and Light generates and sells power to about 510,000 retail customers in Utah, southeastern Idaho, and southwestern Wyoming. Pacific Power and Light generates and sells power to about 680,000 retail customers in California, Idaho, Montana, Oregon, Washington, and Wyoming.

In fiscal year 1988, Utah Power and Light had an ASC of approximately 4.1 cents per kilowatt-hour and received almost $22.8 million in cost savings from Bonneville. Pacific Power and Light had an ASC of approximately 3.1 cents per kilowatt-hour and received more than $48.9 million in cost savings.

In 1987, Bonneville estimated that the merger of Utah Power and Light with Pacific Power and Light could reduce the exchange program's net costs by as much as $5 million annually for fiscal years 1989-95 and $50 million annually for fiscal years 1996-2001. Earlier net cost reductions would be due to operating the combined generating system more efficiently and selling power to other utilities. Net cost reductions after fiscal year 1995 would occur largely because Pacific Power and Light can use Utah Power and Light's surplus power to meet demand instead of building additional generating facilities.

Bonneville is concerned about the equitable distribution of net merger benefits—benefits minus costs—between Pacific Power and Light and Utah Power and Light. For example, Bonneville estimates that $1 of net benefits allocated to Pacific Power and Light would reduce the utility's ASC and the exchange program's net costs more than it would if the same benefit was allocated to Utah Power and Light. This is because a significant portion of Utah Power and Light's service territory is outside Bonneville's service area. According to Bonneville officials, even with net benefits, Pacific Power and Light's ASC could increase because (1) generation and transmission costs may be allocated from a Utah Power and Light service territory that does not qualify for rate relief benefits into a Pacific Power and Light service territory that does qualify for benefits, (2) interdivisional power transfers between the two utilities may include prohibited costs, and (3) merger benefits may not be appropriately allocated between the two utilities' service territories.

In a March 31, 1989, letter to Bonneville, Pacific Power and Light stated that a committee has been established to review the complexities surrounding the allocation of costs between Utah Power and Light and Pacific Power and Light for financial and regulatory reporting. According to the letter, the committee has developed a detailed proposal for allocating costs and is meeting with representatives from the state utility commissions to refine the proposal so that it is acceptable to all parties.

Through the rate intervention process provided for in the ASC method, Bonneville is monitoring the merger to identify increases in Pacific Power and Light's ASC and corresponding increases in the exchange program's net costs. According to Bonneville officials, as part of its monitoring effort, Bonneville may intervene in electric power rate-setting activities to obtain better information concerning the costs used by Pacific Power and Light and Utah Power and Light in setting retail rates and to ensure the equitable allocation of net benefits between the two utilities.

Rate Disparity Has Narrowed

As chapter 1 explained, the exchange program was designed to narrow the disparity between retail power rates for residential and small farm power charged by utilities. To determine whether the disparity that existed before enactment of the Northwest Power Act has been reduced, we reviewed power rates in three states and for nine electric utilities in the region.

The statewide data indicate that power rates have declined. This decline can be seen by comparing statewide averages for Washington, where residents are served primarily by publicly owned utilities, with averages for Oregon and Idaho, where residents are served primarily by investor-owned utilities. Table 3.6 shows the average bill for all utilities serving residential customers in the three states. In 1978, the average monthly bill in Washington was $14.00, or 56 percent of the bill in Oregon and 70 percent of the bill in Idaho. In 1988, the average monthly bill in Washington was still lower than those in the other two states, but it was now almost 88 percent of the average bill in Oregon and 94 percent of the average bill in Idaho.

Table 3.6: Typical Monthly Residential Power Bills for 1,000 Kilowatt-Hours of Electricity in Three Pacific Northwest States

State	Monthly residential power bill 1978	1983	1988
Oregon	$24.91	$34.71	$47.80
Washington	14.00	31.07	41.95
Idaho	19.92	35.63	44.61

Source: Department of Energy's Typical Electric Bills reports.

We also compared rate information from the Department of Energy's Typical Electric Bills reports for 1978 (4 years before the program took effect), 1983 (the second year of the program), and 1988. These bills are based on rates charged by utilities for residential electric use of 1,000 kilowatt-hours per month.[5] Table 3.7 shows residential power bill data for five investor-owned utilities that have participated in the exchange program and four publicly owned utilities that do not participate in the program. The power bill difference between these two groups of utilities was smaller in 1988 than in 1978. For example, in 1978, the average monthly bill of $10.84 for the Seattle Department of Light was 40 to 70 percent of the average monthly bills of the five investor-owned utilities. In 1988, by comparison, the Seattle Department of Light bill was 63 to 78 percent of the bills of the five investor-owned utilities.

Table 3.7: Typical Monthly Residential Power Bills for 1,000 Kilowatt-Hours of Electricity

Utility	Monthly residential power bill 1978	1983	1988
Investor-owned			
Washington Water and Power Company	$15.38	$30.67	$43.37
Puget Sound Power and Light Company	19.28	34.09	46.91
Portland General Electric Company	27.00	35.78	48.93
Pacific Power and Light Company	27.24	37.14	53.55
Idaho Power Company	21.57	38.65	43.95
Publicly owned			
Burley Municipal Distribution System (Burley, ID)	15.26	38.50	45.50
Eugene Water and Electric Board (Eugene, OR)	18.27	32.81	34.23
Seattle Department of Light (Seattle, WA)	10.84	23.99	33.68
Tacoma Department of Public Utilities (Tacoma, WA)	12.80	20.45	29.80

Source: Department of Energy's Typical Electric Bills reports.

According to Bonneville officials, the reductions in the residential rate disparity during the past decade cannot be attributed solely to the

[5]One kilowatt-hour of electrical energy equals 1,000 watts of power supplied for 1 hour.

exchange program because numerous factors have affected rates in the Pacific Northwest. For example, the Washington Public Power Supply System's[6] construction and settlement costs, costs associated with power conservation and fish and wildlife restoration activities, the condition of the regional economy, and the existence of considerable surplus power in the region have affected the disparity of retail rates. Also, between 1981 and 1987, Bonneville increased its power rates by more than 300 percent—primarily to meet debt service obligations on about $6 billion in debts Bonneville had incurred to purchase power from nuclear power plants.

Conclusions

The exchange program has resulted in significant dollar benefits to the utilities participating in the program. Specifically, participating utilities have received $1.37 billion through the exchange program to benefit their residential and small farm customers. In addition, Bonneville estimates that during the next 7 years of the exchange program, participating utilities will receive an additional $1.3 billion in program benefits.

The net costs of the exchange program are paid by Bonneville's customers. As the rate-setting process shows, Bonneville's industrial customers bear the largest portion of the program's costs. However, Bonneville has not identified the actual costs paid by its customers, and the cost allocation factors used for setting rates differ from the actual revenues received.

Three utilities participating in the exchange program are involved in wholesale electric power brokering and merger activities, which could significantly affect the exchange program's net costs. Bonneville is monitoring these activities to ensure that the utilities' ASC claims are appropriate.

The data we reviewed also indicate that the disparity in residential and small farm rates that existed between investor-owned utilities and public utilities before enactment of the Northwest Power Act has been reduced. However, this reduction cannot be attributed solely to the exchange program because numerous factors have affected retail rates in the Pacific Northwest since 1980. The significant increases in Bonneville's costs and rates appear to be a more important reason than the

[6]As of August 1, 1989, the Washington Public Power Supply System was a coalition of 14 public utilities that joined together to create power-generating facilities.

residential exchange program for the reduced disparity in Northwest power rates.

Current Efforts Are Inadequate to Ensure That Utilities' Customers Have Received Rate Relief Benefits

Section 5(c) of the Northwest Power Act requires utilities participating in the exchange program to pass rate relief benefits through to their residential and small farm customers. Included in the exchange program contracts signed by participating utilities are provisions giving Bonneville a contractual right to ensure that the utilities pass the benefits of the exchange to their customers. However, Bonneville has limited its benefit pass-through verification to two utilities and has otherwise relied on state regulatory agencies, utilities, or organizations to ensure that rate relief benefits are passed through by participating utilities.

Bonneville's Reviews of Benefit Pass-Throughs Have Been Limited

According to Bonneville officials, they performed two limited pass-through reviews on a trial basis, both in 1987. Bonneville performed these reviews to (1) determine the methods used by public utilities for passing the exchange program's rate relief benefits through to their residential and small farm customers, (2) verify that the benefits had been properly distributed, (3) identify Bonneville's future role in conducting reviews of benefit pass-throughs, and (4) provide Bonneville with information and experience regarding the relative costs and benefits of conducting such reviews.

Bonneville conducted the pass-through reviews at one public utility district and one electric cooperative utility. Both reviews disclosed problems. Specifically:

- At the public utility district, which had received almost $1.2 million in rate relief benefits through fiscal year 1988, Bonneville's preliminary review indicated that the utility may not have passed through about $73,000 in benefits to customers, may not have passed through benefits to all qualified customers, and may have passed through benefits to unqualified customers. In addition, Bonneville's preliminary review indicated that the utility used a rate approach that made tracing benefits difficult. On the basis of these preliminary data, the review team's draft recommendations were that the utility establish a balancing account (an account in which the receipt and disbursement of rate relief benefits are recorded), maintain sufficient documentation to trace benefits passed through to customers, and allocate retroactive and future benefits to all qualified customers.
- At the electric cooperative utility, which had received about $7 million in rate relief benefits through fiscal year 1988, Bonneville's preliminary review indicated two minor errors. First, the conversion to a new computer program resulted in the utility's not passing through almost $4,300 in benefits. Second, the utility erroneously passed through more

than $2,900 in benefits to nonresidential customers. Bonneville's preliminary review indicated that the utility had a process for receiving and distributing benefits that essentially resulted in benefits being applied to customer's bills. On the basis of these preliminary data, the review team recommended that the utility correct the two minor errors identified and forward the journal entries to Bonneville.

In response to our questions about these reviews, Bonneville, in a November 23, 1988, letter to us, stated that officials in Bonneville's Office of Financial Management reviewed the preliminary results of the two reviews and elected not to issue reports on the preliminary findings and recommendations. Bonneville did not issue the reports because Bonneville management did not want to become involved in the two utilities' rate-setting processes with regard to how the program's benefits would affect the utilities' rates. In addition, Bonneville officials told us that one of the utilities had been informed verbally of Bonneville's review results. Utility officials said, however, that they had not been provided the results.

According to Bonneville officials, they also decided not to conduct additional reviews of benefit pass-throughs to minimize their costs and to avoid raising issues that could negatively affect their relations with the utilities. Instead, they said that Bonneville has relied on (1) the contractual requirement that participating utilities pass rate relief benefits through to their residential and small farm customers and (2) the utilities' customers, public interest groups, and—in the case of investor-owned utilities—state regulatory commissions to ensure that benefits are passed through to residential and small farm customers.

Benefit Pass-Through Reviews by State Officials

We asked officials of state utility regulatory commissions in Oregon, Washington, and Idaho if they verify that investor-owned utilities pass through their rate relief benefits. Investor-owned utilities receive about 86 percent of the program's benefits. They said that they do review the benefit pass-throughs during the utilities' rate-setting process. Officials of all three state public utility commissions acknowledged, however, that their reviews are limited in that they do not test customers' bills to verify that the utility's rate structure actually provides customers with the correct amount of benefits.

The rate-setting process begins when an investor-owned utility submits a proposed rate change to its regulatory commission. The commission establishes the utility's revenue requirement—the amount the utility can collect from its customers to cover reasonable expenses and a return on the utility's investment. On the basis of the revenue requirement, the utility then establishes rates for each of its customer classes, such as its residential, industrial, commercial, and agricultural classes.

The utility also develops a special tariff for customers qualifying for the residential exchange program. These rate schedules and special tariffs are then reviewed by the state utility regulatory commission to ensure that an appropriate credit is being applied to residential and small farm customers. The utility then adjusts its residential and small farm customer bills according to the approved special tariff, which contains the credit for the rate relief benefit.

We found that the methods used to review benefit pass-throughs vary somewhat from state to state as follows:

- The Oregon Public Utility Commission reviews proposed rates and balancing accounts of two investor-owned utilities—Pacific Power and Light Company and Portland General Electric Company. According to the state employee responsible for reviewing the balancing accounts, the Pacific Power and Light account, which is reviewed annually, is straightforward and does not include an interest calculation, while the Portland General Electric account is reviewed quarterly because it is more complex, includes an interest calculation, and has many adjustments. The Commission detected only one minor problem during its reviews of the two balancing accounts. Specifically, Portland General Electric was inconsistent in its interest calculation on overpayment or underpayment of rate relief benefits. In 1987, the Commission sent a letter cautioning Portland General Electric to be consistent in calculating the interest due on the temporary use of funds when Bonneville makes a benefit overpayment or underpayment to the utility.
- The Washington Utility and Transportation Commission reviews the benefit pass-throughs of investor-owned utilities as part of the rate-filing process by reviewing the utilities' rate tariffs and balancing accounts. It does not request utilities to submit their balancing accounts annually or quarterly for review. An example of the Commission's monitoring of the investor-owned utilities involved a rate tariff submitted by Puget Sound Power and Light Company in 1987 to pass through about $7.5 million in rate relief benefits to its residential and small farm customers. In 1988, Puget Sound Power and Light informed the Commission that about $311,000 remained in its balancing account after the 1987 rate tariff had ended in 1988. Puget Sound Power and Light asked the

Commission whether the company could retain the $311,000 in its balancing account. The Commission did not agree and on July 1, 1988, instructed the utility to submit another rate tariff to pass the $311,000 through to the utility's residential and small farm customers.

- The Idaho Public Utility Commission reviews the benefit pass-throughs of investor-owned utilities as part of the rate-filing process. For example, the Commission questioned whether the credit on Utah Power and Light Company's customer bills covered the rate relief benefits received from Bonneville. Utah Power and Light provided the Commission with background data on the development of the credit and a 1989 estimate of the utility's balancing account showing a gradual pass-through of the existing benefits in the account. The Commission agreed that the utility's 1989 estimate was sufficient to pass through the benefits received from Bonneville. However, the Director, Utilities Division, stated that the Division had identified a deficiency in its monitoring of the program's rate relief benefits as a result of their discussions with GAO staff during this review. The Director further stated that, in the future, commission auditors will be required to audit utilities' balancing accounts whenever a general review or rate case audit is done on a utility participating in the exchange program.

The officials said they do not notify Bonneville of the results of their pass-through reviews even if a utility is not passing through benefits, because they believe it is their responsibility to ensure that the situation is corrected.

While the benefit pass-throughs of investor-owned utilities are reviewed by their state public utility commissions, no organizations review the pass-through efforts of municipalities, cooperatives, or public utility districts. This fact was confirmed in our discussions with officials of public utilities, as well as with officials from organizations representing utilities and consumer groups. These utilities accounted for about $195 million, or 14 percent, of the rate relief benefits received from the exchange program.

Bonneville Plans to Review Benefit Pass-Throughs

As a result of our discussions with Bonneville staff, Bonneville officials agreed that reviews of benefit pass-throughs should be performed. They drafted steps (dated May 3, 1989) for reviewing the utilities' procedures and controls over the receipt and disbursement of rate relief benefits. The draft procedures stated that pass-through reviews would be performed at all participating utilities once every 2 to 5 years.

However, our review of these draft procedures showed that additional steps are needed to ensure that the reviews are complete. The draft procedures did not include (1) steps for determining that the benefits are actually being passed through to residential and small farm customers, (2) a process for ensuring timely pass-through of benefits, and (3) coordination with the state utility regulatory commissions to ensure an exchange of the results of pass-through reviews between Bonneville and the commissions.

Conclusions

Bonneville cannot now assure the Congress that utilities participating in the exchange program are passing the appropriate amounts of rate relief benefits through to their residential and small farm customers as intended by the Northwest Power Act. While state utility commissions have reviewed whether some investor-owned utilities have passed through benefits, Bonneville has not determined whether the extent of these reviews is sufficient. Also, public utilities are not being reviewed. Bonneville needs to correct these conditions by implementing a review program.

Recommendations

We recommend that the Administrator, Bonneville, initiate benefit pass-through reviews of utilities that were and are now participants of the exchange program. Bonneville should include in its review procedures for (1) testing customer billings to ensure that the appropriate amounts of benefits are passed through to customers, (2) ensuring the timely pass-through of these benefits, and (3) coordinating Bonneville's reviews with those performed by state utility regulatory commissions. Bonneville could consider placing some reliance on state commissions' reviews. Before doing so, however, Bonneville should determine the adequacy of the commissions' reviews. In addition, we recommend that Bonneville inform the two public utilities—for which it conducted pilot benefit pass-through reviews—of the review results and follow up to ensure that issues raised in the reviews are resolved.

Agency Comments and GAO Evaluation

The Department of Energy (DOE), in commenting on a draft of our report (see app. III), stated that it agreed with the thrust of the report that the pass-through of benefits to utilities' residential and small farm customers should be monitored. DOE further stated that Bonneville started implementing benefit pass-through reviews in September 1989 that will help ensure the timely and accurate pass-through of benefits to eligible customers.

DOE provided the following specific information about Bonneville's plans:

- Bonneville has added a benefit pass-through component to its load review procedures;
- Utilities that are current program participants, as well as utilities whose contracts were purchased or mutually terminated, will be considered for review;
- Bonneville will work with utility commissions and elected governing bodies to address any apparent deficiencies; and
- Bonneville will take action to ensure that problems identified in its 1987 reviews of two public utilities are resolved.

We believe that the reviews Bonneville has initiated are appropriate steps that appear to be consistent with our recommendations. If fully implemented, these reviews should provide information Bonneville needs to assess whether benefit pass-throughs are taking place in a timely and appropriate manner.

The Department expressed concern that our recommendation appeared to require that Bonneville perform detailed reviews of utilities' retail rates and cost of service studies because, according to the Department, that is the only way to ensure that appropriate benefits are passed through to qualified customers. The Department further stated that efforts recently undertaken by Bonneville are effective and appropriate, whereas extensive retail rate reviews would not be cost-effective and would be inconsistent with, and unnecessarily duplicative of, existing regulatory oversight.

We do not envision the need for Bonneville to perform detailed utility rate reviews of utilities participating in the program. Our recommendation is directed at establishing a process by which Bonneville can determine whether benefit pass-throughs meet the requirements of the Northwest Power Act. Our recommendation is not intended to specify precisely how Bonneville should make its reviews. To the extent benefits provided to participating utilities are separately accounted for by those utilities, we do not envision a major review effort by Bonneville to determine that a timely pass-through occurs. On the other hand, if benefits are treated by participating utilities as one source of revenue among other sources, Bonneville's review efforts may need to be more extensive to make its determination. In either case, the results of Bonneville's review efforts should provide a sufficient basis for Bonneville to determine whether appropriate pass-throughs are occurring.

Utilities, State Regulatory Agencies, and Organizations Contacted by GAO

Utilities	Location
Central Electric Cooperative, Inc.	Redmond, OR
Clark County Public Utility District	Vancouver, WA
Consumers Power, Inc.	Philomath, OR
Idaho Power Company	Boise, ID
Lewis County Public Utility District	Chehalis, WA
Pacific Power and Light Company	Portland, OR
Portland General Electric Company	Portland, OR
Puget Sound Power and Light Company	Bellevue, WA
Snohomish County Public Utility District	Everett, WA
Utah Power and Light Company	Salt Lake City, UT
Washington Water and Power Company	Spokane, WA
State Regulatory Agencies	
Idaho Public Utilities Commission	Boise, ID
Oregon Public Utility Commission	Salem, OR
Washington Utilities and Transportation Commission	Olympia, WA
Organizations	
Direct Service Industries, Inc.	Portland, OR
Evergreen Legal Services	Seattle, WA
Idaho Citizens Network	Boise, ID
Idaho Legal Aid	Couer d'Alene, ID
League of Publicly Owned Electric Utilities of Oregon	Salem, OR
Oregon Farm Bureau Federation	Salem, OR
Oregon Public Utility District Association	Salem, OR
Oregon Rural Electric Cooperative Association	Salem, OR
Pacific Northwest Generating Company	Portland, OR
Pacific Northwest Power Planning Council	Portland, OR
Pacific Northwest Utilities Conference Committee	Portland, OR
Public Power Council	Portland, OR
Washington Industrial Customers for Fair Utility Rates	Portland, OR
Washington State Assistant Attorney General, Office of Public Involvement	Seattle, WA

Utilities That Have Participated in the Exchange Program

Active Participants

Benton Rural Electric Association
Blachly-Lane County Coop
Central Electric Coop Inc.
Clearwater Power Company
Consumers Power Inc.
Coos-Curry Electric Coop Inc.
Douglas Electric Coop Inc.
Fall River Rural Electric Coop Inc.
Harney Electric Coop Inc.
City of Idaho Falls
Lewis County Public Utility District
Lincoln Electric Coop
Lost River Electric Coop Inc.
Lower Valley Power and Light Company
Montana Power Company
Oregon Trail Electric Consumer's Coop
(assignment from CP National)
Pacific Power and Light Company
Portland General Electric Company
Puget Sound Power and Light Company
Raft River Rural Electric Association
Umatilla Electric Coop Association
Utah Power and Light Company

Suspensions

Ferry County Public Utility District No. 1
Idaho Power Company
Peninsula Light Company Inc.
Springfield Utility Board
Washington Water Power Company

Terminations

Montana Light and Power Company
City of Soda Springs

Buy-Outs

Clark County Public Utility District No. 1
Snohomish County Public Utility District No. 1
Clallam County Public Utility District No. 1
Flathead Electric Coop Inc.
Glacier Electric Coop Inc.
Grays Harbor County Public Utility District No. 1
Klickitat County Public Utility District No. 1

Orcas Power and Light Company
Prairie Power Coop Inc.
Salmon River Electric Coop
Vigilante Electric Coop Inc.

Department of Energy Comments

Department of Energy
Washington, DC 20585

October 23, 1989

Mr. Keith O. Fultz
Director, Energy Issues
Resources, Community, and
Economic Development Division
U.S. General Accounting Office
Washington, DC 20548

Dear Mr. Fultz:

The Department of Energy (DOE) appreciates the opportunity to review and comment on the General Accounting Office (GAO) draft report entitled Federal Electric Power: Bonneville's Residential Exchange Program (GAO/RCED-90-34). Minor editorial changes are enclosed. DOE hopes that the comments in this letter and the enclosure will assist GAO in their preparation of the final report.

The significant dollar amounts associated with this program required BPA to develop and maintain extensive internal controls and management systems to ensure that the exchange benefit payments made by BPA to public and investor-owned utilities (IOU) are proper and correct.

We are concerned about GAO's recommendation regarding BPA's role in reviewing the benefits passed through to residential and small farm customers by exchanging utilities. While we agree with the thrust of the report that benefit pass-through should be monitored, DOE does not concur with GAO's specific recommendations to the extent that we understand them to require that BPA perform extensive retail rate reviews. The only way to ensure that the appropriate amounts of benefits are passed through to qualified customers is to analyze the utilities' cost of service studies and retail rates. We believe that the changes that BPA has recently implemented to review benefit pass-through are effective and appropriate. DOE believes that GAO's recommendations would not be cost-effective and would be inconsistent with, and unnecessarily duplicative of, existing regulatory oversight of benefit pass-through.

As noted in GAO's draft report, 86 percent of total exchange program benefits have been paid to IOUs. IOUs are regulated by State public utility commissions (PUCs) which have oversight responsibility for retail rates. The PUCs have ordered corrective actions, when necessary, to ensure exchanging IOUs in their respective jurisdictions are passing through appropriate benefit amounts to eligible utility customers.

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The public utilities participating in the Residential Exchange Program have received 14 percent of total exchange benefits. While not generally regulated by State PUCs, these public utilities are nonprofit organizations regulated by elected officials who represent the interests of, and are accountable to, the utilities' ratepayers. Residential and small farm customers represent the largest constituency of these elected officials.

GAO concludes that, given the significant dollar amounts paid through the program (approximately $1.4 billion), further action must be taken by BPA to avoid potential problems in passing benefits through to eligible ratepayers, even though GAO's audit identified no particular utility discrepancies or improprieties in processing exchange benefits. GAO's findings did include a specific reference to the two pilot benefit pass-through reviews initiated by BPA staff in 1987, and recommended that BPA take followup action to resolve outstanding items.

BPA management concluded from these pilot reviews that apparent over and under payments were attributable to either startup problems, involved a question of timing of benefits, or were not materially significant in regard to total benefits paid. Based on these conclusions, and the fact that there was no statutory requirement for BPA audits of benefit pass-through, BPA decided not to undertake a formal, ongoing program to audit the pass-through of exchange benefits, and that no followup was necessary at that time on the two pilot exercises.

BPA does share, and has responded to, GAO's concerns by developing and implementing a benefit pass-through component to its existing load review procedures. BPA worked closely with GAO staff during their audit to assure that these reviews would be consistent with GAO's objectives. We believe this enhancement, coupled with the existing level of regulatory oversight, provides reasonable assurance that appropriate benefits are being received. This approach is cost-effective and documents the utility pass-through systems and procedures. BPA will share this information, and work with utility commissions and elected governing bodies to address any apparent deficiencies.

In addition, to assure the apparent problems with the results of the pilot reviews have been resolved, BPA will review the two subject utilities' benefit pass-through systems. This will be undertaken as part of BPA's load review program which is conducted on a 3-year cycle. The methodology for selecting utilities for review will include consideration of those utilities whose contracts have been purchased (bought out) by BPA or mutually terminated. BPA has initiated these reviews in September 1989.

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In summary, DOE shares GAO's concern that appropriate and effective controls must exist to ensure the timely and appropriate pass-through of benefits to eligible residential and small farm customers. To that end, BPA will continue to exercise its contractual rights in a cost-effective manner consistent with the intent of Congress and BPA's statutory obligations.

Sincerely,

For : Donna R. Fitzpatrick
Assistant Secretary
Management and Administration

Enclosure

Major Contributors to This Report

Resources, Community, and Economic Development Division, Washington, D.C.

John W. Sprague, Associate Director
Paul O. Grace, Assistant Director
Charles M. Adams, Assistant Director

Seattle Regional Office

Laurence L. Feltz, Regional Assignment Manager
Robert B. Arthur, Evaluator-in-Charge
Janet L. George, Evaluator

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