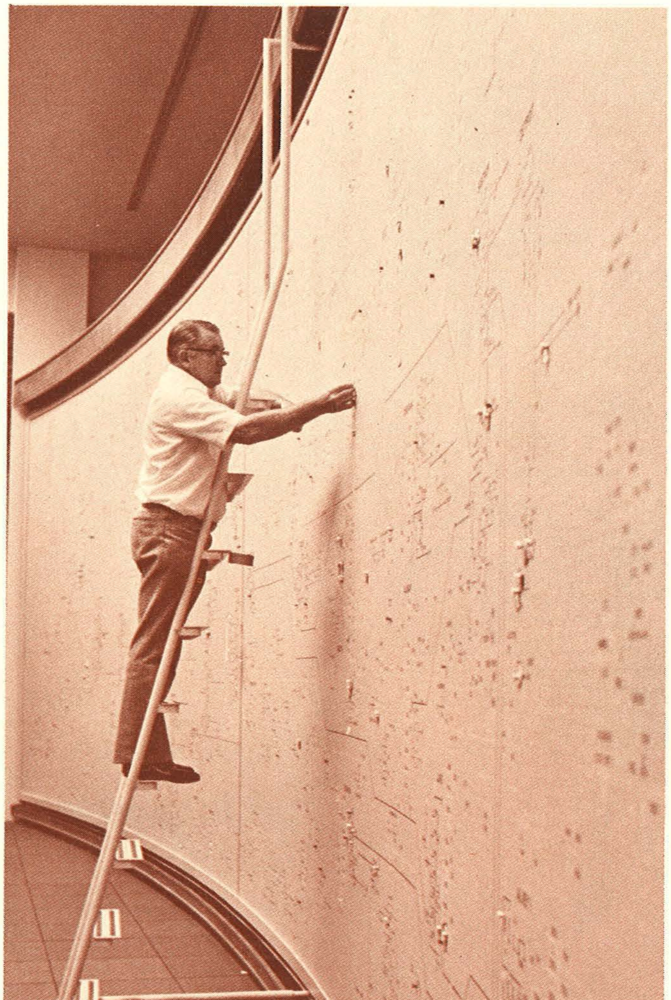
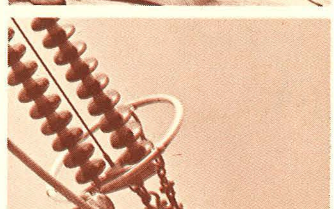
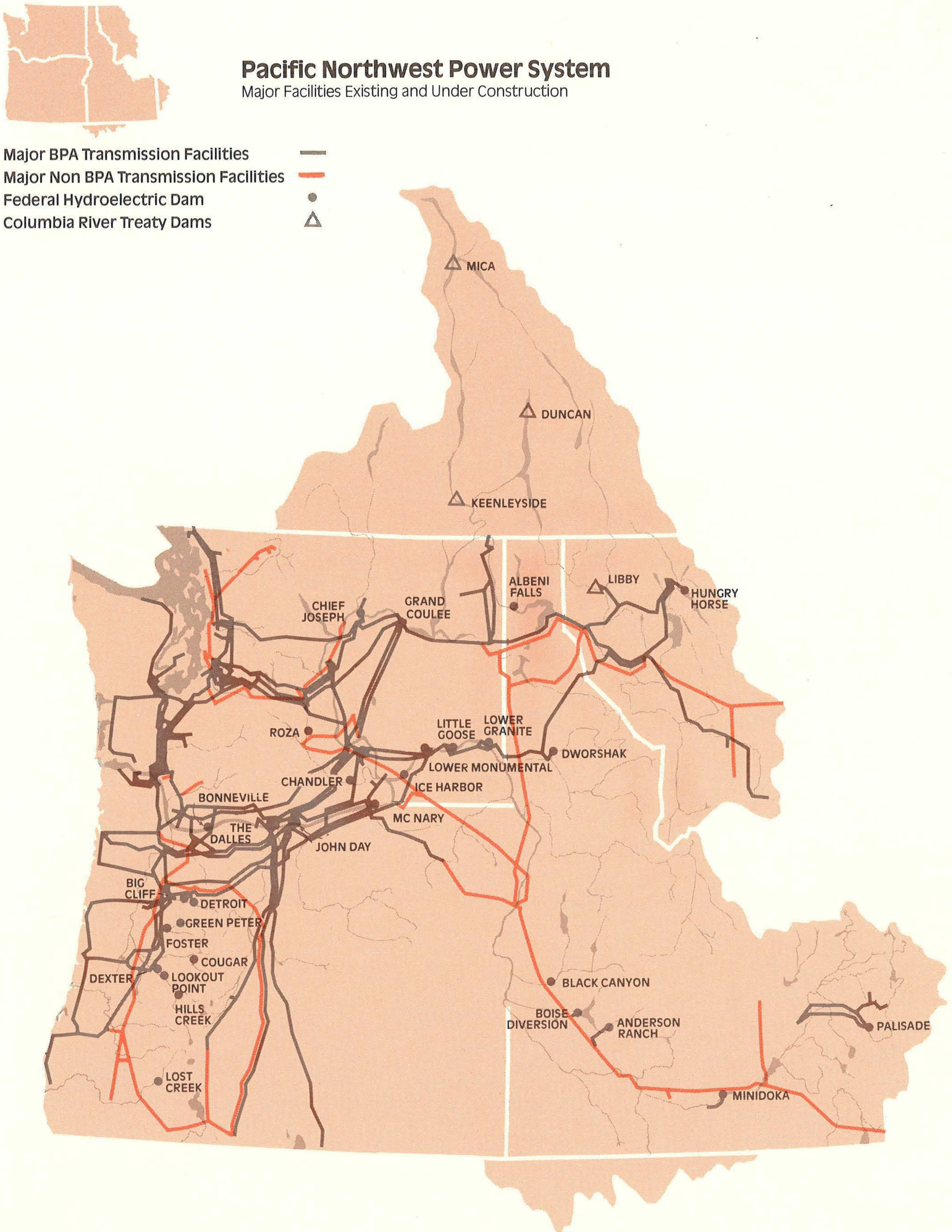
1978 Annual Report
U.S. Department of Energy
Bonneville Power Administration

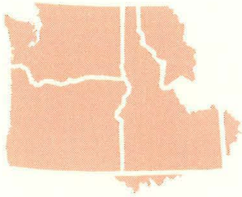





Pacific Northwest Power System

Major Facilities Existing and Under Construction





1978 Annual Report

Federal Columbia River Power System

U.S. Department of Energy
James R. Schlesinger
Secretary

Bonneville Power Administration
Sterling Munro
Administrator

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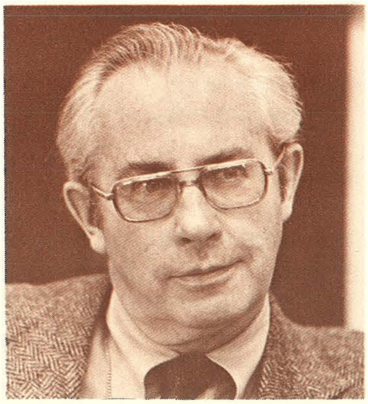
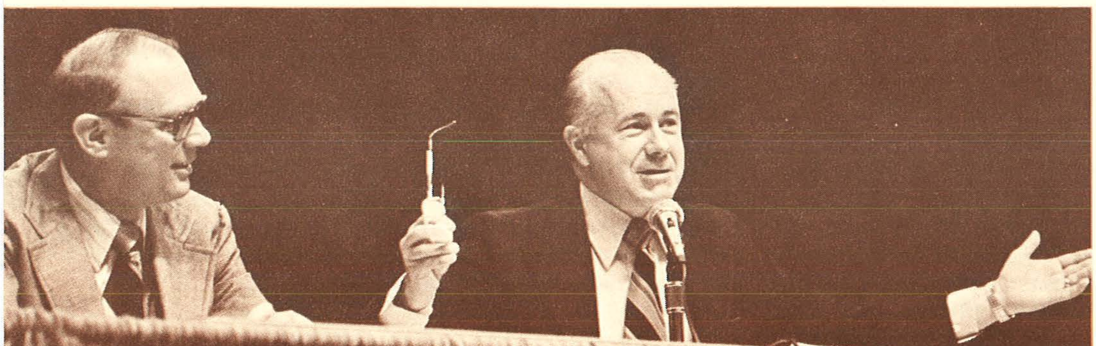
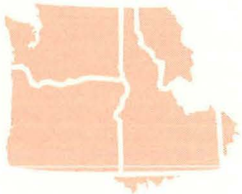




Left to right, top row: Assistant Secretary McIsaac, Under Secretary Myers, Deputy Secretary O'Leary.
Below: Deputy Administrator Foleen and Administrator Munro

Above:
Secretary Schlesinger



Letter to the Secretary

January 2, 1979

Honorable James R. Schlesinger
Secretary of Energy
Washington, D.C. 20545

Dear Mr. Secretary:

This 41st Annual Report of the Bonneville Power Administration underscores the reason for BPA's existence — to help our customers serve the public.

Most of our customers are public utility districts and municipals and cooperatives who have preference rights to Federal power and who in turn serve the homes, farms, businesses, and factories of the region. We also sell directly to 17 large industries and six Federal agencies, and provide large amounts of peaking and non-firm power and wheeling services to investor-owned utilities.

If we cannot supply the needs of our utility customers, then their customers — residential, farm, commercial and industrial — will be faced with more severe problems of supply and price. If our transmission lines fail, they go without power. If we don't stay abreast of technology, the consumer pays in the end. And if we can't pay our way, the whole Federal power program that has helped the region grow and prosper is threatened.

So you will find in this 41st Annual Report, which comes at the end of my first year as Administrator, emphasis on those things that may most affect our ability to help our customers help the region's consumers:

- *The proposed regional power bill, which was endorsed, with amendments, by the Department of Energy.*
- *The environmental impact statement — called the "Role EIS"— that is now nearing completion and which relates to BPA's future role in the region.*
- *The new Public Participation Procedure that we have adopted to assure public access and involvement in the making of all major BPA policies.*
- *System reliability.*
- *Forecasting.*
- *Research and development.*
- *Conservation.*
- *Financial solvency.*

As for financial matters, there was a mix of good and bad financial news in Fiscal Year 1978. Although we recorded a net loss for the second consecutive year, on a cumulative basis the Federal Columbia River Power System (FCRPS) was $312 million in the black at the end of FY 1978. After the drought which contributed heavily to a record loss of $55.9 million in 1977, streamflows were sufficient to refill the Northwest reservoirs in 1978 and to permit the sale of substantial amounts of power outside the region. This produced revenue totaling $334 million, some $110 million greater than in FY 1977. Still, because we have been tied to a five-year rate review period and rates established in 1974 are not sufficient to pay the higher costs of today, we had a deficit of some $17 million in FY 1978.

The repayment figures on page 38 show even more dramatically than the cost accounting figures the need for a substantial rate increase at the earliest date by which we are permitted to adjust rates, which is December 1979.

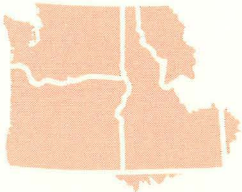
However, it is not certain that Bonneville revenues will have to be increased by the 90 percent we announced August 25 for the period December 1979-July 1981 in order to wipe out the deficits and meet all our obligations. This is because we may be able to postpone our payment of debt service on one nuclear power plant now under construction until it actually comes on line, and maybe two. The constructing agency, the Washington Public Power Supply System (WPPSS) has indicated willingness to consider issuing separate bonds to finance the debt service for one or more of the three plants involved until start up. That would enable BPA to defer including the costs of these facilities in the FCRPS repayment schedule. BPA and WPPSS are studying this financial alternative to make certain the short-term benefits to the region's ratepayers would not be overshadowed by higher costs in the longer term. We expect to reach a decision early in 1979.

The long-range electric power supply outlook for the region remains "iffy." Conservation is the only way we know to make supplies of existing low-cost Federal power go further. Of the 13 thermal projects either under construction or scheduled in the region between now and 1989, 11 have slipped further behind schedule in the past year, and only two remain on the schedule forseen in 1977 which had already reflected slippage from earlier years. According to utility forecasts, the region continues to face potential electric energy shortages in any year between now and 1990 in which critical water conditions occur and, of course, there is nothing presently scheduled for 1990 or beyond. This situation focuses attention on the conservation and new supply aspects of the regional power bill that sponsors say will be reintroduced early in the new Congress.

Clearly, new conditions require new solutions for the region's power supply. If BPA is to be a more effective part of the new solutions, the regional power bill or some reasonable facsimile must be passed. We appreciate your continued support in the region's efforts to assure meeting future needs in a manner consistent with the nation's energy goals and policies.

Sincerely,

Sterling Munro



The Region's Power Future

Being Shaped Now

The region's power future, and BPA's role in it, are being shaped now.

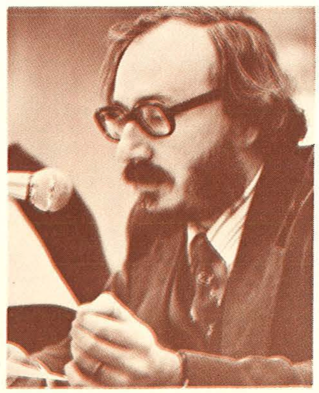
Both are being shaped in the halls of Congress, in the capitols of the Northwest states, in the region's city halls, and in the councils of utility, environmental, business and other interest groups. Congressional sponsors have said they will reintroduce early in the 1979 session the same or an amended version of the regional power bill that was before the last Congress. It was called the "Pacific Northwest Electric Power Planning and Conservation Act," and bore the number S.3418 in the Senate and H.R. 13931 in the House. Meanwhile, the States and local governments and the interest groups are working on perfecting amendments.

BPA's role in the region's power future is also being shaped in the form of the "Role EIS" and subsequent environmental impact statements that will have to be done relative to specific energy resources. The basic "Role EIS" has been four years in the making and now is expected to be issued in final form early in 1979.

The Regional Bill

The regional power bill, sponsored last year by almost all members of the Northwest Congressional delegation, is intended to assure the region of adequate power supplies in the future, at the lowest costs possible. The bill would assign broader power marketing responsibility and authority to BPA, and provide for full participation of the states and interested parties in the big power decisions to be made. It takes the view that a kilowatthour saved through conservation is the best new kilowatthour, but it also provides for a mix of other new resources to the extent required along with conservation to meet the region's future needs. The region's planners would be required to give top priority to cost-effective and feasible conservation. Then, in planning new generation, priority would go to projects utilizing the sun and wind and other renewable resources and cogeneration before nuclear or other conventional generation would be included in the mix.

Preference customers would continue to come first — and always first — in their claim on Federal power. BPA also would be authorized to enter into new long-term contracts with the industries we now serve, but only at substantially higher rates, and to acquire power for investor-owned utilities so long as preference customer requirements were met first. In exchange for long-term contracts, the industries would give up their present contracts for low-cost Federal power, which expire one by one between 1981 and 1991. The low-cost power relinquished by the industries and not required to serve preference customers would become available to the residential and farm



Congressmen Weaver, Meeds and Duncan
Subcommittee Counsel Potter and Congressman Dingell

Witnesses at Seattle hearings on the regional power bill customers of the region's investor-owned utilities through exchanges of power; the benefits would go to these consumers and not the utilities.

The bill with these and other provisions was introduced in August as an outgrowth of hearings on different regional power bills developed earlier by the Pacific Northwest Utilities Conference Committee (PNUCC) and Representative Weaver of Oregon. Hearings on S.3418 and H.R. 13931 were held during the fall by Senator Henry M. Jackson's Senate Energy Committee, Congressman Lloyd Meeds' Water and Power Subcommittee of the House Committee on Interior and Insular Affairs, and Congressman John Dingell's Energy and Power Subcommittee of the House Committee on Interstate and Foreign Commerce. The Dingell Committee also held hearings in Idaho, Washington, and Oregon in December. A scheduled hearing in Montana had to be canceled because of transportation problems.

The Department of Energy and BPA generally supported the basic proposals in the bill, but offered a number of perfecting amendments. Altogether, the 1978 hearings in the House and Senate produced some 200 proposed amendments. There were indications that many of the proposed changes would be favorably received in the new Congress.

The Role EIS

The Draft Role EIS containing a proposed role for BPA and a range of alternatives was placed before the region for public review in the fall of 1977 and produced considerable public comment. More than 6,000 individual comments were contained in some 500 letters and the transcripts of 13 public meetings. All have been considered in preparation of the Final Role EIS that is expected to be issued early in 1979.

In particular, the Final Role EIS will reflect the many comments relative to conservation, and the growing recognition of conservation as a resource to be treated on par with other power resources in meeting future demand for electricity.

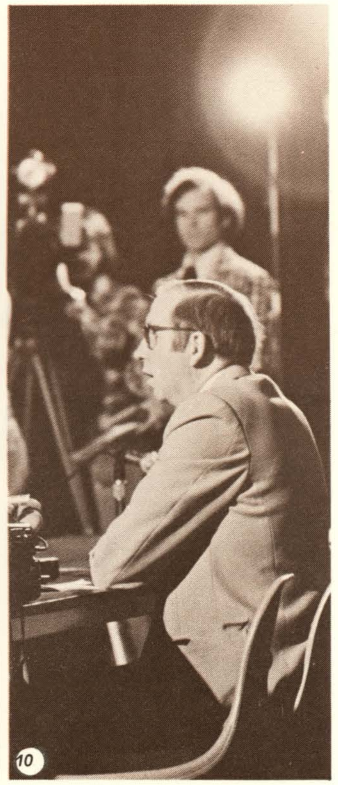
The Final Role EIS also will take into account a number of significant events that have occurred since the public review of the Draft, especially passage of the National Energy Act and completion of the Northwest Energy Policy Project (NEPP) study of the region's energy picture.

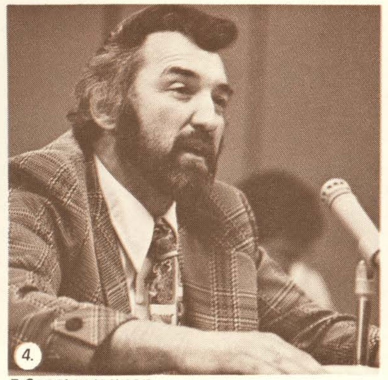
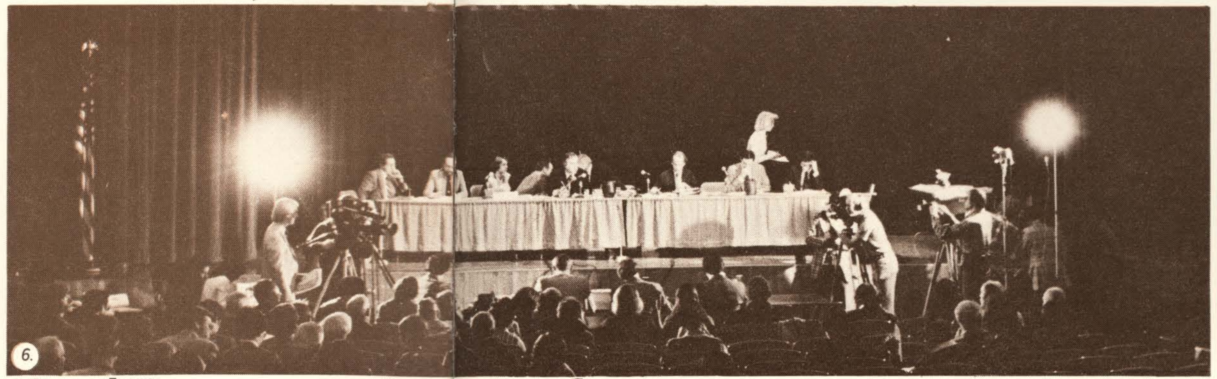
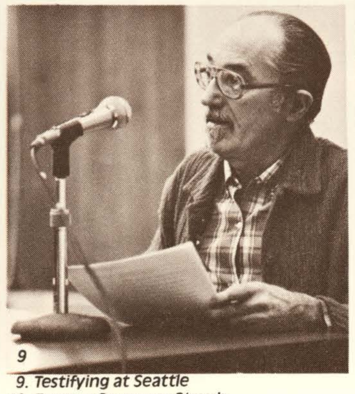
The Final Role EIS will have a different format, and be much shorter than the Draft. It describes alternatives including what BPA can do within existing authority and what would require new legislation. The Final Role EIS will not exceed 300 pages, the limit on environmental impact statements under new regulations adopted by the Council on Environmental Quality (CEQ). Many of the comments we received on the Draft had criticized its 3200 page length.

The Final Role EIS should be ready for transmittal to the Department of Energy by the end of March for filing with the Environmental Protection Agency (EPA) and subsequent distribution to the public. It will help shape the region's power future and BPA's role in it, and it will set the stage for future environmental impact statements relating to any BPA involvement in specific resources.





1. Congressman McCormack
2. Witness at Seattle hearing

3. Senator Jackson
4. Witness at Boise

5. Governor Evans
6. Portland hearings

7. Governor Ray
8. Attentive audience at Portland hearings

9. Testifying at Seattle
10. Former Governor Straub

Public Involvement

First Use

In 1978, we put to use for the first time our new Procedure for Public Participation in the formulation of major policies. The first use was in connection with rates. We also started the process in connection with power allocations and conservation.

We had proposed the procedure, and the Department of Energy had approved it, in 1977, as a way to provide interest groups and individual members of the public a meaningful opportunity to have a say in the making of Bonneville policies that affect them.

It requires that we publish in the Federal Register an official Notice of Intent whenever we plan to adopt or change a major marketing policy. The Notice of Intent provides a period of time for initial public comment prior to formulation and publication in the Federal Register of a specific proposal. Information forums and formal public comment forums at convenient locations around the region follow. We then evaluate the comments and modify the proposed policy before publishing it again in the Federal Register, with an opportunity for further public comment before we adopt the final policy.

Rates

Our formal Notice of Intent with respect to adopting new rates was published in the Federal Register January 18, 1978, and the specific proposal appeared in the Federal Register on August 25, allowing until November 30 for comments.

We conducted a series of eight information forums throughout the region during September followed by eight formal public comment forums in November. These forums resulted in approximately 300 specific comments that are being evaluated as we move toward adoption of new rates that will take effect December 20, 1979.

A more complete discussion of our rate proposals appears in the Financial Section, on page 32.

Allocations

Right on the heels of the Notice of Intent with respect to rates, on January 26 we published the required formal notice of our intent to develop a formula for allocating the limited supply of energy available to BPA. As noted in prior annual reports, we have given our preference customers advance Notice of Insufficiency stating that as of July 1, 1983, their supply from BPA would have to be limited to an allocation specified in their contracts. We also have had to tell our direct-service industrial customers that we cannot renew their contracts as they expire, one by one, between 1981 and 1991. And we did not renew our firm energy contracts with investor-owned utilities when they expired in mid-1973.

The public pays attention to power issues

The allocation formula contained in our present contracts with preference customers does not include a method for allocating energy which will be available when current contracts with direct-service industrial customers expire in the 1980s or when preference customer contracts expire. Further, BPA is receiving applications for power from existing and newly formed public bodies and cooperatives that are not now our customers, and these applications will have to be considered.

Following the Notice of Intent, we received about 120 comments containing suggestions for specific allocations proposals. We are considering these and others in developing our proposals for publication in the Federal Register in the spring of 1979. Our target date for adoption of a new allocations policy is mid-1980.

Conservation

On March 29, we published in the Federal Register our formal Notice of Intent to adopt a new conservation policy, and received about 75 letters of comment.

Many of the comments urged us to move faster with our conservation program, and we have concluded it would enable us to do so if we were to present our conservation options as part of the Final Role EIS, which is nearing completion. Much of the public input related to conservation.

Meanwhile, as part of our effort to strengthen our conservation program we have established a new Conservation Section within the Branch of Power Resources.

BPA official leads discussion

Power Operations

Lingering Effects

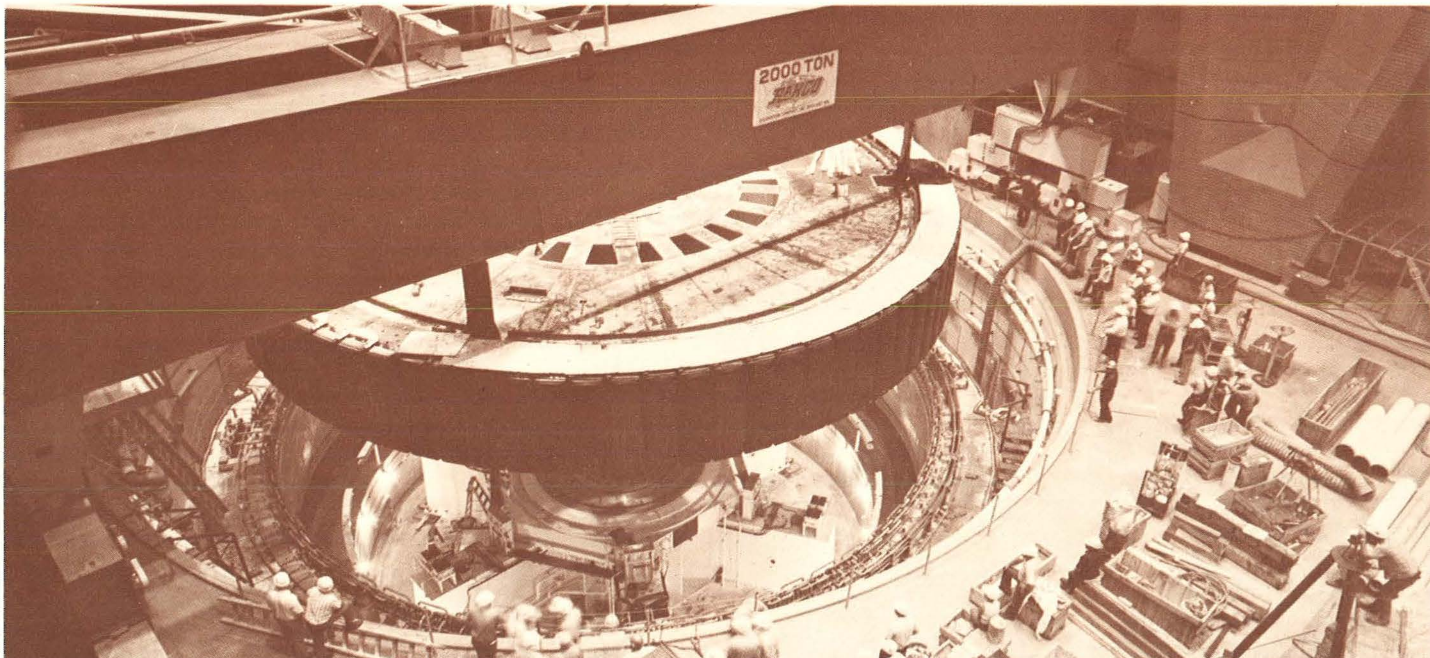
The 1977-78 operating year (July 1, 1977-June 30, 1978) began under the lingering effects of the 1976-77 drought in the Pacific Northwest. Consequently, by the end of July 1977, when power reservoirs would normally have been full for the beginning of the storage drawdown period, reservoirs were about one-third short of water, equivalent to about 14 billion kilowatthours of hydroelectric energy.

The drought broke late in the fall of 1977. There was a substantial snowpack buildup and improved streamflow patterns prevailed in the Northwest throughout the remainder of the 1977-78 operating year. Early in December, the region's major utilities and BPA were able to rescind their call for voluntary curtailment of electric energy use issued the previous February; and by the end of December, reservoirs had recovered by more than 30 percent from the storage deficiency at the end of July 1977.

In January 1978, BPA restored partial secondary energy deliveries to all of its Pacific Northwest customers, and in March increased its deliveries to serve the total Northwest secondary energy requirements. Deliveries of surplus energy to markets outside the Pacific Northwest area, which had been discontinued on September 13, 1976, were resumed by BPA on April 2. Curtailment of secondary energy deliveries to private utilities and BPA industrial customers had been in effect since November 1, 1976, and to public agencies since December 1, 1976.

The 1978 January 1-July 31 volume runoff of the Columbia River as measured at The Dalles, Oregon, was 105.1 million acre-feet, or 95 percent of the 1958-72 average. All major reservoirs were full on July 31, 1978, except Mica which filled during the first half of August. To assure its refill, BPA and the region's utilities had arranged to store additional water in Mica. As it turned out, Mica would have refilled without the special arrangements, but most of the stored energy was returned by BC Hydro later in August and this energy was usable in Pacific Northwest loads.

Heavy rainfalls in September caused a temporary surplus condition, and water that could not be stored was used to produce electricity for sale to California. But from late October to year's end we had to carry part of our industrial customers' load with "advance energy" deliveries. If the reservoirs run low in 1979, the industries will have to buy the same amount of power elsewhere and return it to us or curtail load. But if snowpack as measured in January turns out to be good, we would be able to resume secondary energy sales to industry. Meanwhile, the obligation to return "advance energy" remains until the reservoirs refill or are operated for flood control purposes.



Vandalism target: one of the giant new generators at Grand Coulee Dam

Trojan and PGE

We also "advanced" energy to Portland General Electric in the latter part of 1978, to help offset that company's loss of energy due to the continued shutdown of its Trojan nuclear plant. PGE must return this energy to BPA next spring, unless it appears the reservoirs will refill without it.

The Trojan plant had gone down during mid-March for its first annual refueling and maintenance. The plant was ready to return to service in May, but operation was further delayed when it was determined that control house walls did not meet Nuclear Regulatory Commission (NRC) standards. On December 22, the NRC's Atomic Safety and Licensing Board decided to permit resumption of operations while repairs are being made.

The Outlook

Each spring we plan the Federal Columbia River Power System (FCRPS) operations assuming critical water conditions for each of the next four years. "Critical" means the minimum streamflows that we anticipate, based on historical streamflow records.

Our 1978 studies show that we will be 183 average megawatts short of needs for firm energy loads during the current four-year critical period. However, we have contract rights to restrict firm power deliveries to our direct service industrial customers by amounts sufficient to cover the projected shortage under adverse water conditions.

The outlook for the 1978-79 operating year was based upon BPA receiving its share of Trojan generation. Because the outlook for Trojan power was questionable by June 1978, we withdrew from our industrial customers their share of the 1978-79 Hanford Project generation, as permitted by contracts. For the full year, the estimated cost of Hanford power is \$22 to \$27 million on top of the fixed costs we must pay for Trojan whether it operates or not. If Trojan returns to service soon, or if snowpack indicates reservoirs will refill in 1979, we would sell the Hanford energy to the industries or outside the region on a recallable basis.

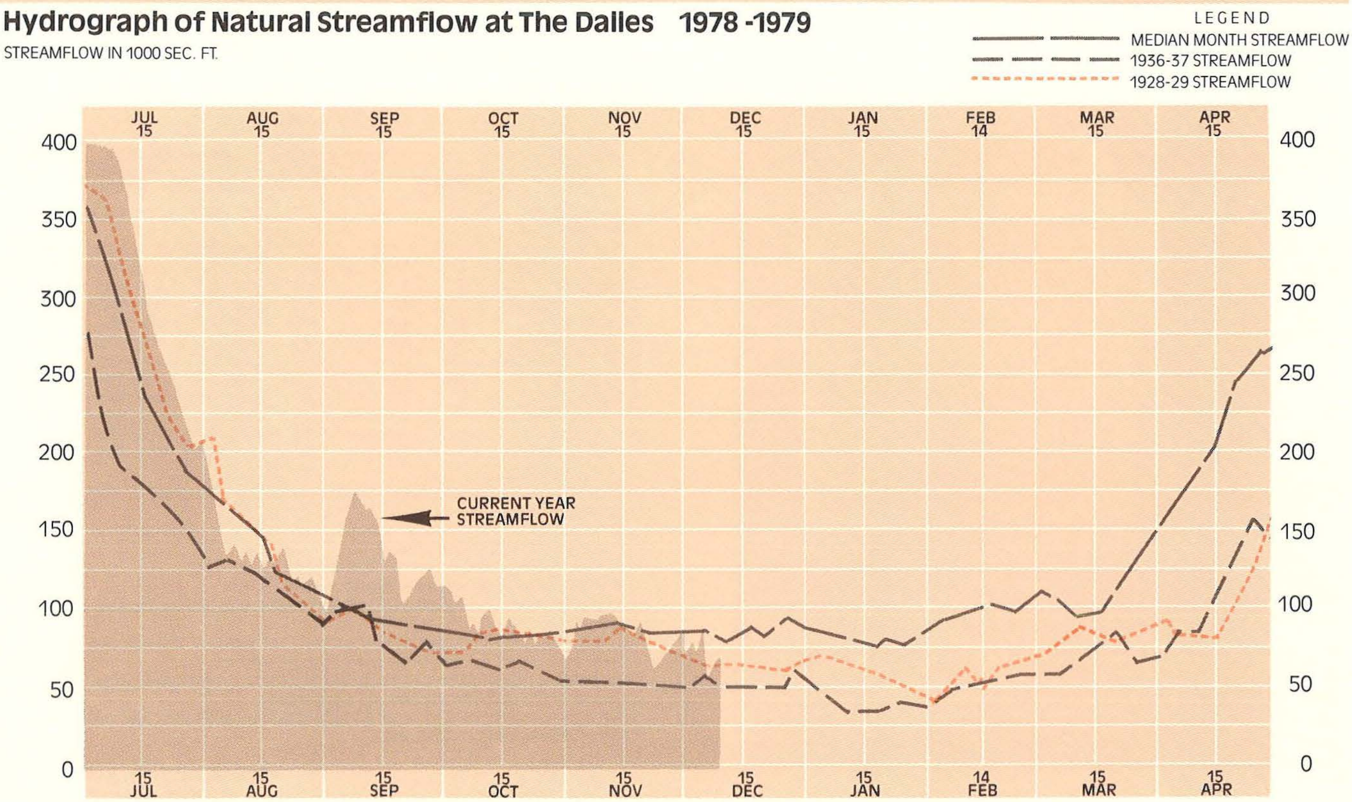
Troubles at Grand Coulee

Three new generators at the Grand Coulee Third Powerhouse were damaged in October 1978 by a person or persons who used a sharp instrument to gouge deep into 19 coils. The FBI is investigating the vandalism.

The massive machines, each 61 feet in diameter, are thought to be the largest hydro generators in the world. One had been in service for several weeks and was shut down for maintenance when it was damaged. Another was due to go into service in December.

Hydrograph of Natural Streamflow at The Dalles 1978-1979

STREAMFLOW IN 1000 SEC. FT.



The third was scheduled for operation in mid-1979.

Bureau of Reclamation officials estimated it will cost about $180,000 to repair each of the generators. The generators are expected to be out of service for about three months. Inasmuch as they were planned for use as peaking units, we may or may not be able to meet peak loads without them during the repair period, depending on weather conditions. If we were required to purchase power from other utilities to meet peak demand on extremely cold days, it could cost BPA — and the region's ratepayers — as much as $1.5 million during the repair period.

Meanwhile, a river bank instability problem extending six miles downstream from Grand Coulee Dam has been identified which limits operations of the dam for peaking purposes whenever more than four of the six Third Powerhouse units at Grand Coulee are in operation. The restriction is in the form of tailwater limitations, reducing the amount of water that may be released through the turbine-generators to produce power during peak hours.

Until remedial action can be taken by the Bureau of Reclamation, Grand Coulee's peaking capability will be reduced by about 1.5 million kilowatts or nearly one-fourth of the project's capacity.

Thermostat turn-off—
Conservation turn-on

Peaking Problems

The Grand Coulee operating limitations, construction delays for new thermal plants, and other operating problems associated with a new look at the nature and duration of the region's daily peaks, affect the region's peaking capability. The other operating problems include inability of reservoirs to supply sufficient water to downstream dams — especially on the lower Snake River — to sustain peaking operations, and restrictions associated with fish runs and navigation and recreation.

All of these factors together are expected to leave the region with shortages of peaking power in at least 5 of the next 10 years and reduce the cushion we once thought the region had. New PNUCC load-resource studies to be completed by March 1979 will tell us more.

As for the nature of peak loads, for years we have been doing regional planning on the basis of the highest instantaneous peak demand, without regard for duration. However, we have become increasingly aware of the importance of duration of high use as well as the instantaneous or single "spike" peak. Our studies show that loads remain very high for 10 or more hours on peak days of the year, usually cold winter days when people turn up the heat in the morning and leave it on all day. Consequently, for planning purposes, we have adopted a 10-hour peak.

Installation Schedule for Thermal Power Projects

79 West Group Forecast

	Status[1]	Type or Fuel	Name-plate Rating Mega-watts	Operation Date Scheduled	Operation Date Probable Energy	Principal Sponsor[2]
Jim Bridger #4	UC	Coal	333[4]	Dec. 1979	Dec. 1979	PPL
Boardman Coal (Carty)	UC	Coal	477[5]	July 1980	Nov. 1980	PGE
WNP #2 - Hanford	UC	Nuclear	1100	Sept. 1981	Sept. 1981	WPPSS
Colstrip #3	C	Coal	420[3]	July 1983	July 1983	PSPL
WNP #1 - Hanford	UC	Nuclear	1250[6]	Dec. 1983	Dec. 1983	WPPSS
Colstrip #4	C	Coal	420[3]	May 1984	May 1984	PSPL
WNP #3 - Satsop	LWA	Nuclear	1240	Dec. 1984	Mar. 1985	WPPSS
WNP #4 - Hanford	LWA	Nuclear	1250[6]	June 1985	June 1985	WPPSS
WNP #5 - Satsop	LWA	Nuclear	1240	June 1986	June 1986	WPPSS
Skagit #1	C	Nuclear	1288	Sept. 1986	Nov. 1986	PSPL
Pebble Springs #1	C	Nuclear	1260	Mar. 1987	Mar. 1987	PGE
Skagit #2	C	Nuclear	1288	Sept. 1988	Nov. 1988	PSPL
Pebble Springs #2	C	Nuclear	1260	Apr. 1989	Apr. 1989	PGE

[1]UC - Under Construction; LWA -- Limited Work Authorization; C - Committed
[2]Abbreviations are:
PPL - Pacific Power & Light Co.
PGE - Portland General Electric Co.
PSPL - Puget Sound Power & Light Co.
WPPSS - Washington Public Power Supply System
[3]Colstrip Units #3 and #4 are rated 700 MW each; 60% will be used by West Group Area.
[4]Jim Bridger Unit #4 is rated at 500 MW and two-thirds of the unit will be Pacific Power and Light Co.'s share for their East Group Area.
[5]Boardman is rated 530 MW and 90% will be used by West Group Area. The remaining 10% will be Idaho Power Co.'s share.
[6]WNP #1 and #4 are initially rated at 1220 MW. After their first fuel cycle, their ratings will increase to 1250 MW.

BPA - Branch of Power Resources

The new forecasts show not only a potential need for imports of winter peaking power during the next five years — if it can be obtained — but also a future need for additional peaking units earlier than we had previously foreseen.

Intertie Upgrade

In recent years we have been studying three methods for adding to our present intertie capability with California and the Pacific Southwest. In 1978 we decided to include in our FY 1980 budget funds to upgrade the capability of the existing d-c line.

Uncertainties in estimating delays in bringing new generating projects on the line in the Pacific Northwest greatly complicate the analysis of transactions on existing and proposed lines. But there are times — particularly during the spring and summer — when our region has more surplus power available for sale outside the region than existing interties can carry. During these periods of high river flows the water cannot be stored for later use and economic benefits of additional sales and savings in line losses at such times justified adding capacity to the existing d-c line.

The other two alternatives — still under study as to economic benefits and possible later implementation — are to build a third a-c line to California and to construct the second d-c line to Nevada and Arizona. The latter was part of the original intertie proposal approved by the Congress in 1964.

Other than still larger sales of surplus power, additional benefits that might justify either or both of the new lines relate to the potential for saving capacity requirements in both regions by pooling reserves and by exchanges of Northwest summertime surplus capacity for Southwest surplus wintertime capacity.

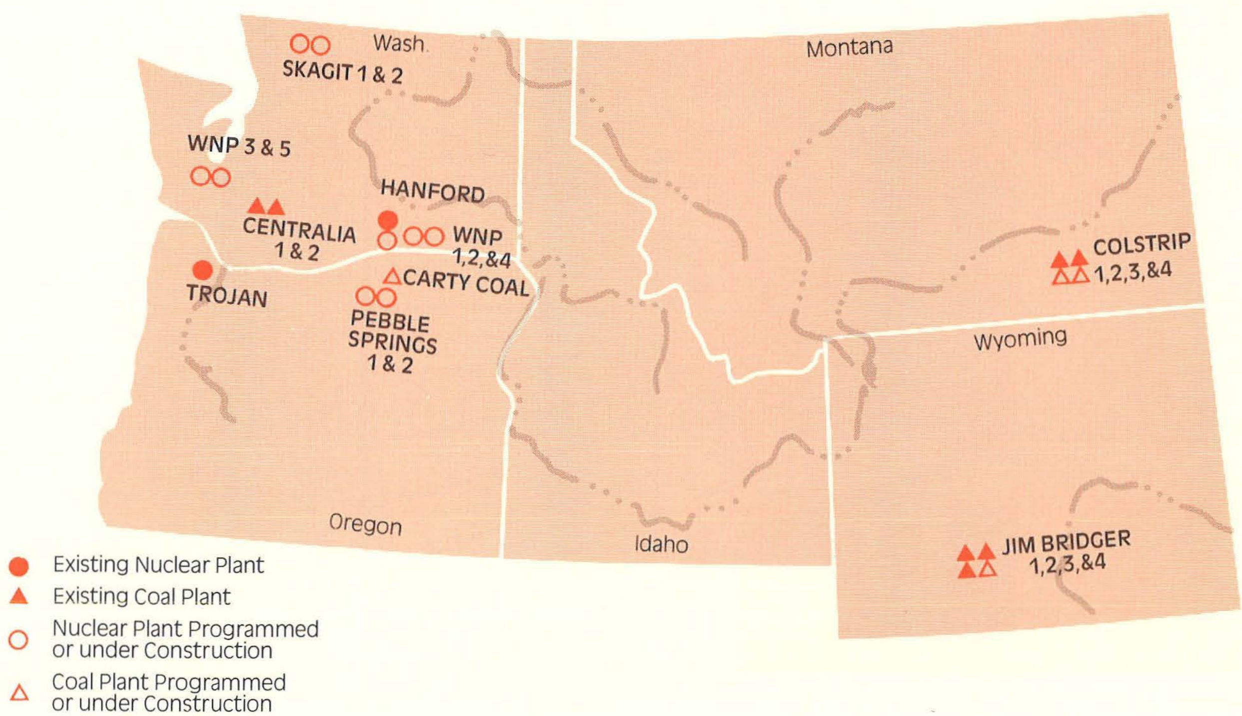
A Forecasting First

Here in the Northwest — for the first time anywhere in the United States, to the best of our knowledge — the input of non-utility representatives has been sought along with that of utility experts in developing a test of the reasonableness of the utility industry's upcoming forecast of regional power needs. The test of reasonableness involves preparation of an econometric model forecast and comparison of it with the official forecast for the region.

The official forecast is not related to the model and instead is a summation of the individual utilities' forecasts for their own service territories. It is published each year by the PNUCC in two forms: a "Black Book" in February looking 10 years ahead and a "Blue Book" a month or two later looking 20 years ahead.

The use of an econometric model against which to

Pacific N.W. Thermal Plants



test the official forecast began three years ago, but broad input of non-utility representatives was not especially sought. However, in preparation of input data for the model that will be summarized in next year's "Black Book" forecasts and published separately, as well, the PNUCC subcommittee responsible for preparation of the model decided to actively seek out public participation, and non-utility views.

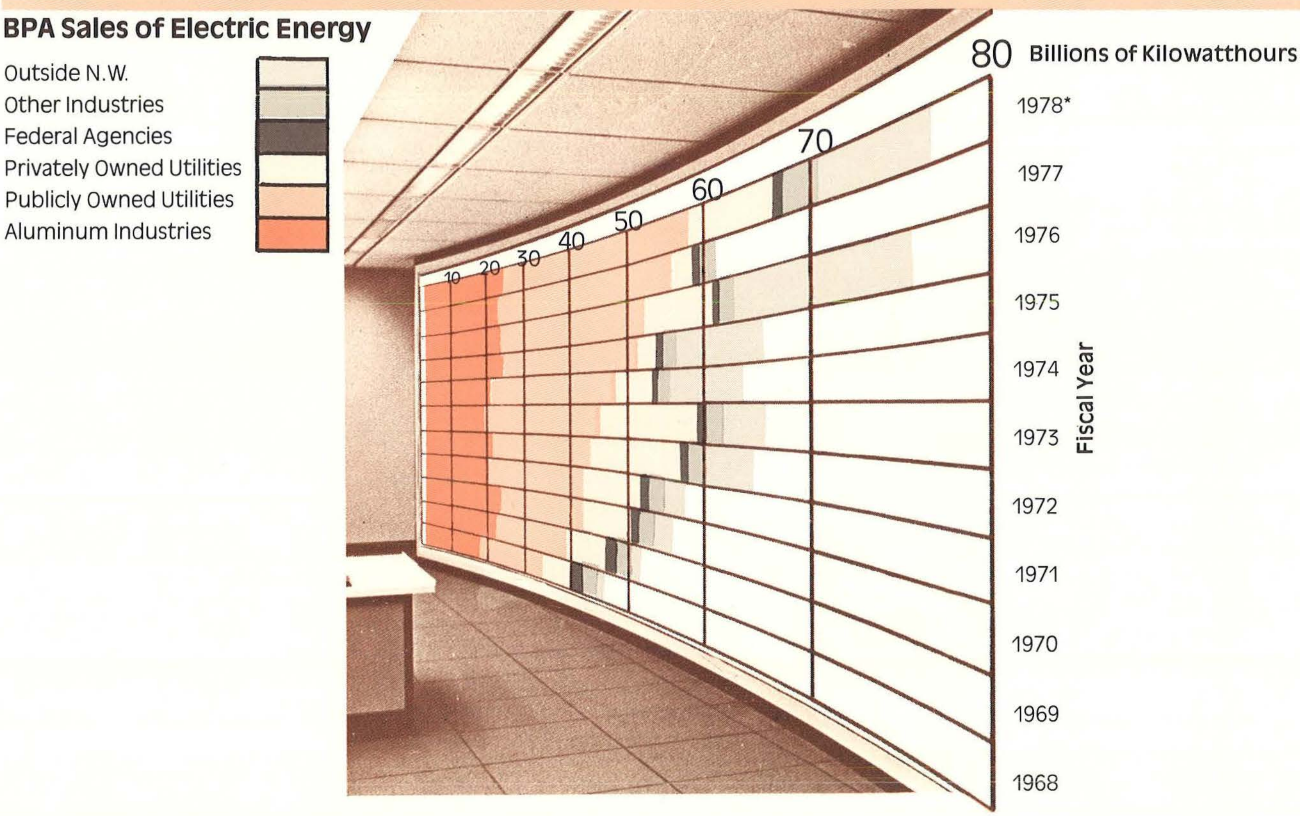
So on September 14 and 15, in the Portland State University ballroom, there were assembled in a "Delphi" workshop 56 persons, about half representing utilities and the other half the Northwest States, universities, business and other interested groups. They listened to expert presentations and panel discussions as to future population, residential conservation, oil and natural gas prices, income growth and other variables that are being used in the model forecast, and they asked their own questions. Then they voted on what they believed should be the major input assumptions. Each of the participants' votes counted equally.

We must await results from the new input to the econometric model to see to what extent it differs from the first two, which tended to corroborate the official forecasts in those years. In recent years, each forecast has predicted lower future requirements than the preceding year's forecast. We also must wait until February to learn whether the official forecast will differ significantly from last year's, which showed a firm energy deficit every year in the next 10 should critical water conditions occur. The utilities' own forecasts, of course, take into account population growth, past energy use, business trends within each utility's service territory, and other socio-economic conditions.

Helping prepare the econometric model is one of three ways in which BPA works with PNUCC and others making cooperative load forecasts. A second way is the help provided by BPA's Area Economists to many of the region's public bodies and coops in preparing their system forecasts. The third way is to act as the clearinghouse for PNUCC utilities in summing up all of the utilities' individual forecasts into a regional, or "West Group," forecast.

To help further, BPA moved in 1978 to develop with PNUCC and the energy offices of the four Northwest states and other interests a cooperatively designed end-use energy consumption data base. It would be used both as a benchmark against which to measure energy conservation and to aid in forecasting. The joint project will give all parties a common source of information, minimize costs, and maximize the usefulness and compatibility of the data acquired.

BPA Sales of Electric Energy



Power Sales

A return of better water conditions after a year of drought brought a dramatic 24 percent increase in BPA sales for FY 1978 over 1977. But sales totaling 76.5 billion kilowatthours were about 1 percent below the record high of FY 1976, an extremely good water year. With the interties in use, sales vary with the amount of surplus and non-firm energy available, and no longer follow the pattern for the prior decade when sales were increasing on an average of 7 percent annually.

Total energy sales for FY 1978 were 76,517,682,000 kilowatthours, an increase of 23.9 percent over the 61,746,026,000 kilowatthours sold in FY 1977. Average revenue from all sales was 3.27 mills per kilowatthour, compared with the average rate of 3.24 in the previous year.

BPA preference customers, composed of municipalities, cooperatives, and public and people's utility districts, purchased the largest amount of power, accounting for 44 percent of total sales. Their total purchase from BPA in FY 1978 of 33.7 billion kilowatthours was an increase of less than one percent over FY 1977 purchases.

The availability of non-firm power made it possible for investor-owned utilities in the Northwest to purchase from BPA in FY 1978 more than three times the amount purchased in FY 1977, representing 12.8 percent of total BPA sales. Some 87.8 percent of the 9.8 billion kilowatthours they bought from BPA was non-firm. The only firm energy investor-owned utilities obtain from BPA on a continuing basis stems from commitments related to their participation in the Hanford Project and rights associated with Hungry Horse Dam.

Federal agencies were supplied 757.3 million kilowatthours from BPA, a 6.5 percent increase over FY 1977, but less than one percent of total BPA sales.

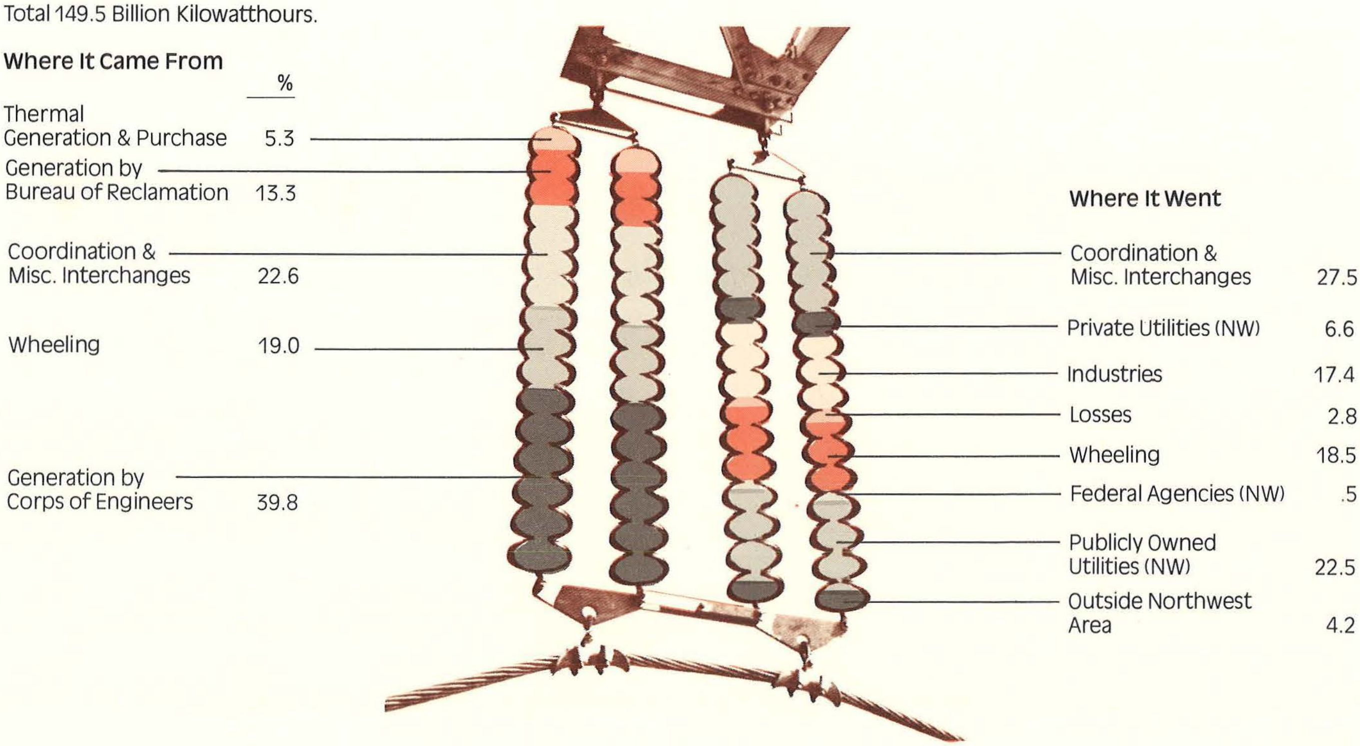
During FY 1978, the aluminum industry bought nearly 24 billion kilowatthours from BPA, up 8.1 percent from FY 1977. This was 31.3 percent of BPA sales. The increase was due mainly to availability of non-firm power.

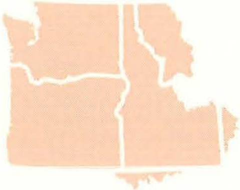
Sales to BPA's other direct-service industrial customers in FY 1978 of 2.1 billion kilowatthours were less than three percent of total sales, a slight decrease from FY 1977.

Sales outside the Northwest region, mostly to California customers, were 6.2 billion kilowatthours in FY 1978, about 8.2 percent of all BPA sales, and a sharp contrast to FY 1977, when no energy was sold outside the region. Without intertie access to this market, it would have been necessary to spill water rather than use it for generating power. Sales outside the region enabled the purchasing utilities to save in excess of 10 million barrels of oil in FY 1978 and thus helped lessen the strain on the nation's oil supplies.

Source and Disposition of Total Energy Handled by BPA

Fiscal Year 1978
Total 149.5 Billion Kilowatthours.





Conservation

Viewed As a Resource

We have two major responsibilities in the area of energy conservation.

One is to help our utility customers — who have direct relationships with the region's power consumers that BPA does not have — to carry out effective conservation programs.

The other is to do those things to save energy that are fully within our own hands.

The new National Energy Act broadened the range of energy conservation actions available to us and we anticipate that if a regional energy bill is passed by Congress we could do still more, especially in the way of investing in conservation. Authority to invest substantially in cost-effective conservation is, in our view, the key to our ability to work with and through our utility customers to put more effective conservation programs into being. For example, we think it is possible, up to a point, to get kilowatthours at less cost by insulating electrically heated homes of the region than by producing the same amount of energy in a new power plant, but we would need new legislative authority to do so on a large scale.

To develop conservation programs within our present legislative authority and to identify others that could be carried forward with new legislation, we established in mid-1978 a new Conservation Section within the Branch of Power Resources. The placement of this section within that branch results from our view that conservation must be treated as a resource, at least on par with any other resource.

Working With Others

To help our utility customers with their energy audit programs, we jointly financed with them a series of infrared aerial photography flyovers of their service territories during the winter of 1977-78, and are doing so again this winter. We also purchased eight hand-held infrared cameras for loan to our utility customers to follow up the flyovers and to photograph homes or other buildings not covered by the aerial photographs.

The success of the flyover program in any year depends upon several factors, weather being perhaps the most important. Weather conditions limited last year's flyover program to 39 communities involving eight utilities. Cold December weather in 1978 gave this winter's flyover program a good start.

We also distributed to our utility customers the first two editions of a new publication called *Ideas that Work,* which supplements a variety of other conservation informational materials that we produce. Each edition features one practical example of a successful conservation program of one utility that may be useful to other utilities.

We built 20 model insulation house exhibits and

Cheney customer checks BPA infrared photo of her home sponsored our fifth consecutive annual Energy Conservation Management Conference.

We are working to develop conservation pilot programs jointly with our utility customers and expect to have one or more in effect early in 1979.

Our Own Program

As for things within our own hands, in 1978 we adopted a new transmission line program designed to reduce line losses by about 90 million kilowatthours annually, or about three percent of BPA's total transmission system losses. We will accomplish this mainly by conversion of lines to higher voltages and use of higher capacity conductors.

In Fiscal 1978 we used 25 percent less energy — including electricity, gasoline and other fuels converted to the common denominator of Btu's — than five years earlier.

We started a complete energy audit of all 220 of our own buildings with 1000 square feet or more. We expect to complete the audits by September 30, 1979, and already have let contracts for upgrading insulation for the first six of these buildings.

Initial analyses indicated that cost-effective investments can be made to conserve energy — up to 75 percent in some cases — used to heat and cool our substation buildings.

We now subject all of our new building designs to computer-assisted energy analysis to maximize their energy efficiency. Passive as well as active solar heating and cooling systems are being evaluated for possible inclusion in building designs now on our drawing boards.

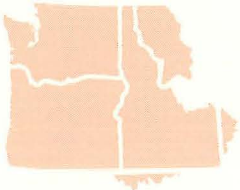
We purchased three electric vehicles in FY 1978 and plan to purchase more in 1979. These are in addition to the two we have owned and test-operated since 1975. The new models have significantly more speed and range. We look for continued improvements in technology that will make electric vehicles viable replacements for gasoline-powered vehicles in some circumstances.

We continue to encourage our employees to conserve energy on and off the job.

Significant conservation R&D projects are reported in the R&D section on page 22.

Inspecting a cellulose insulation display

BPA energy auditor trains hand-held infrared camera on BPA control center



Operations & Maintenance

Power and Mother Nature

We try to build our transmission system strong enough to withstand very bad weather conditions, and we install all sorts of automatic equipment to help overcome system disturbances. Then we try to operate and maintain the system in ways that will prevent interruptions of service, and restore service quickly should outages nevertheless occur.

We like to think that our reliability record is outstanding. But two incidents during FY 1978 demonstrated how difficult it is for the system to withstand all that Mother Nature is capable of doing to us, and how the best available automatic equipment can sometimes fail to work. One incident blacked out the whole State of Montana for up to 2 hours and 15 minutes; the other knocked out service to three small Oregon communities for 45 hours.

The first incident demonstrated, happily, our ability to put things back together fast after a big system disturbance. The other showed, unhappily, how difficult it can be to restore service after a small outage, even when our crews work around the clock for days on end.

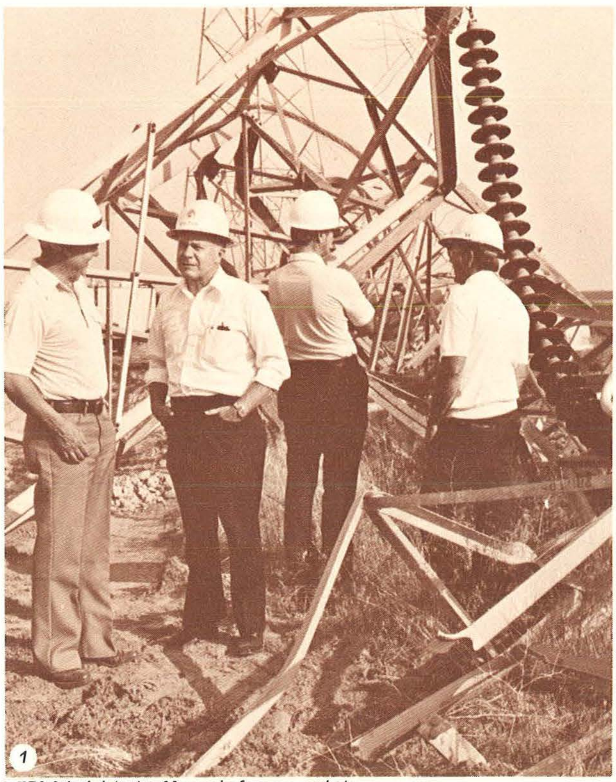
Montana Blackout

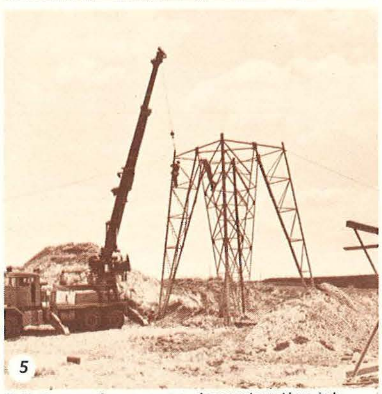
We operate two 500-kilovolt lines connecting the BPA main grid to the west with four Federal dams on the Lower Snake and Clearwater rivers.

In mid-afternoon on Saturday, July 1, high winds knocked down seven steel towers on one of these lines, the Lower Monumental-Hanford 500-kV line, 30 miles north of Richland, Washington. (The same windstorm also downed five steel towers on the parallel Midway-Scootney 230-kV line.) Loss of this 500-kV line left the Lower Monumental-John Day 500-kV line as the only link between the four dams and the BPA main grid to the west.

Late the very next night, lightning struck this remaining link. The generation-dropping system installed at Lower Monumental Substation for just such an emergency did not operate as it should have, and 1.5 million kilowatts of generation from the four dams all flowed eastward toward the Montana Power Company system. The surge caused major instability in the eastern portion of the BPA system as numerous lines relayed out of service. This also occurred on the MPC system and blacked out most of the state of Montana for periods of from 25 minutes to 2 hours and 15 minutes. Both the Idaho Power Company and the Utah Power Company lost industrial load. Several other western states were affected to a far lesser extent.

The second 500-kV line was reenergized within five minutes and other lines were restored to service within 1½ hours. But rebuilding the downed towers on the other 500-kV line was something else. It was done in seven days by BPA crews rushed to the scene





1. BPA Administrator Munro in foreground at wind-damaged transmission scene near Richland, Wash.

2-8. Scenes from seven-day restoration job requiring 100 tons of steel and 100 repairmen from all over the region — more than 100 persons in all — a remarkable feat involving 100 tons of tower steel and nine miles of conductor that had to be located and moved to the scene as well as to be assembled once there.

Serious as this system disturbance was, it could have been more widespread. Two factors explain why it was not. First, BPA had agreements and operating procedures with its direct-service industrial customers which provide for dropping their loads when trouble occurs.

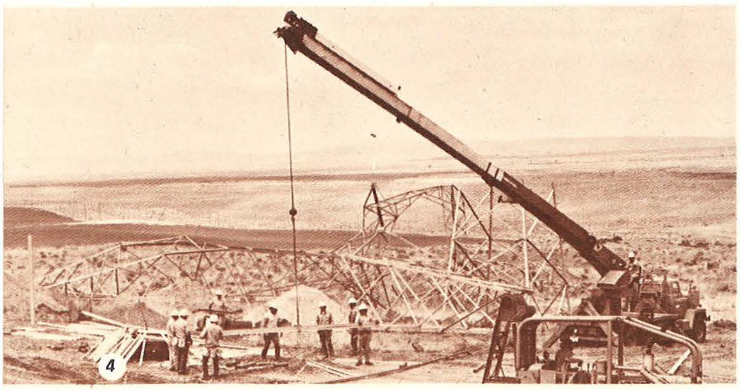
In this case, four industrial loads — two in eastern Washington and two in Montana — were immediately dropped for short periods, enabling the rest of the BPA grid to remain intact. Second, the flow of power on the d-c leg of the interties was automatically reversed, providing power from California to replace generation temporarily curtailed on the Pacific Northwest power system.

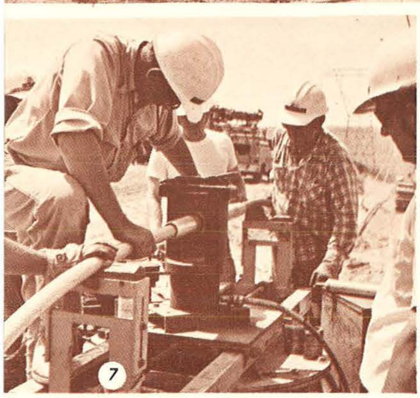
Oregon Outage

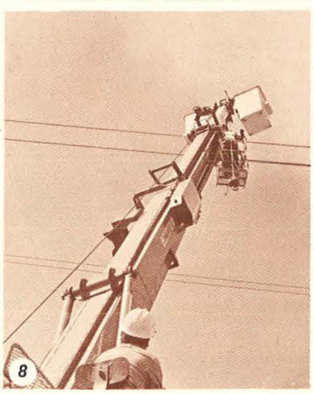
The communities of Condon, Fossil and Antelope — all in Oregon — are served by a 110-mile, 69-kV loop feeder with termination points at DeMoss and Maupin, Oregon. Starting at DeMoss, there are six line sections, the first three BPA-owned and the other three coop-owned but leased by BPA.

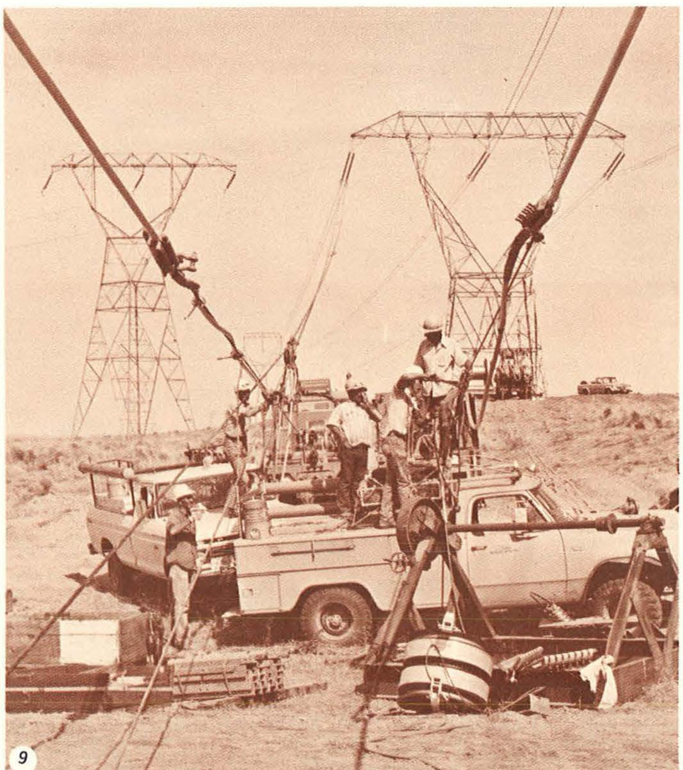
On Saturday, January 14, a severe ice storm coated this feeder line, called the DeMoss-Fossil Line, with ice six inches in diameter. Twelve H-frame wood structures and a 1½-mile stretch of conductor on line Section 2 went down when moderate winds kicked up in mid-afternoon, and 13 single pole structures and conductor on line Section 5 went down that night.

BPA crews from The Dalles, Sunnyside, Redmond, and Pasco, together with crews from three small coops — Wasco, Columbia Power, and Columbia Basin — worked 45 hours around the clock Saturday night, Sunday, Sunday night and Monday before the number 5 section was repaired, permitting restoration of service to the three communities. It was a full five days of round-the-clock work before Section 2 repairs were completed.

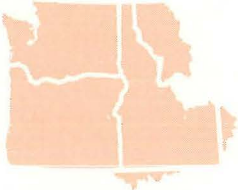








9. Restringing conductor on the rebuilt towers



Engineering & Construction

Long-Range Planning

There will come a day — possibly as early as the year 2000, but more likely 2010 or 2020 — when present transmission corridors across the mountains will no longer suffice.

Our studies show that the seven corridors we now utilize to bring power from generating plants east of the Cascade mountains to load centers on the Coast can be upgraded from their present 10½ million kW capacity to about 87 million kW. This would be accomplished by rebuilding existing 345 kilovolt and lower voltage lines to double-circuit 500-kV and — as soon as the higher voltage lines we are now testing become commercially available — to single-circuit 1100-kV.

When the limit on the potential capacity of the existing transmission corridors is reached depends on future load growth and the location of generating plants.

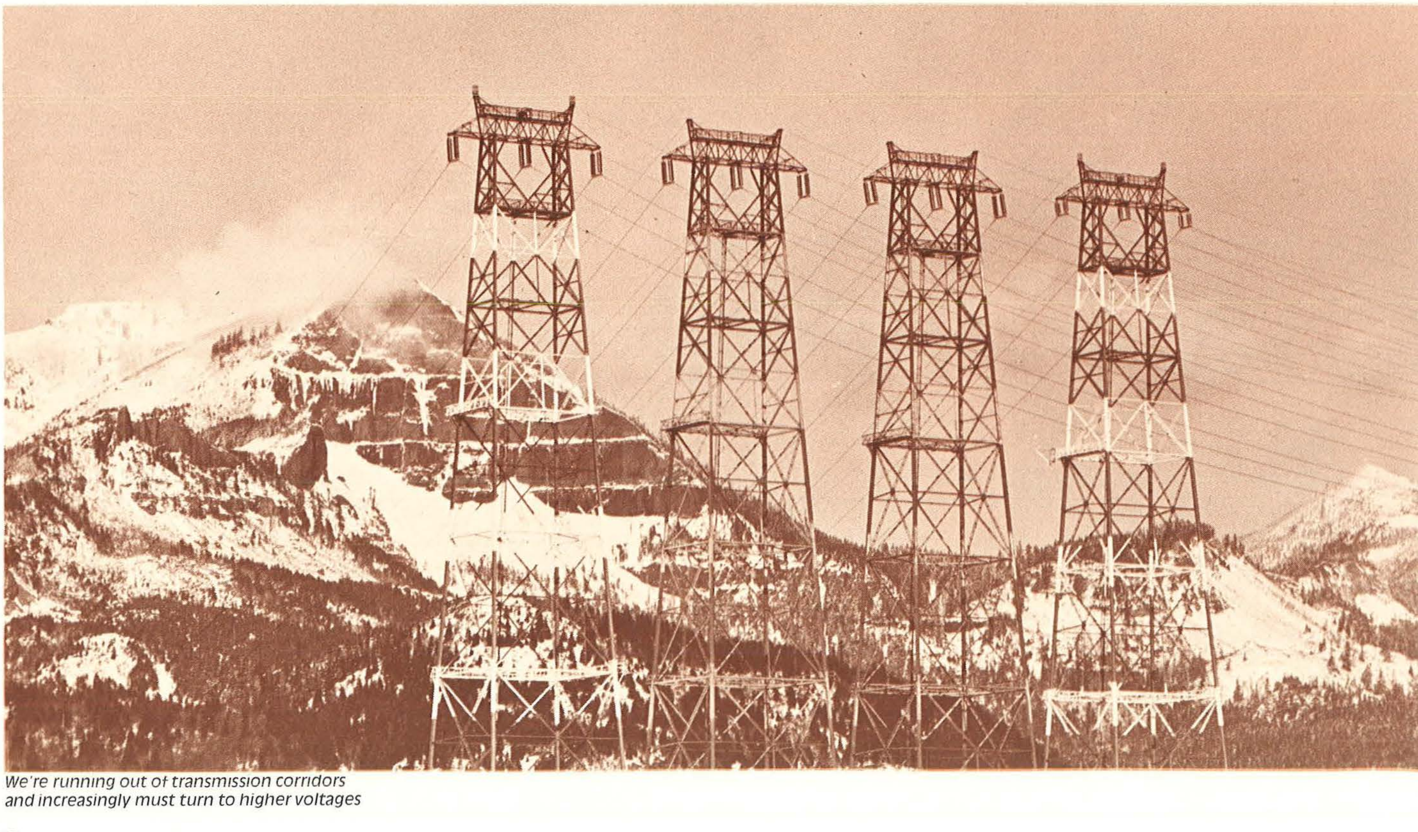
Assuming all of the region's future generating plants are to be built on the east side of the mountains, that would not occur until the year 2020 or later if new generation is not added at a rate faster than three percent per year. At five percent load growth, it would come closer to 2010. At the seven percent rate of load growth that characterized the region prior to 1976, it would come by the year 2000.

To be ready for the day it becomes necessary to find new transmission corridors, we have done studies jointly with the Forest Service that identify corridors physically capable of accommodating future bulk power lines. While we have identified corridor segments across critical mountain passes, we have not attempted to reserve them for future use, and have not identified the missing links. When that becomes necessary, it also will become necessary to involve state and local governments and other Federal agencies, and in all likelihood it also would require environmental impact statements.

But this is the sort of long-range planning that we must pursue now as the major bulk power transmission agency in the region. Because of uncertainties as to future load growth and specific generation sites, we can plan only 10 to 20 years ahead as to specific transmission needs, but we do take this longer 40 to 50-year look ahead in our general planning.

Customer Service Substations

We completed a study of customer service substation cost and construction time in 1978 that now has us working on designs for a number of substation modules. The modules promise reductions of up to one-third in cost and three-fourths in installation time — from the present 120 days to approximately 30 days. Modules are being designed for high voltage



We're running out of transmission corridors and increasingly must turn to higher voltages transformer fuses and isolating switches, low voltage switch gear, transmission line tap and sectionalizing switches.

Modules would be added as they are needed rather than as part of the initial installation. The design will reduce the number of structures required and permit partial assembly before shipment to the site for installation.

New Facilities Energized

During FY 1978, we energized 126 circuit miles of transmission lines. This included the 500-kV Chief Joseph Power House Line No. 6 to integrate new generation being added at Chief Joseph Dam and the 500-kV loop to McNary Substation.

On September 30, 1978, the BPA System included 12,454 circuit miles of transmission lines. An additional 1652 miles are in various stages of design and construction. Seven additional substations were energized during the period, for a total of 346 substations.

Projects Underway...

The Ashe-Willamette Valley Project consists of a 500-kV double-circuit line from the Hanford area to the proposed Slatt Substation near Arlington, Oregon, and another 500-kV double-circuit line from the proposed Slatt Substation to Marion Substation, near Santiam, Oregon. This FY 1975 Budget Item was originally scheduled for completion in the fall of 1979. The Ashe-Slatt portion is now expected to be completed early in 1980, and the Slatt-Marion portion late in 1980. This delay was the result of problems in obtaining rights-of-way. However, due to reduced load growth in the Willamette Valley, the delay has not been a major problem for us or our customers.

...And Under Study

During 1978 BPA and Tacoma City Light (TCL) continued to study whether multiple circuit 230-kV or a combination of 500-kV and 230-kV circuits would best provide needed transmission support in that area.

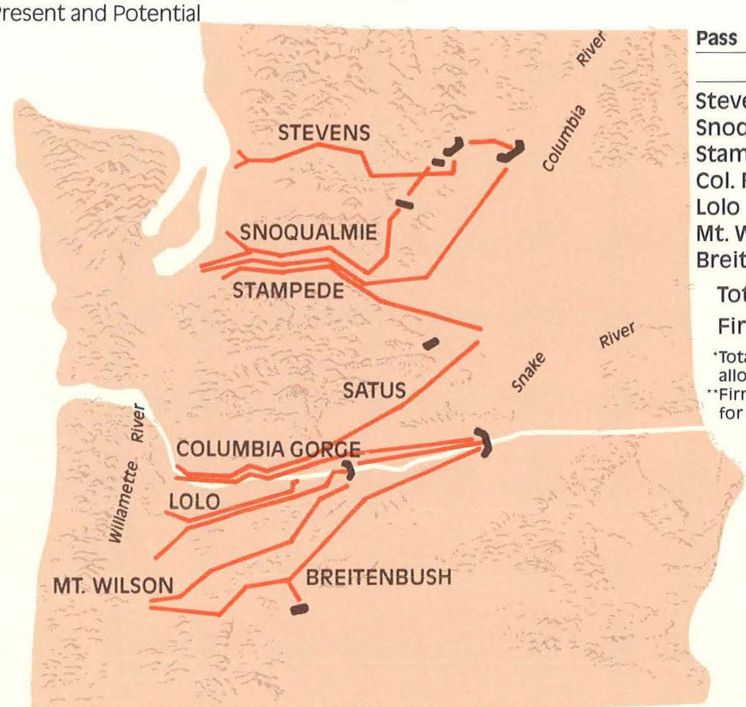
TCL now foresees the need for 230-kV double circuit between BPA's Tacoma Substation and TCL's Cowlitz Substation, utilizing TCL right-of-way to be vacated by removal of the present 115-kV facilities. This plan should also provide needed support for BPA facilities.

Negotiations with TCL to determine the necessary transmission and substation facilities and an equitable sharing of costs are continuing and should be completed during 1979.

...And Delayed

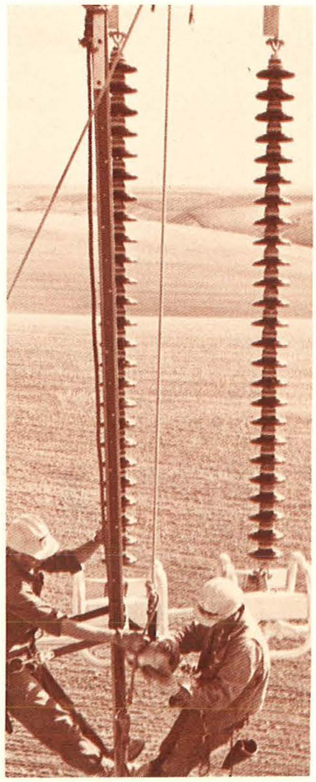
BPA service to Alumax Pacific Corporation at its Umatilla site is still being delayed by a District Court

Transmission Corridor Capacity
Present and Potential



Pass	Present Capacity	Potential Capacity
	(Millions of KW)	
Stevens	2.6	11.5
Snoqualmie	.55	10.0
Stampede	3.7	22.7
Col. River	2.25	16.5
Lolo	1.95	21.2
Mt. Wilson	1.5	16.5
Breitenbush	.5	10.0
Total*	13.05	108.4
Firm**	10.5	87.0

*Total includes redundancy allowed for system reliability
**Firm figures reflect allowance for outages.



judgment which ruled BPA's contract for service with Alumax at Umatilla unenforceable until BPA has prepared and considered an acceptable environmental impact statement. Notices of appeal have been filed by all parties in the Alumax case. Until the matter has been resolved, BPA activities are limited to system studies, preliminary design, and preparation of the Environmental Impact Statement (EIS) which is now expected to be filed with the EPA in early 1979.

Another court judgment may delay a number of facilities to integrate thermal generation. On January 9, 1978, the United States District Court for the District of Oregon issued a judgment in the case of Natural Resources Defense Council, Inc. (NRDC), et al, vs. Hodel, et al, which ordered, in part, that BPA could not construct any new transmission facilities to service generating facilities associated with Phase 2 of the Hydro-Thermal Power Program (HTPP) until it has prepared, publicly circulated, and considered an environmental impact statement concerning Phase 2 of the HTPP or any equivalent or substitute arrangements or programs subsequent to Phase 1.

The construction of the Ashe-Slatt double circuit 500-kV line across the Columbia River at Crow Butte Island is being delayed because of difficulties in obtaining permits to cross the Columbia River.

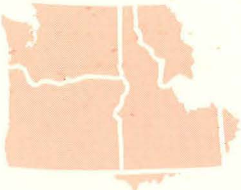
BPA has delayed other major facilities to coordinate with delays in electrical power generating plants. These facilities include the 500-kV line integrating transmission for Washington Public Power Supply System's WNP 1 and WNP 4 nuclear plants near Richland, Washington. A 165-mile, single circuit, 500-kV line from Hot Springs Substation near Hot Springs, Montana, to Bell Substation near Spokane, Washington, has been delayed pending a final decision on privately owned coal-fired Colstrip units No. 3 and 4.

During FY 1978, two problems which had been causing delays were resolved. The court order enjoining the construction of the Lower Monumental-Ashe 500-kV line was lifted and the right-of-way across the Warm Springs Indian Reservation for the Slatt-Marion double-circuit 500-kV Line was obtained. Contracts for both of these projects were awarded.

Contracts Awarded

In FY 1978, BPA contracted for the construction of portions of three major transmission line additions. The first contract for $2.1 million is to build the 500-kV 41-mile Lower Monumental-Ashe No. 1 line to bring into the BPA network generation being added at the Lower Snake River dams. The second contract, for $5.4 million, covers the building of 50 miles of the 72-mile Ashe-Slatt double circuit 500-kV line. Two contracts for a total of $20 million were awarded to build 114 miles of the 151-mile Slatt-Marion double circuit 500-kV line.

Indians once fished like this at Celilo Falls



Power and Fish

Large Sums

From the beginning of Federal power development in the Pacific Northwest, the Congress has placed a high priority on maintaining the Columbia and its tributaries as one of the world's great salmon and steelhead producers.

Power consumers have been assigned responsibility for repaying approximately $300 million worth of capital costs for the fisheries investment in the Federal Columbia River Power System. These costs cover such things as hatcheries, fish ladders, and other bypass facilities.

Currently, some $19.5 million per year of BPA power revenues go to pay operation, maintenance, interest and amortization on these facilities.

Working With The Tribes

In late 1977 and early 1978, BPA entered into a Memorandum of Understanding with the four Confederated Tribes (Nez Perce, Warm Springs, Umatilla and Yakima) and the Pacific Northwest Regional Commission (PNRC) to assure a single coordinated and comprehensive approach to solving fisheries problems.

The Memorandum of Understanding recognized, for the first time, the cultural and economic concerns and needs of the Tribes for the fishery resource, and made the Tribes full partners in the program.

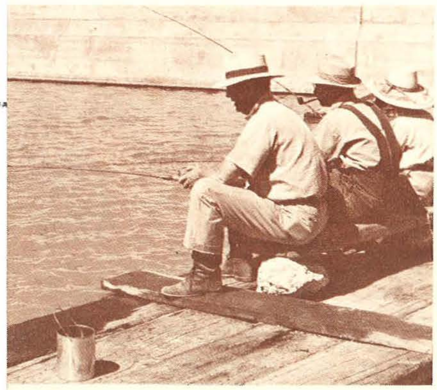
Pilot Studies

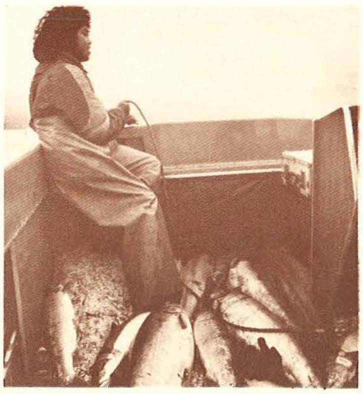
We contributed $500,000 for two pilot programs in FY 1978, the first year of this joint program, and in FY 1979 will add six new projects at a total program cost of $1,225,000.

It will be several years before these studies bear fruit, primarily because of the long average life cycle of anadromous fish (three to four years). In addition to improving fish runs, the studies are expected to provide information that will permit more flexible operation of the power system.

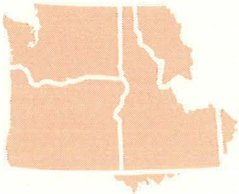
Advance Guarantee

BPA management staff and biologists also serve on several committees that negotiate and coordinate power and fisheries activities and operations, most notably on the Committee on Fishery Operations (COFO), a joint committee of fishery agencies, utilities and operating agencies. COFO was responsible for the "Operation Fish Flow '77" which was credited with averting disastrous fish losses during the period of low streamflows in 1977. In an effort to avoid some of the "last minute" type of problems encountered in 1977 and which were repeated in 1978, BPA and other generating utilities have now taken steps to guarantee in advance certain flow and spill levels for the 1979 juvenile fish migration season.





Indians and non-Indians, commercial and sports fishermen, all have a stake in Columbia fish runs



Research and Development

Solar

During 1978, BPA's R&D Program took on a new look with the initiation of several solar energy projects.

Solar-electric direct conversion (Photovoltaic cells) is cost effective today at remote sites and under special circumstances. BPA has identified several such applications. These include airway beacons on river crossing towers; microwave repeater stations at remote sites where conventional power supply is costly; and portable power supply for remote water pump applications. DOE is supporting BPA in these applications. The University of Oregon Solar Energy Institute is participating in the survey of solar energy potential in Oregon.

In the area of heating and cooling, we have embarked on two demonstration projects: 1) at Big Eddy Substation, in cooperation with DOE, the development of a commercial model solar assisted lithium bromide absorption air conditioner; and 2) at Redmond Substation, in cooperation with DOE and NASA, a solar power heating and cooling system using the Organic Rankine Cycle principles.

Wind

For the past two years, BPA has contracted with Oregon State University to determine the characteristics of wind energy and to assess wind energy potential in the BPA service area. A number of sites have been identified as possibilities. We have presented these locations to DOE as candidate sites for installation and evaluation of the 2,500-kilowatt MOD II Protype Wind Turbine Generators currently being developed with DOE funding.

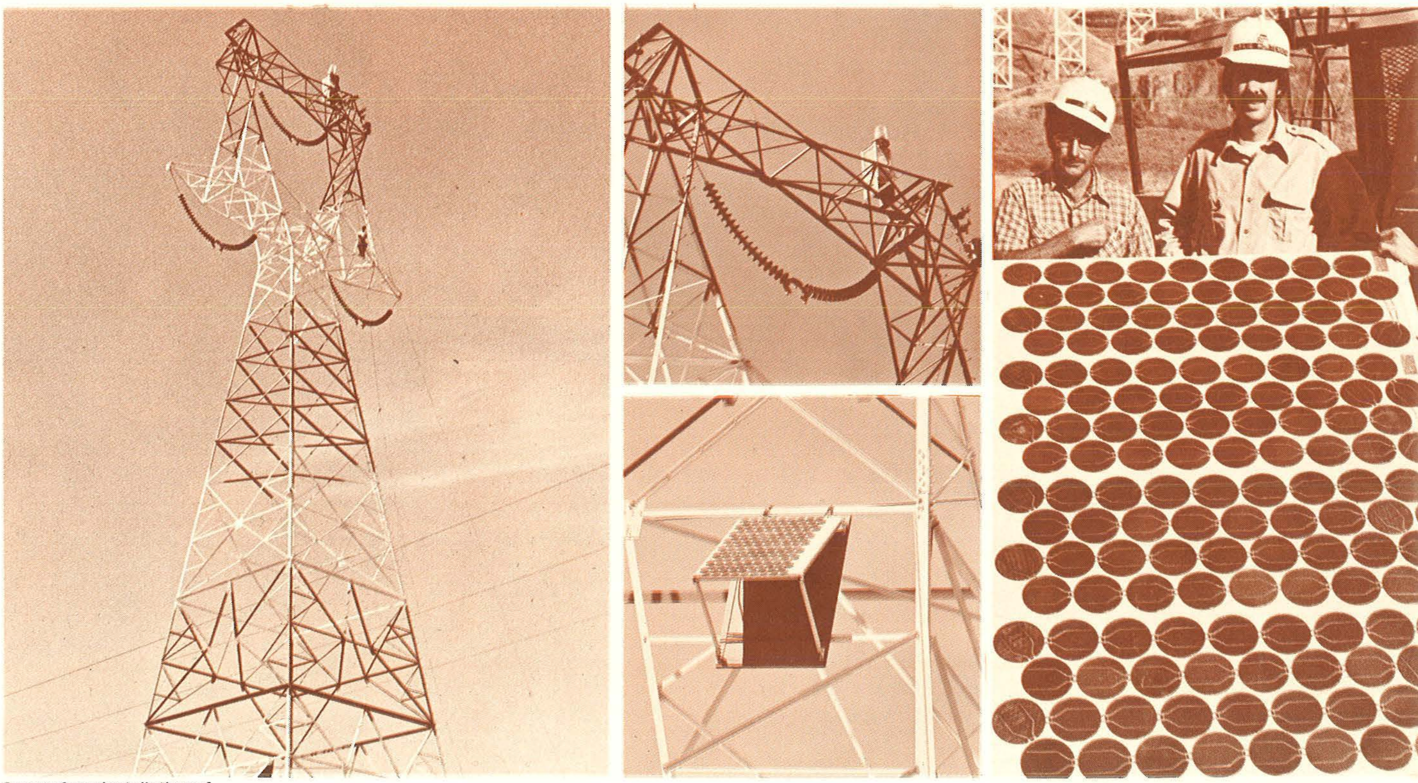
1100 -kV Transmission

BPA believes 1100-kV is a viable option for the 1990's. Transmission at 1100-kV is attractive because it has only half as much loss as 500-kV and requires 25 percent less right-of-way to transmit the same amount of power.

BPA has constructed a 1.3 mile three-phase electrical test line at Lyons, Oregon, and a one-mile mechanical test line at Moro, Oregon. The electrical test line is designed for 1200-kV — the test voltage being somewhat higher than the proposed operating voltage of 1100-kV. The lines have been in operation since December 1976.

BPA engineers are studying line parameters such as audible noise, radio and television interference, structural loading, mechanical vibrations, and conductor motions under various operating conditions.

Biologists of the Battelle Pacific Northwest Laboratory, under contract to BPA, are conducting biological studies to determine the effects of ultra-high voltage (UHV) lines on natural vegetation, crops, mammals, birds, livestock, and honeybees.



Scenes from installation of photovoltaic aircraft warning system

EPRI

In addition to our in-house R&D Program, BPA is an active participant in the Electric Power Research Institute (EPRI) program. In FY 1978 we agreed to contribute to EPRI $4.6 million in 1979 and $5.2 million in 1980. These sums represent the contributions of the region's public agencies and coops which buy their wholesale power from BPA and have chosen to make their research contributions through BPA, as well as BPA's share for its direct sales to large industries.

Founded in 1972 by the nation's private and public utilities, EPRI was given the mission to coordinate an R&D program to help the utility industry meet the nation's energy needs in an environmentally, economically, and technologically desirable manner. It has some 500 members representing three-fourths of the nation's electric service. Many BPA personnel serve on EPRI's various committees and task forces.

Conservation

Two R&D projects in the area of conservation are worthy of special mention. One is the Prototype Energy Retrieval and Solar System at our Ross Substation in Vancouver; the other is a housing energy efficiency study at our Midway Substation.

The Ross Substation project is intended to advance the state of the art for an energy retrieval and solar collection, storage and conversion system.

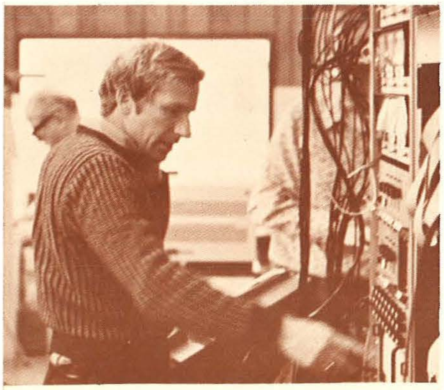
At present, the heat associated with transformers is lost — dissipated to the atmosphere. If it can be retrieved and collected economically, it can be stored and converted to serve useful purposes such as building heating and cooling.

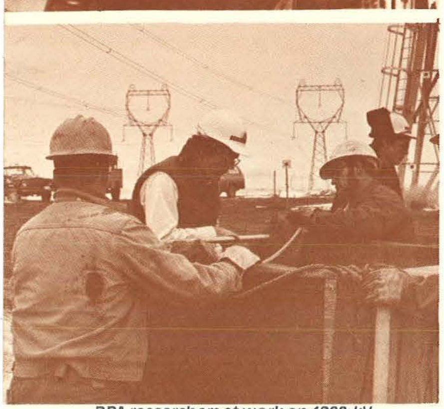
The energy loss from transformers fluctuates with load, so for such a system to provide a reliable energy supply a means of supplementing the waste heat is necessary. Vacuum insulated tubular glass solar collectors were selected for this project because of their reputed high collection efficiency, even in overcast weather.

The experimental system supplies up to 90 percent of the heating and cooling requirement of the Ross Substation Control House.

This technology may also be applicable to other industries such as aluminum plants, where large quantities of waste heat are generated.

At Midway, we are retrofitting 19 residential homes for energy efficiency, mainly by adding insulation and installing vapor barriers and storm windows. The homes have been fully instrumented to allow BPA engineers to compare and study various conservation measures and their cost effectiveness.





BPA researchers at work on 1200-kV test line at Moro, Oregon

Management & Legal

The Barry Report

In 1978, we engaged the consulting firm of Theodore Barry & Associates to make recommendations concerning:

1. Ways to reduce remaining construction costs and remaining construction time for three nuclear power plants being built by the Washington Public Power Supply System (WPPSS), the costs of which must be factored into BPA wholesale power rates under net billing agreements; and,
2. Ways to make more effective BPA's oversight rights and responsibilities that go along with our financial obligations related to these projects.

Net billing is a method by which we take into our system the output of thermal plants built by others to help meet our customers' power needs, and meld the costs with those of the Federal hydro system. Net billing covers 100 percent of the costs of two of the WPPSS plants, 70 percent of the third, and the City of Eugene's 30 percent share of the Trojan nuclear power plant built by the Portland General Electric Company.

The three WPPSS plants are running from two to three years behind schedule, each, and at year's end were scheduled to come on line in December 1980, December 1982, and January 1984, respectively. Their current cost estimates are, on average, more than double original cost estimates.

The final Barry Report was expected momentarily but had not been delivered by the time this Annual Report went to press. However, both BPA and WPPSS have had an opportunity to comment on a preliminary draft.

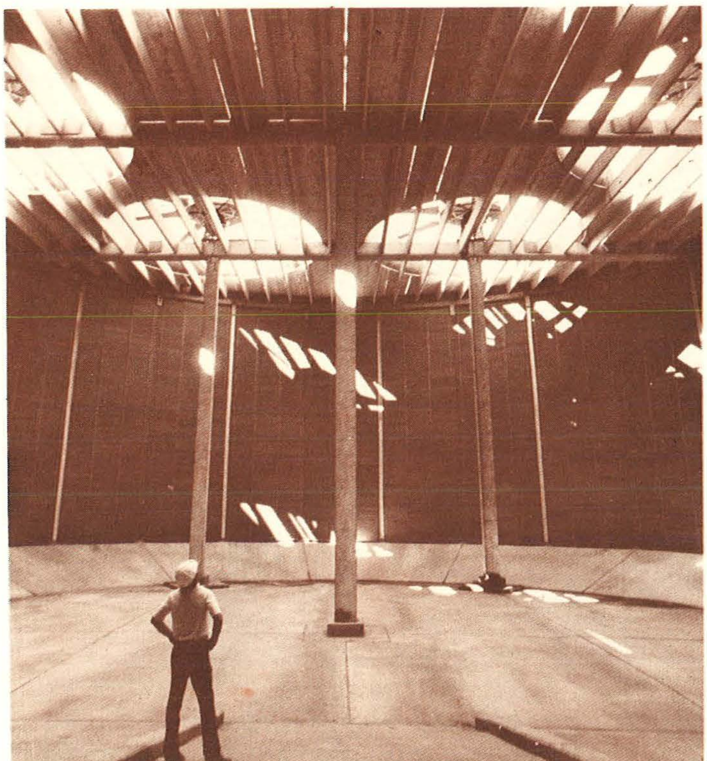
The preliminary report highlighted problem areas such as change-order and other financial controls, and suggested that as much as $100 million might be pared from remaining construction costs for the three plants.

And while the preliminary report said there are many opportunities to strengthen WPPSS' overall management function, it also said that WPPSS has one of the greatest pools of technical talent in the nuclear field and has selected reputable and experienced construction firms.

New Planning Tool

We prepared an Annual Management Plan (AMP) to guide our operations commencing with FY 1979 and Assistant Secretary McIsaac wholeheartedly approved it.

Similar in concept to an annual operating plan prepared by the head of a wholly owned corporate subsidiary for the parent corporation, we view it as a tracking mechanism to assist the Department of Energy in carrying out its legislatively mandated duties while allowing the flexibility given BPA by our



Inside one of the cooling towers for WPPSS Nuclear Unit No. 2

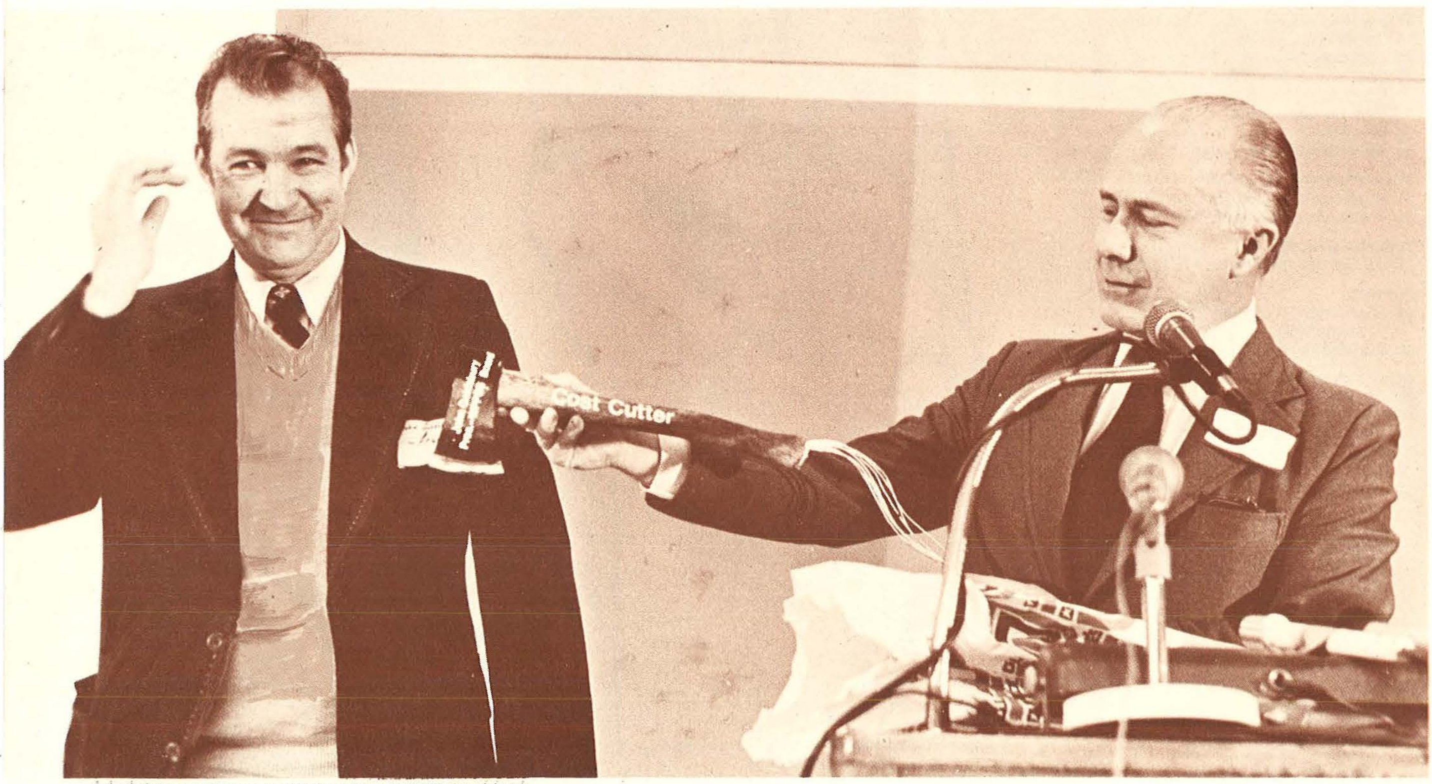
We're still in litigation

authorizing statutes and agreements between Congress and the Department of Energy.

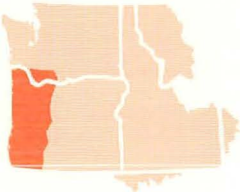
Each AMP sets goals to do certain things by certain times and at certain costs. Quarterly reports to the Assistant Secretary covering major elements of the AMP will enable the Department to monitor how well we are performing.

Portland Lawsuits

Two lawsuits were filed by the City of Portland against BPA in 1977. The court dismissed without prejudice the first lawsuit, which challenged BPA's interpretation of the "preference clause" and its methods of allocating Federal power, and asked the court to declare the City to be a preference customer of BPA. The second lawsuit challenges the validity of each of the power sales contracts and net billing agreements which BPA has executed since January 1, 1970, the date that the National Environmental Policy Act (NEPA) became effective, without preparing environmental impact statements (EIS). Another dimension was added to this litigation during 1978 by the claims of Pacific Power & Light Company, Portland General Electric Company, and Montana Power Company for entitlement to power for their domestic and rural customers under the BPA preference clause.



Administrator Munro (right) hands to WPPSS President John Goldsbury hatchet symbolic of ways to cut nuclear costs



The Portland Customer Service Area

OUR CUSTOMERS

To provide a variety of services for our 147 customers in the Pacific Northwest, BPA maintains four Area offices — at Seattle, Spokane, Walla Walla, and Portland. We also maintain four District offices — at Wenatchee, Kalispell, Idaho Falls, and Eugene.

The maps on this and the next three pages show the boundaries and names of our utility customers within each of the four areas. The location of each BPA area within the overall BPA service territory is shown by the color overlay on the minature map at the top of each page.

Of our 147 Northwest customers, 116 are public and cooperative utilities and eight are investor-owned utilities. The other BPA customers in the Northwest are 17 direct service industrial customers and six Federal agencies. We also sell and exchange power with 10 utilities in California, one in British Columbia, and two Federal agencies east of the Continental Divide, bringing our total number of customers to 160.

While industries and investor-owned utilities have purchased large amounts of wholesale power from BPA over the years, first call on Federal power sold by BPA goes to public power systems and rural electric cooperatives in the region. Public power entities existed long before BPA, but the creation of BPA in 1937 gave them an effective working partner, the Bon-

Publicly Owned Utilities

Municipalities
1. Bandon, Oregon
2. Canby, Oregon
3. Cascade Locks, Oregon
4. Drain, Oregon
5. Eugene, Oregon
6. Forest Grove, Oregon
7. McMinnville, Oregon
8. Monmouth, Oregon
9. Springfield, Oregon

Public Utility Districts
10. Central Lincoln PUD
11. Clark Co. PUD #1
12. Clatskanie PUD
13. Cowlitz Co. PUD #1
14. Skamania Co. PUD #1
15. Tillamook PUD
16. Wahkiakum Co. PUD #1

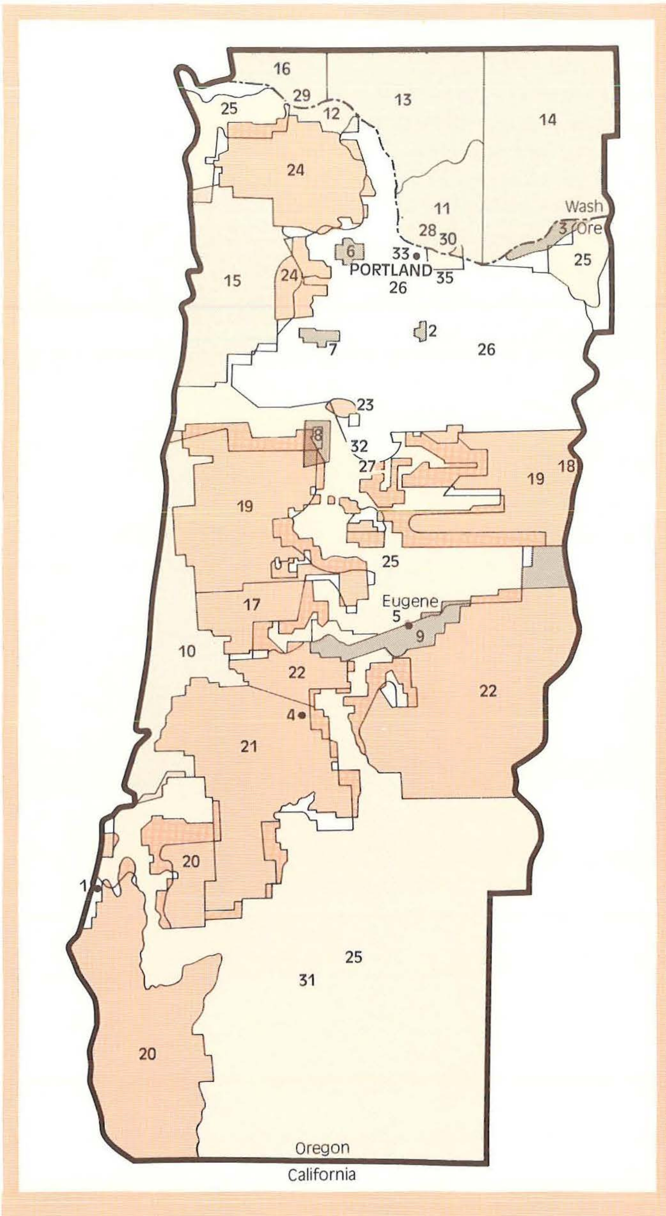
Cooperatives
17. Blachly-Lane Co. Coop. Elec. Assn.
18. Central Elec. Coop.
19. Consumers Power
20. Coos-Curry Elec. Coop.
21. Douglas Elec. Coop.
22. Lane Co. Elec. Coop.
23. Salem Elec.
24. West Oregon Elec. Coop.

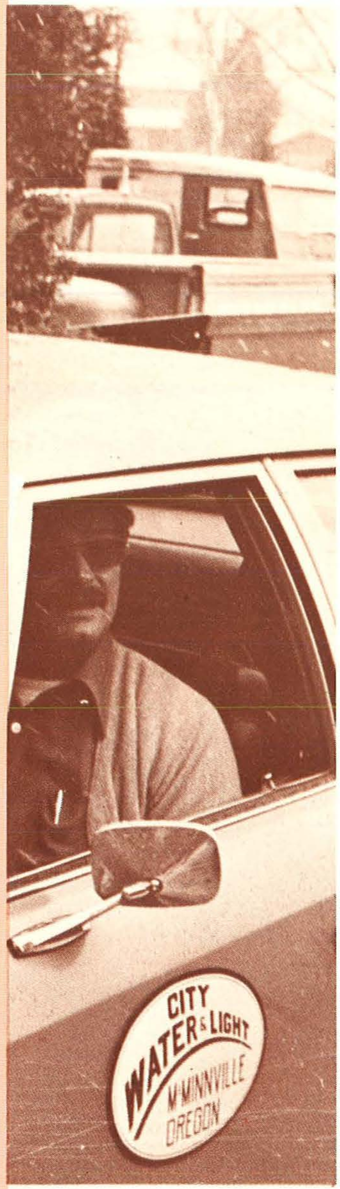
Privately -Owned Utilities
25. Pacific Power & Light Co.
26. Portland General Elec. Co.

Federal Agencies
27. U.S. Bureau of Mines

Aluminum
28. Aluminum Co. of America (combined)
29. Reynolds Metals Co. (combined)

Other Industries
30. Carborundum Co.
31. Hanna Nickel Smelting Co.
32. Oregon Metallurgical Corp.
33. Pacific Carbide & Alloys Co.
34. Pennwalt Corporation
35. Union Carbide Corp.





The Seattle Customer Service Area

neville Project Act stating the preference principle not once but five times.

We presently serve the requirements of the preference customers, except to the extent that some choose to serve part of their requirements from their own generation or to purchase part from other utilities. But we have had to give notice to our preference customers that on the basis of present supplies we will not be able to supply their load growth after 1983.

Municipals

Seven Pacific Northwest cities were operating municipal systems by 1900; McMinnville, Milton-Freewater, and Forest Grove in Oregon; and Tacoma, Centralia, Port Angeles, and Ellensburg in Washington. Today BPA serves 33 city-owned systems plus two irrigation districts and a joint operating agency that qualify as municipals. Five of the cities generate or purchase from other than BPA substantial amounts of their own requirements. In 1977, the latest year for which figures were available at presstime, these amounts were as follows: Seattle 67.3 percent; Tacoma 59.7 percent; Centralia 42.3 percent; Bonners Ferry 44.4 percent, and Eugene 30.6 percent. The city-owned systems range in size from Minidoka, which in 1977 served some 68 customers, to

Publicly Owned Utilities

Municipalities
1. Blaine, Washington
2. Centralia, Washington
3. Eatonville, Washington
4. Fircrest, Washington
5. McCleary, Washington
6. Milton, Washington
7. Port Angeles, Washington
8. Seattle, Washington
9. Steilacoom, Washington
10. Sumas, Washington
11. Tacoma, Washington

Public Utility Districts
12. Clallam Co. PUD #1
13. Grays Harbor Co. PUD #1
14. Lewis Co. PUD #1
15. Mason Co.PUD #1
16. Mason Co. PUD #3
17. Pacific Co. PUD #2
18. Snohomish Co. PUD #1
19. Whatcom Co. PUD #1

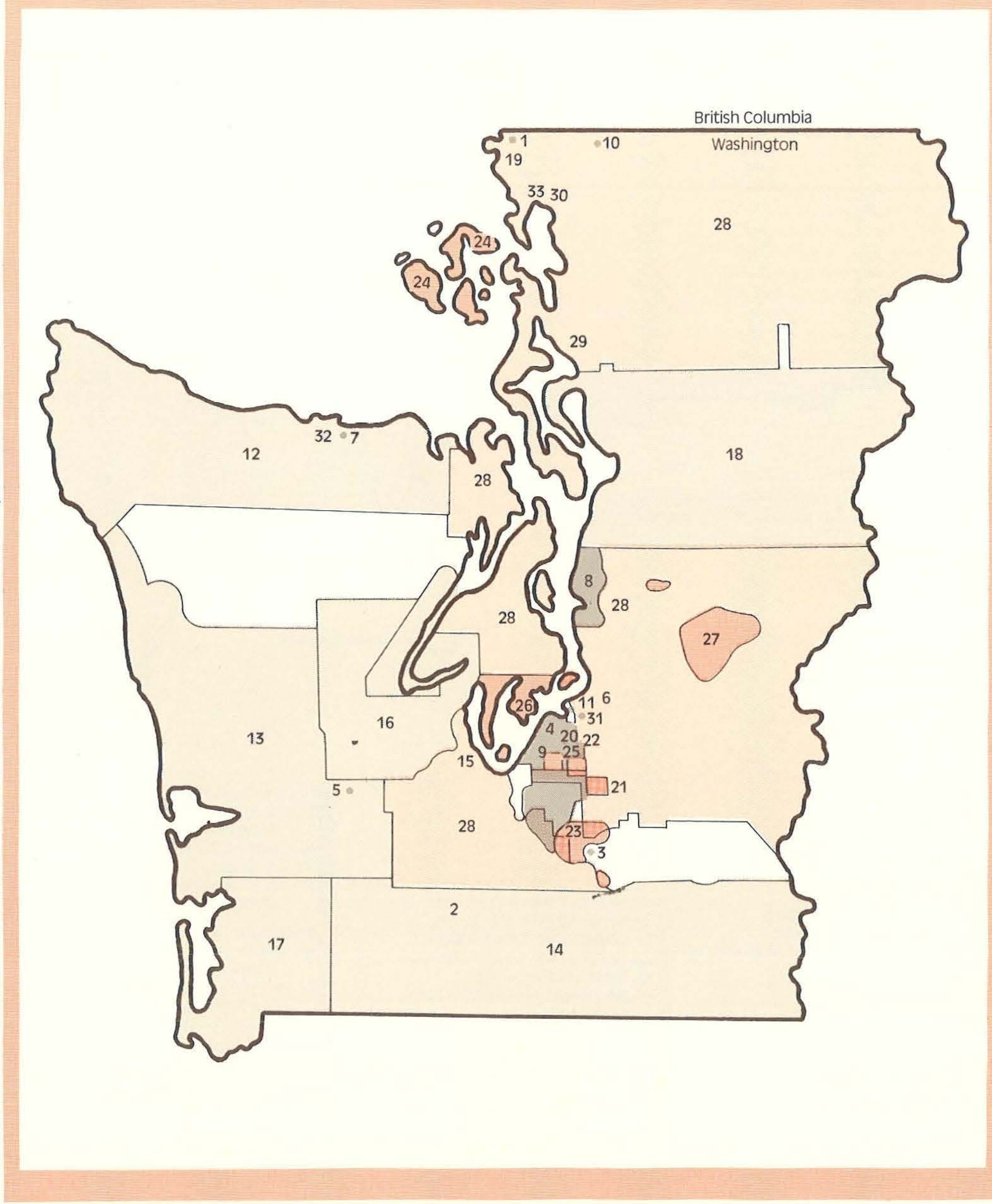
Cooperatives
20. Alder Mutual Light Co.
21. Elmhurst Mutual Power & Light Co.
22. Lakeview Light & Power Co., Inc.
23. Ohop Mutual Light Co.
24. Orcas Power & Light Co.
25. Parkland Light & Water Co.
26. Peninsula Light Co.
27. Tanner Elec.

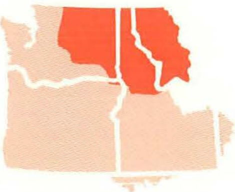
Privately -Owned Utilities
28. Puget Sound Power & Light Co.

Federal Agencies
29. U.S. Navy

Aluminum
30. Intalco Aluminum Co.
31. Kaiser Alum. & Chem. Corp. (combined)

Other Industries
32. Crown Zellerbach Corp.
33. Georgia Pacific Corp.





The Spokane Customer Service Area

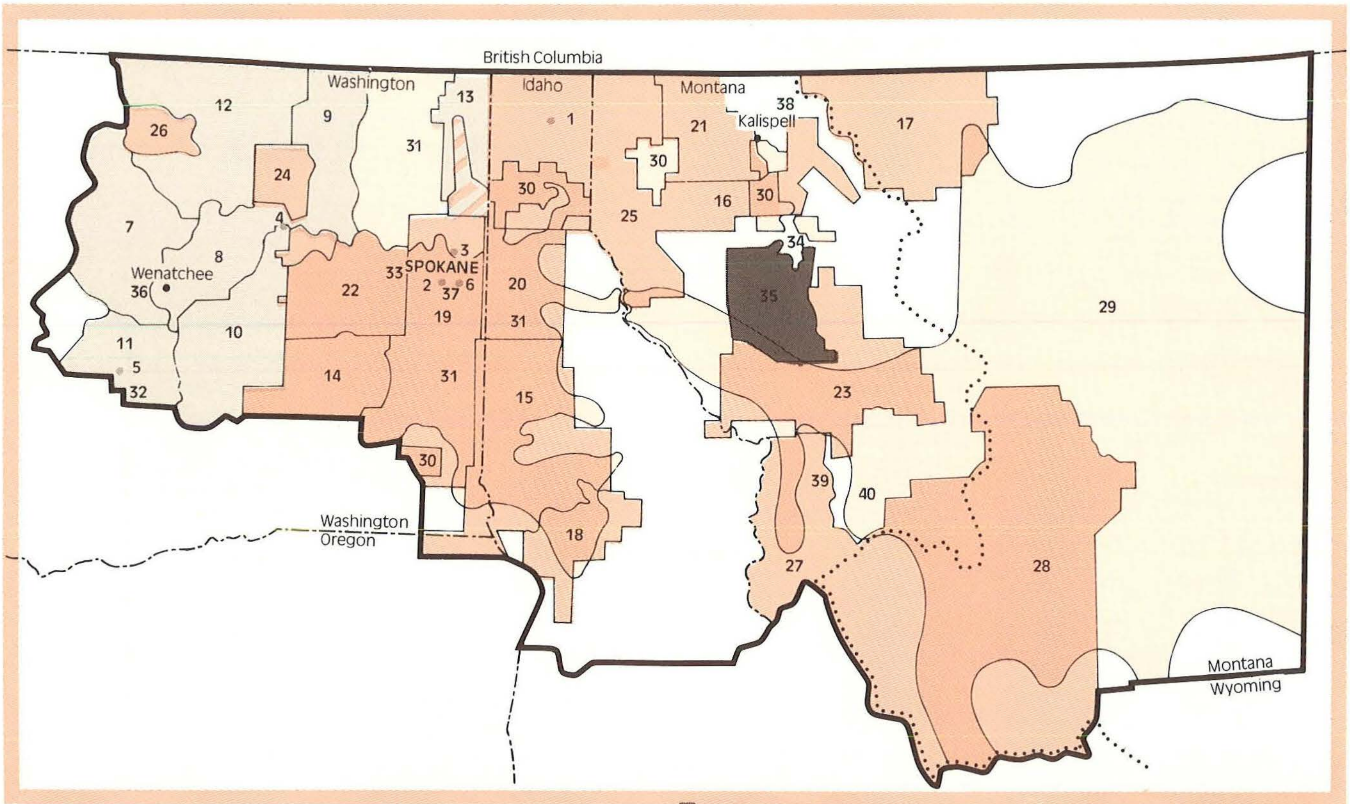
Seattle, serving 274,154. The number of customers does not equate with the number of people served; for example, a household of six would be counted as only one customer.

Coops

Some rural cooperatives were organized between 1910 and 1925 in the areas of Burley, Idaho, and Tacoma, Washington, but most of the 54 coops BPA now serves came into being after establishment of the Rural Electrification Administration in 1935. In 1977, only one coop (Lower Valley Power and Light) served by BPA generated any of its own power — four percent. In 1977, the coops served by BPA ranged in size from Alder Mutual Light with 113 ultimate consumers to Inland Power and Light with 16,051 consumers. Both of these coops are located in Washington State.

PUDs

Enactment of the PUD initiative ballot measure in Oregon and Washington in November 1930 created a new public power movement. The 1930 PUD laws did not create PUDs — called Public Utility Districts in Washington and People's Utility Districts in Oregon — but permitted voters to do so at the local level. Washington voters created four PUDs in 1934, 15 in 1936, six in 1938 and four in 1940, not all of which actually went into business. Oregon voters created far



Publicly Owned Utilities

Municipalities

1. Bonners Ferry, Idaho
2. Cheney, Washington
3. Consolidated Irrigation District, Washington
4. Coulee Dam, Washington
5. Ellensburg, Washington
6. Vera Irrigation District, Washington

Public Utility Districts

7. Chelan Co. PUD #1
8. Douglas Co. PUD #1
9. Ferry Co. PUD #1
10. Grant Co. PUD #2
11. Kittitas Co. PUD #1
12. Okanogan Co. PUD #1
13. Pend Oreille Co. PUD #1

Cooperatives

14. Big Bend Elec. Coop.
15. Clearwater Power Co.
16. Flathead Elec. Coop.
17. Glacier Elec. Coop.
18. Idaho Co. Light & Power Coop. Assn.
19. Inland Power & Light Co.
20. Kootenai Elec. Coop., Inc.
21. Lincoln Elec. Coop.—Mont.
22. Lincoln Elec. Coop.—Wash.
23. Missoula Elec. Coop.
24. Nespelem Valley Elec. Coop.
25. Northern Lights
26. Okanogan Co. Elec. Coop.
27. Ravalli Elec. Coop.
28. Vigilante Elec. Coop.

Privately -Owned Utilities

29. Montana Power Co.
30. Pacific Power & Light Co.
31. Washington Water & Power Co.

Federal Agencies

32. U.S. Bureau of Reclamation-Roza Project
33. Fairchild Air Base
34. U.S. Bureau of Indian Affairs
35. U.S. Bureau of Indian Affairs-Flathead Irrigation Project

Aluminum

36. Aluminum Co. of America (combined)
37. Kaiser Alum. & Chem. Corp. (combined)
38. The Anaconda Co. Aluminum Division

Other Industries

39. Cominco American Inc.
40. Stauffer Chemical Works

The Walla Walla Customer Service Area

fewer PUDs and, due to a more restrictive PUD law in Oregon, only four eventually became active. Tillamook in 1932, Northern Wasco in 1939, and Clatskanie and Central Lincoln in 1940. Today BPA serves these four Oregon PUDs and 22 in Washington. Four of the Washington PUDs generate a percentage of their own needs — in 1977, the percentage was 96.3 for Pend Oreille, 75.3 for Chelan County, 32.5 for Grant County, and 73.0 for Douglas County. In 1977, PUDs ranged in size from Kittitas County PUD with 1,395 consumers to Snohomish County PUD with 119,187.

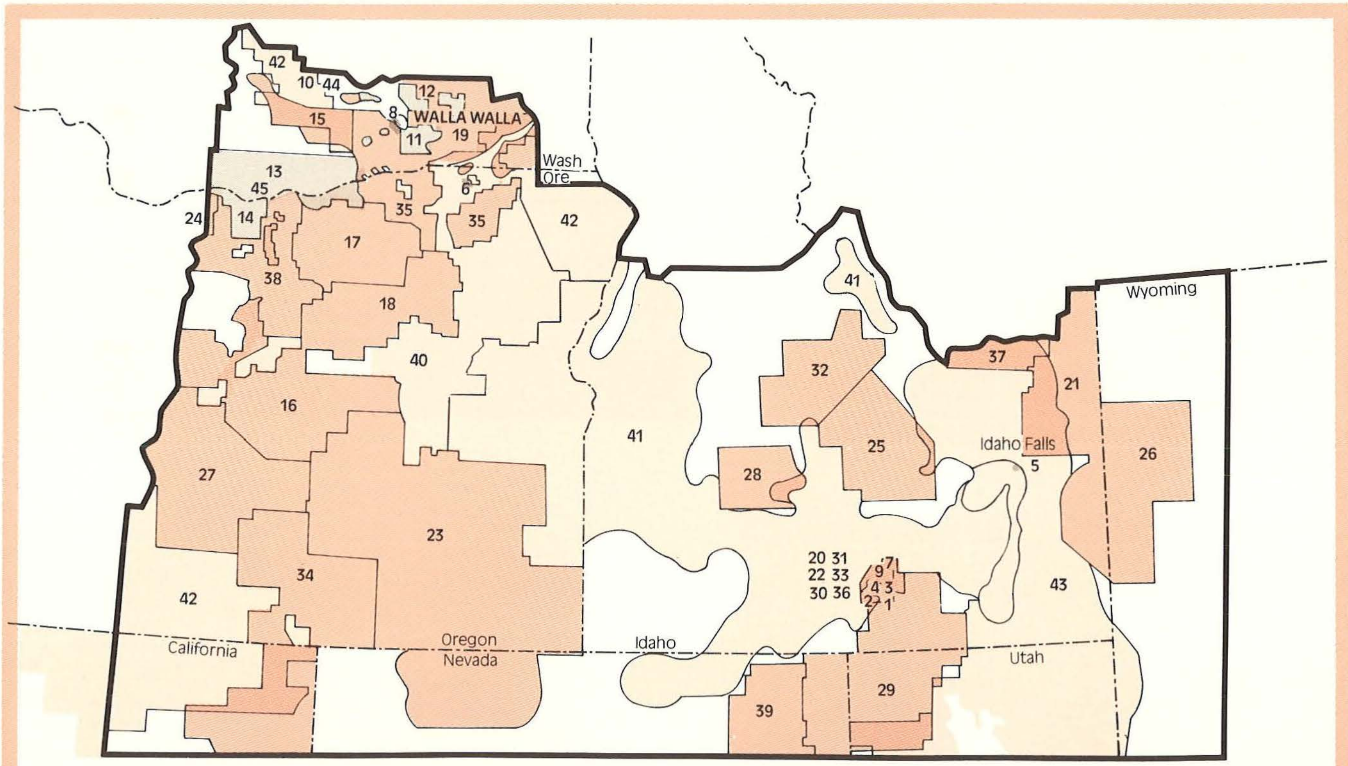
Investor-Owned

Investor-owned electric systems in the region date back to 1888 when a predecessor of Portland General Electric was formed, followed by Washington Water Power Company a year later.

Prior to 1940, some 80 percent of the electric consumers of the region got their power from investor-owned utilities, a figure that now stands closer to 50 percent.

Prior to 1953, BPA power sales contracts with investor-owned utilities were one-year contracts. In 1953, 20-year contracts were signed for sales of firm power on a computed demand basis. When these contracts expired in 1973, they were not renewed. Today, we sell to investor-owned utilities relatively

(continued on page 56)



Publicly Owned Utilities

Municipalities
1. Albion, Idaho
2. Burley, Idaho
3. Declo, Idaho
4. Heyburn, Idaho
5. Idaho Falls, Idaho
6. Milton-Freewater, Oregon
7. Minidoka, Idaho
8. Richland, Washington
9. Rupert, Idaho
10. Washington Public Power Supply System

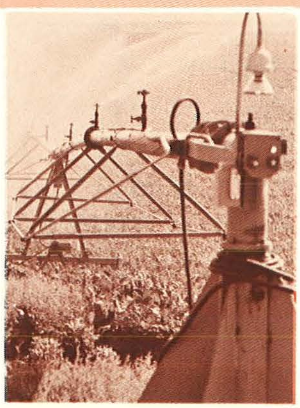
Public Utility Districts
11. Benton Co. PUD #1
12. Franklin Co. PUD #1
13. Klickitat Co. PUD #1
14. Northern Wasco Co. PUD

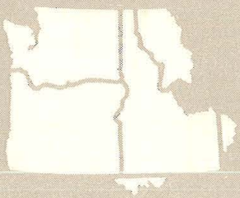
Cooperatives
15. Benton Rural Elec. Assn.
16. Central Elec. Coop.
17. Columbia Basin Elec. Coop.
18. Columbia Power Coop. Assn.
19. Columbia Rural Elec. Assoc.
20. East End Mutual Elec. Co. Ltd.
21. Fall River Elec. Coop.
22. Farmers Elec. Co.
23. Harney Elec. Coop.
24. Hood River Elec. Coop.
25. Lost River Elec. Coop.
26. Lower Valley Power & Light Co.
27. Midstate Elec. Coop.
28. Prairie Power Coop.
29. Raft River Elec. Coop.
30. Riverside Elec. Co.
31. Rural Elec. Co.
32. Salmon River Elec. Coop.
33. South Side Elec. Lines
34. Surprise Valley Elec. Corp.
35. Umatilla Elec. Coop. Assn.
36. Unity Light & Power Co.
37. Vigilante Elec. Coop.
38. Wasco Elec. Coop.
39. Wells Rural Elec. Co.

Privately-Owned Utilities
40. California-Pacific Utilities Co.
41. Idaho Power Co.
42. Pacific Power & Light
43. Utah Power Co.

Federal Agencies
44. U.S. Energy Research Development Administration

Aluminum
45. Martin Marietta Aluminum Inc. Oregon Washington





Financial Section

The Financial Year

Federal Columbia River Power Systems (FCRPS) revenues rebounded strongly from the drought-induced decline of the previous year, but due to the inadequacy of our rates to cover higher power costs the FCRPS nevertheless recorded a net loss for the second consecutive year.

Revenues increased $110 million during FY 1978 to a record total of $334 million. This increase of 49 percent was the largest year to year revenue gain in FCRPS history.

Counterbalancing this positive note, however, total expenses also increased by a substantial 26 percent. The net result was a deficit of $17 million compared to a loss of $55.9 million in the drought year of 1977, the worst year financially in our history. The largest cost increase was for purchased power, which totaled $51.1 million during FY 1978 compared to $23.7 million during FY 1977.

Nevertheless, due to many previous profitable years, on a cumulative basis net revenues still totaled a healthy $312 million as of the end of FY 1978.

One Basis for Financial Reporting...

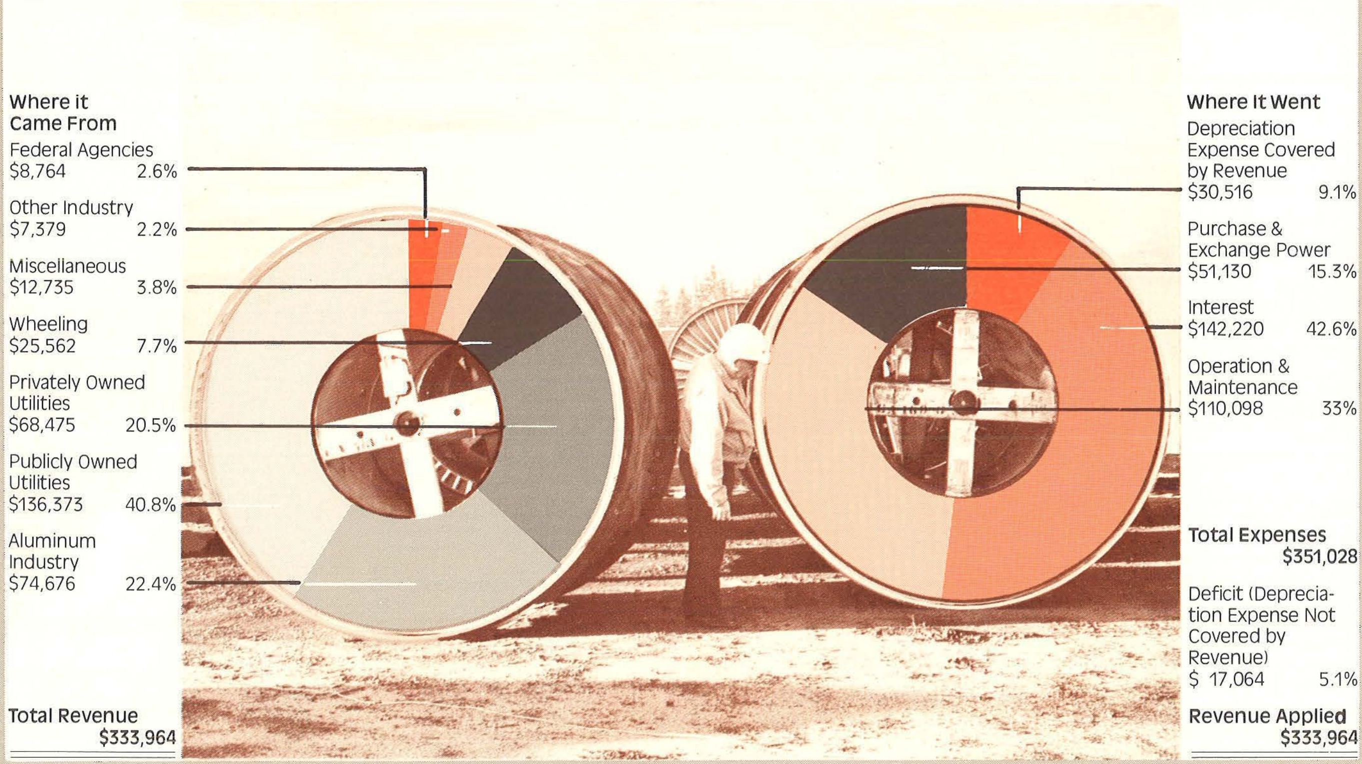
The above results are based on the accrued cost accounting method of financial reporting. BPA prepares financial statements for the FCRPS on this basis to assess its financial condition from the viewpoint of a commercial enterprise. The financial statements are independently audited by the firm of Coopers & Lybrand in accordance with generally accepted auditing standards. The complete financial statements with the auditor's opinion appear on pages 41 through 52. A graphic portrayal of financial results on this basis, together with a forecast for FY's 1979 and 1980 appears on page 31.

...Another Basis for Setting Rates

Power rates, however, are not set to match costs as determined on the cost accounting basis. Rates are based upon what is called the repayment basis. This report also includes the FCRPS repayment study for FY 1978 (table 6, pages 38 and 39, and graph on page 33) which determines the adequacy of revenues for rate making purposes.

The repayment study shows the need for a substantial increase in future revenues, i.e., it clearly demonstrates that revenues from the existing rates cannot recover all costs as required by the repayment policy. BPA's power sales contracts, however, restrict the frequency of rate adjustments. The earliest date that a rate increase can be implemented is December 20, 1979, which falls in FY 1980. The unfavorable financial results shown by both the cost accounting financial statements and the repayment study, therefore, can

Source and Disposition of Revenue Dollar.
Fiscal Year 1978 *(in thousands)*



be expected to continue until the necessary rate increase is implemented.

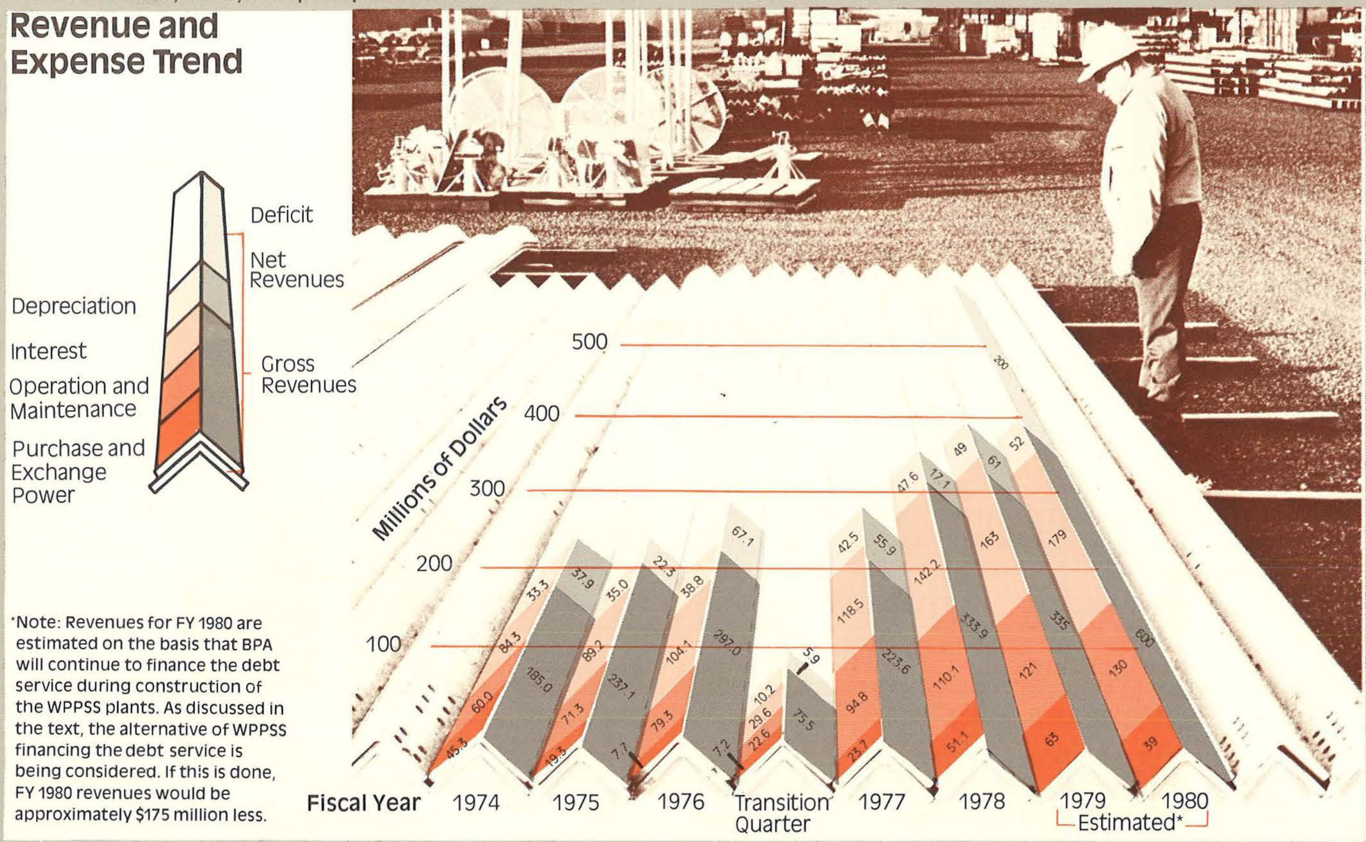
The Major Differences

The cost accounting financial statements present financial results on an annual basis. The repayment study, on the other hand, consists of long-range forecasts of future revenues and expenses and the repayment of the investment in power facilities. The two sets of financial reports, therefore, seek to measure two different things, that is, current financial results on the one hand and future financial requirements on the other.

The cost accounting financial statements include depreciation of the power facilities over their expected useful lives which extend up to 100 years in some cases. The repayment policy, however, requires that the investment in such facilities be fully repaid within 50 years following each facility being placed in service. Consequently, the level of revenue required to meet the repayment requirements is higher than needed to cover costs on the cost accounting basis. Therefore, the normal situation with a rate level sufficient to meet the repayment requirements will be for the FCRPS to produce net revenues, which equates to operating "in the black." But with the power rates now in effect, which cannot be increased until December 20, 1979, the prospects are for the deficits to continue through FY 1979. But with adequate new rates, substantial net revenues will accrue thereafter. This prospect is illustrated graphically below.

Another noteworthy difference between the cost accounting statements and the repayment study is that the latter reflects costs, such as purchased power, on a cash payment basis. The cost accounting statements, on the other hand, record such costs on the accrual basis. This results in different amounts being shown in the two sets of reports — in some cases for the same item. This is especially true of purchased power expense where the contracts under which BPA is purchasing the capability of the nuclear plants commit BPA to pay beginning on specified dates even though the plants may not have commenced operation. For example, BPA's payment for its 100 percent share of the capability of the WPPSS Nuclear Project No. 2 commenced in January 1977 even though the plant, due to construction delays, is not expected to be in operation before 1981. In this situation, the repayment study shows the amount of cash payments, but the cost accounting statements defer charging such amounts to purchased power expense until the plant starts operating. This explains the different amounts shown for purchased power for the next several years in the repayment study (pages 38 and 39) and the forecast of the cost accounting results below.

Revenue and Expense Trend



*Note: Revenues for FY 1980 are estimated on the basis that BPA will continue to finance the debt service during construction of the WPPSS plants. As discussed in the text, the alternative of WPPSS financing the debt service is being considered. If this is done, FY 1980 revenues would be approximately $175 million less.

A more complete explanation of the repayment policy is presented on page 40.

Power Rate Increase Proposal

As noted above, it has been apparent for several years that BPA must propose higher power rates to increase revenues sufficiently to assure meeting its repayment obligation in the future. BPA's last power rate increase took effect December 20, 1974. Wheeling (transmission) rates, which produce about 8 percent of total revenues, were last increased July 1, 1977, but only on an interim basis pending final approval.

The principal factors necessitating higher rates are:

1. BPA's acquisition of increasing amounts of thermal power which, while the least expensive incremental power available to it, nevertheless is substantially more costly than power from hydroelectric facilities of the Federal system built over the past several decades.
2. The overall effects of inflation, which are increasing virtually all costs.
3. Higher interest rates which must currently be paid on funds needed for new construction.

The impact of all of these factors has accelerated in recent years. However, BPA's power sales contracts for many years included a provision that power rates could be adjusted no more often than once every five years. In addition, some wheeling contracts limit wheeling rate increases to no more often than each three years. The accelerated rate at which costs have been escalating made it apparent that it would not be desirable to continue the five-year cycle for adjusting power rates. Consequently, during FY 1978 BPA proposed contract amendments which were accepted by all but one of our customers which will permit adjusting the power rates at one year intervals, if necessary, commencing July 1, 1981 (the one exception is expected to agree to the same change).

Developing proposed new power rates is a major undertaking.

A series of rate studies led us to the conclusion that approximately a 90 percent revenue increase would be needed for the rate period beginning December 20, 1979.

The new rates designed to produce this amount of additional revenue would impact different customers and different end users to varying degrees. High load factor customers would feel the greatest impact because the bulk of the increase falls on the "energy" side of our rates.

The public review of our preliminary rate proposal under the Public Involvement Procedure described on page 6 produced a large number of comments. Two basic points, however, received the most attention. These were:

1. The extent to which costs for power facilities not yet in service are included in the rate proposal.
2. The relationship between the energy and capacity components of the power rates.

The general thrust of the comments was that future costs should be excluded from the current rate proposal and that the relationship between the capacity and energy charges should be adjusted so that the capacity charge would bear proportionately more of the cost of generation and the energy charge less.

We are currently examining all comments. Significant changes may be made in the rate proposal as a result. For example, BPA and the Washington Public Power Supply System announced in late November studies of the feasibility of WPPSS issuing additional bonds to pay the interest and amortization due on the construction bonds during the entire construction period for the WPPSS nuclear plants from which BPA is acquiring plant capability. The present agreements provide that BPA pay the debt service on the construction bonds from BPA revenues starting from fixed dates which because of construction delays are now two to three years ahead of the expected completion of the plants. The proposed change in financing of the nuclear plants would permit a much lower initial rate increase by deferring the inclusion of the plants in the BPA repayment analysis until the plants are operating.

The main purpose of our further study of this potential alternative method of financing debt service prior to commencement of commercial operation of these plants is to assure that immediate benefits to power consumers would not be overshadowed by the higher costs in the long term.

To obtain approval and implement the new rates by the December 20, 1979, date fixed by the power sales contracts, BPA plans to issue a revised rate proposal by March 1979 taking into account all comments received on the preliminary proposal. The revised proposal will undergo further public review and comment. A final proposal is expected to be submitted for approval to the Department of Energy by June 1979.

Approval of BPA Power Rates

Prior to the establishment of the Department of Energy in October 1977, BPA power rates by law had to be approved by the Federal Power Commission. The legislation which created the DOE, however, abolished the FPC and created two new regulatory agencies within the DOE, the Economic Regulatory Administration (ERA) and the Federal Energy Regulatory Commission (FERC). ERA is headed by a single Administrator reporting directly to the Secretary, but FERC is a quasi-independent five-member commission.

Upon the initial establishment of DOE, the Secretary delegated authority to ERA to approve the rates of all Federal power marketing agencies, including BPA. However, a new delegation order was approved effective January 1, 1979, assigning authority for final approval of all power marketing agency rates to FERC.

Wheeling Rates

As previously reported, BPA proposed new wheeling rates for approval by the old FPC in June 1976. The FPC approved implementing the new wheeling rates, which increased wheeling revenues by about 22 percent, for a one year interim period commencing July 1, 1977. The ERA assumed jurisdiction of the wheeling rate case when it was established effective October 1, 1977. In June 1978 ERA approved a one year extension of the interim approval through June 30, 1979. Final approval of the wheeling rates is still pending.

The cost-of-service study prepared in conjunction with the preliminary power rate proposal indicates that a future increase in BPA wheeling rates will be needed. As some of the wheeling contracts limit rate adjustments to once each three years, the earliest opportunity for implementing a wheeling rate increase presumably will be July 1, 1980. BPA intends to develop proposed new wheeling rates to be proposed for approval by July 1, 1980.

BPA Financing

As reported last year, BPA utilized its borrowing authority under the Federal Columbia River Transmission System Act for the first time on September 30, 1977. At that time we obtained a $125 million one-year cash advance from the U.S. Treasury.

That initial advance was repaid in full on September 30, 1978.

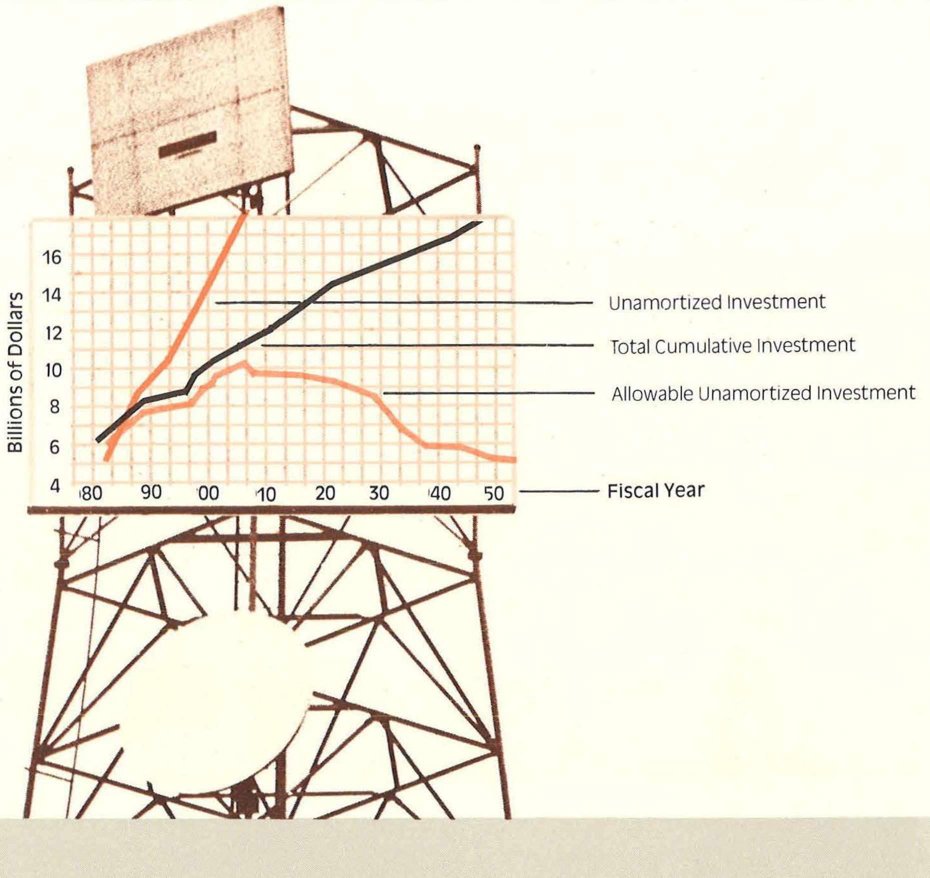
To meet our cash needs for our construction program during FY 1979, we obtained a new one-year cash advance on September 30, 1978, in the amount of $250 million. In addition, we issued our initial long-term bond to the Treasury in the amount of $50 million. The bond, which has a term of 35 years, bears an interest rate of 8.95 percent and the one-year cash advance bears interest at 9.125 percent.

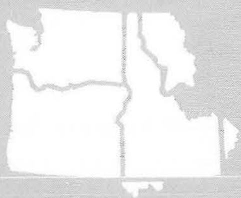
Under the terms of the Transmission System Act, the Treasury sets the interest rates on BPA's bonds and cash advances based upon its assessment of the interest rates that would have to be paid on securities of comparable quality if sold in the open market.

BPA now anticipates that it will be borrowing from the Treasury on a regular basis each year to finance the continuation of its construction program. BPA's need to borrow is determined by analysis of its cash position. The BPA cash flow forecast through FY 1980 is shown on table 5 on page 37.

Repayment Study Chart

Fiscal Year 1978





Tables

Table 1

Electric Energy Account

Fiscal Year 1978

Energy Received (millions of kilowatthours)	
Energy Generated for BPA:	
Bureau of Reclamation	19,909
Corps of Engineers	59,457
Hanford Steamplant (NPR)	4,050
Centralia Thermal Project	2,117
Trojan Nuclear Plant	1,116
Other Generation	318
Power Interchanged In	62,532
Total Received	149,499
Energy Delivered (millions of kilowatthours)	
Sales	76,511
Power Interchanged Out	68,800
Used by Administration	65
Total Delivered	145,376
Energy Losses in Transmission	4,123
Total	149,499
Losses as Percent of Total Received	2.8
Maximum Demand on Generation (kilowatts)	14,447,000
(Date & Time) January 27, 1978, 9 a.m.	
Load Factor	68.7

Table 2

Generation by the Principal Electric Utility Systems of the Pacific Northwest

Fiscal Year — 1978[1]

Utility	Kilowatt-hours (Billions)	Of Total Generation (Percent)
Publicly Owned:		
Federal Columbia River Power System[2]	87.0	54.2
Grant County PUD	10.4	6.5
Chelan County PUD	7.7	4.8
Seattle City Light	6.1	3.8
Douglas County PUD	3.8	2.4
Tacoma City Light	2.5	1.6
Eugene Water & Electric Board	0.5	0.3
Pend Oreille County PUD	0.5	0.3
Total Publicly Owned	118.5	73.9
Privately Owned:		
Idaho Power Company	10.8	6.7
Pacific Power & Light Company	12.1	7.5
Montana Power Company	6.8	4.2
Washington Water Power Co.	4.9	3.1
Portland General Electric Co.	5.1	3.2
Puget Sound Power & Light Co.	2.2	1.4
Total Privately Owned	41.9	26.1
Total Generation	160.4	100.0

[1]Generation shown is for members of the Northwest Power Pool plus Pend Oreille County PUD and Washington Public Power Supply System. Utah Power & Light Co., British Columbia Hydro and Power Authority and West Kootenay Power and Light, who are members of the Power Pool, are not included because their service area lies outside the Pacific Northwest.

[2]Includes generation from the Washington Public Power Supply System's Hanford steamplant (NPR), Okanogan PUD's share of Wells, the municipalities of Forest Grove, McMinnville, and Milton-Freewater share of Priest Rapids and Wanapum and the Federal share of the Centralia steamplant and the Trojan Nuclear Plant.

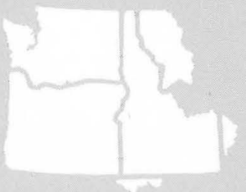


Table 3
Federal Columbia River Power System

General Specifications, Projects Existing, Under Construction and Authorized

Nameplate Rating of Installations as of December 31, 1978

					Existing		Under Construction		Authorized		Other Potential		Total	
Project	Operating Agency[1]	Location	Stream	Initial Date in Service	Number of Units	Total Capability Kilowatts	Number of Units	Total Capability Kilowatts	Number of Units	Total Capability Kilowatts	Number of Units	Total Capability Kilowatts	Number of Units	Total Capability Kilowatts
Bonneville	CE	Ore.-Wash.	Columbia	Jun. 1938	10	518,400	8-2	558,000[6]	—	—	—	—	18-2	1,076,400
Grand Coulee	BR	Washington	Columbia	Sep. 1941	22-3	4,763,000[2]	2	1,400,000[3]	—	—	6	4,200,000	30-3	10,363,000
Grand Coulee (Pump Generator)		Washington	Columbia-Banks Lake	Dec. 1974	2	100,000	4	200,000	—	—	—	—	6	300,000
Hungry Horse	BR	Montana	S. Fk. Flathead	Oct. 1952	4	285,000	—	—	—	—	—	—	4	285,000
Detroit	CE	Oregon	North Santiam	Jul. 1953	2	100,000	—	—	—	—	—	—	2	100,000
McNary	CE	Ore.-Wash.	Columbia	Nov. 1953	14	980,000	—	—	10	1,050,000	—	—	24	2,030,000
Big Cliff	CE	Oregon	North Santiam	Jun. 1954	1	18,000	—	—	—	—	—	—	1	18,000
Lookout Point	CE	Oregon	M. Fk. Willamette	Dec. 1954	3	120,000	—	—	—	—	—	—	3	120,000
Albeni Falls	CE	Idaho	Pend Oreille	Mar. 1955	3	42,600	—	—	—	—	—	—	3	42,600
Dexter	CE	Oregon	M. Fk. Willamette	May 1955	1	15,000	—	—	—	—	—	—	1	15,000
Chief Joseph	CE	Washington	Columbia	Aug. 1955	23	1,689,000	4	380,000	—	—	13	1,573,000	40	3,642,000
Chandler	BR	Washington	Yakima	Feb. 1956	2	12,000	—	—	—	—	—	—	2	12,000
The Dalles	CE	Ore.-Wash.	Columbia	May 1957	22-2	1,807,000[4]	—	—	—	—	—	—	22-2	1,807,000
Roza	BR	Washington	Yakima	Aug. 1958	1	11,250	—	—	—	—	—	—	1	11,250
Ice Harbor	CE	Washington	Snake	Dec. 1961	6	602,880	—	—	—	—	—	—	6	602,880
Hills Creek	CE	Oregon	M. Fk. Willamette	May 1962	2	30,000	—	—	—	—	—	—	2	30,000
Minidoka	BR	Idaho	Snake	May 1909	7	13,400	—	—	—	—	—	—	7	13,400
Boise Diversion	BR	Idaho	Boise	May 1912	3	1,500	—	—	—	—	—	—	3	1,500
Black Canyon	Br	Idaho	Payette	Dec. 1925	2	8,000	—	—	—	—	—	—	2	8,000
Anderson Ranch	BR	Idaho	S. Fk. Boise	Dec. 1950	2	27,000	—	—	—	—	1	13,500	3	40,500
Palisades	BR	Idaho	Snake	Feb. 1957	4	118,750	—	—	—	—	2	135,000	6	253,750
Cougar	CE	Oregon	S. Fk. McKenzie	Feb. 1964	2	25,000	—	—	1	35,000	—	—	3	60,000
Green Peter	CE	Oregon	Middle Santiam	Jun. 1967	2	80,000	—	—	—	—	—	—	2	80,000
Foster	CE	Oregon	South Santiam	Aug. 1968	2	20,000	—	—	—	—	—	—	2	20,000
John Day	CE	Ore.-Wash.	Columbia	Jul. 1968	16	2,160,000	—	—	4	540,000	—	—	20	2,700,000
Lower Monumental	CE	Washington	Snake	May 1969	3	405,000	3	405,000	—	—	—	—	6	810,000
Little Goose	CE	Washington	Snake	May 1970	6	810,000	—	—	—	—	—	—	6	810,000
Dworshak	CE	Idaho	N. Fk. Clearwater	Sep. 1974	3	400,000	—	—	3	660,000	—	—	6	1,060,000
Lower Granite	CE	Washington	Snake	Apr. 1975	6	810,000	—	—	—	—	—	—	6	810,000
Libby	CE	Montana	Kootenai	Aug. 1975	4	420,000	4	420,000	—	—	—	—	8	840,000
Teton[5]	BR	Idaho	Teton	—	—	—	—	—	3	30,000[5]	—	—	3	30,000
Lost Creek	CE	Oregon	Rogue	Dec. 1977	2	49,000	—	—	—	—	—	—	2	49,000
Libby Reregulating	CE	Montana	Kootenai	—	—	—	3	76,400	—	—	—	—	3	76,400
Strube	CE	Oregon	S. Fk. McKenzie	—	—	—	—	—	1	4,500	—	—	1	4,500
Total Installed Capacity						16,441,780		3,439,400		2,319,500		5,921,500		28,122,180
Total Number of Projects						30		1		2		0		33

[1]CE — Corps of Engineers; BR — Bureau of Reclamation
[2]Includes three service units, an increase of 17,000 kW each for 17 rewound main units, three 600,000 kW units and one 700,000 kW unit at the Third Powerplant.
[3]Two 700,000 kW units being installed at the Third Powerplant.
[4]Includes two fishway units of 13,500 kW each, 14 units of 78,000 kW each, and 8 units of 86,000 kW each at The Dalles Powerplant.
[5]Teton Dam ruptured June 5, 1976. Future status is unknown.
[6]Includes two fishway units of 13,000 kW each at the Bonneville Second Powerplant.

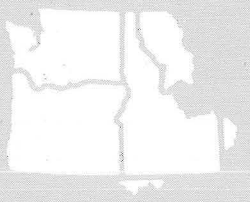


Table 4
Sales of Electric Energy
Fiscal Year 1978

Customer	KWH (000)	Sales
NORTHWEST AREA		
Publicly Owned Utilities		
Municipalities		
Albion, Idaho	2,915	$ 12,808
Bandon, Oregon	53,605	236,341
Blaine, Washington	38,418	160,956
Bonners Ferry, Idaho	32,234	155,991
Burley, Idaho	96,232	380,706
Canby, Oregon	83,524	371,311
Cascade Locks, Oregon	32,031	133,620
Centralia, Washington	108,723	480,499
Cheney, Washington	96,347	407,674
Consolidated Irrigation District, Washington	1,350	8,625
Coulee Dam, Washington	18,242	74,445
Declo, Idaho	2,483	11,745
Drain, Oregon	26,245	113,955
Eatonville, Washington	10,942	46,979
Ellensburg, Washington	142,016	569,798
Eugene, Oregon	1,496,682	4,891,995
Fircrest, Washington	42,264	178,805
Forest Grove, Oregon	54,803	201,069[1]
Heyburn, Idaho	69,285	275,991
Idaho Falls, Idaho	359,812	1,467,294
McCleary, Washington	32,221	141,869
McMinnville, Oregon	219,672	844,558[1]
Milton, Washington	24,114	103,070
Milton-Freewater, Oregon	32,833	123,621[1]
Minidoka, Idaho	1,065	4,557
Monmouth, Oregon	57,469	260,678
Port Angeles, Washington	566,195	2,313,237
Richland, Washington	455,755	1,923,647
Rupert, Idaho	60,836	262,216
Seattle, Washington	2,069,276	6,168,510[1]
Springfield, Oregon	657,493	2,534,617
Steilacoom, Washington	35,985	155,745
Sumas, Washington	6,690	29,059
Tacoma, Washington	2,156,274	6,253,763[1]
Vera Irrigation District, Washington	128,756	550,571
Wash. Public Power Supply System	45,371	163,767
Total Municipalities (36)	**9,318,158**	**$ 32,014,092**
PUBLIC UTILITY DISTRICTS		
Benton Co. PUD #1	1,072,032	$ 4,208,319
Central Lincoln PUD	1,068,134	4,085,627
Chelan Co. PUD #1	208,709	998,512[1]
Clallam Co. PUD #1	400,416	1,724,252
Clark Co. PUD #1	2,338,901	9,132,844
Clatskanie PUD	629,812	2,312,313
Cowlitz Co. PUD #1	2,556,197	8,346,223[1]
Douglas Co. PUD #1	291,657	1,003,086[1]
Ferry Co. PUD #1	50,260	208,855
Franklin Co. PUD #1	477,171	1,820,907
Grant Co. PUD #2	634,024	2,210,671[1]
Grays Harbor Co. PUD #1	1,193,805	4,420,192
Kittitas Co. PUD #1	24,270	99,869[1]
Klickitat Co. PUD #1	223,129	849,782
Lewis Co. PUD #1	615,375	2,384,515
Mason Co. PUD #1	52,035	223,934
Mason Co. PUD #3	349,699	1,432,975
Northern Wasco Co. PUD	205,235	851,349
Okanogan Co. PUD #1	380,329	1,526,020
Pacific Co. PUD #2	250,131	1,094,867
Pend Oreille Co. PUD #1	4,841	12,101
Skamania Co. PUD #1	90,888	378,618
Snohomish Co. PUD #1	4,258,434	16,220,444
Tillamook Co. PUD	323,104	1,379,796
Wahkiakum Co. PUD #1	43,275	185,246
Whatcom Co. PUD #1	124,758	399,909
Total PUD's (26)	**17,866,621**	**$ 67,511,226**

Customer	KWH (000)	Sales
Cooperatives		
Alder Mutual Light Co.	2,045	$ 8,996
Benton Rural Elec. Assn.	219,167	878,997
Big Bend Elec. Coop.	365,242	1,323,821
Blachly-Lane Co. Coop. Elec. Assn.	111,262	463,762
Central Elec. Coop.	234,937	960,873
Clearwater Power Co.	143,510	627,612
Columbia Basin Elec. Coop.	130,618	463,608
Columbia Power Coop. Assn.	30,448	116,820
Columbia Rural Elec. Assn.	141,396	540,421
Consumers Power	288,846	1,239,969
Coos-Curry Elec. Coop.	226,497	899,216
Douglas Elec. Coop.	127,591	541,576
East End Mutual Elec. Co. Ltd.	10,942	44,883
Elmhurst Mutual Power & Light Co.	131,814	550,147
Fall River Elec. Coop.	110,338	456,925
Farmers Elec. Co.	7,132	32,413
Flathead Elec. Coop.	100,816	411,563
Glacier Elec. Coop.	38,796	121,880
Harney Elec. Coop.	130,973	430,040
Hood River Elec. Coop.	80,430	337,506
Idaho Co. Light & Power Coop. Assn.	34,418	146,116
Inland Power & Light Co.	378,214	1,595,656
Kootenai Elec. Coop., Inc.	143,162	601,036
Lakeview Light & Power Co., Inc.	182,128	744,686
Lane Co. Elec. Coop.	224,419	978,373
Lincoln Elec. Coop.—Mont.	49,491	210,724
Lincoln Elec. Coop.—Wash.	112,277	407,003
Lost River Elec. Coop.	57,648	189,152
Lower Valley Power & Light Co.	221,817	861,748
Midstate Elec. Coop.	143,643	560,674
Missoula Elec. Coop.	93,867	385,885
Nespelem Valley Elec. Coop.	37,763	160,292
Northern Lights	125,356	499,463
Ohop Mutual Light Co.	26,607	118,102
Okanogan Co. Elec. Coop.	24,896	103,707
Orcas Power & Light Co.	97,439	422,022
Parkland Light & Water Co.	91,769	385,853
Peninsula Light Co.	226,426	986,914
Prairie Power Coop.	8,797	36,309
Raft River Elec. Coop.	194,206	657,086
Ravalli Elec. Coop.	67,125	277,260
Riverside Elec. Co.	5,971	26,861
Rural Elec. Co.	63,508	262,647
Salem Elec.	206,076	847,998
Salmon River Elec. Coop.	35,439	118,791
South Side Elec. Lines	25,574	101,422
Surprise Valley Elec. Corp.	80,841	292,446
Tanner Elec.	20,241	90,814
Umatilla Elec. Coop. Assn.	568,104	1,966,905
Unity Light & Power Co.	42,071	167,961
Vigilante Elec. Coop.	84,294	315,522
Wasco Elec. Coop.	84,529	357,977
Wells Rural Elec. Co.	41,547	155,005
West Oregon Elec. Coop.	60,419	257,310
Total Cooperatives (54)	**6,492,882**	**$ 25,740,748**
Total Publicly Owned Utilities (116)	**33,677,661**	**$125,266,066**
Federal Agencies		
U.S. Dept. of Energy—Richland Operations	349,532	$ 1,195,899
U.S. Bureau of Mines	6,973	36,879
Fairchild Air Force Base	24,519	91,667
U.S. Bureau of Indian Affairs	99,256	446,725
U.S. Bureau of Reclamation—Roza	27,041	108,158
U.S. Navy	238,383	942,766
Total Federal Agencies (6)	**745,704**	**$ 2,822,094**

Customer	KWH (000)	Sales
Privately-Owned Utilities		
CP National	13,956	$ 44,558
Idaho Power Co.	797,477	2,572,145
Pacific Power & Light Co.	3,007,434	14,964,006[1]
Portland General Elec. Co.	2,210,098	11,564,466[1]
Puget Sound Power & Light Co.	1,540,251	6,382,179[1]
The Montana Power Co.	780,881	2,708,124
The Washington Water Power Co.	804,791	2,874,276[1]
Utah Power Co.	653,454	2,039,144
Total Privately-Owned (8)	9,808,342	$ 43,148,898
Aluminum		
Aluminum Co. of America (combined)[2]	4,015,697	$ 10,069,694
Anaconda Aluminum Co.	2,782,203	6,343,839
Intalco Aluminum Co.	3,378,139	8,415,299
Kaiser Alum. & Chem. Corp. (combined)[2]	5,204,297	12,359,041
Martin Marietta Aluminum Inc.		
Oregon	1,363,178	2,842,806
Washington	1,697,877	3,511,454
Reynolds Metals Co. (combined)[2]	5,500,784	13,606,843
Total Aluminum (6)	23,942,175	$ 57,148,976
Other Industries		
Cominco American Inc.	0	0
Crown Zellerbach Corp.	89,829	236,904
Georgia Pacific Corp.	103,148	264,981
Hanna Nickel Smelting Co.	706,132	1,888,677
Oregon Metallurgical Corp.	32,402	148,456
Pacific Carbide & Alloys Co.	60,085	157,924
Pennwalt Corporation	343,331	869,520
Stauffer Chemical Works	445,366	1,140,291
Stewart Elsner	25	328
The Carborundum Co.	200,106	536,142
Union Carbide Corp.	110,543	284,278
Total Other Industries (11)	2,090,967	$ 5,527,501
Total Northwest Region (147)	70,264,849	$233,913,535
Outside Northwest Region		
British Columbia Hydro & Power	16,960	$ 50,880
Burbank, California	109,599	606,366
Glendale, California	124,848	671,729
Los Angeles, California	964,475	3,456,435
Pasadena, California	53,430	191,774
Sacramento, California	0	0
Pacific Gas & Elec. Co.	2,064,223	15,589,000[1]
San Diego Gas & Elec. Co.	306,129	1,970,972
Southern California Edison Co.	1,386,918	5,126,133
State of California	2,676	8,028
Western Area Power Administration		
Mid-Pacific Region	971,488	3,753,493[1]
Upper Missouri Region	200,000	2,000,000
Upper Colorado Region	45,491	140,491
Total Outside Northwest Region (13)	6,246,237	$ 33,565,301
Total Sales of Electric Energy (160)	76,511,086	$267,478,836[3]

[1]Includes capacity sales
[2]See table below
[3]Based on actual billings not including cost accounting accruals

	Pro rata break down by plant location	
Customer	MWH	Revenue
Aluminum Co. of America		
Addy	385,507	$ 966,691
Vancouver	1,791,001	4,491,083
Wenatchee	1,839,189	4,611,920
Kaiser Alum. & Chem. Corp.		
Spokane Reduction	3,466,062	8,231,121
Spokane Rolling	457,978	1,087,596
Tacoma Reduction	1,280,257	3,040,324
Reynolds Metals Co.		
Longview	3,338,976	8,259,354
Troutdale	2,161,808	5,347,489

Table 5

BPA Cash Flow Forecast

(In Millions of Dollars)

	Fiscal Year	
	1979	1980
SOURCE OF FUNDS		
Revenues	335	600
Miscellaneous Receipts	1	1
Borrowing (Net)[1]	123	71
Total Received	459	672
APPLICATION OF FUNDS		
Net-billing	135	147
BPA O&M	68	71
BPA construction	112	123
Bond int. & amort.	25	28
Payments due Treasury	(202)	(303)
amount paid	119	303
amount deferred	(83)	
Total Payments	459	672
Cumulative Borrowing (Net)[1]	423	494
Borrowing Limitation[2]	423	556

[1]BPA borrowing from the U.S. Treasury includes the sale of long-term bonds as well as use of short-term cash advances to finance construction work in progress. Interest is payable on the net amount of the short-term advances actually used, with any unused cash remaining on deposit in the BPA Fund until needed or until repaid to the Treasury. To assure having sufficient cash to cover normal variations in the receipt and expenditure of cash, BPA ordinarily obtains a gross cash advance sufficient to cover forecasted expenditures plus a reserve. The amount of borrowing shown on this table is the net amount, i.e., the long-term bonds outstanding plus the amounts of the short-term advances expended.

[2]The borrowing limitation is the cumulative total of expenditures for construction, including capitalized interest during construction, since BPA went on the self-financing basis.

Table 6
Federal Columbia River Power System

Repayment Study for 1978

Authorized Projects

(All Amounts in $1,000)

1	2	3	4	5	6	7	8	9	10	11
								PLANT ALLOCATED TO		
					Investment Placed in Service			Cumulative Investment in Service		
Fiscal Year Ending Sept. 30	Revenues	Operation and Maintenance Expense	Purchase and Exchange Power	Interest Expense	Initial Project	Replace-ments	Total	Initial Project	Replace-ments	Total
Cumulative 1978	3,632,915	1,073,937	464,546	1,361,962	5,547,837		5,547,837	5,547,837		5,547,837
1979	337,000	118,220	134,000	178,863	610,269	27,197	637,466	6,158,106	27,197	6,185,303
1980	345,000	121,679	100,363	200,355	140,000	64,338	204,338	6,298,106	91,535	6,389,641
1981	358,000	125,562	118,017	230,007	329,475	40,085	369,560	6,627,581	131,620	6,759,201
1982	379,000	130,133	177,529	260,177	424,125	57,626	481,752	7,051,707	189,246	7,248,953
1983	389,000	130,729	196,527	279,424	43,000	33,068	76,068	7,094,707	222,314	7,317,021
1984	396,000	132,758	176,529	318,134	388,546	39,951	428,497	7,483,253	262,265	7,745,518
1985	408,000	133,914	176,529	332,730	3,000	42,866	45,866	7,486,253	305,131	7,791,384
1986	422,000	133,964	176,529	345,073		40,143	40,143	7,486,253	345,274	7,831,527
1987	429,000	133,964	176,529	358,759		53,452	53,452	7,486,253	398,726	7,884,979
1988	429,000	133,964	176,529	373,509		45,717	45,717	7,486,253	444,443	7,930,696
1989	417,000	133,964	176,529	391,194		57,760	57,760	7,486,253	502,203	7,988,456
1990	416,000	133,964	176,529	410,969		68,444	68,444	7,486,253	570,647	8,056,900
1991	415,000	133,964	176,529	432,384		61,292	61,292	7,486,253	631,939	8,118,192
1992	414,000	133,964	176,529	458,756		127,453	127,453	7,486,253	759,392	8,245,645
1993	412,000	133,964	176,529	490,870	96,574	53,689	150,263	7,582,827	813,081	8,395,908
1994	413,000	137,084	176,529	564,793	604,100	84,507	688,607	8,186,927	897,588	9,084,515
1995	421,000	138,484	177,529	608,856		60,128	60,128	8,186,927	957,716	9,144,643
1996	422,000	138,484	177,529	650,188	131,200	100,069	231,269	8,318,127	1,057,785	9,375,912
1997	430,000	141,888	177,529	701,800	131,000	87,173	218,173	8,449,127	1,144,958	9,594,085
1998	440,000	143,848	177,529	732,262		63,307	63,307	8,449,127	1,208,265	9,657,392
1999	445,000	143,848	177,529	767,582		73,700	73,700	8,449,127	1,281,965	9,731,092
2000	448,000	143,848	176,529	804,436		66,810	66,810	8,449,127	1,348,775	9,797,902
2001	448,000	143,848	176,529	843,833		86,344	86,344	8,449,127	1,435,119	9,884,246
2002	448,000	143,848	177,529	888,419		109,889	109,889	8,449,127	1,545,008	9,994,135
2003	449,000	143,848	177,529	932,340		65,861	65,861	8,449,127	1,610,869	10,059,996
2004	450,000	143,848	177,529	977,745		75,026	75,026	8,449,127	1,685,895	10,135,022
2005	450,000	143,848	177,529	1,025,631		73,580	73,580	8,449,127	1,759,475	10,208,602
2006	450,000	143,848	177,529	1,077,484		96,892	96,892	8,449,127	1,856,367	10,305,494
2007	450,000	143,848	176,529	1,137,663		160,279	160,279	8,449,127	2,016,646	10,465,773
2008	449,000	143,848	176,529	1,198,761		72,983	72,983	8,449,127	2,089,629	10,538,756
2009	449,000	143,848	177,529	1,264,188		87,313	87,313	8,449,127	2,176,942	10,626,069
2010	447,000	143,848	177,529	1,356,277		118,306	118,306	8,449,127	2,295,248	10,744,375
2011	443,000	143,848	161,529	1,462,674		203,721	203,721	8,449,127	2,498,969	10,948,096
2012	442,000	143,848	142,529	1,575,170		206,065	206,065	8,449,127	2,705,034	11,154,161
2013	442,000	143,848	41,806	1,690,280		111,854	111,854	8,449,127	2,816,888	11,266,015
2014	442,000	143,848	41,806	1,791,986		89,758	89,758	8,449,127	2,906,646	11,355,773
2015	442,000	143,848	41,806	1,897,914		79,841	79,841	8,449,127	2,986,487	11,435,614
2016	437,000	143,848	41,806	2,021,191		212,101	212,101	8,449,127	3,198,588	11,647,715
2017	422,000	143,848		2,154,597		97,178	97,178	8,449,127	3,295,766	11,744,893
2018	422,000	143,848		2,309,578		107,880	107,880	8,449,127	3,403,646	11,852,773
2019	421,000	143,848		2,492,626		80,109	80,109	8,449,127	3,483,755	11,932,882
2020	420,000	143,848		2,700,747		170,571	170,571	8,449,127	3,654,326	12,103,453
2021	418,000	143,848		2,861,977		153,072	153,072	8,449,127	3,807,398	12,256,525
2022	418,000	143,848		3,031,839		140,840	140,840	8,449,127	3,948,238	12,397,365
2023	418,000	143,848		3,209,757		85,879	85,879	8,449,127	4,034,117	12,483,244
2024	418,000	143,848		3,396,823		91,259	91,259	8,449,127	4,125,376	12,574,503
2025	418,000	143,848		3,598,173		142,270	142,270	8,449,127	4,267,646	12,716,773
2026	418,000	143,848		3,811,615		114,787	114,787	8,449,127	4,382,433	12,831,560
2027	418,000	143,848		4,037,976		107,983	107,983	8,449,127	4,490,416	12,939,543
2028	418,000	143,848		4,277,414		87,433	87,433	8,449,127	4,577,849	13,026,976
2029	418,000	143,848		4,531,656		104,304	104,304	8,449,127	4,682,153	13,131,280
2030	418,000	143,848		4,800,925		84,531	84,531	8,449,127	4,766,684	13,215,811
2031	418,000	143,848		5,087,310		127,803	127,803	8,449,127	4,894,487	13,343,614
2032	418,000	143,848		5,393,495		145,418	145,418	8,449,127	5,039,905	13,489,032
2033	418,000	143,848		5,716,178		85,215	85,215	8,449,127	5,125,120	13,574,247
2034	418,000	143,848		6,057,673		94,637	94,637	8,449,127	5,219,757	13,668,884
2035	418,000	143,848		6,420,726		89,021	89,021	8,449,127	5,308,778	13,757,905
2036	418,000	143,848		6,807,493		106,222	106,222	8,449,127	5,415,000	13,864,127
2037	418,000	143,848		7,219,378		103,468	103,468	8,449,127	5,518,468	13,967,595
2038	418,000	143,848		7,655,842		88,663	88,663	8,449,127	5,607,131	14,056,258
2039	418,000	143,848		8,117,280		98,471	98,471	8,449,127	5,705,602	14,154,729
2040	418,000	143,848		8,608,647		107,323	107,323	8,449,127	5,812,925	14,262,052
2041	418,000	143,848		9,130,035		116,876	116,876	8,449,127	5,929,801	14,378,928
2042	418,000	143,848		9,687,616		171,103	171,103	8,449,127	6,100,904	14,550,031
2043	418,000	143,848		10,277,864		89,167	89,167	8,449,127	6,190,071	14,639,198
2044	418,000	143,848		10,903,314		105,191	105,191	8,449,127	6,295,262	14,744,389
2045	418,000	143,848		11,570,905		134,844	134,844	8,449,127	6,430,106	14,879,233
2046	418,000	143,848		12,281,889		210,393	210,393	8,449,127	6,640,499	15,089,626
2047	418,000	143,848		13,033,785		126,865	126,865	8,449,127	6,767,364	15,216,491
2048	418,000	143,848		13,830,918		140,002	140,002	8,449,127	6,907,366	15,356,493
2049	418,000	143,848		14,676,412		101,103	101,103	8,449,127	7,008,469	15,457,596
2050	418,000	143,848		15,574,152		107,292	107,292	8,449,127	7,115,761	15,564,888
Totals	33,980,915	11,218,528	6,440,547	267,661,254	8,449,127	7,115,761	15,564,888			

12	13	14	15	16	17	18	19	20	21	22
COMMERCIAL POWER						IRRIGATION ASSISTANCE				
		Allowable Unamortized Investment								
Amorti-zation	Unamortized Investment	Initial Project	Replace-ments	Total	Cumulative Amount in Service	Amorti-zation	Unamortized Amount	Allowable Unamortized Amount	Cumulative Surplus Revenues	Fiscal Year Ending Sept. 30
732,470	4,815,367	5,480,935		5,480,935	607,631		607,631	607,631		
94,083—	5,546,916	6,089,423	27,197	6,116,620	607,631		607,631	607,631		1979
77,397—	5,828,651	6,224,751	91,535	6,316,286	608,160		608,160	608,160		1980
115,586—	6,313,797	6,551,006	131,620	6,682,626	608,162		608,162	608,162		1981
188,839—	6,984,388	6,972,029	189,246	7,161,275	608,667		608,667	608,667		1982
217,680—	7,278,136	7,005,271	222,314	7,227,585	653,964		653,964	653,964		1983
231,421—	7,938,054	7,384,289	262,264	7,646,553	687,843		687,843	687,843		1984
235,173—	8,219,093	7,357,054	305,103	7,662,157	751,678		751,678	751,678		1985
233,566—	8,492,802	7,336,748	345,220	7,681,968	785,455		785,455	785,455		1986
240,252—	8,786,506	7,309,159	398,623	7,707,782	825,057		825,057	825,057		1987
255,002—	9,087,225	7,240,713	444,328	7,685,041	850,787		850,787	850,787		1988
284,687—	9,429,672	7,195,614	501,985	7,697,599	889,038		889,038	889,038		1989
305,462—	9,803,578	7,161,202	570,327	7,731,529	911,421		911,421	911,421		1990
327,877—	10,192,747	7,077,185	631,558	7,708,743	936,942		936,942	936,942		1991
355,249—	10,675,449	7,017,116	758,772	7,775,888	983,230		983,230	983,230		1992
389,363—	11,215,075	7,023,280	812,279	7,835,559	1,016,225		1,016,225	1,016,225		1993
465,406—	12,369,088	7,594,618	896,641	8,491,259	1,043,666		1,043,666	1,043,666		1994
503,869—	12,933,085	7,583,859	955,992	8,539,851	1,071,235		1,071,235	1,071,235		1995
544,201—	13,708,555	7,692,629	1,055,870	8,748,499	1,094,343		1,094,343	1,094,343		1996
605,937—	14,532,665	7,777,434	1,142,176	8,919,610	1,117,553	14,720	1,102,833	1,102,833		1997
613,639—	15,209,611	7,740,652	1,204,524	8,945,176	1,130,302		1,115,582	1,115,582		1998
643,959—	15,927,270	7,695,411	1,276,675	8,972,086	1,166,385		1,151,665	1,151,665		1999
676,813—	16,670,893	7,624,022	1,340,779	8,964,801	1,204,286		1,189,566	1,189,566		2000
726,458—	17,483,695	7,556,871	1,425,570	8,982,441	1,227,069	10,248	1,202,101	1,202,101		2001
761,796—	18,355,380	7,453,139	1,519,677	8,972,816	1,249,950		1,224,982	1,224,982		2002
804,717—	19,225,958	7,225,238	1,583,891	8,809,129	1,272,649		1,247,681	1,247,681		2003
849,903—	20,150,887	7,016,384	1,656,515	8,672,899	1,295,445	781	1,269,696	1,269,696		2004
897,008—	21,121,475	6,648,425	1,728,037	8,376,462	1,326,691		1,300,942	1,300,942		2005
948,851—	22,167,228	6,473,111	1,803,684	8,276,795	1,355,074		1,329,325	1,329,325		2006
1,008,040—	23,335,547	6,235,907	1,962,526	8,198,433	1,392,127		1,366,378	1,366,378		2007
1,073,089—	24,481,619	6,003,371	2,034,481	8,037,852	1,422,757	2,951	1,394,057	1,394,057		2008
1,142,806—	25,711,738	5,876,936	2,119,817	7,996,753	1,453,801	6,241	1,418,860	1,418,860		2009
1,230,654—	27,060,698	5,730,221	2,234,762	7,964,983	1,469,389		1,434,448	1,434,448		2010
1,325,051—	28,589,470	5,632,657	2,437,002	8,069,659	1,493,155		1,458,214	1,458,214		2011
1,420,050—	30,215,585	5,401,109	2,628,819	8,029,928	1,517,020	503	1,481,576	1,481,576		2012
1,471,552—	31,798,991	5,310,615	2,738,204	8,048,819	1,550,904	37,618	1,477,842	1,477,842		2013
1,576,950—	33,465,699	5,177,080	2,822,726	7,999,806	1,579,128	41,310	1,464,756	1,464,756		2014
1,686,336—	35,231,876	5,037,080	2,897,612	7,934,692	1,607,352	44,768	1,448,212	1,448,212		2015
1,834,110—	37,278,087	4,941,080	3,104,014	8,045,094	1,628,996	64,265	1,405,591	1,405,591		2016
1,931,643—	39,306,908	4,881,241	3,196,029	8,077,270	1,650,640	55,198	1,372,037	1,372,037		2017
2,051,698—	41,466,486	4,717,287	3,299,225	8,016,512	1,684,568	20,272	1,385,693	1,385,693		2018
2,275,608—	43,822,203	4,413,915	3,376,115	7,790,030	1,713,815	60,134	1,354,806	1,354,806		2019
2,451,133—	46,443,907	4,157,353	3,507,584	7,664,937	1,745,990	26,538	1,360,443	1,360,443		2020
2,606,494—	49,203,473	4,085,267	3,647,618	7,732,885	1,775,237	18,669	1,371,021	1,371,021		2021
2,775,219—	52,119,532	4,085,267	3,747,842	7,833,109	1,795,858	17,532	1,374,110	1,374,110		2022
2,941,731—	55,147,142	3,993,057	3,829,555	7,822,612	1,816,479	6,126	1,388,605	1,388,605		2023
3,140,063—	58,378,464	3,898,982	3,908,227	7,807,209	1,836,660	17,392	1,391,394	1,391,394		2024
3,332,653—	61,853,387	3,242,526	4,041,597	7,284,123	1,856,842	8,632	1,402,944	1,402,944		2025
3,556,898—	65,525,072	2,738,405	4,151,645	6,890,050	1,884,628	19,435	1,411,295	1,411,295		2026
3,783,926—	69,416,981	2,667,038	4,229,130	6,896,168	1,912,414	20,102	1,418,979	1,418,979		2027
4,021,605—	73,526,019	2,411,290	4,313,387	6,724,677	1,932,009	18,343	1,420,231	1,420,231		2028
4,270,458—	77,900,781	1,823,021	4,366,357	6,189,378	1,951,605	12,954	1,426,873	1,426,873		2029
4,529,238—	82,514,550	1,823,021	4,417,461	6,240,482	1,987,875	2,465	1,460,678	1,460,678		2030
4,822,372—	87,464,725	1,589,546	4,467,500	6,057,046	2,022,972	9,214	1,486,561	1,486,561		2031
5,119,343—	92,729,486	1,069,420	4,523,502	5,592,922	2,055,438		1,519,027	1,519,027		2032
5,442,026—	98,256,727	1,069,420	4,572,361	5,641,781	2,086,578		1,550,167	1,550,167		2033
5,791,033—	104,142,397	738,874	4,619,153	5,358,027	2,105,362	7,512	1,561,439	1,561,439		2034
6,167,006—	110,398,424	738,874	4,664,863	5,403,737	2,123,986	20,432	1,559,631	1,559,631		2035
6,568,895—	117,073,541	738,874	4,709,480	5,448,354	2,123,986	35,554	1,524,077	1,524,077		2036
6,977,213—	124,154,222	738,874	4,753,148	5,492,022	2,123,986	31,987	1,492,090	1,494,090		2037
7,381,690—	131,624,575	738,874	4,795,754	5,534,618	2,123,986		1,492,090	1,492,090		2038
7,857,376—	139,580,422	738,874	4,837,421	5,576,295	2,123,986	14,248	1,477,842	1,477,842		2039
8,334,495—	148,022,240	738,874	4,878,053	5,616,927	2,123,986		1,477,842	1,477,842		2040
8,884,233—	157,023,349	738,874	4,917,836	5,656,710	2,123,986	28,350	1,449,492	1,449,492		2041
9,441,991—	166,636,443	738,874	4,956,766	5,695,640	2,123,986	28,527	1,420,965	1,420,965		2042
10,034,770—	176,760,380	642,300	4,995,224	5,637,524	2,123,986	31,058	1,389,907	1,389,907		2043
10,693,228—	187,558,799	131,200	5,032,953	5,164,153	2,123,986	64,066	1,325,841	1,325,841		2044
11,338,761—	199,032,404	131,200	5,070,006	5,201,206	2,123,986	42,008	1,283,833	1,283,833		2045
12,022,738—	211,265,535		5,106,743	5,106,743	2,123,986	15,001	1,268,832	1,268,832		2046
12,780,458—	224,172,858		5,143,255	5,143,255	2,123,986	20,825	1,248,007	1,248,007		2047
13,582,496—	237,895,356		5,179,430	5,179,430	2,123,986	25,730	1,222,277	1,222,277		2048
14,440,511—	252,436,970		5,216,102	5,216,102	2,123,986	38,251	1,184,026	1,184,026		2049
15,322,383—	267,866,645		5,252,967	5,252,967	2,123,986	22,383	1,161,643	1,161,643		2050
252,301,757—						962,343				

Repayment Policy

Federal Columbia River Power System revenues from power sales, wheeling service and other miscellaneous sources must be sufficient to satisfy the following repayment criteria:

1. Pay the cost of obtaining power through purchase and exchange agreements.
2. Pay the cost of operating and maintaining the power system.
3. Pay interest on and amortize outstanding revenue bonds sold to the Treasury to finance transmission system construction.
4. Pay interest on the unamortized investment in power facilities financed with appropriated funds. (Federal hydroelectric projects and BPA transmission facilities constructed prior to BPA's authorization to finance its construction program with sales receipts and revenue bonds were financed with appropriated funds.)
5. Repay:
   a. Each increment of the power investment at the Federal hydroelectric projects within 50 years after such increment becomes revenue producing.
   b. Each annual increment of the investment in the BPA transmission system previously financed with appropriated funds within the average service life of the transmission facilities (currently 35 years).
   c. The investment in each replacement of a facility at a Federal hydroelectric project within its service life. (In repaying the investment financed with appropriated funds, the investment bearing the highest interest rate will be amortized first to the extent possible while still completing repayment of each increment of investment within its prescribed repayment period.)
6. Repay the portion of construction costs at Federal reclamation projects which is beyond the ability of the irrigation water users, and which is assigned for repayment from commercial power revenues, within the same overall period available to the water users for making their repayments. These periods range from 40 to 66 years, with 60 years being applicable to most of the irrigation repayment assistance.

The FY 1978 Repayment Study (Table 6, pages 38 and 39), prepared in accordance with the foregoing criteria, shows that cumulative revenues through September 30, 1978, totaled $3,633 million. These have been applied to pay purchase and exchange power costs of $465 million, operation and maintenance costs of $1,074 million, interest costs of $1,362 million, with $732 million having been applied to amortization of the investment in power facilities. Cumulative power investment to be repaid from power revenues totaled $5,547 million with the unamortized balance totaling $4,815 million.

Starting with these cumulative results, the repayment study forecasts future revenues and costs over the balance of the repayment period. Costs and revenues are included for all Federal hydroelectric projects which are (1) currently in service, (2) under construction, and (3) authorized by Congress and scheduled for construction by the constructing agency, plus the costs of the transmission facilities necessary to market the output of these projects as well as handle the other sources of power transmitted by BPA. The repayment study also includes BPA power purchase costs for which payment is currently being made by BPA.

This repayment study shows that revenues are insufficient to meet all of the repayment criteria; i.e., the investment is not repaid within the permissible 50-year period.

The repayment study demonstrating complete repayment of all costs with the revenues from the proposed rates was included in the cost of service study prepared in conjunction with the BPA rate proposal. The cost-of-service study was made available to all interested parties through the Public Participation Program.

Accountants' Report

Coopers & Lybrand
Certified Public Accountants

Administrator
Bonneville Power Administration
United States Department of Energy

We have examined the statement of assets and liabilities of the Federal Columbia River Power System (FCRPS) as of September 30, 1978 and 1977, and the related statements of revenues, expenses and accumulated net revenues and source and use of funds for the fiscal years then ended. Our examinations were made in accordance with generally accepted auditing standards and, accordingly, included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Recorded revenues are based upon rates for service established in accordance with the Bonneville Project Act and related legislation which are intended to provide for the full recovery of all FCRPS costs and repayment to the U.S. Treasury of its investment in power facilities and assigned irrigation costs within repayment periods established pursuant to such statutory requirements. As discussed in Note 1 to the financial statements, revenues needed to recover the costs of generating facilities are based on required repayment periods which are shorter than the periods over which such facilities are being depreciated, and the periods over which required net billed projects payments are recovered through revenues differ from the periods in which such payments are included in operating expenses. Under generally accepted accounting principles, revenues based upon cost recovery and the related costs should be included in the determination of net revenues in the same accounting period. Accordingly, the financial statements are not intended to present financial position and results of operations in conformity with generally accepted accounting principles. The financial statements are, however, appropriately presented in accordance with accounting principles required by or appropriate to applicable legislation and executive directives of other government agencies, as described in Note 1, and in accordance with accounting principles and standards prescribed by the Comptroller General of the United States.

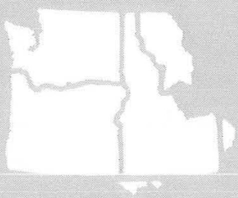
As described in Note 3, certain utility plant cost and operation and maintenance expenses relating to multi-purpose projects have been allocated on a tentative basis between power and nonpower purposes, and the amount of adjustments, if any, that may be necessary when allocations become firm is not determinable at this time.

In our opinion, subject to the effects, if any, on the financial statements of the ultimate resolution of the tentative cost allocations referred to above and the outcome of the wheeling rate proceeding described in Note 1, such financial statements present fairly the assets and liabilities of the Federal Columbia River Power System at September 30, 1978 and 1977, and its revenues, expenses and accumulated net revenues and source and use of funds for the fiscal years then ended, in conformity with accounting principles described in Note 1 applied on a consistent basis.

Supplemental Schedule A showing the amount and allocation of plant investment as of September 30, 1978 was subjected to the audit procedures applied in the examination of the basic financial statements and in our opinion, subject to the effects, if any, on Schedule A of the ultimate resolution of the tentative cost allocations referred to above, is fairly stated in all material respects in relation to the basic financial statements taken as a whole.

Portland, Oregon
December 15, 1978

Coopers & Lybrand



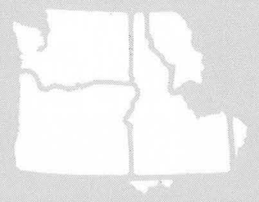
Federal Columbia River Power System

Statement of Revenues, Expenses and Accumulated Net Revenues

for the fiscal years ended September 30, 1978 and 1977

	Fiscal Year 1978	Fiscal Year 1977
	(Thousands of Dollars)	
OPERATING REVENUES (Note 1):		
Sales of electric power:		
Publicly owned utilities	$136,373	$125,292
Privately owned utilities	68,475	24,299
Federal agencies	8,764	3,530
Aluminum industry	74,676	37,401
Other industry	7,379	4,083
	295,667	194,605
Other operating revenues:		
Wheeling	25,562	19,060
Other	12,735	9,927
	38,297	28,987
Total operating revenues	333,964	223,592
OPERATING EXPENSES:		
Operation	68,184	55,772
Maintenance	41,914	39,019
Total operation and maintenance expense	110,098	94,791
Purchase and exchange power (Note 1)	51,130	23,719
Depreciation	47,580	42,495
Total operating expenses	208,808	161,005
Net operating revenues	125,156	62,587
INTEREST EXPENSE (INCOME) (Notes 2, 3, 4 and 7):		
Interest on Federal investment:		
On appropriated funds	162,869	151,913
On Transmission System Act borrowings	6,210	
Allowance for funds used during construction	(26,859)	(28,373)
Interest income		(5,047)
Net interest expense	142,220	118,493
NET REVENUES (EXPENSE)	(17,064)	(55,906)
ACCUMULATED NET REVENUES:		
Balance at beginning of period	329,142	385,048
Balance at end of period	$312,078	$329,142

The accompanying notes are an integral part of the financial statements.



Federal Columbia River Power System

Statement of Assets and Liabilities

at September 30, 1978 and 1977

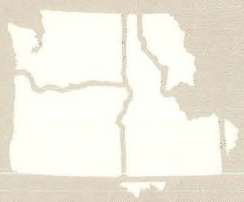
Assets

	September 30 1978	September 30 1977
	(Thousands of Dollars)	
UTILITY PLANT (Notes 2 and 3):		
Completed plant (Schedule A)	$5,386,878	$4,979,967
Accumulated depreciation	(427,884)	(392,603)
	4,958,994	4,587,364
Construction work in progress (Schedule A)	758,028	817,335
Net utility plant	5,717,022	5,404,699
CURRENT ASSETS:		
Unexpended funds (Note 4)	78,981	94,482
Accounts receivable	14,957	6,674
Accrued unbilled revenues	18,373	11,843
Materials and supplies, at average cost	25,981	25,833
Total current assets	138,292	138,832
OTHER ASSETS AND DEFERRED CHARGES:		
Trust funds (Note 6)	5,967	13,386
Net billing advances, less amortization (Note 5)	153,445	97,449
Investment in Teton Dam (Note 9)	13,637	13,717
Other	9,540	10,359
Total other assets and deferred charges	182,589	134,911
	$6,037,903	$5,678,442

Liabilities and Federal Investment

	1978	1977
FEDERAL INVESTMENT:		
Investment of U.S. Government in power facilities:		
Congressional appropriations	$6,461,889	$6,206,970
U.S. Treasury transfers to Continuing Fund	7,005	7,005
Transfers from other Federal agencies, net	48,885	41,338
Federal Columbia River Transmission System Act borrowings (Note 2)	300,000	125,000
Interest on Federal investment	1,791,551	1,622,472
Less funds returned to U.S. Treasury	(2,974,088)	(2,780,280)
Net investment of U.S. Government (Note 7)	5,635,242	5,222,505
Accumulated net revenues	312,078	329,142
Irrigation assistance (Schedule A and Note 8) $608 million and $590 million, respectively		
Total federal investment	5,947,320	5,551,647
COMMITMENTS AND CONTINGENCIES: (Notes 1, 2, 3, 5, 8, 9 and 10)		
CURRENT LIABILITIES:		
Accounts payable	71,006	99,135
Employees accrued leave	7,874	7,544
Total current liabilities	78,880	106,679
DEFERRED CREDITS:		
Trust fund advances (Note 6)	5,967	13,386
Other	5,736	6,730
Total deferred credits	11,703	20,116
	$6,037,903	$5,678,442

The accompanying notes are an integral part of the financial statements.



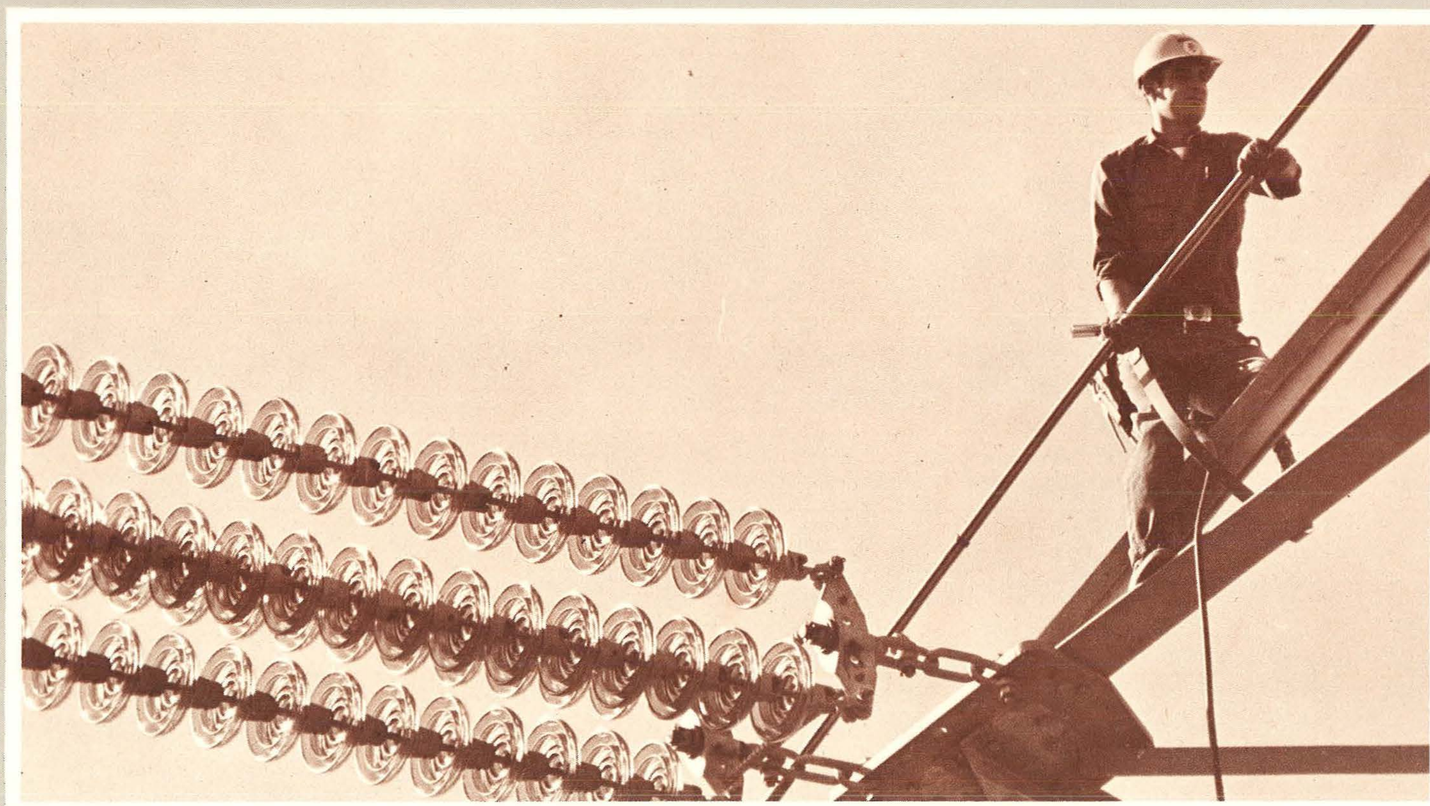
Federal Columbia River Power System

Statement of Source and Use of Funds

for the fiscal years ended September 30, 1978 and 1977

	Fiscal Year	
	1978	1977
	(Thousands of Dollars)	
Source of Funds:		
Operations:		
Net revenues (expense)	$ (17,064)	$ (55,906)
Charges not requiring funds:		
Depreciation	47,580	42,495
Amortization of net billing advances (Note 1)	10,010	913
Funds provided from (used in) operations	40,526	(12,498)
Change in net investment of U.S. Government (Note 7)	412,737	392,844
Decrease (increase) in current assets:		
Unexpended funds	15,501	(23,829)
Investment in U.S. Government securities		34,208
Receivables	(14,813)	27,690
Materials and supplies	(148)	(361)
Increase (decrease) in current liabilities	(27,799)	24,347
Total source of funds	$426,004	$442,401
Use of Funds:		
Investment in utility plant, net	$359,903	$377,796
Increase in net billing advances	66,006	62,872
Other, net	95	1,733
Total use of funds	$426,004	$442,401

The accompanying notes are an integral part of the financial statements.



Federal Columbia River Power System

Notes to Financial Statements

Note 1. Basis of Preparation of Financial Statements and Summary of Significant Accounting Policies:

General

The Federal Columbia River Power System (FCRPS) includes the accounts of the Bonneville Power Administration (BPA), which purchases, transmits and markets power, and the accounts representing the Pacific Northwest generating facilities of the Corps of Engineers (Corps) and the Bureau of Reclamation (Bureau) for which BPA is the power marketing agency. Each entity is separately managed and financed, but the facilities are operated as an integrated power system with the financial results combined under the FCRPS title. Costs of multipurpose Corps and Bureau projects are assigned to the individual purposes through a cost allocation process. The portion of total project costs allocated to power is included in these statements as Utility Plant. Schedule A lists the projects included in FCRPS and the allocation of plant investment to the various purposes. Properties and income are exempt from taxation.

Accounts are kept in accordance with standards and principles prescribed by the Comptroller General of the United States and the uniform system of accounts prescribed for electric utilities by the Federal Energy Regulatory Commission (FERC). FCRPS accounting policies described herein also reflect requirements of specific legislation and executive directives issued by the involved government departments (BPA is a unit of the Department of Energy; the Bureau is a part of the Department of Interior and the Corps of the Department of Defense).

Revenues

Operating revenues are recorded on the basis of service rendered. The region-wide drought during most of fiscal year 1977 reduced BPA sales of electric power in that year.

Rates established under requirements of the Bonneville Project Act and related legislation are intended to provide sufficient cash to meet all required payments for system costs (including operating expenses, repayment to the U.S. Treasury for debt service on borrowings and for its investment in power facilities and interest thereon, and costs of net billed thermal projects and assigned irrigation costs — see Notes 5, 7 and 8). The rates are also required to be low enough to encourage widespread use of electric energy at the lowest possible cost to consumers consistent with sound business principles.

If revenues in any year are not sufficient to meet all required payments, the order of priority for use of revenues is: net billing credits; additional payments required for net billed thermal projects and BPA operating expenses; debt service on Federal Columbia River Transmission System Act borrowings from the U.S. Treasury; Corps and Bureau operating expenses; interest on and then amortization of the Federal investment in power facilities financed through appropriations; irrigation repayment assistance. Presently no irrigation repayment assistance is required until 1997. If insufficient cash is available to meet all payment obligations, the priority order for the application of revenues will be used in reverse order to determine what payments will be deferred. There is no fixed annual requirement for payment of the power investment or assigned irrigation costs, the only requirement being that repayments be completed within prescribed periods. Payments to repay an investment bearing a higher rate of interest may be scheduled ahead of other investments bearing a lower rate to the extent that this is possible while still complying with prescribed repayment periods.

The rates are intended to provide for recovery of the capital investment in transmission facilities within their average estimated useful service lives and within 50 years for power generating facilities. As set forth below, these assets are being depreciated in the accounts on a compound interest method over their estimated useful lives, which currently average approximately 35 years for transmission facilities and 85 years for generating facilities. Thus, annual depreciation charges are not matched with the recovery of the related capital costs and will, in the case of generating facilities, continue beyond the period within which such costs will have been recovered through revenues. Also, provision is currently being made in the rates for recovery of advances for net billed thermal projects under construction, which amounts will not be charged to expense until the projects become operational.

Regulatory Authorities

BPA power and transmission rate schedules, formerly subject to confirmation and approval by the Federal Power Commission (FPC), are currently subject to confirmation and approval by the Economic Regulatory Administration (ERA) of the U.S. Department of Energy which was created by Congressional action, effective as of October 1, 1977. It is expected that confirmation and approval authority over BPA rates will be transferred from ERA to FERC.

Under terms of BPA's current power sales contracts, rates can only be adjusted as of December 20, 1979 or July 1, 1980; July 1, 1981 and each July 1 thereafter. The present rates were approved by the FPC effective on December 20, 1974. Wheeling rates charged for transmission of nonfederal power were increased approximately 22% on July 1, 1977 under a temporary FPC rate order final approval of which is currently pending before the ERA. Revenues applicable to these rate increases, which revenues are subject to refund with interest in the event of regulatory disapproval, totaled approximately $6,500,000 and $750,000 at September 30, 1978 and 1977, respectively.

Utility Plant and Depreciation

Utility plant is stated at original cost. Cost includes direct labor and materials, payments to contractors, indirect charges for engineering, supervision and similar overhead items, and an allowance for funds used during construction. The cost of additions, renewals and betterments is capitalized. Repairs and minor replacements are charged to operating expenses. With minor exceptions, the cost of utility plant retired, together with removal costs and less salvage, is charged to accumulated depreciation when it is removed from service.

Depreciation of utility plant is computed based on the estimated service lives of the various classes of property using the compound interest method (rates from 2½% to 3¼%). Service lives currently average approximately 35 years for transmission plant and 85 years for generating plant. Based on a study of depreciable lives and salvage values, effective October 1, 1977, the estimated average service life of transmission plant was reduced from 40 to 35 years. This change increased 1978 depreciation expense by approximately $600,000.

Depreciation provisions recorded in the accounts, expressed as a percent of the average cost of transmission and generating plant in service, approximated 1.9% and .4%, respectively, in each of the periods presented.

The compound interest method adopted pursuant to executive directives of government agencies results in increasing depreciation charges in the later years of service lives.

Allowance for Funds Used During Construction

The practice of capitalizing an allowance for funds used during construction is followed. Rates used are based upon interest rates stipulated for certain generating projects (2½% to 3¼%) and rates approximating the cost of borrowings from the U.S. Treasury for other construction (6% to 7% during 1978 and 1977).

Thermal Plant Net Billing Advances and Amortization

Net billing agreements (see Note 5) provide that BPA make payments and/or grant billing credits prior to a nuclear project's date of commercial operation. Additionally, after the date of commercial operation amounts are payable by BPA (principally related to fuel purchases, major plant additions and additions to debt service reserves) prior to the periods in which related economic benefits accrue. Such amounts are included as deferred charges under the caption "net billing advances" in the accompanying statement of assets and liabilities. These advances are amortized ratably over the project lives (approximately 35 years) or over lesser specific periods benefited and, together with other annual project costs, are included in purchase and exchange power expense. As a result of a redetermination of the periods to be benefited by net billing advances made in prior years, 1978 purchase and exchange power expense was increased by approximately $4.8 million.

Research and Development

Research and development costs, including depreciation of the cost of facilities constructed for research and development activities, are charged to expense. Costs charged to expense totaled approximately $8.5 million in 1978 and $2.9 million in 1977.

Retirement Benefits

Substantially all employees engaged in FCRPS activities participate in the Federal government's Civil Service Retirement Fund, a contributory pension plan. Retirement benefit expense is equivalent to 7% of eligible employee compensation.

Note 2. Financing of FCRPS Construction Program:

The Federal Columbia River Transmission System Act (Act), approved October 18, 1974, authorized BPA to use its operating receipts and proceeds from sales of revenue bonds, which the Act authorized it to issue, to finance further construction of the Federal transmission system in the Pacific Northwest. Prior to the enactment of this legislation, the transmission system construction program was financed through the appropriation process. During fiscal year 1976 BPA expended all unused portions of prior construction appropriations and commenced financing its construction program through use of its operating receipts and borrowing authority. Construction performed by the Corps and the Bureau continues to be financed through annual Congressional appropriations. In order to assist in financing the construction, acquisition and replacement of the transmission system, the Act authorized BPA to issue to the U.S. Treasury and have outstanding at any time up to $1.25 billion of bonds, notes or other evidences of indebtedness bearing interest and having terms and conditions comparable to those prevailing in the market for similar utility debt instruments. On September 30, 1977 BPA borrowed $125 million at 6.73%, repayable on or before September 30, 1978. On September 30, 1978, BPA repaid the $125 million and borrowed $300 million ($250 million at 9.125% repayable on or before September 30, 1979 and $50 million at 8.95% due in 35 years). BPA's borrowing authority within the aforementioned $1.25 billion maximum is limited at any one time to its cumulative expenditures for transmission plant (including capitalized interest) which have not been financed from appropriations. At September 30, 1978, BPA had borrowed all but approximately $3 million available with this limitation at that date. BPA has the option, which it intends to exercise, to convert the $250 million into long-term bonds having maturities and subject to such terms and conditions as may be prescribed by the Treasury.

BPA's construction budget for fiscal year 1979 is $123 million, for which substantial commitments have been incurred. Fiscal 1979 construction appropriations for power facilities have been authorized by Congress for the Corps and the Bureau totaling $193 million and $28 million, respectively.

Note 3. Tentative Cost Allocations:

Allocations of plant cost and operation and maintenance expenses between power and nonpower purposes for six system projects are presently based on tentative allocations. At September 30, 1978, total costs for these six projects approximated $2.1 billion of which $1.5 billion was tentatively allocated to power and subject to adjustment. In prior years, adjustments were made to plant cost and to accumulated net revenues (for adjustments relating to operation and maintenance, interest or depreciation) when firm allocations were adopted. The amount of adjustments that may be necessary when the allocations for these six projects become firm is not determinable at this time. The final cost allocation was made for the Dworshak project in 1978, resulting in a $7.1 million decrease in power utility plant and a $1.3 million decrease in power expenses since commencement of operations, which decrease has been recorded in 1978 expense ($.2 million operation and maintenance, $1.0 million interest, $.1 million depreciation).

Note 4. Unexpended Funds:

Unexpended funds consist of the unexpended balance of funds appropriated by Congress for construction, operation and maintenance purposes for the Corps and Bureau, and cash balances of BPA. Amounts shown in the statement of assets and liabilities comprise:

	September 30, 1978	September 30, 1977
	(Thousands of Dollars)	
Corps and Bureau unexpended appropriated funds	$57,110	$59,781
BPA cash balances with U.S. Treasury	21,871	34,701
	$78,981	$94,482

The Treasury credits FCRPS with interest on unexpended appropriated funds by deducting them from the unamortized federal investment in determining the required interest on the federal investment. Prior to the commencement of its self-financing borrowing activity on September 30, 1977, BPA made temporary investments in U.S. Government securities. Beginning in 1978, BPA receives credit for its cash balances in determining interest expense on outstanding Treasury borrowings. The interest expense on Treasury borrowings in 1978 reflects a reduction of $2.2 million arising from credits for cash balances.

Note 5. Commitments to Exchange Power and Acquire Project Capability:

Existing net billing and exchange agreements provide that BPA will acquire all or part of the generating capability of the nuclear power plants listed in the table below. BPA is obligated to make payments, exchange power, or apply credits (net billings) to participating customers equal to the customers' portions of the annual project costs, including annual debt service requirements, whether or not the projects are completed, operable, or operated. Annual project budgets have not included provisions for any future costs associated with spent fuel reprocessing, off-site storage of spent fuel or plant decommissioning.

The "Present Termination Commitment" represents the outstanding debt issued to finance the projects (without credit for salvage of assets or unspent construction funds) which would be payable over the varied financing repayment periods if the projects were terminated as of September 30, 1978:

Projects and % Capability Acquired	Projected in Service Date	Estimated BPA Portion: Capacity in Megawatts	Estimated BPA Portion: Present Termination Commitment	Estimated BPA Portion: Additional Estimated Financing Requirements for Projects under Construction
			(Thousands of Dollars)	
WPPSS* Hanford Project (100%)	Operational	860	$ 51,565	
Net billed projects:				
Trojan Nuclear project (30%)	Operational	339	152,100	
WPPSS* Nuclear Project #1 (100%)	Dec. 1982	1,250	715,000	$703,000
WPPSS* Nuclear Project #2 (100%)	Dec. 1980	1,100	973,500	198,500
WPPSS* Nuclear Project #3 (70%)	Jan. 1984	868	680,000	351,000

*Washington Public Power Supply System

BPA's commitment period under the net billing agreements extends for the life of the projects, except that the terms of the Trojan Nuclear Project net billing agreements under which Eugene Water & Electric Board (Eugene) assigned its 30% share of the project output to BPA and other participants contain a provision allowing Eugene to withdraw the project capability for use in its own system beginning in 1984. Eugene has until July 1, 1979 to give BPA notification of its intention to withdraw project capability.

The net billing agreements provide for the repayment by Eugene to BPA of the net billing advances existing at the dates related capability is withdrawn. It is expected that any withdrawal would be in annual increments over a period of years. No such withdrawal options exist for the WPPSS projects. See Note 1 for information concerning net billing advances. Amounts shown therefor in the accompanying statements of assets and liabilities comprise:

	1978	1977
	(Thousands of Dollars)	
Trojan Nuclear Project, net of accumulated amortization of $10,923 and $913	$ 39,972	$41,912
Washington Public Power Supply System Nuclear Project No. 2 (under construction)	113,473	55,537
	$153,445	$97,449

BPA has also entered into agreement with a group of utilities to exchange an agreed amount of power for their rights to the Canadian Entitlement (one-half of the additional power benefits realized by downstream U.S. projects from three Canadian Treaty dams). The Canadian Entitlement was purchased for a 30-year period from the completion of each dam (the last dam was placed in service in 1973) by 41 Pacific Northwest utilities. BPA furnishes specified amounts of power to the utilities regardless of entitlement power generated. BPA's minimum average energy commitment to the utilities declines annually from approximately 690 megawatts currently to approximately 100 megawatts in the last year of the exchange agreement (2003).

Note 6. Trust Funds and Trust Fund Advances:

Balance sheet amounts are comprised of funds received by BPA from customers and others for the purchase of nonfederal power for customers' benefit and for construction to be done for others.

Note 7. Net Investment of U.S. Government:

The Federal investment in each of the generating projects and for each year's investment in the transmission system is being repaid to the U.S. Treasury within 50 and 35 years, respectively, from the time the facility is placed in service. No such repayments are required during the next five years. However, amounts are normally expected to be paid annually for interest on outstanding Federal investment, net of interest capitalized on projects financed through appropriations, and for operating expenses of the Corps and Bureau funded by annual appropriations. To the extent that funds are not available for payment, such amounts become payable from the subsequent year's revenue prior to any repayment of Federal investment. At September 30, 1978 all such required annual amounts were paid or accrued. See Note 1, revenues caption, for the priority order for the application of revenues.

Interest rates (other than on Transmission System Act borrowings) range from 2½% to 6⅛% (the weighted average rate was approximately 3.2% in 1977 and 1978). The rates have been set either by law, by administrative order pursuant to law, or by administrative policies and have not necessarily been established to recover the interest costs to the U.S. Treasury to finance the investment. See Note 1 — Revenues and Note 8 for additional information concerning repayment requirements and policies.

Following is an analysis of changes in the Net Investment of U.S. Government:

	1978	1977
	(Thousands of Dollars)	
Federal appropriations	$ 254,919	$ 288,490
Transfers from other Federal agencies, net	7,547	1,799
Federal Columbia River Transmission System Act borrowings	175,000	125,000
Interest on Federal investment	169,079	151,913
Gross investment of U.S. Government	606,545	567,202
Funds returned to U.S. Treasury	(193,808)	(174,358)*
Change in net investment of U.S. Government	412,737	392,844
Balance, beginning of period	5,222,505	4,829,661
Balance, end of period	$5,635,242	$5,222,505

*Includes $3.825 million accrued.

Note 8. Repayment Responsibility for Irrigation Costs:

Legislation requires that FCRPS net revenues will be used to repay to the U.S. Treasury that portion of the cost allocated to irrigation of any Pacific Northwest project authorized by Congress and determined by the Secretary, Department of Interior, to be beyond the ability of the irrigation water users to repay. The use of power revenues for such repayment represents a payment for irrigation assistance to the benefiting water users and, while paid by power rate payers, such costs do not represent a regular operations cost of the power program and are not included therein. The $608 million in irrigation assistance payments shown as payable from power revenues (detailed in Schedule A) will be reflected as reductions of accumulated net revenues at the time future payments are made. The first payment is scheduled to be made in 1997. The $608 million does not include any portion of $21 million of costs allocated to irrigation at six Corps projects where completion of irrigation facilities is not yet authorized. If completion is authorized, a determination of water users' repayment ability will probably be made which might result in additional irrigation assistance being payable from accumulated net power revenues.

Note 9. Teton Dam:

On June 5, 1976, before the project had been completed and turned over for the use of FCRPS, a breach occurred in the Teton Dam. The project was extensively damaged, and a vast amount of damage occurred downstream from the resulting flood. The total investment in the project at September 30, 1978 (excluding interest totaling approximately $949,000 subsequent to June 1976 which has been charged to expense) was $77.7 million. The amount of investment allocated to power was $13.6 million, and the amount of investment allocated to irrigation but repayable from power revenues was $48.2 million.

Disposition of the project's costs and final decision as to the repayment obligation are dependent upon Department of the Interior administrative action and/or Congressional action. If repayment is not required, the cost associated with the investment in power facilities will be charged off against the investment of the U.S. Government. Should FCRPS be directed to repay, the costs will be recovered through rates. Until a decision is made, the investment allocated to power is included as a deferred charge in the statement of assets and liabilities and the cost of applicable irrigation assistance is included in the total of other irrigation costs described in Note 8.

FCRPS will not be required to repay the costs of claims of non-federal entities and individuals resulting from failure of Teton Dam. The Congress enacted legislation to pay the costs of these claims and stipulated that all such payments would be non-reimbursable.

Note 10: Litigation:

The Confederated Tribes of the Colville Indians and the Spokane Indian Tribes (the Tribes) have asserted numerous claims in unspecified amounts arising from the construction of the Grand Coulee and Chief Joseph Dam projects. A major unresolved issue is the Tribes' contention that they should be reimbursed by sharing in the power revenues from both projects. The Tribes and the Government have assumed that the claims would ultimately be resolved by Congressional action, and the main focus of the negotiations has been the drafting of appropriate language for the means of relief. If Congressional action should be taken the question of whether or not reimbursement is to come from power revenues would need to be resolved by Congress. An alternative method of settlement would be litigating the claims in the United States Court of Claims. In that event, any recovery would be paid out of the U.S. Treasury and would not be reimbursable by the FCRPS. It is not possible at this time to determine the financial effect, if any, of the ultimate resolution of these claims on the FCRPS.

On November 14, 1977, the City of Portland (the City) filed two lawsuits in the United States District Court for the District of Oregon against the Administrator of BPA and the Secretary of the Department of Energy. In the first suit the City alleges BPA has acted illegally in its sales of power to preference customers, private utilities and direct service industrial customers and that, as a result of such actions, the City has been denied an ability to purchase power from BPA. The City then requests that it be declared a preference customer; that BPA power sales agreements be set aside; that BPA adopt revised allocation procedures; and that BPA sell power to the City of Portland until such reallocation and revised rules are complete. The second suit is based upon BPA's alleged failure to comply with the terms of the National Environmental Policy Act. In this suit the City alleges that all BPA power sales contracts, extensions, renewals and the net billing agreements executed since January 1, 1970, were major Federal actions significantly affecting the quality of human environment in BPA's service area. The suit further alleges that BPA's actions have caused a serious impact on the City by reducing the quality of the environment. The City then asks that all power sales contracts, extensions, renewal agreements and net billing agreements entered into by BPA since January 1, 1970 be declared null and void; that BPA be required to prepare an environmental impact statement (EIS) on each of these agreements and that BPA be enjoined from executing any new power sales agreements or net billing agreements until BPA completes an EIS. In July 1978 three private utilities, Pacific Power & Light Company, Portland General Electric Company and Montana Power Company, who had previously been joined by BPA as defendants, filed cross-claims against BPA. They contend that the BPA preference clause entitles them to power for their domestic and rural customers. Montana Power Company also claims a statutory geographic preference for Federal hydro power produced at Hungry Horse and Libby Dams. In the opinion of the BPA General Counsel the lawsuits originally filed by the City of Portland and counterclaims filed by the private

Schedule A
Federal Columbia River Power System

Schedule of Amount and Allocation of Plant Investment

as of September 30, 1978 (Thousands of Dollars)

Project	Total	Commercial Power: Completed Plant	Commercial Power: Construction Work in Progress	Commercial Power: Total Commercial Power	Irrigation: Returnable from Commercial Power Revenues	Irrigation: Returnable from Other Sources	Irrigation: Total Irrigation	Nonreimbursable: Navigation	Nonreimbursable: Flood Control	Nonreimbursable: Fish and Wildlife	Nonreimbursable: Recreation	Nonreimbursable: Other	Percent of Total Returnable from Commercial Power Revenues
Projects in service:													
Transmission facilities (BPA)	$1,939,788	$1,755,905	$183,883	$1,939,788									100.0%
Albeni Falls (CE)	33,673	32,122		32,122				$ 135	$ 174		$ 1,242		95.4%
Boise (BR)	74,954	5,246	2,444	7,690	$ 13,442	$ 38,553	$ 51,995		15,269				28.2%
Bonneville (CE)	318,891	89,423	192,201	281,624				34,426			1,069	$ 1,772	88.3%
Chief Joseph (CE)	400,284	343,024	55,557	398,581	728		728				255	720	99.8%
Columbia Basin (BR)	1,322,691	491,047	257,088	748,135	441,024	83,092	524,116	1,000	47,101	$ 1,812		527	89.9%
Cougar (CE)	60,355	18,392		18,392		3,062	3,062	545	38,148			208	30.5%
Detroit-Big Cliff (CE)	66,819	40,566	6	40,572	4,783		4,783	220	20,954			290	67.9%
Dworshak (CE)	329,972	282,224		282,224				7,788	32,181		7,779		85.5%
Green Peter-Foster (CE)	89,878	49,652	29	49,681		5,781	5,781	363	30,136		1,856	2,061	55.3%
Hills Creek (CE)	48,959	17,380	65	17,445		4,319	4,319	626	26,297			272	35.6%
Hungry Horse (BR)	101,577	76,886	46	76,932					24,645				75.7%
Ice Harbor (CE)	176,217	128,699	41	128,740				45,098			2,379		73.1%
John Day (CE) (a)	524,986	384,428	54	384,482				87,999	14,818		11,277	26,410	73.2%
Libby (CE) (a)	541,963	411,044	13,639	424,683					84,642		612	32,026	78.4%
Little Goose (CE) (a)	227,784	173,743	19	173,762				47,371		4,047		2,604	76.3%
Lookout Point-Dexter (CE)	97,041	45,808	495	46,303		1,362	1,362	728	48,043		511	94	47.7%
Lost Creek (CE) (a)	144,478	26,616	(1)(e)	26,615		1,938	1,938		51,730	23,788	26,890	13,517	18.4%
Lower Granite (CE) (a)	376,106	305,310	158	305,468				53,928			9,133	7,577	81.2%
Lower Monumental (CE) (a)	251,057	150,104	49,506	199,610				48,208			2,822	417	79.5%
McNary (CE)	324,503	264,848	2,238	267,086				55,386			2,031		82.3%
Minidoka-Palisades (BR)	135,618	13,447	139	13,586	10,248	49,634	59,882		56,959	10	4,886	295	17.6%
The Dalles (CE)	321,542	276,331	421	276,752				42,689			2,079	22	86.1%
Yakima (BR)	72,158	4,633		4,633	11,075	54,467	65,542		593	1,152	238		21.8%
Irrigation assistance at 11 projects having no power generation	77,286				77,286		77,286						
Plant investment	8,058,580	5,386,878	758,028	6,144,906	558,586	242,208	800,794	426,510	491,690	30,809	75,059	88,812	83.2%
Repayment obligation retained by Columbia Basic Project	2,211	1,352		1,352(b)	859		859						
Investment in Teton Project (d)	77,666		13,637	13,637	48,186	30	48,216		11,436	2,150	2,227		79.6%
	$8,138,457	$5,388,230	$771,665	$6,159,895	$607,631	$242,238	$849,869	$426,510	$503,126	$32,959	$77,286	$88,812(c)	83.2%

utilities are without merit. This litigation is being vigorously defended by BPA. The financial effects on FCRPS in the event of adverse decisions in these cases cannot be estimated. During the last session of Congress, legislation was introduced to authorize BPA to develop a regional power program and purchase additional power resources which would enable it to meet the loads of public agencies, direct service industrial customers, and private utilities. Similar legislation is expected to be introduced in the next session of Congress which, if enacted, may render moot the City of Portland lawsuits and the counter-claims of the private utilities.

A number of lawsuits are pending and threatened against the Corps and others for damages under alleged breaches of contract and for business losses incurred by individuals and business relocatees of the Town of North Bonneville in connection with construction of a second powerhouse at Bonneville Dam. The cost of disposing of these actions and resultant construction delays cannot be determined at this time.

Certain other claims, suits and complaints have been filed or are pending against entities of FCRPS. In the opinion of counsel and management, these actions are either without merit, involve amounts which are not significant to FCRPS' financial position or results of operations or, as in the case of the North Bonneville actions, primarily affect the overall cost of construction projects which will be capitalized and recovered through future power rates.

Note 11. Reclassifications:

For comparability, certain fiscal year 1977 amounts have been reclassified to conform with account classifications used in fiscal year 1978. There was no effect on previously reported net revenues.

BPA — Bonneville Power Administration
CE — Corps of Engineers
BR — Bureau of Reclamation

(a) Projects in service that have tentative cost allocations at September 30, 1978.
(b) Joint facilities transferred to Bureau of Sport Fisheries and Wildlife. This portion is included in other assets and deferred charges in the accompanying statement of assets and liabilities.
(c) Included in this amount are nonreimbursable road costs amounting to $74.6 million.
(d) Commercial power portion of Teton is included in other assets and deferred charges in the accompanying statement of assets and liabilities. Amounts exclude interest totaling approximately $949,000 subsequent to June 1976 which has been charged to expense.
(e) Negative amount results from estimated transfer to completed plant.

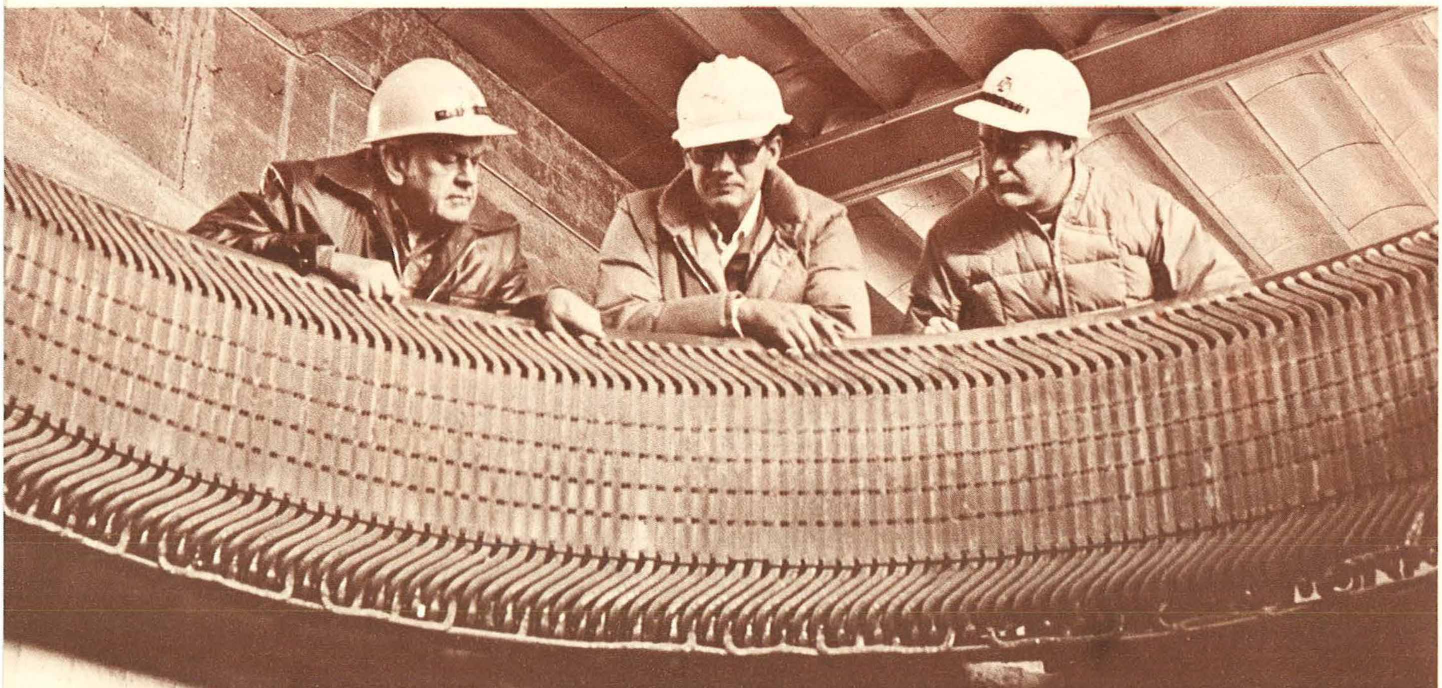
Schedule B
Federal Columbia River Power System

Reconciliation of Cost Accounting Financial Statements to the Repayment Study

For the Fiscal Year Ended 9-30-78
(unaudited)

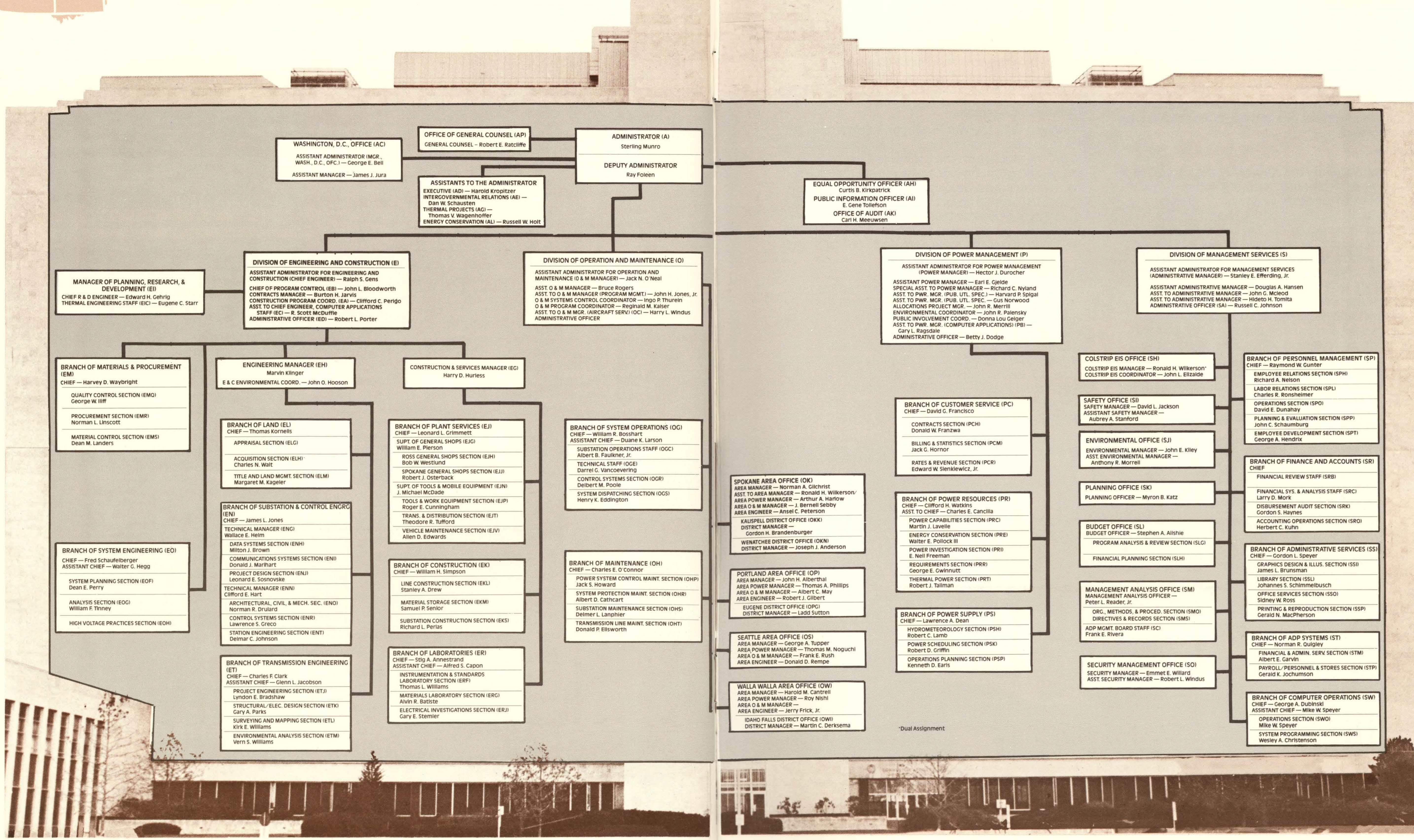
	Cumulative Balance 9-30-77	Fiscal Year 1978 Operations	Cumulative Balance 9-30-78	Cumulative Adj. to Repayment Basis	Cumulative Data Thru 9-30-78 on Repayment Study
		(Thousands of Dollars)			
OPERATING REVENUES	$3,298,951	$ 33,964	$3,632,915		$3,632,915
EXPENSES:					
Purchase and Exchange Power	259,971	51,130	311,101	$153,445	464,546
Operation and Maintenance Expense	963,839	110,098	1,073,937	—	1,073,937
Interest Expense	1,220,691	142,220	1,362,911	(949)	1,361,962
Depreciation	525,308	47,580	572,888	(572,888)	—
Total Expense	2,969,809	351,028	3,320,837	(420,392)	2,900,445
NET REVENUES	$ 329,142	$ (17,064)	$ 312,078		
RECONCILIATION TO CUMULATIVE AMORTIZATION			$ 312,078	$ 420,392	$ 732,470(a)
PLANT INVESTMENT					
Completed Plant			$5,386,878		
Retirement Work in Progress			29,723		
Repayment Obligation Retained by Columbia Basin Project (Schedule A)			1,352		
Repayment Obligation for Teton Project (Schedule A)			13,637		
Net Retirements				$115,278	
Other				969	
			$5,431,590	$116,247	$5,547,837
Less Amortization					732,470(a)
Unamortized Plant Investment					$4,815,367

(a) Changes in Cumulative Amortization:	
Cumulative Amortization through September 30, 1977	$ 766,194
Fiscal Year 1978:	
Depreciation	47,580
Net Revenues (Expense)	(17,064)
Purchase and Exchange Power Adjustment to Cash Basis	(64,668)
Interest Adjustment for Teton Project	428
Amortization for the year	(33,724)
Cumulative Amortization through September 30, 1978	$ 732,470



BPA Organization Chart

December 31, 1978



(continued from page 29)
small amounts of firm power, but mainly peaking power and non-firm energy. We also provide wheeling and other services. The only firm power investor-owned utilities obtain from BPA on a continuing basis stems from commitments related to their participation in the Hanford Project and rights associated with Hungry Horse Dam.

Industries

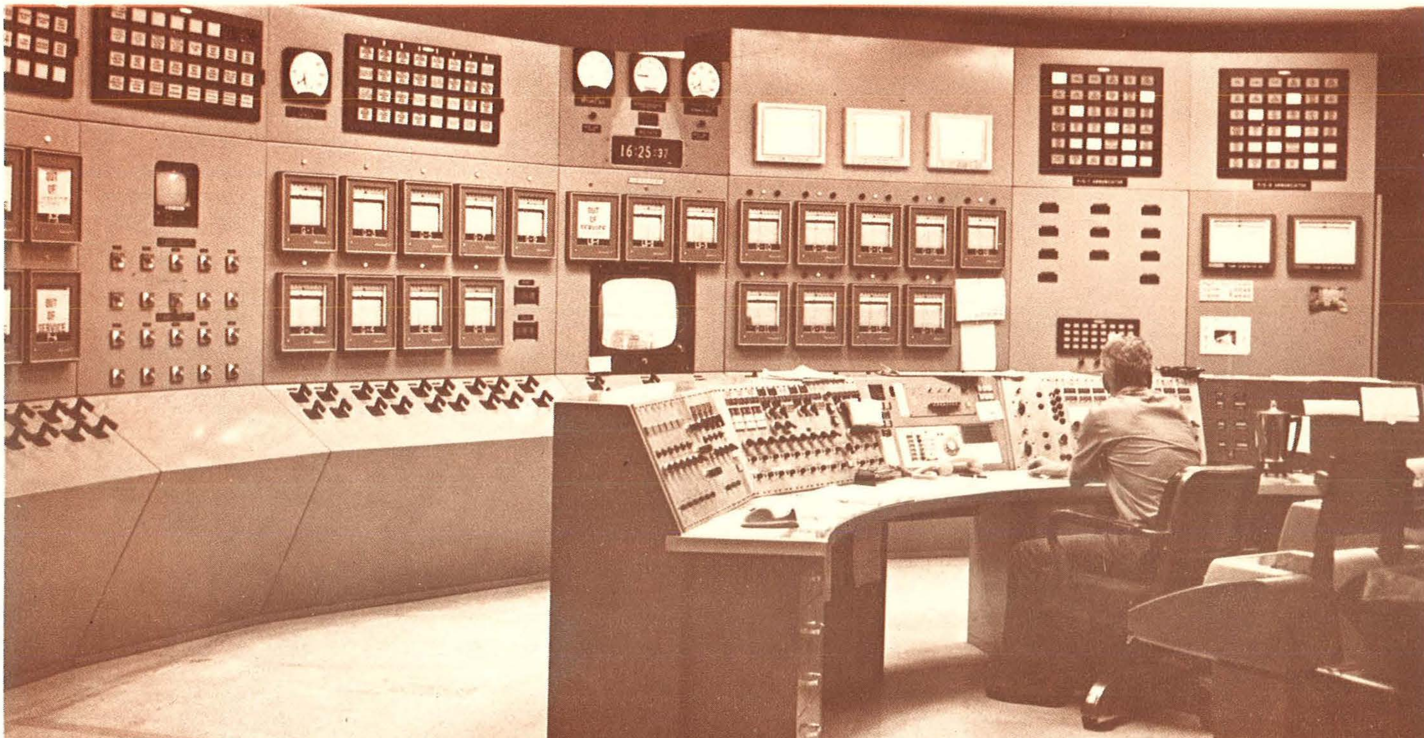
As for industries, by the early 1930s the advocates of Columbia River power development had made clear that one of their purposes was to attract industry. When the drafters of the Bonneville Project Act included some language making industrial sales "a secondary purpose," it was deleted when testimony from the Northwest made clear the people here welcomed industry and did not wish to discourage it. On December 20, 1939, the Aluminum Company of America became the first new industrial company to sign a BPA contract and move into the Pacific Northwest because of availablity of BPA power, locating an aluminum reduction plant at Vancouver, Washington. BPA now has 17 direct service industrial (DSI) customers including six aluminum companies which operate 12 plants in the region. World War II airplane needs for the metal brought several government aluminum plants to the region, and after the war BPA made industrial power available on long-term contracts that enabled the Government to dispose of its defense-built aluminum plants. Industrial loads peaked to the present levels in the decade of the 60s.

Government Agencies

In March 1943, the War Production Board directed BPA to serve a "mystery load" of between 75,000 and 150,000 kW at a site on the Columbia River near Hanford, Washington. On this site was built the Hanford Engineering Works which produced the plutonium for the first atomic bomb. We continue to serve the Department of Energy there and also provide service to five other government agencies for a total Government load of less than one percent of our total sales.

Interties

The first intertie outside our service territory was completed in 1947 with B.C. Electric. It was the forerunner to the giant grid which 20 years later interconnected West Coast utilities from the Peace River in Canada to Mexico. However, the primary BPA marketing area remains the Columbia Basin drainage of the U.S. Pacific Northwest — and was so specified by Congress in 1964 — and BPA sales outside this region are limited to temporary surpluses and exchanges of power that are benefical to both regions.



2M Jan. 1979
U.S. Department of Energy
Bonneville Power Administration
Portland, Oregon