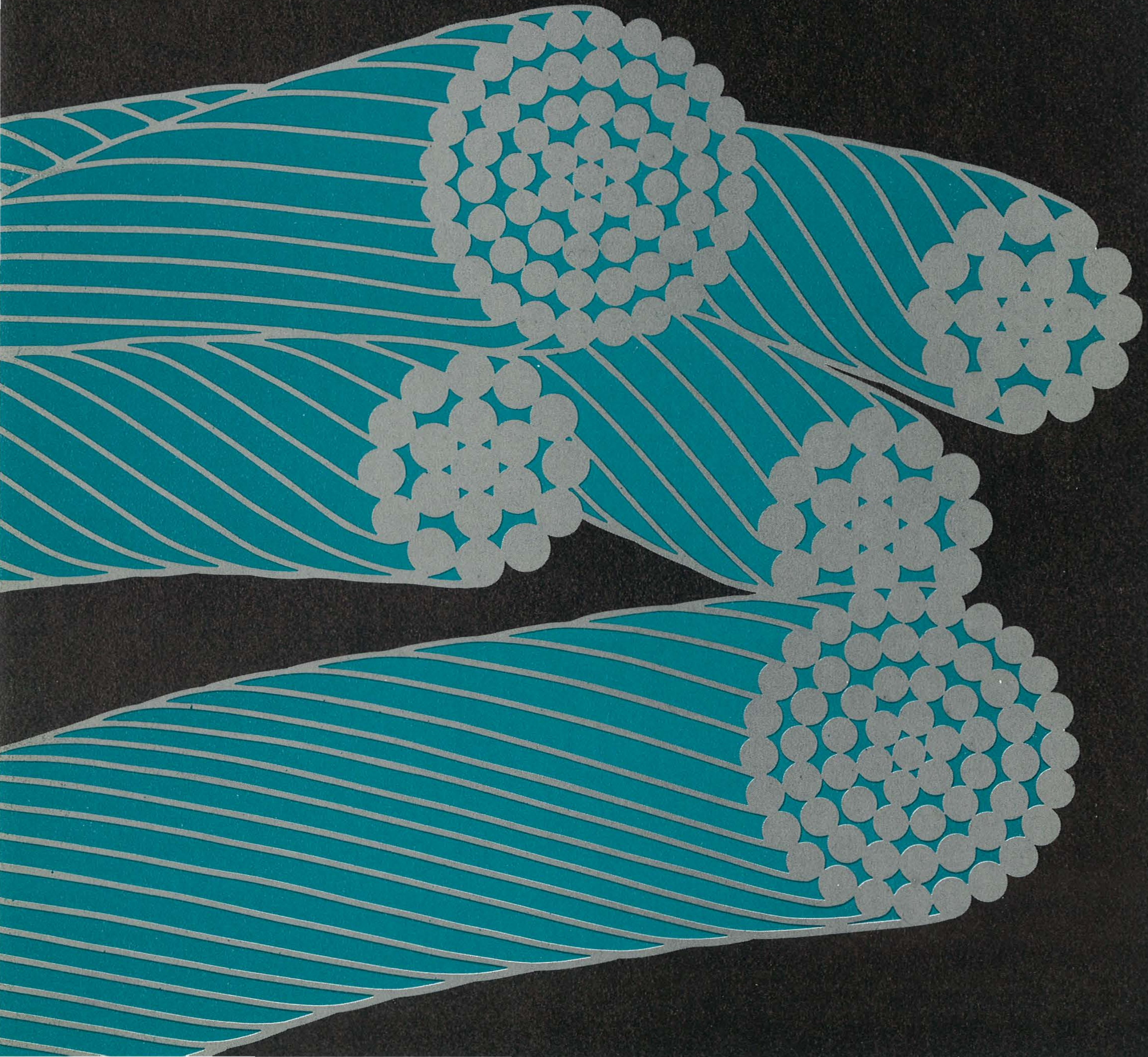
1976 Annual Report

Bonneville Power Administration

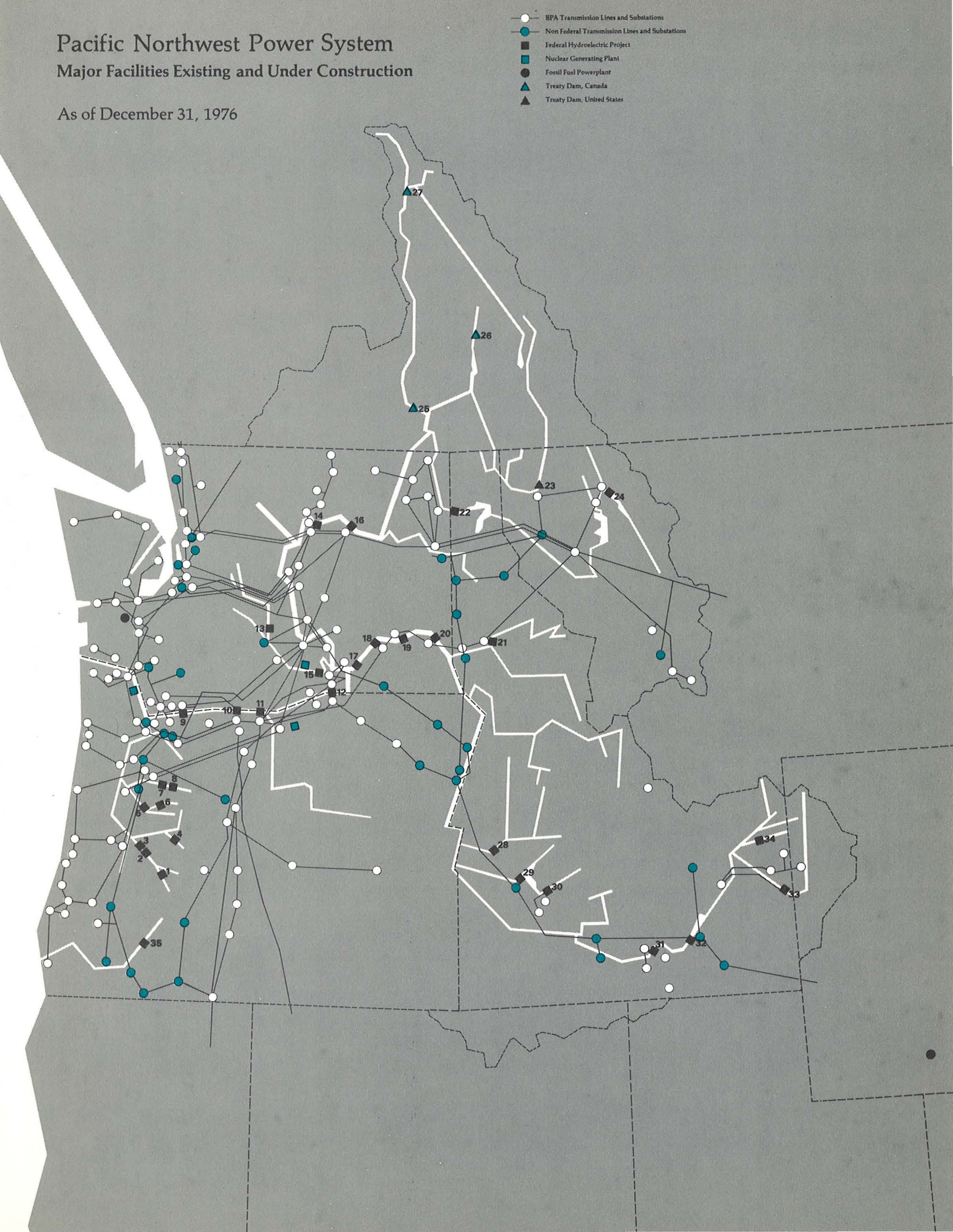
U.S. Department of the Interior



Pacific Northwest Power System

Major Facilities Existing and Under Construction

As of December 31, 1976



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Bonneville Power Administration

Federal Columbia River Power System

December 31, 1976

U.S. Department of the Interior
Thomas S. Kleppe
Secretary

Bonneville Power Administration
Donald Paul Hodel
Administrator

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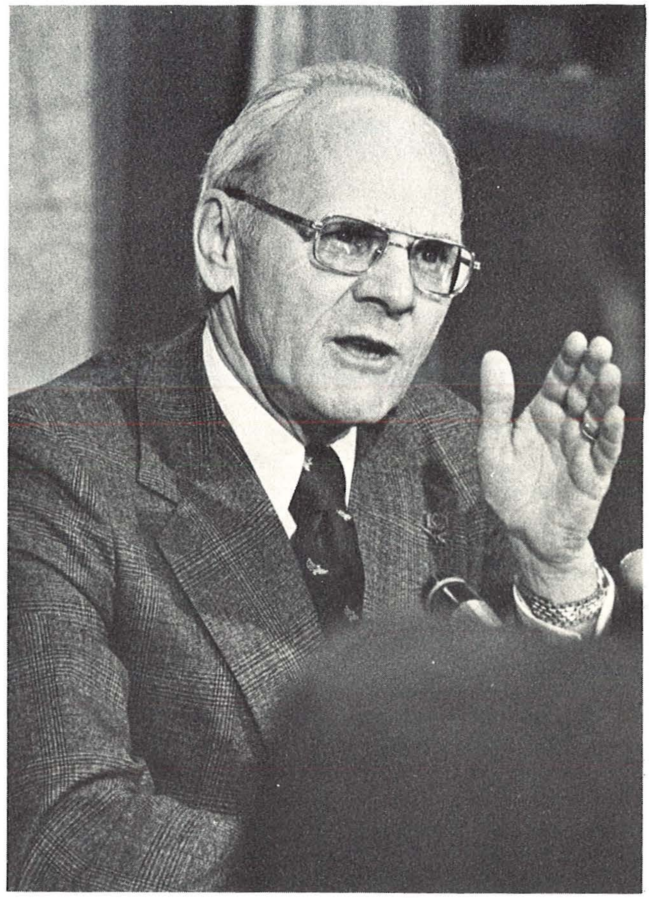


Secretary of the Interior Thomas S. Kleppe.

Letter to the Secretary

December 31, 1976

Honorable Thomas S. Kleppe
Secretary of the Interior
Washington, D.C. 20240

Dear Mr. Secretary:

This is the Bonneville Power Administration's 39th annual report on the Federal Columbia River Power System. It covers events of fiscal year 1976 plus significant developments since the fiscal year ended on June 30.

The Pacific Northwest enjoyed above-normal precipitation and favorable streamflows for the third consecutive year. Coupled with increasing demands for electric energy, this resulted in the highest sales in BPA's history. Gross revenues of the Federal Columbia River Power System totaled $297 million. A new high was also achieved in net revenues — $67.1 million.

The favorable water conditions had a significant impact too on the sale of surplus hydroelectric power to the Pacific Southwest. From July 1975 until October 1976, such surplus energy was available in every month except October and November 1975. During FY 1976, BPA and the Northwest utilities sold 18.9 billion kilowatthours of surplus energy to the Southwest, which saved the latter's utilities from burning some 31 million barrels of oil. Additional surplus sales during the period July–September 1976 totaled 6.7 billion kWh, equivalent to 11 million barrels of oil.

The ratepayers in both regions obviously benefit from these transactions. More importantly, there is a favorable impact on U.S. balance-of-payments from this prudent use of a renewable energy resource which would otherwise be wasted. It is a form of energy conservation which we are seeking to expand.

On a more somber note, for the first time in its nearly 40-year history BPA determined that it could not be assured of having sufficient power to supply the future growth requirements of its preference customers. Consequently, as required by our contracts, formal notices of insufficiency were sent in June 1976 to all BPA preference customers; these notices will become effective on July 1, 1983.

This is but one aspect of the increasingly grim power supply picture for the Pacific Northwest. With most proposed thermal resources continuing to fall behind schedule, regional energy deficits in the event of unfavorable water conditions are now forecasted for every one of the next 10 years. For five consecutive years — 1978–79 through 1982–83 — the magnitude of these deficits could exceed 2 million average kilowatts.

Since the prolonged drought which gripped this region in 1973, BPA has intensified and expanded its energy conservation program, and we are on the threshold of undertaking major initiatives to achieve energy savings. Concurrently, in the face of projected deficits, we and the utilities are seeking to formulate workable contingency plans for curtailing electric energy usage through incentives and mandatory means.

As a result of the U.S. District Court decision involving the proposed Alumax aluminum plant, on which we reported last year, BPA has been extensively involved in the preparation of a broad-ranging environmental impact statement. With the completion of this "Role EIS" late in 1977, BPA should once again be able to implement key decisions toward developing an ongoing electric energy program in the Pacific Northwest.

In the interim, a number of plans are being scrutinized by electric energy interests in the region. These include a study paper prepared by BPA which attempts to amalgamate the viewpoints of our utility and industrial customers, the States and other energy planners in addressing various alternatives for maintaining an adequate power supply in the Pacific Northwest. One of the concepts in this paper is that of obtaining legislative authority to use the equity of the Federal Columbia River Power System to secure financing for non-Federal generating facilities.

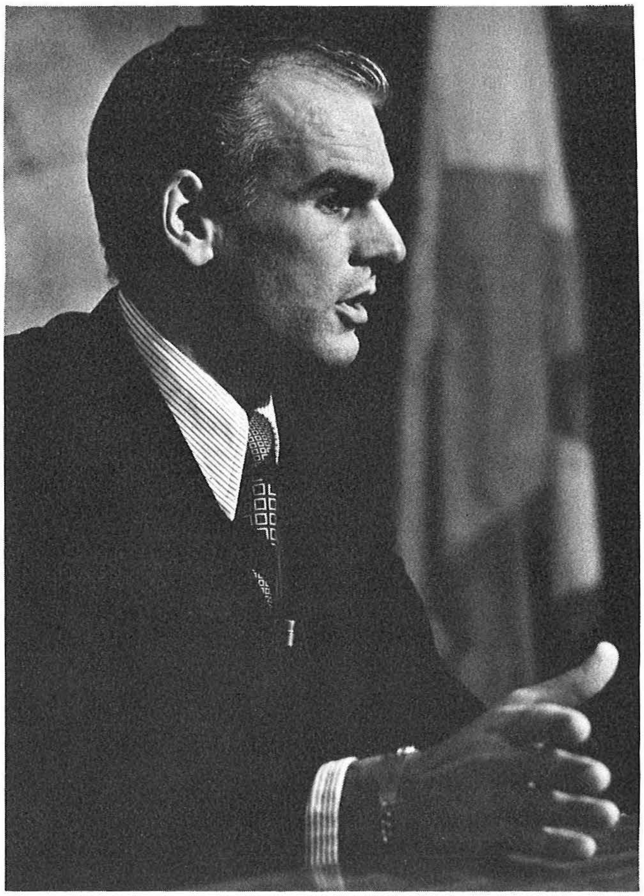
After 20 months on appeal, a long-standing lawsuit involving BPA service to a magnesium-ferrosilicon plant near Addy, Washington, neared a final determination when the Ninth U.S. Circuit Court of Appeals handed down its decision in October 1976. It was neither a clearcut victory nor a defeat for BPA. The appellate court agreed with the District Court that BPA had complied with the National Environmental Policy Act in agreeing to sell power and in preparing the environmental impact statement on the transmission line to the plant. The lower Court was reversed, however, on the issue of BPA's preparation of an environmental impact statement on the magnesium plant itself, the Court of Appeals holding that such a statement is required. The Court of Appeals dissolved its injunction against BPA construction of the line. Since that decision, construction of the final segment of the line has begun while the magnesium plant continues operating at partial capacity with temporary transmission facilities.

Forecasted energy shortages, protracted litigation, lack of a consensus plan for meeting future energy requirements — all of these combine to create concern over the power picture in the Pacific Northwest. It is fair to say, however, that Northwest utility leaders and BPA are encouraged by the growing public awareness of the role of energy in the region's future. Hopefully this public recognition and involvement in the problems we face will soon be translated into a comprehensive program supported by all sectors of the Northwest community.

Sincerely yours,

Donald Paul Hodel

Donald Paul Hodel
Administrator



BPA Administrator Don Hodel.

Overview

For Bonneville Power Administration, Fiscal Year 1976 was a period of coping with and, to an appreciable extent, thriving under circumstances which were less than ideal.

Long-Range Planning Decisions Deferred

In FY 1976, BPA and the Pacific Northwest utilities continued to operate without the benefit of fullscale, long-range, regional planning decisions.

As discussed in last year's annual report, BPA is heavily involved in the preparation of a broadbased Environmental Impact Statement covering its overall role in the Pacific Northwest power supply system (Role EIS). Consequently, BPA's activities associated with implementing any additional regionally coordinated program beyond Phase 1 of the Hydro-Thermal Power Program to meet future demands for electricity are being held in abeyance pending the completion of the Role EIS.

BPA's Role EIS an Important Energy Document

Some 100 BPA staff members are working on the draft of the comprehensive Environmental Impact Statement describing BPA's present and future roles in the economic, social, and environmental life of the Pacific Northwest. The draft EIS is now estimated to run nearly 2,500 pages at an ultimate cost approaching $4 million.

Understandably the sheer size and complexity of the document have led to some delay. Nevertheless the draft EIS should be issued for comment in early 1977. Public meetings and other means of stimulating comments by hundreds of organizations and individuals will be scheduled over a 3-month period. The present timetable calls for publishing the final EIS and submitting it to the President's Council on Environmental Quality in late 1977. All in all, this comprehensive EIS should be one of the most important documents ever produced on the subject of electric energy in the Pacific Northwest. The analyses and alternatives it presents will help to formulate decisions which could shape the future of BPA — and the region — for many years to come.

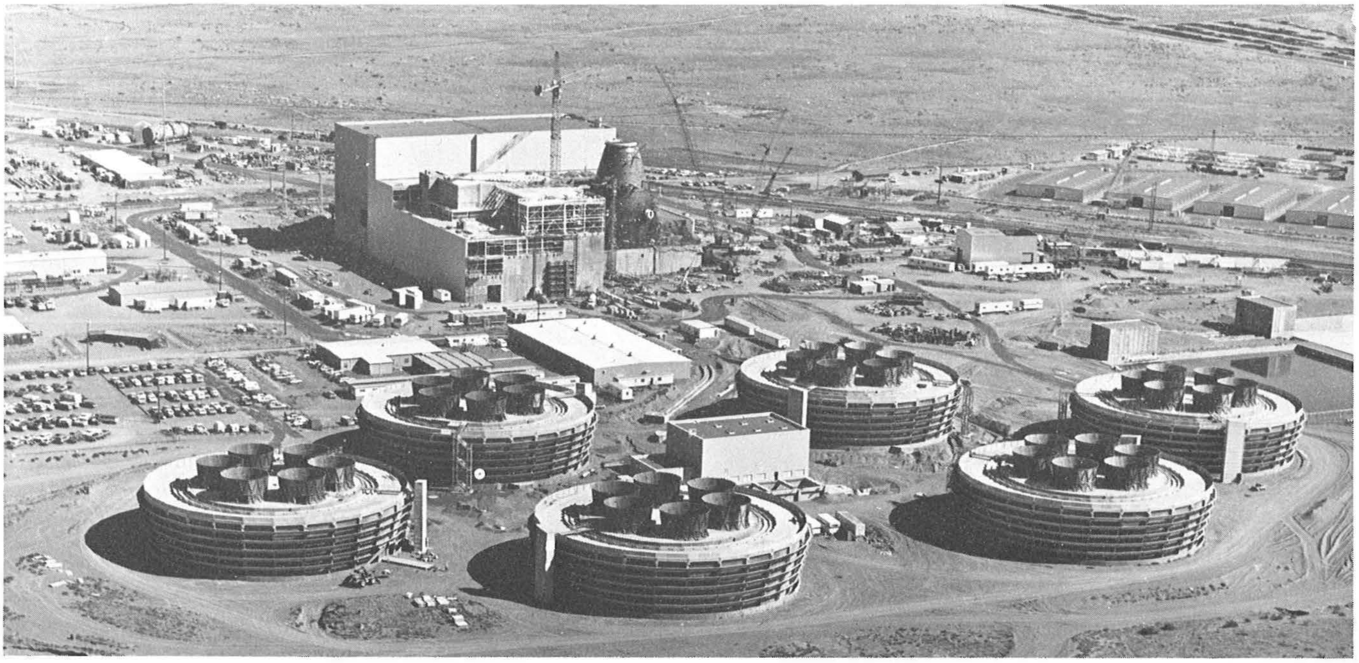
Regional Power Outlook Worsens

Since last year's annual report, the power outlook for the Pacific Northwest has further deteriorated. While additional Federal hydro generation is coming on line in general adherence with its revised schedules, these units are primarily peaking facilities, and will not add significantly to the region's energy base. For that we must look to the non-Federal thermal projects now planned or under construction — and here there is little ground for optimism.

Presently there are 15 large thermal powerplants in the planning stage or under construction in the Pacific Northwest. A BPA power outlook report issued in March 1976 described what progress had been made on these projects over the previous 12 months. Of the 15 plants, 4 were slightly ahead of the 1975 schedule, one was on schedule, and the remainder had suffered delays of from 2 to 36 months.

The result is that regional energy deficits — assuming critical water conditions — are now forecasted for every one of the next 10 years. For 5 consecutive

BPA Deputy Administrator Ray Foleen (right) reviews draft Role EIS with Acting Environmental Manager Ron Wilkerson (center) and Assistant Environmental Manager Jack Kiley.



Construction proceeds on WPPSS Nuclear Project No. 2 on the Hanford Reservation, with the six cooling towers in foreground. (Photo courtesy of Washington Public Power Supply System)

years — 1978-79 through 1982-83 — these deficits could exceed 2 million average kilowatts, roughly 2½ times the electric requirements of the City of Seattle. Further inevitable delays in thermal construction will exacerbate what is now a grim energy outlook.

Load Forecasts Under Attack

A controversy has been growing over the past year in the Pacific Northwest which has a direct bearing on these planned generation additions. Electric utility forecasts are subject to increasing skepticism, and nearly every proposed new powerplant is seemingly being challenged on the basis that its output may not be needed.

The City of Seattle has issued a report which points to load growth rates for Seattle substantially less than those forecasted by other utilities for their service areas. The substance of a preliminary study released by the Oregon Department of Energy is along the same line. A growing array of forecasting methods and assumptions is complicating the utility planning process — so are differences in opinion as to the energy savings which can realistically be expected from conservation efforts. Until some accepted mechanism can be developed for validating electric energy forecasts, power supply planning will be plagued by disputes over the issue of future energy requirements.

Energy Conservation Continues in Region

Energy conservation is very much a fact of life in the Pacific Northwest, with BPA and the utilities

Modernday Ben Franklin explains heat pump exhibit at BPA's 3rd Annual Energy Conservation Management Conference.

continuing their efforts to promote conservation in the public sector as well as seeking energy economies within their own systems.

As part of its Role EIS preparation, BPA retained an architectural/engineering firm to study the potential for energy savings in the region over the next 20 years. The resultant study is a useful tool for a more detailed analysis of the social, political and economic tradeoffs inherent in the complex energy equation.

Another area being explored by BPA is that of infrared aerial photography to identify building heat loss. Preliminary flyovers of target communities in northcentral Washington were conducted in early 1976. This program will be expanded during the period January-March 1977 with the cooperation of several utilities in Idaho, Oregon and Washington. It is hoped that these local utilities will be able to use the infrared photography to point out to their consumers where savings in electric heat can be achieved through improved insulation.

Improved insulation and weatherstripping have been installed at most BPA installations, and a prototype heat retrieval system is being introduced at the BPA Ross Substation in Vancouver, Washington.

BPA headquarters staff as well as field personnel conduct periodic seminars for employees of BPA's utility and industrial customers. In March 1976 the 3rd Annual Energy Conservation Management Conference hosted by BPA attracted some 250 utility and industrial managers. This two-day program featured energy conservation speakers from throughout the U.S. as well as an array of energy-saving products and exhibits.

A number of BPA audio-visual presentations, publications and posters emphasizing energy conservation have been distributed or made available for loan. BPA also conducts an Employee Energy Awareness Program through lunch-time presentations to acquaint BPA employees with vehicular energy conservation, insulation, heat pumps and alternate energy resources. For the second year, a BPA specialist chairs a regional energy conservation committee comprised of Interior representatives.

As a leader in energy management, BPA views conservation as an essential energy resource to assist in averting near-term power shortages and in meeting future regional requirements.

Curtailment Planning Emphasized

In view of the looming energy shortages, BPA has pointed to the very real possibility of mandatory curtailment measures being initiated over the next few years when anticipated power shortages materialize. To encourage the utilities in their planning to meet these deficits, BPA has asked its preference customers to develop detailed curtailment plans for their respective service areas. Discussions have also been held with State energy offices to explore State participation in load curtailment planning.

Most parties have reacted affirmatively to the need for such contingency planning. Quite understandably, the utilities do not have the authority to order curtailments nor do they want to assume that responsibility. But they realize that any such political mandate should rely upon their recommendations as to how electric service can best be managed on a system-by-system basis. Coordinated planning among the utilities, major power-use industries, BPA and the States is necessary to assure an equitable sharing of available resources when power shortages do occur.

Notices of Insufficiency Issued

Paralleling the regional power outlook, current forecasts indicate that BPA faces continuous energy deficits over most of the next decade unless the region has favorable streamflows, mild weather and lower-than-anticipated load growth. These forecasts show that BPA will not have adequate resources to guarantee meeting the energy requirements of its preference customers in the region — customers to whom BPA, by law, must give preference in service. Power sales contracts with these customers require the BPA Administrator to give advance notification if and when he determines that BPA cannot meet preference customer load growth.

Accordingly, in June 1976 formal notices of insuffiency were sent by BPA to all of its preference customers. As required by its power sales contracts, the notices serve as advance advisories that for 1983–84 and each operating year thereafter, BPA has determined that it cannot meet customers' projected needs and instead will limit its obligation to each customer to an energy allocation. A preliminary forecast of the energy to be available and the allocations for the post-1983 period were announced in April 1976. When new data are developed, the future availability of energy will be reassessed and the allocations updated in accordance with procedures outlined in the power sales contracts. BPA is also currently drafting procedures for allocations of power beyond the term of its existing contract commitments.

As was anticipated, the issuance of the notices of insufficiency caused serious concern among BPA preference customers. Both they and prospective new preference customers have expressed intention to lay claim to the large block of BPA power which would become available with the expiration of BPA industrial contracts in the mid-1980's. BPA's direct-service industries were also put on notice that it is doubtful under present arrangements that their contracts could be renewed.

Financing Secured for Thermal Powerplants

During the past year, Northwest public power utilities obtained substantial financing for thermal projects being built under Phase 1 of the region's Hydro-Thermal Power Program. Since BPA has contracted for power from several of these projects, it follows their financing programs with interest.

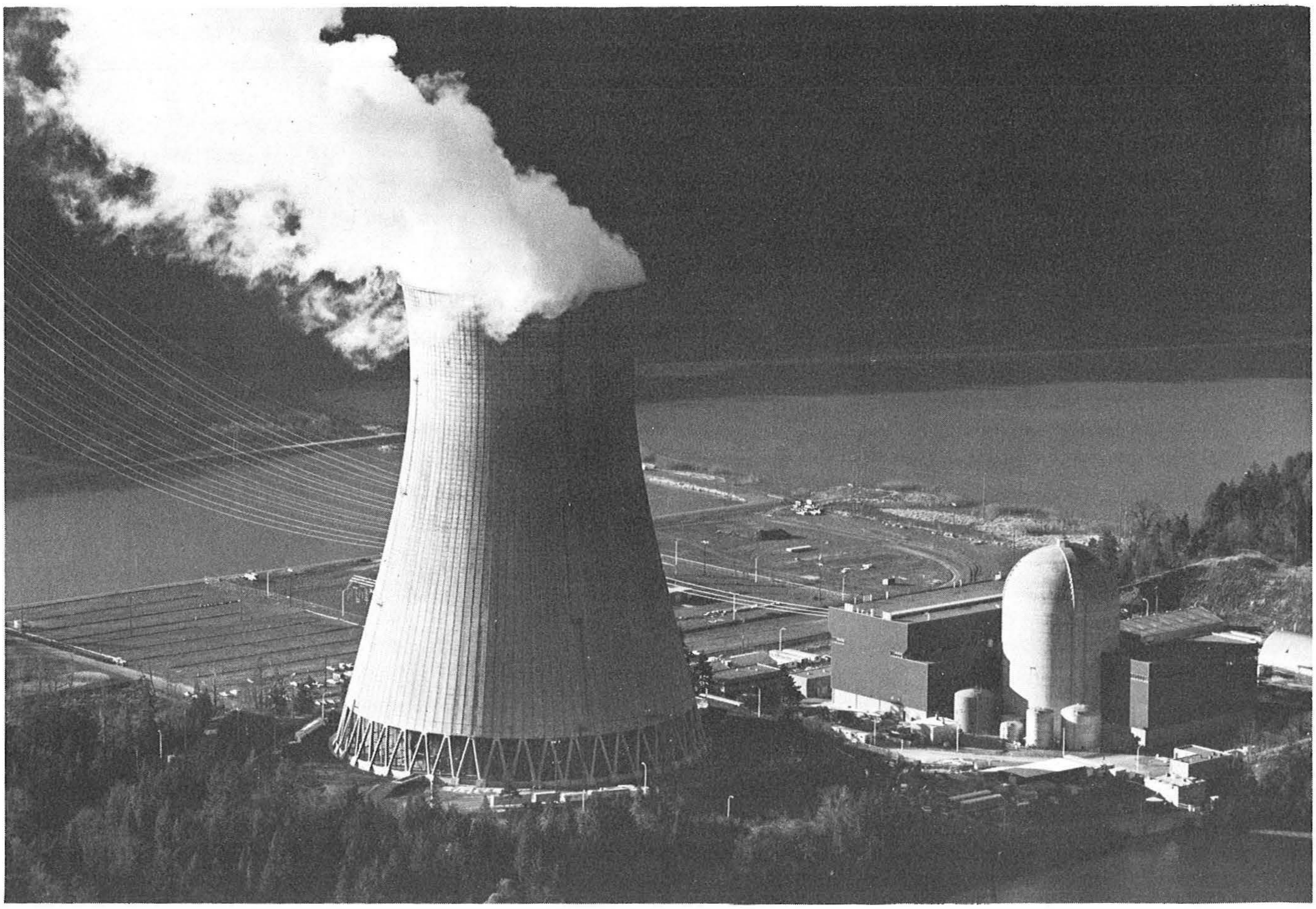
Five issues of revenue bonds of the Washington Public Power Supply System (WPPSS) were sold to provide some $725 million for construction of WPPSS Nuclear Projects 1, 2 and 3. The City of Eugene also marketed $59 million in revenue bonds and $10 million in revenue notes for construction of its 30-percent ownership share of the Trojan nuclear plant now completed and operating in northwestern Oregon.

Added to previous bond sales, FY 1976 issues brought the total revenue bond financing for WPPSS Phase 1 nuclear plants to about $1.4 billion and Eugene's financing of its Trojan participation to about $145 million. WPPSS intends to issue an additional $1.9 billion in revenue bonds to complete the financing of its three Phase 1 projects.

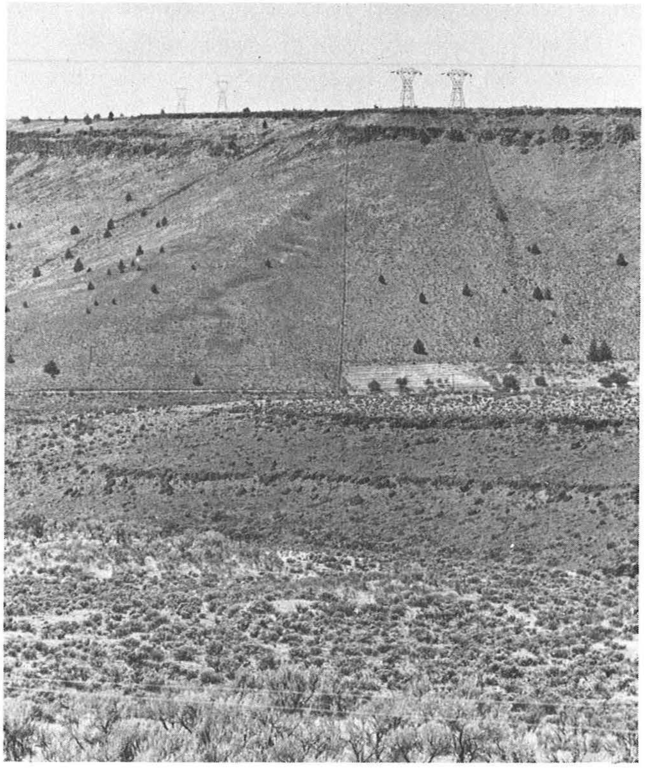
"Net-Billing" a Key to Bond Sales

Selling bonds in Fiscal Year 1976 was not without difficulty since the municipal market was shaken by the financial difficulties of New York City in 1975–76. Another deterrent was a general lack of understanding on the part of investors about the "net-billing" agreements between BPA, project owners and preference customer participants, and how these agreements obligate the U.S. Government through BPA to underwrite project annual costs as security for the municipal bonds sold to finance project construction.

In simple terms, "net-billing" is a marketing/accounting process whereby the power generated by net-billed projects is acquired by BPA and integrated with its hydropower. This "melded" power is marketed to all BPA customers at a melded rate. The cost to BPA is credited — "net-billed" — to BPA billing of the project participants.



Trojan nuclear plant near Rainier, Oregon, began test operation in December 1975. The visibility of its water vapor plume depends upon weather conditions. (Photo courtesy of Portland General Electric Company.)



BPA transmission line spans sagebrush valley in central Oregon.

In the spring of 1975, WPPSS obtained the highest rating (AAA) for its net-billed project bonds from Moody's Investor Services, Inc., and Standard and Poor's. When those issues were sold, however, the successful bids accepted by WPPSS were at interest rates higher than would normally be expected for bonds with an AAA rating. These high interest rates demonstrated that purchasers did not fully understand how BPA provides security for the bonds under net-billing arrangements.

In recognition of this shortcoming, Robert E. Ratcliffe, Regional Solicitor of the Department of Interior, recommended that BPA take a more active role in explaining the BPA/WPPSS contractual arrangements to the investment community. Under his leadership and guidance, BPA and WPPSS personnel in early 1976 expanded the information meetings in support of WPPSS bond issues to over a dozen cities throughout the country to emphasize the extent and quality of security provided by BPA through net-billing. This joint BPA/WPPSS information effort has had a positive effect. Since January 1976, WPPSS bonds have sold at interest rates as much as ¾ of one percent lower than the pre-1976 WPPSS sales when compared to standard market indexes for both periods. Should underwriting of the remaining $1.9 billion for the three WPPSS nuclear plants be sold at interest rates just ½ of one percent below market averages, the resultant savings to BPA customers could appraoch $100 million over the life of the projects.

Participation in Future Pŕojects Assured

While financing proceeded for the net-billed plants of the Phase 1 segment of the region's Hydro-Thermal Power Program, the Northwest utilities took a major step in underwriting future thermal projects. By July 1976, participants' agreements had been signed by 88

Administrator Hodel describes BPA transmission grid to Secretary Kleppe.

of the region's publicly owned utilities to share the output of WPPSS Nuclear Projects 4 and 5. A notable exception was the City of Seattle, whose 9-member Council voted against participation based on the findings of a broadbased "Energy 1990" study completed last spring. The study concluded that there is but minimal need for thermal generation on the premise that energy conservation and additional hydro development can satisfy City of Seattle load growth through the 1980's.

Fourth and Fifth Intertie Lines Contemplated

Fiscal Year 1976 also saw the revival of study of a project deferred "indefinitely" in 1969 — a 1,054-mile second direct-current Intertie line linking the Pacific Northwest to Phoenix, Arizona, via the Hoover Dam. Presently two alternating-current lines and one direct-current line connect the electric systems of the Pacific Northwest and California.

The second d-c line would permit Northwest and Southwest utilities to take better advantage of the seasonal diversity in peakloads between the two regions. Preliminary studies indicate a benefit-cost ratio of better than 2:1 for the line.

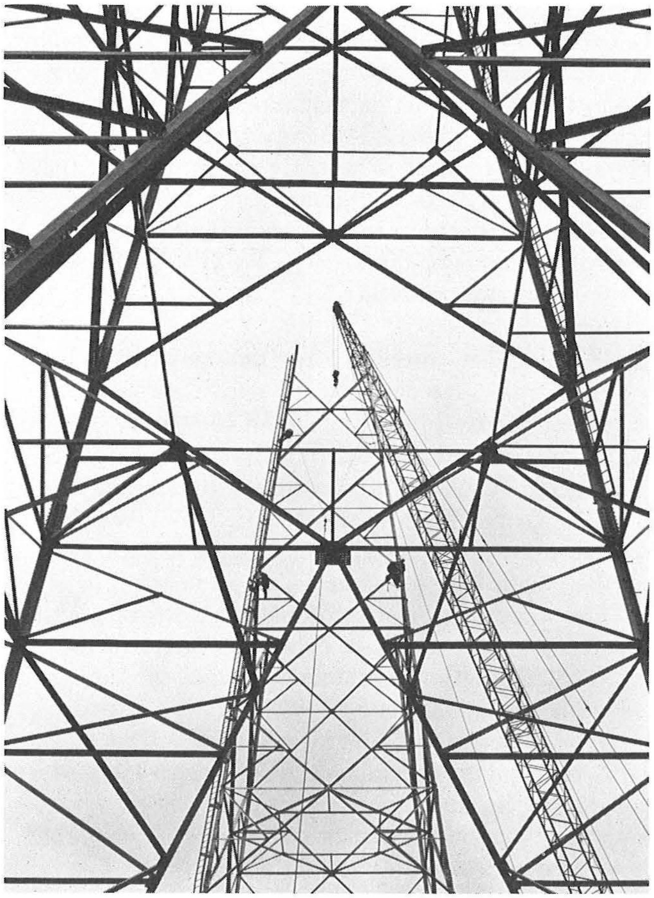
A proposal is also under study to construct a third 500-KV a-c line to California. The addition of the contemplated a-c and d-c lines would more than double the total Intertie capacity — from its present 3.9 million kilowatts to over 8 million kW.

More detailed study of the many technical, political, economic, and environmental aspects of these projects, however, is needed before a final decision to build either or both of the new lines can be made.

Hot Springs - Bell Line Reactivated

During Fiscal Year 1976, BPA and the regional utilities began to reactivate another deferred project. In June 1976 the Montana Board of Natural Resources and Conservation, after three years of public and governmental hearings and deliberations, gave limited approval to The Montana Power Company to build Units 3 and 4 of the Colstrip coal-fired generation project.

Subsequent to the board's decision, BPA announced the reprogramming of a transmission line originally budgeted for Fiscal Year 1975. This 165-mile, 500-kilovolt line is designed to integrate thermal generation from the east and hydropower from Libby Dam into the Northwest network. The proposed line will extend from BPA's Hot Springs Substation in western Montana to its Glenn H. Bell Substation near Spokane, Washington.

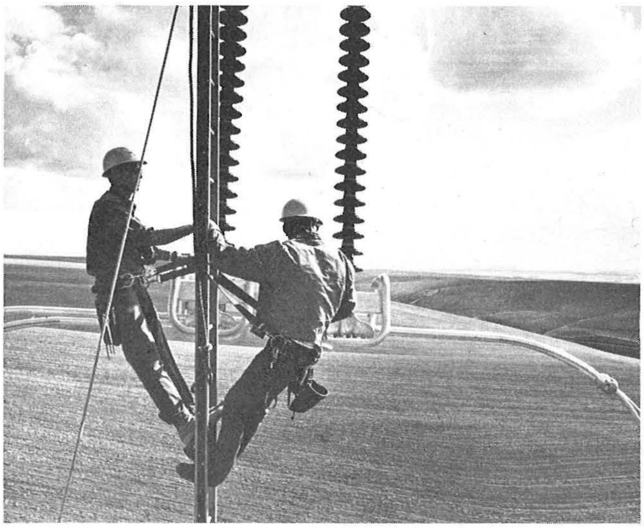


Rights-of-Way Disputes Delay Construction

Delays in the completion of several major BPA projects have resulted from rights-of-way disputes. These include two court actions initiated during FY 1976 with regard to proposed BPA rights-of-way in eastern Washington.

In the first of these, environmental issues were raised in defense to a condemnation action commenced by BPA to acquire right-of-way for the 16-mile Franklin–Badger Canyon line addition near Pasco, Washington. This case was settled in BPA's favor after a February 1976 hearing on a landowner challenge to the adequacy of the BPA environmental impact statement prepared on the project.

A second lawsuit citing the National Environmental Policy Act was brought by a group of landowners in southeastern Washington known as the Columbia Basin Land Protection Association. These plaintiffs own farmland along the selected right-of-way for the proposed 35-mile Lower Monumental–Ashe line. Their suit challenged the route selected by BPA on procedural and environmental grounds, and sought to demonstrate that the landowners would suffer irreparable harm if the project were to proceed. After denying a motion for a preliminary injunction, the



U.S. District Court in Spokane held a hearing in August 1976. A decision on this lawsuit is still pending.

Longstanding litigation involving BPA service to an Aluminum Company of America magnesium-ferrosilicon plant near Addy, Washington, was tentatively resolved by a Ninth Circuit Court of Appeals decision handed down in October 1976. This suit, which sought to establish that BPA is responsible for preparation of an environmental impact statement on

BPA customers discuss future electric energy resources.

the environmental effects of the plant operation, was previously determined in BPA's favor by a U.S. District Court decision in June 1974. The case was appealed to the Circuit Court of Appeals, where hearings were held in April 1975. The resulting opinion upheld BPA's efforts at compliance with NEPA in certain aspects but directed that an environmental impact statement be prepared by BPA on the Alcoa plant.

In the meantime, the Alcoa plant has been completed and is operational. Limited transmission facilities, however, prevent it from operating at its full capacity. Completion of the 230-kV line required for full service is presently underway.

Transition to Self-Financing Proceeds Smoothly

Fiscal Year 1976 marked the first complete fiscal cycle under the Federal Columbia River Transmission System Act of 1974, which placed BPA on a self-financing basis. The transition was accomplished smoothly, due in large measure to the cooperativeness of the U.S. Department of the Treasury. Midway through the fiscal year, BPA expended all previously appropriated dollars, and now, in accordance with the Act, makes all program expenditures from operating receipts. The self-financing legislation also authorizes BPA to sell revenue bonds to the U.S. Treasury Department, but current financial planning does not call for the use of borrowed funds until the end of Fiscal Year 1977.

The Operating Year

Despite the constraints on long-range planning, solid gains were posted during FY 1976 in the BPA transmission program. Substantial progress was also made in system control and transmission-related research and development.

Heavier Intertie Loading Spurs Surplus Sales

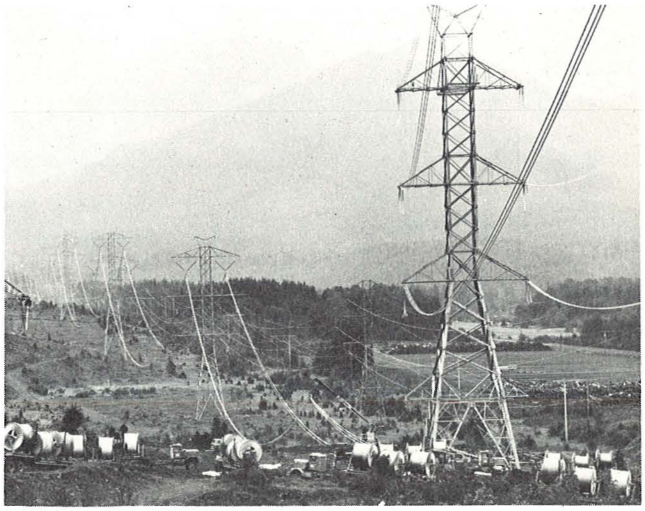
During the past year a joint determination was made by the Southwest utilities and BPA which could have an important bearing on future power exchanges between the two regions. As a result of the agreement, the operating capability of the two 500-kilovolt alternating-current lines of the Pacific Northwest–Pacific Southwest Intertie has been provisionally increased by nearly 40 percent.

Under the new criteria, the allowable limit on power transmitted over the two a–c lines can be increased from 1.8 million to 2.5 million kilowatts when a heavy volume of surplus energy is available. This decision recognizes that a greater risk of service interruption must be accepted, since the heavier loading impinges upon system reliability. To date, however, the increased Intertie loading appears to be well worth the risk. It was especially advantageous during the past year, when the Pacific Northwest enjoyed one of its best water periods in history while California experienced a severe drought. These conditions — combined with the uprated Intertie loading level — resulted in record sales of Northwest surplus power to the Southwest utilities. During Fiscal Year 1976, BPA and the Northwest utilities sold a total of some 18.9 billion kilowatthours of surplus energy to the Pacific Southwest — energy which otherwise would have been wasted. The resultant savings to the Southwest utilities were equivalent to more than 31 million barrels of costly, substantially imported oil.

Effects of Service Interruptions Minimized

As noted, stretching the operating capacity of transmission facilities inevitably increases the risk to system reliability. This was demonstrated with regard to the Intertie by two major service interruptions during the past fiscal year.

On April 7, 1976, in the early morning hours when some 34 million kilowatts of load was being carried in the Pacific Northwest, Rocky Mountains and the Pacific Southwest, the interconnected power systems separated due to the loss of the 500-kV alternating-current Intertie. This resulted in only a 4-percent shedding of load involving some 700,000 California users for periods of between 3 and 13 minutes.



Stringing conductors on the 500-kV, double-circuit Grand Coulee–Raver line through Stampede Pass in western Washington. (Photo courtesy of Western Aluminum Producers)

The second incident occurred in the afternoon of June 8, 1976, also on the a–c segment of the Intertie. Although the total connected load in British Columbia and 11 Western states was considerably higher — 53 million kilowatts — the separation between areas lasted only 12 minutes. Less than a 2-percent load loss occurred, mostly in the Rocky Mountain area. About 600,000 kilowatts was dropped due to planned underfrequency load shedding, most of it being irrigation pumping in Idaho and some loads in Colorado.

On balance, the severity and duration of these outages were commendably mild in view of the large load magnitudes involved and the relatively small losses incurred.

Construction Outages Pose Reliability Problems

BPA's system reliability practices were put to a test in the construction of the new high-capacity, 500-kilovolt, double-circuit Grand Coulee–Raver transmission line from eastern to western Washington. The right-of-way plan dictated that the new line make several crossings over three existing east-to-west lines, the Sickler-Raver and Vantage-Raver 500-kilovolt lines and the No. 3 Columbia-Covington 230-kV line. To avoid the possibility of accidental short circuiting, the lower lines are usually de-energized while the crossing conductors are strung. In this case, two or more lines had to be crossed simultaneously. Their scheduled de-energization would substantially reduce the capacity of the system to carry power. Under these conditions, the forced outage of an additional line would have disrupted service to most of the Puget Sound area.

BPA employed a number of techniques to reduce the precariousness of the operation. During 4 days in May 1976, the new double-circuit line containing 18 separate conductors was strung over both the Sickler-Raver and the Vantage-Raver lines with only the Sickler-Raver line de-energized. The Vantage-Raver line remained energized. Favorable terrain made this "hot" crossing possible and marked the first time in history that a 500-kV line has been kept energized during a construction line crossing.

The situation became even more ticklish during the 5 days beginning June 28 when all three crossed lines had to be simultaneously de-energized. To make the area less dependent on eastern Washington generation transmitted over the single remaining 500-kV line serving the Puget Sound area, a transmission circuit to the British Columbia Hydro and Power Authority system north of Bellingham was opened and all available generation in the Seattle area was operated at maximum output. Loads were light, no forced outage occurred, and the area survived one of the most extensive scheduled de-energizations of lines ever undertaken in the Pacific Northwest.

Building the Transmission System

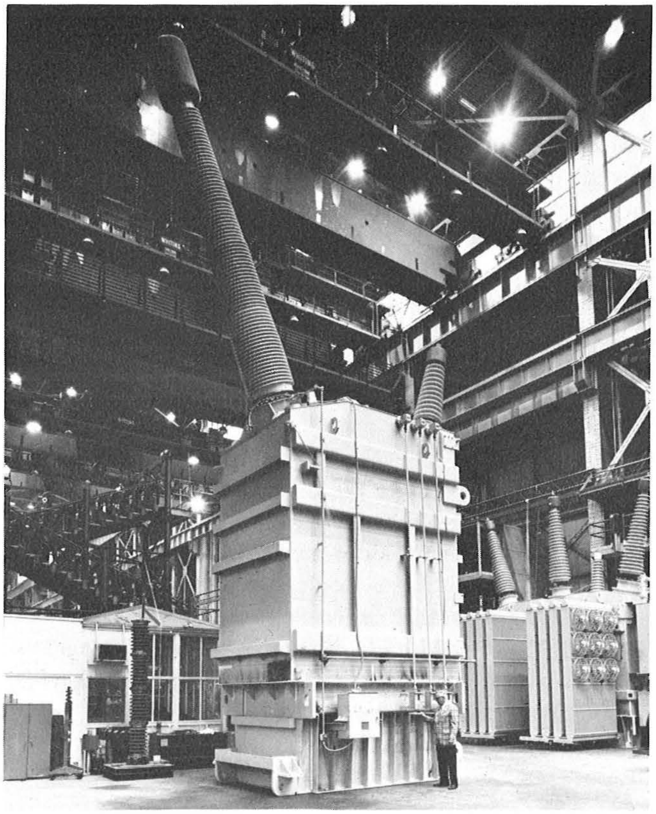
A net 189 circuit miles of transmission was energized during Fiscal Year 1976. More than half of this — 96 circuit miles — operates at 500 kilovolts.

During the fiscal year, BPA also increased the capacity of its transmission system by upgrading the voltages of some 57 circuit miles of line. By June 30, 1976, the BPA system comprised 12,514 circuit miles of transmission lines, of which 21 percent was 500-kV. Seven additional substations were energized during the period, for a total of 347 substations.

Two major 500-kV transmission facilities were energized: the 87-mile Monroe-Custer No. 2 line and the 24-mile, double-circuit Tacoma-Raver line, 15 miles of which had previously operated at 230-kV.

The new Monroe-Custer line increases the reliability of service to the Bellingham, Washington, area and provides necessary transmission capacity for the exchange of large blocks of power between BPA and British Columbia Hydro and Power Authority.

The Tacoma-Raver line and supporting substation equipment reinforce the 230-kV transmission system serving the Tacoma area. These facilities assure the capacity to meet all residential and commercial loads even should one of the large 500-kV transformer banks in the Seattle/Tacoma area be out of service.



One of three 175-ton, 1,100-kV transformers for the BPA UHV Lyons test facility. (Photo courtesy of Westinghouse Electric Corp.)

New UHV Milestones Reached

During Fiscal Year 1976, BPA made important strides in its program to develop and test ultra-high-voltage (UHV) transmission. Prototype equipment was installed at two locations for testing the 1.1 million-volt transmission facilities which will provide the high capacity (10 million kilowatts per circuit) needed to transmit power in the late 1980's.

By July 30, 1976, the construction reached 65-percent completion at the UHV electrical test facility — a substation and a 1.3-mile electrical test line — located near Lyons, Oregon. Towers averaging 200 feet in height will be strung with two overhead ground wires and 8-conductor lines for each of three phases of 1,100-kV alternating current.

The Lyons facility will evaluate the electrical effects of 1,100-kV transmission, such as the production of audible noise and radio and TV interference and ecological effects. BPA also contracted with the Battelle Pacific Northwest Laboratories to monitor vegetation, wildlife, and domestic animals in the vicinity of the energized line as part of a 31-month biological study.

In June 1976, a 1.1-mile UHV mechanical test line was completed near Moro, Oregon. Located on the eastern rim of the Deschutes River Canyon, the site is exposed to extreme weather conditions. The line was installed to measure the ability of bundled conductors to withstand "worst case" stresses caused by icing and wind oscillations. Initially BPA will test a bundle consisting of eight 1.6-inch-diameter conductors as compared to the maximum three-conductor bundles now in use on the BPA system.

To support the UHV program, BPA also constructed a three-acre test yard with a control room and an impulse generator at its J.D. Ross Complex in Vancouver, Washington. This generator can develop short duration impulses of up to 5,600,000 volts to test UHV air gaps, insulator configurations, and conductor mounting assemblies.

New Study to Evaluate Biological Effects of D-C Line

In cooperation with the Western Interstate Commission for Higher Education (WICHE), BPA is continuing to test the biological effects of lines already operating in its transmission system. In 1975, a WICHE study was made of the impact of BPA's 500-kV Dworshak-Hot Springs line on elk and other wildlife. This study indicated that movements of big game near and under 500-kV lines do not differ from their use of other forest clearings.

In the summer of 1976, BPA and WICHE began another study for evaluating effects of the Oregon portion of the 800-kV direct-current Intertie on nearby plants and animals. Since the line was energized in 1970, not one incident of a deleterious biological effect has been reported. The current study is expected to substantiate this history of acceptable performance.

Computer Control Expands

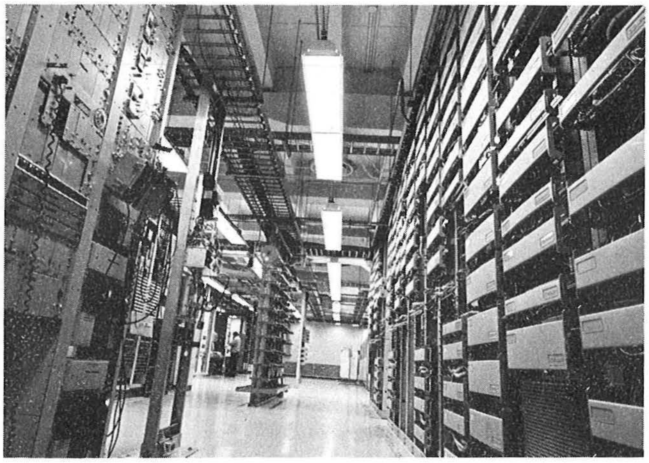
BPA also continued to extend computer-directed control of the far-ranging and complex Federal Columbia River Power System. On June 13, 1976, BPA's new Eastern Control Center (ECC) near Moses Lake in eastern Washington became operational. The ECC provides computerized wall and CRT displays for carrying out dispatch functions for the subtransmission grid east of the Cascades in the Pacific Northwest. (A subtransmission grid essentially consists of 230-kV and lower voltage facilities which provide service to individual utilities and industrial facilities.)

Wall schematic displays eastern segment of the BPA transmission grid at the Eastern Control Center near Moses Lake, Washington.

The ECC's computer serves as a basic part of the second BPA SCADA (supervisory control and data acquisition) system which will be fully operational by December 1976. This SCADA II system will permit supervisory control of equipment at 35 substations and will supply data on the status of the eastern subtransmission system in northern Idaho, western Montana, and areas of Washington and Oregon east of the Cascade Mountains.

The Dittmer Control Center in Vancouver, Washington, dispatches power over the BPA main grid and houses the earlier SCADA I system which collects data and provides supervisory control of equipment at 48 major substations on the main grid. (The main grid is comprised of high voltage facilities which provide for the movement of the bulk power supply throughout the region.)

SCADA III, now being fabricated by Boeing under a $3.39 million contract, will be installed at Dittmer along with SCADA I. The SCADA III system will



Automated control system "hardware" at the Dittmer Control Center.

provide centralized supervisory control of and data acquisition from approximately 40 substations in the BPA subtransmission grid west of the Cascades.

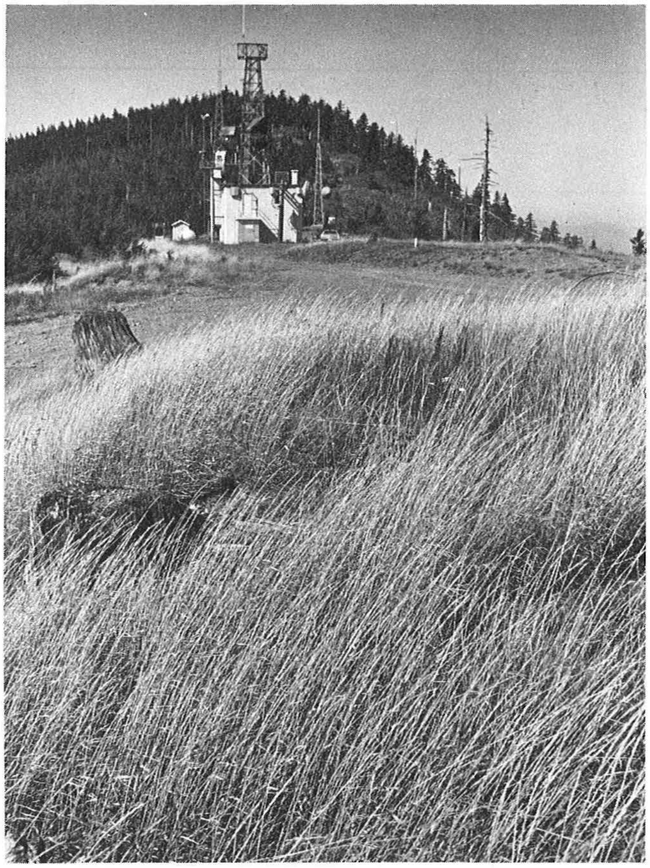
BPA Moves Ahead in Energy Research

While expanding its electronic control base, BPA made other technological strides in FY 1976, particularly in the area of energy research and development.

Planning is now underway to install an energy retrieval system on a large transformer at the BPA Ross Substation in Vancouver, Washington. During the winter, energy usually lost as heat will be captured and used to drive a heat pump to heat a nearby building. In summer, because of lower electrical demand in the Northwest, the transformer operates at a lower power level; therefore, summer heat losses are not adequate to drive the heat pump in its air conditioning mode. This transformer heat, therefore, will be supplemented by solar energy (heat) from high-performance solar collectors. These collectors will probably be of the cylindrical vacuum insulated type.

After installation, scheduled for 1977, a mini-computer system will gather and evaluate data to determine the feasibility and economy of installing energy retrieval systems at a number of BPA substations.

BPA is also considering retrieving the energy from other equipment besides transformers which have high heat losses, such as the rectifier valves at Celilo Converter Station, the northern terminus of the d-c Intertie.



Approximate site of proposed wind turbine generator near Augspurger Mountain in southwestern Washington (BPA microwave station in background).

Northwest Site Considered For Wind Power Facility

A location in southwestern Washington has been proposed by BPA to the Energy Research and Development Administration for installing and testing a prototype wind turbine generator (WTG). This site, adjacent to a BPA microwave station near Augspurger Mountain, is one of 17 tentative locations throughout the continental United States and Hawaii for installing pilot WTG facilities. Wind data will be collected over a 12-18 month period at the 17 sites and will be analyzed with a view to selecting 4 of them for the construction of two 200-kilowatt WTG's and two 1,500-kilowatt WTG's — essentially giant two-blade, power-producing windmills. The WTG's will be operated and monitored over a period of at least 2 years to accumulate performance data on wind energy conversion systems under utility operating conditions.

Power Sales

For the third consecutive year, the Pacific Northwest enjoyed above-normal precipitation and favorable streamflow conditions. The total runoff for Fiscal Year 1976 at The Dalles Dam was 159.8 million acre-feet — the eighth highest runoff in 48 years of record.

Surplus Sales Set Records

Because of the abundant water, BPA began to ship Federal surplus energy to the Southwest in early December 1975, the earliest date that surplus energy has become available for sale out of the region. In the 1974–75 water year, for example, surplus energy from Federal dams was not available for Southwest delivery until mid-February.

The favorable water, plus increasing the operating capacity of the Intertie (discussed in the previous chapter) and the installation of about 2.5 million kilowatts of new Federal generation, resulted in several records for surplus deliveries to the Southwest over the fiscal year. The new generation consisted of the completed Libby Dam, the net-billed share of the Trojan nuclear plant, the addition of generating units at Dworshak and Ice Harbor Dams, and the energization of two giant 600,000-kilowatt generators in the third powerhouse at Grand Coulee Dam.

BPA surplus sales to the Southwest during FY 1976 totaled a record 13.2 billion kilowatthours, the highest since the Intertie lines were energized. The Northwest utilities shipped an additional 5.7 billion kWh of surplus energy over the Intertie during the fiscal year.

It should be emphasized that, under Public Law 88-552, BPA sales of surplus energy outside of the Pacific Northwest represent energy for which there is no demand within the region and which cannot be stored for future use within the region. This surplus energy is generated from water which would otherwise be "spilled" over the Federal dams and which would, in effect, be wasted. This situation only occurs during periods of high streamflow, and such surplus energy cannot be depended upon to serve firm loads — those uses which require a constant, year-round power supply.

Administrator Hodel and Assistant Secretary William L. Fisher (right center) visit Grand Coulee Dam, accompanied by Darrel Hansen, Third Powerplant Construction Engineer, (left) and Robert Mueller, Chief, Field Engineer Branch. (Photo courtesy of U.S. Bureau of Reclamation)

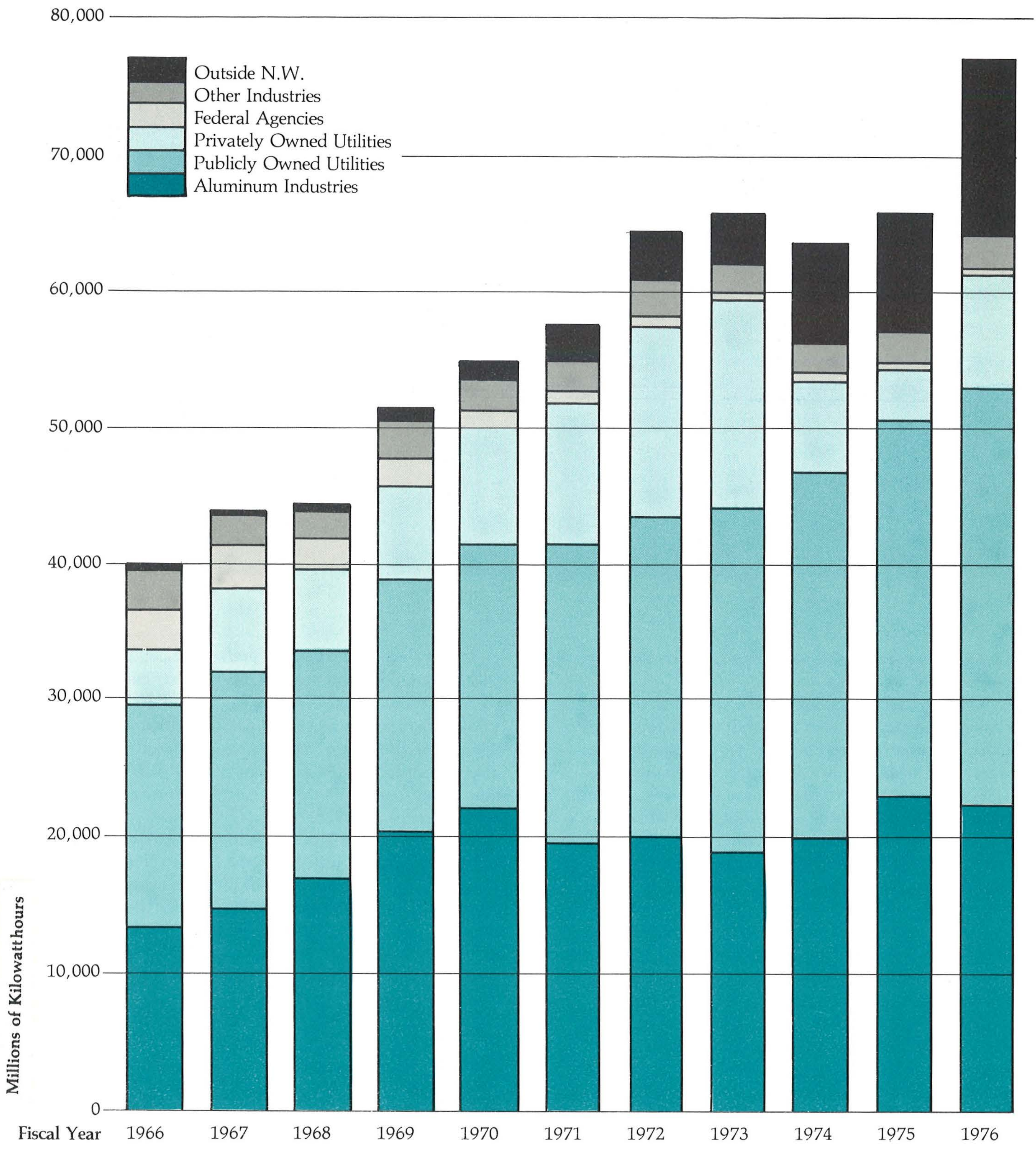
BPA Sales Up in Pacific Northwest

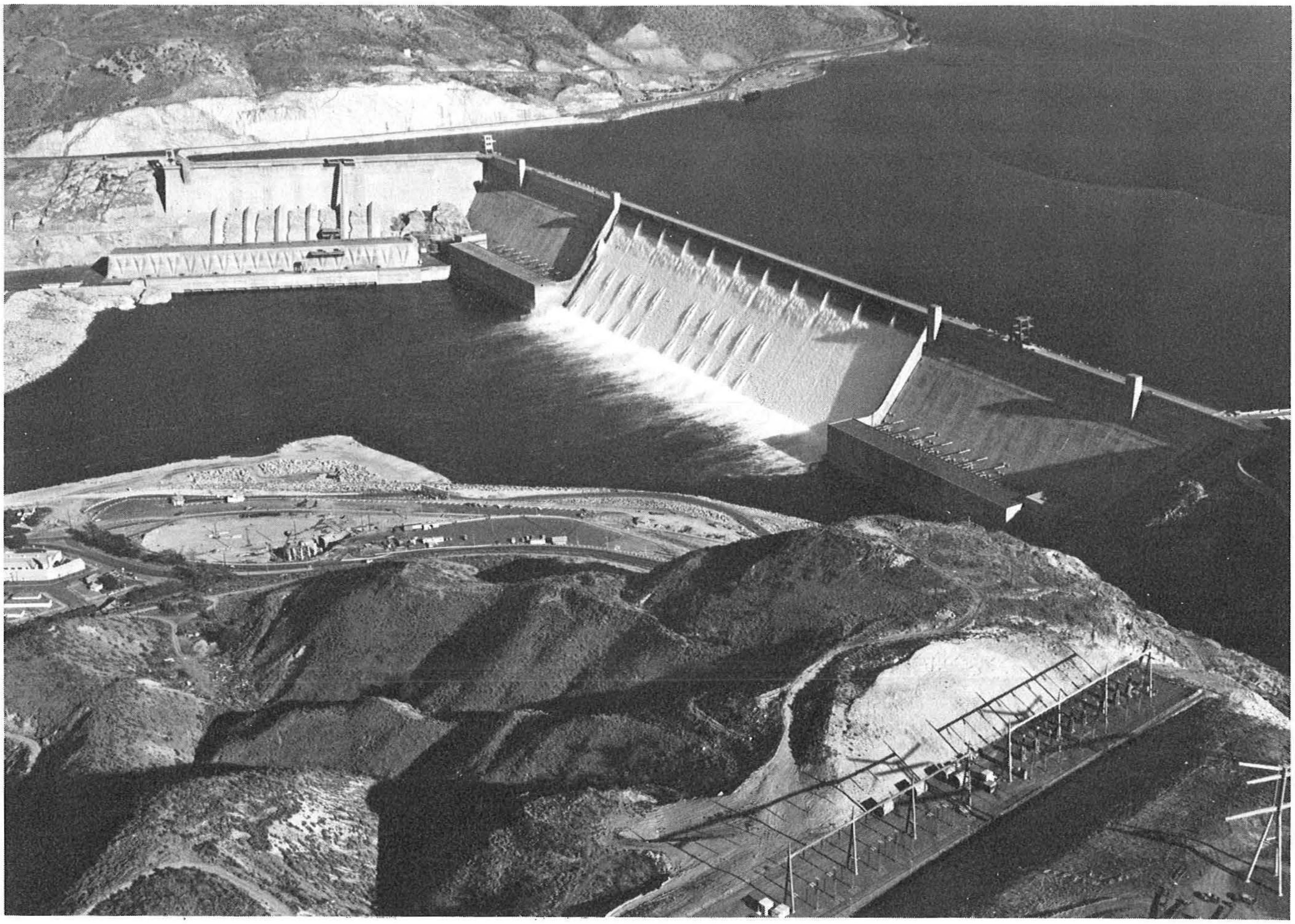
Despite a mild winter, continued energy conservation, and depressed economic conditions, BPA and regional utility loads continued their upward trend during Fiscal Year 1976. Throughout most of the period, BPA's nonfirm industrial sales ran well below those of the previous year. Late in the year, however, some nonfirm industrial loads were restored, and by June 1976, the average nonfirm industrial load was 728,000 kilowatts compared to 394,000 kW during June 1975.

New generation records were commonplace during the year. The Federal Columbia River Power System set a new one-hour peak generation record of 13.6 million kilowatts between 9 and 10 a.m. on January 2, 1976. The record exceeded the previous winter's high by more than 1.5 million kilowatts. Also, a new record 24-hour total generation of 295.3 million kilowatthours was established on January 7, 1976.

Energy sold by BPA during Fiscal Year 1976 totaled 77.5 billion kilowatthours, an increase of 17.9 percent over Fiscal Year 1975. Firm energy sales increased by

BPA Sales of Electric Energy





Heavy "spill" at Grand Coulee Dam during 1976 runoff season.

11.2 percent, and nonfirm energy sales by 44.7 percent.

The average revenue from the sale of energy to all classes of customers was 3.58 mills per kilowatthour. (Sales of capacity and revenues from other services were not considered in computing this figure.) The 3.58 mills, a 22.6-percent increase over the 2.92 mills for FY 1975, reflects the fact that the 27-percent average increase in the wholesale power rates, effective December 20, 1974, was applied over the entire 1976 fiscal year as compared to only half of Fiscal Year 1975.

Revenues from sales of capacity during FY 1976 totaled $10.1 million, an increase of almost 50 percent from FY 1975, primarily as a result of the sale of seasonal capacity to Pacific Gas and Electric Company in California. Energy associated with the delivery of this capacity is returned to BPA during the recipient's off-peak hours. Investor-owned utilities in the Pacific Northwest increased their purchases of capacity by 16 percent; their purchases represented 56 percent of BPA's total capacity revenues for the year.

In the Pacific Northwest, preference customers, including public and peoples' utility districts, cooperatives, and municipal systems, purchased 30.8 billion kilowatthours of energy and associated capacity during the fiscal year. Preference customer purchases also accounted for 39.8 percent of total BPA sales and amounted to an 11.4-percent increase over such purchases for FY 1975.

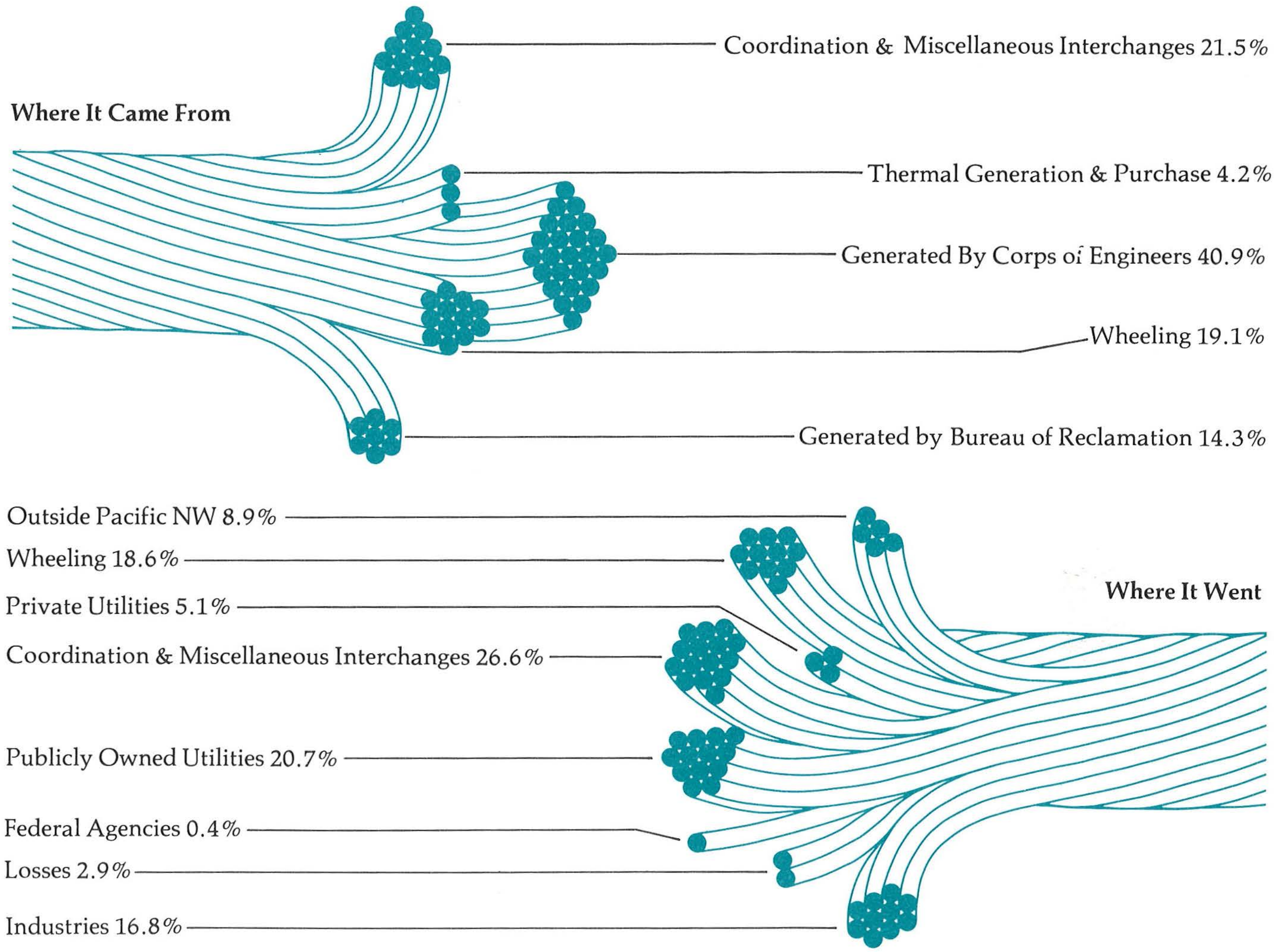
BPA delivered 6.2 billion kilowatthours of energy to investor-owned utilities in the Pacific Northwest during FY 1976, an increase of 29 percent over the 4.8 billion kWh delivered in FY 1975. Under the BPA statistical accounting system, an additional 1.5 billion kWh was classified as a sale in FY 1976 when the bill was rendered, rather than in FY 1975 when the energy was delivered.

Energy sales to Federal agencies in the Northwest increased 6.4 percent in FY 1976 to 637 million kilowatthours from 599 million kilowatthours sold in FY 1975.

Sales to the aluminum industry totaled 22.7 billion kilowatthours, 2.4 percent less than last year's 23.2

Source and Disposition of Total Energy Handled by BPA

Fiscal Year 1976
Total 149.0 Billion Kilowatthours



billion kilowatthours. In FY 1975, the aluminum companies purchased 35.4 percent of all BPA energy sold. This declined to 29.3 percent in FY 1976.

During this period, BPA's other direct-service industrial customers purchased 3.1 percent of BPA's energy, totaling 2.4 billion kilowatthours, a 3.6 percent increase over the 2.3 billion kWh delivered in FY 1975.

The record 13.2 billion kilowatthours of surplus energy sold by BPA to the Pacific Southwest in FY 1976 represented a 55 percent increase over the previous year. An additional 89 million kWh was sold to British Columbia during the year.

The Financial Year

During Fiscal Year 1976, gross revenues of the Federal Columbia River Power System totaled $297 million, which is 25 percent higher than those of the previous year, and an all-time record. Net revenues totaled $67.1 million — also a record. Cumulative revenues since the start of operations surpassed the $3 billion mark during July 1976.

A milestone in BPA self-financing occurred in February 1976 with the expenditure of the last of the funds previously appropriated to BPA. Since then, all BPA outlays have been paid from receipts from operations. Future construction outlays will be paid from receipts and the proceeds of revenue bonds to be sold to the Treasury. The initial bond sale is forecast for September 1977.

Basis for Financial Reporting

BPA prepares financial statements for the FCRPS based on the accrued cost accounting method of financial reporting customarily used by commercial enterprises. Costs include operation and maintenance, the purchase of power, interest, and depreciation of facilities over their useful lives. These financial statements are audited in accordance with generally accepted standards by the General Accounting Office under the direction of the Comptroller General. The complete financial statements together with the Comptroller General's opinion appear on pages 28 through 39.

The adequacy of revenues to recover power costs, however, is based upon the repayment study which is described later in this chapter.

Revenue and Expense Trends

The substantial increase in FY 1976 revenues was due primarily to two factors. First, the 27 percent wholesale power rate increase which was placed into effect in December 1974, and which was thus in effect for only the second half of Fiscal Year 1975, was in effect for the entire Fiscal Year 1976. Second, water conditions generally were very favorable. This made possible the sale of substantial amounts of surplus power. These sales, together with additional intertie wheeling revenues from utilities which resulted from the transfer of power to the southwest, amounted to slightly over $50 million.

This offset the less-than-anticipated sales in the Pacific Northwest, which were caused by the combined effects of a mild winter and the effect of the economic recession upon load growth. The net result was that total revenues were very close to the estimate made at the start of the year.

On the expense side, the cost of purchasing power decreased by $11.7 million. This was attributable in large part to a delay in the commercial operation of the Trojan nuclear plant until near the end of the fiscal year. This decrease, however, was offset by increases in operation and maintenance costs, which rose by almost $8 million due to the combined effects of increased power system size and continuing inflation. Interest expense increased by almost $15 million, due principally to the Libby and Lower Granite projects being placed in service.

BPA Self-Financing

With the advent of self-financing and the expenditure of its last appropriated funds, BPA now finances all of its outlays from power revenues and other receipts. BPA's cash flow forecast, which is shown on page 24, indicates that receipts will continue to be adequate to finance the program until September 1977. At that time BPA anticipates making its initial borrowing from the Treasury under its authority conferred in the Federal Columbia River Transmission System Act to sell revenue bonds. BPA is authorized under the Act to have up to $1.25 billion in bonds outstanding at any time.

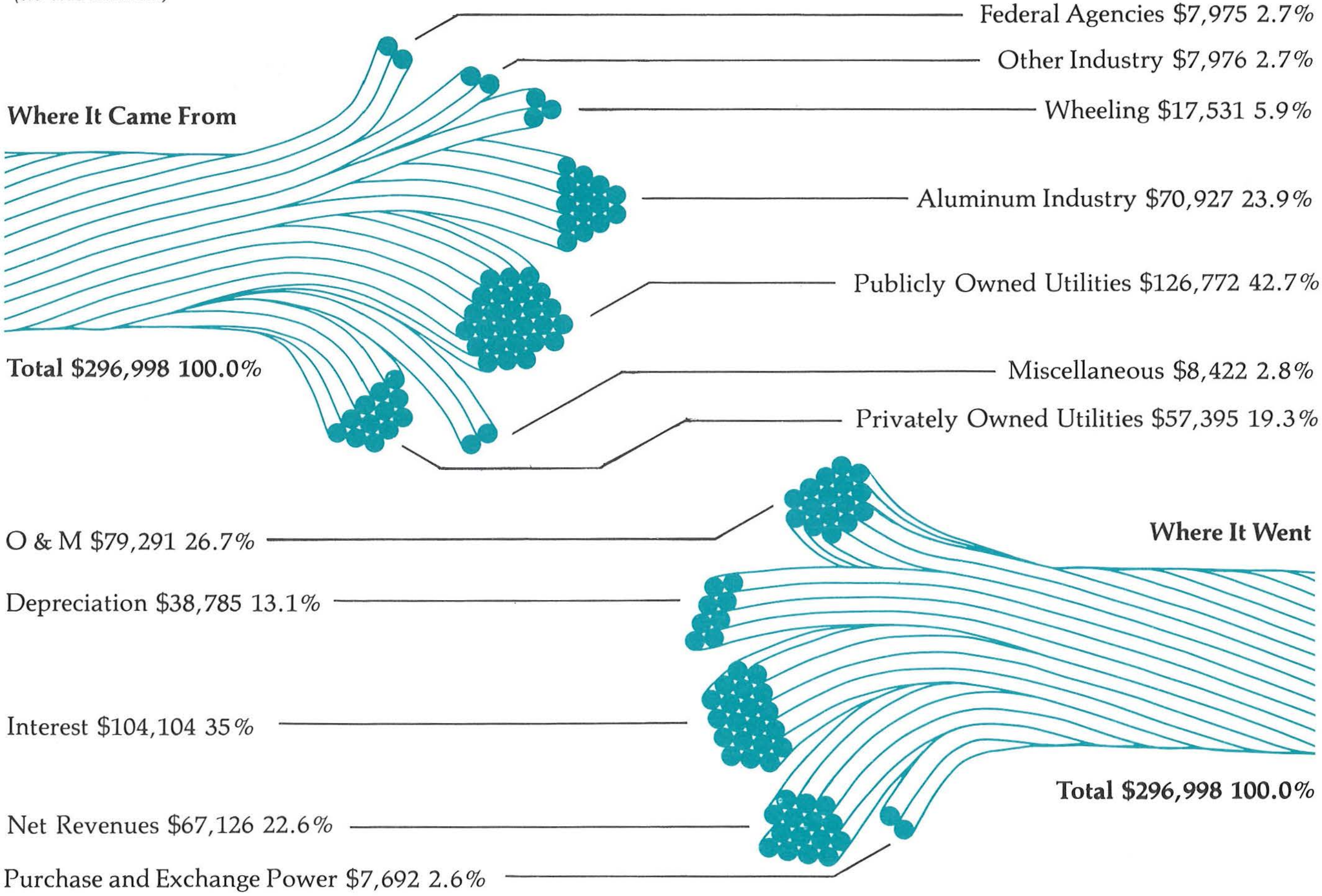
New BPA Wheeling Rates Filed with FPC

For the decade-and-a-half since the completion of non-Federal dams on the Mid-Columbia, BPA transmission lines have been used to wheel power for a number of customers from generating plants to their load service points.

Charges for wheeling services had always been determined by BPA without need for further approval. However, the Federal Columbia River Transmission System Act, signed into law in October 1974, calls for Federal Power Commission confirmation and approval of BPA's wheeling rates.

Source and Disposition of Revenue Dollar

Fiscal Year 1976
(in thousands)



In keeping with this requirement, BPA filed new wheeling rates with the Federal Power Commission in July 1976. The filing of the wheeling rates followed in-depth studies of BPA's transmission costs and a review of proposed rates with the wheeling customers. To cover increased costs which have resulted from the effects of inflation and higher interest rates, the new wheeling rates provide for an average increase of approximately 22 percent.

As of the publication date of this Annual Report, FPC approval of the wheeling rate schedule is still pending.

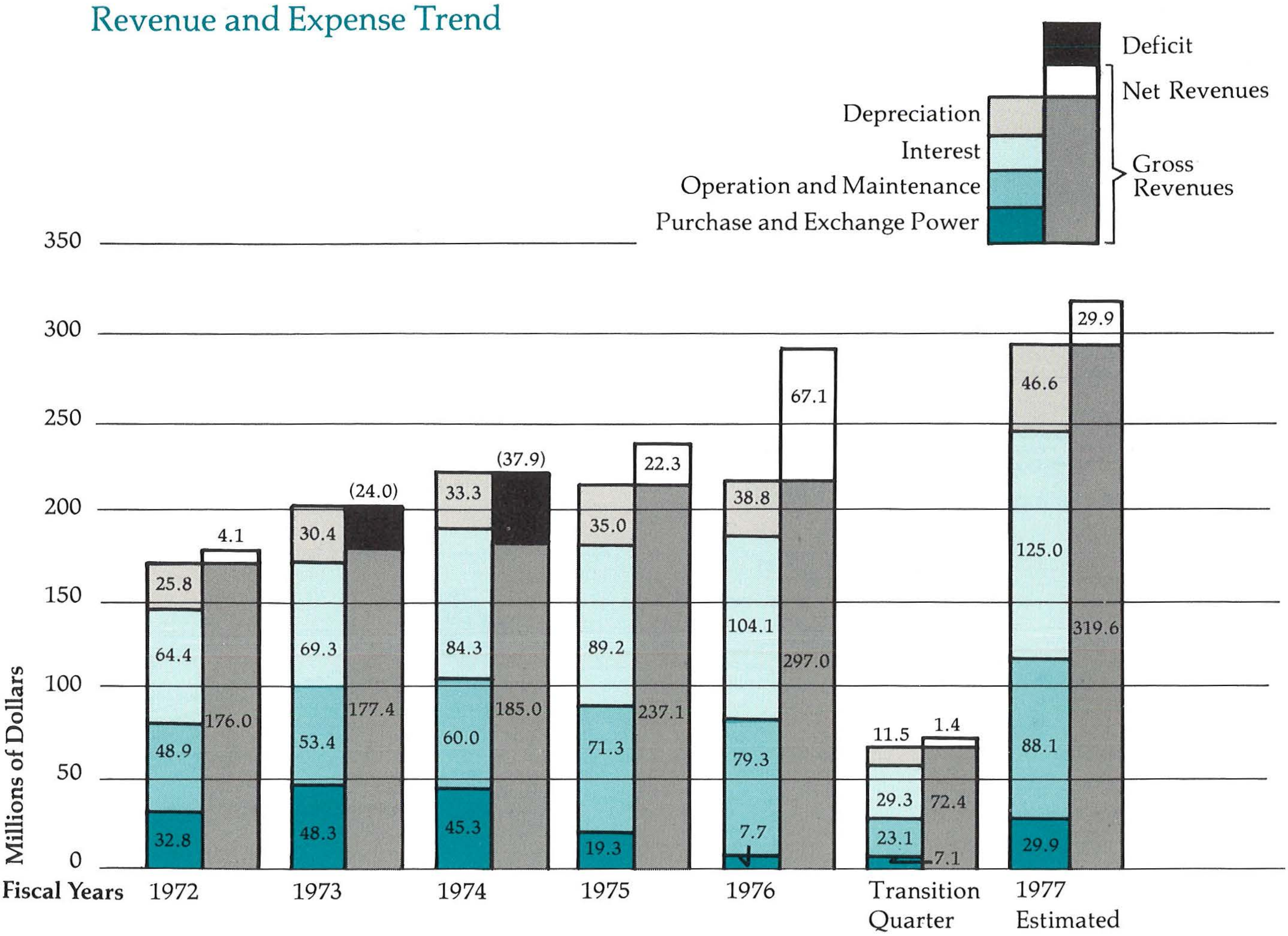
Cost Accounting and Repayment Reporting

As noted above, this report includes both the cost accounting financial statements and the repayment study which constitutes the basis for determining the adequacy of the power rate level. The cost accounting 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, i.e., current financial results on the one hand and future financial requirements on the other.

The repayment study, in summarized form, is found on page 25 with an explanation of the repayment policy on page 26.

It should be noted that 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 rate level,

Revenue and Expense Trend



and hence the level of revenues required to meet the repayment requirements, is higher than that needed to cover costs on the cost accounting basis. Therefore, the normal situation with a rate level sufficient to meet the repayment requirement will be for the FCRPS to produce net revenues, i.e., operate "in the black." With the rate level now in effect, which is approved by the Federal Power Commission through December 19, 1979, the prospect is for net revenues of some $30 million in Fiscal Year 1977 (assuming a normal water year). This projection is illustrated graphically in the chart above.

Another noteworthy difference between the cost accounting statements and the repayment study is that the latter reflects costs, such as for 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 through which BPA is purchasing the capacity of certain thermal plants commit BPA to pay for such capacity beginning on specified dates even though the plants may not have commenced operation. In this situation the repayment study shows the amount of the cash payments, but the cost accounting statements defer charging such amounts to purchased power expense until the plant starts operating. This explains, for example, the different amounts shown for purchased power for the next several years in the repayment study (page 25) and the forecast of cost accounting results shown above.

Prospects for Future Rate Increases

As explained in previous annual reports, there has been substantial upward pressure on BPA's repayment requirements in recent years due to the following factors:

1. The purchase of the capacity of certain Phase 1

thermal plants, which is much more costly than hydroelectric power;
2. Inflation;
3. Higher interest rates on new construction;
4. Increased operation and maintenance expenses.

All of these factors contributed to the necessity for the 27 percent rate increase, which was approved by the Federal Power Commission effective December 20, 1974.

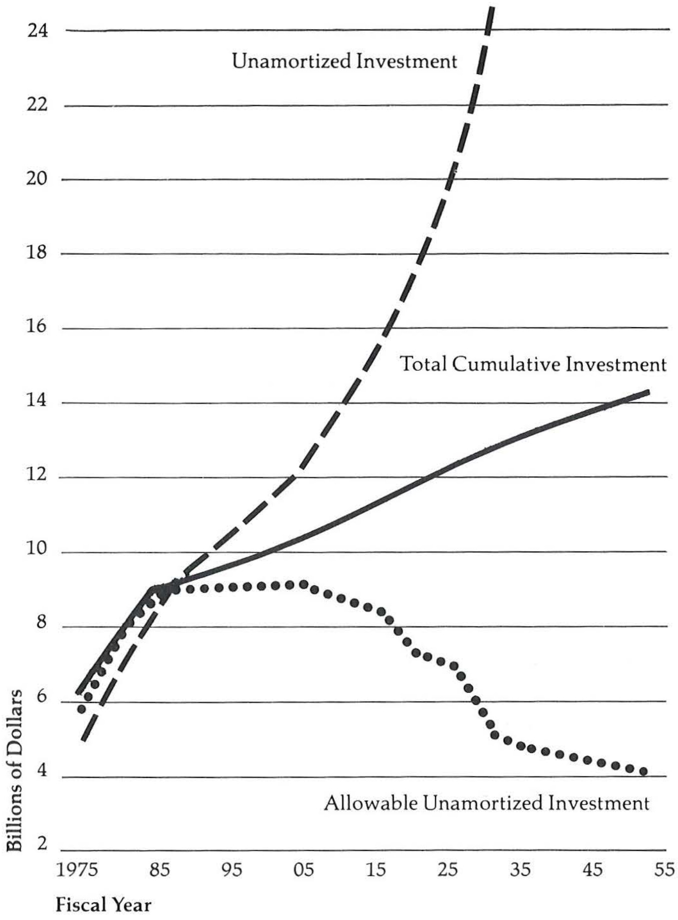
The repayment study included in this report is an updated version of the study which documented the need for the aforementioned increase. The new study includes more recent cost estimates which reflect additional escalation occurring since the preceding study was prepared. This study shows that the revenues which can be expected from the current wholesale power rates will fall short of meeting all repayment requirements, thus indicating the need for a future rate adjustment. (This result is illustrated graphically by the repayment study chart appearing opposite.)

Under the terms of BPA's current power sales contracts, the earliest date that power rates can be increased is December 20, 1979. The current repayment study, however, does not indicate the extent to which the rates will have to be increased at that time. This is because the current study does not include the costs of additional thermal generation which BPA has entered into commitments to acquire commencing in the early 1980s. Also, the current study does not attempt to reflect the extent to which costs may further escalate and interest rates fluctuate between now and the 1979 rate adjustment date. Furthermore, the amount of the increase to be proposed in 1979 also may be influenced by whether or not BPA is successful in changing the power sales contracts to permit more frequent rate adjustments. For example, if the 5-year rate approval cycle were to be continued, the 1979 increase would have to be adequate through 1984. This would probably require a larger increase to cover additional future costs which would not have to be covered in the 1979 increase than if it could be based on covering a shorter period, i.e., a more frequent rate adjustment would permit increases in smaller increments.

Preliminary repayment studies prepared by the BPA staff (not included in this report) indicate the need for a very substantial rate increase in December 1979. These studies — which it must be emphasized are preliminary — indicate the need for at least 60 percent more revenue commencing December 1979, and point to another rate increase of at least 20 percent in July 1981.

BPA also plans to review its wheeling rates for possible adjustment as of December 1979, so that in the future both the power and wheeling rates can be considered simultaneously to assure equitable treatment for all classes of BPA customers. Wheeling rates, however, will not be affected by the high cost of the thermal power BPA will be purchasing. The amount of the wheeling rate increase, if any, is expected to be relatively modest compared to the expected power rate increase.

Repayment Study Chart
Fiscal Year 1976



Cash Flow Forecast

Now that BPA is on a fully self-financing basis, the BPA cash flow takes on particular significance. First, effective cash management will minimize net interest costs. Secondly, the balance between cash receipts and outlays will determine the amount and timing of future BPA bond sales to the Treasury. The estimated BPA cash flow through Fiscal Year 1978 is shown in the tabulation on page 24. (Forecasting cash flow beyond FY 1978 is impractical because of the present uncertainty regarding the amount and timing of future rate increases.)

It will be noted in the cash flow forecast that the first bond sales are anticipated commencing in September 1977. Because BPA entered the transition to self-financing with a substantial cash balance due to the availability of previously approved appropriations which had not yet been expended, that initial balance, together with the substantial cash receipts generated through its operations, is expected to provide BPA sufficient cash to meet all requirements until the end of Fiscal Year 1977. Thereafter, BPA anticipates an increasing volume of bond sales to the Treasury to complete the financing of its construction program.

It is anticipated that BPA will use a combination of short-term notes and long-term bonds, depending, among other things, upon the interest rates BPA will have to pay at the time. For instance, assuming a favorable short-term rate, BPA likely will sell short-term notes to finance its ongoing construction program and then "roll" the short-term notes into long-term bonds either on a regular annual basis or as major power facilities are completed. Under the terms of the Federal Columbia River Transmission System Act, the Secretary of the Treasury will determine the interest rate to be paid on BPA bonds and notes based on his determination of what securities of comparable quality would sell for in the money market.

Table 1

Electric Energy Account

Fiscal Year 1976

Energy Received (millions of kilowatt-hours)	
Energy Generated for BPA:	
Bureau of Reclamation	21,353
Corps of Engineers	60,857
Washington Public Power Supply System (Hanford)	2,552
Centralia Thermal Project	2,134
Other Generation	166
Power Interchanged In	61,893
Total Received	148,955
Energy Delivered (millions of kilowatt-hours)	
Sales	77,471
Power Interchanged Out	67,140
Used By Administration	69
Total Delivered	144,680
Energy Losses in Transmission and Transformation	4,275
Total	148,955
Losses as Percent of Total Received	2.9
Maximum Demand on Generation (kilowatts) (Date and Time) January 2, 1976, 10 A.M.	13,576,000
Load Factor in Percent of Total Generated for BPA	73.0

Table 2

Generation by the Principal Electric Utility Systems of the Pacific Northwest

Fiscal Year 1976

Utility	Kilowatt-Hours (Billions)	Of Total Generation (Percent)
Publicly Owned:		
Federal Columbia River Power System[2]	87.1	55.4
Grant County PUD	11.0	7.0
Chelan County PUD	8.0	5.1
Seattle City Light	7.1	4.5
Douglas County PUD	4.2	2.7
Tacoma City Light	3.0	1.9
Eugene Water & Electric Board	0.5	0.3
Pend Oreille County PUD	0.5	0.3
Total Publicly Owned	121.4	77.2
Privately Owned:		
Idaho Power Company	11.0	7.0
Pacific Power & Light Co.	9.0	5.7
Montana Power Company	5.8	5.7
Washington Water Power Co.	5.0	3.2
Portland General Electric Co.	3.2	2.0
Puget Sound Power & Light Co.	1.9	1.2
Total Privately Owned	35.9	22.8
Total Generation	157.3	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), Centralia steamplant, and the Trojan Nuclear Plant.

Federal Columbia River Power System

Table 3

General Specifications, Projects Existing, Under Construction and Authorized

Nameplate Rating of Installations as of June 30, 1976

					Existing		Under Construction		Authorized		Other Potential		Total	
Project	Operating Agency	Location	Stream	Initial Date in Service	Number of Units	Total Capacity Kilowatts	Number of Units	Total Capacity Kilowatts	Number of Units	Total Capacity Kilowatts	Number of Units	Total Capacity Kilowatts	Number of Units	Total Capacity Kilowatts
Bonneville	CE	Ore.-Wash.	Columbia	June 1938	10	518,400	8	544,000			—	—	18	1,062,400
Grand Coulee	BR	Washington	Columbia	Sept. 1941	20-3	3,463,000[2]	4	2,717,000[3]			6	3,600,000	30-3	9,780,000
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	July 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	June 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	16	1,024,000	11	1,045,000	—	—	13	1,573,000	40	3,642,000
Chandler	BR	Washington	Yakima	Feb. 1956	2	12,00	—	—	—	—	—	—	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[5]	BR	Idaho	Snake	May 1909	7	13,400	—	—	—	—	—	—	7	13,400
Boise Diversion[5]	BR	Idaho	Boise	May 1912	3	1,500	—	-	—	—	—	—	3	1,500
Black Canyon[5]	BR	Idaho	Payette	Dec. 1925	2	8,000	—	—	—	—	—	—	2	8,000
Anderson Ranch[5]	BR	Idaho	S. Fk. Boise	Dec. 1950	2	27,000	—	—	—	—	1	13,500	3	40,500
Palisades[5]	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	June 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	July 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	3	405,000	3	405,000	—	—	—	—	6	810,000
Dworshak	CE	Idaho	N. Fk. Clearwater	Sep. 1974[6]	3	400,000	—	—	3	660,000	—	—	6	1,060,000
Lower Granite	CE	Washington	Snake	Apr. 1975	3	405,000	3	405,000	—	—	—	—	6	810,000
Libby	CE	Montana	Kootenai	Aug. 1975	4	420,000			4	420,000	—	—	8	840,000
Teton[7]	BR	Idaho	Teton		—	—	3	30,000[7]	—	—	—	—	8	30,000[7]
Lost Creek	CE	Oregon	Rogue		—	—	2	49,000	—	—	—	—	2	49,000
Libby Reregulating	CE	Montana	Kootenai		—	—	—	—	4	43,800	—	—	4	43,800
Strube	CE	Oregon	S. Fk. McKenzie		—	—	—	—	1	4,500	—	—	1	4,500
Total installed capacity						13,617,780		5,800,000		1,703,300		6,371,500		27,492,580
Total number of projects						29		2		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, and two 600,000 kW units at the Third Powerplant.

[3] Includes an increase of 17,000 kW for one unit to be rewound, one 600,000 kW unit, and three 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] U.S. Bureau of Reclamation project incorporated into the Federal Columbia River Power System, effective July 1, 1963.

[6] Dworshak units were operated at reduced capability beginning in March 1973.

[7] Teton Dam ruptured June 5, 1976. Future status is unknown.

Federal Columbia River Power System

Table 4

Sales of Electric Energy

Fiscal Year 1976

Customer	Energy Delivered for Year KWH (000)	Revenue From Sales of Energy
NORTHWEST AREA		
Publicly Owned Utilities		
Municipalities		
Albion, Idaho	2,794	$ 12,343
Bandon, Oregon	52,737	230,329
Blaine, Washington	33,076	137,570
Bonners Ferry, Idaho	24,867	126,136
Burley, Idaho	94,754	372,522
Canby, Oregon	68,743	301,272
Cascade Locks, Oregon	31,374	128,459
Centralia, Washington	79,503	385,989
Cheney, Washington	93,324	380,199
Consolidated Irrigation District, Washington	1,371	6,954
Coulee Dam, Washington	23,103	101,595
Declo, Idaho	2,310	10,624
Drain, Oregon	26,425	117,955
Eatonville, Washington[2]	9,880	41,193
Ellensburg, Washington	144,065	569,160
Eugene, Oregon	1,551,998	5,186,977
Fircrest, Washington[2]	42,846	183,301
Forest Grove, Oregon	132,193	556,431
Heyburn, Idaho	65,595	252,552
Idaho Falls, Idaho	301,892	1,208,760
McCleary, Washington	32,774	140,526
McMinnville, Oregon	255,480	1,036,909
Milton, Washington[2]	21,143	85,461
Milton-Freewater, Oregon	100,428	412,280
Minidoka, Idaho	1,064	4,483
Monmouth, Oregon	56,671	248,676
Port Angeles, Washington	528,760	2,042,078
Richland, Washington	430,540	1,770,375
Rupert, Idaho	55,959	231,005
Seattle, Washington	1,340,556	4,598,549[1]
Springfield, Oregon	633,014	2,481,142
Steilacoom, Washington	32,266	139,464
Sumas, Washington	5,911	25,952
Tacoma, Washington	1,525,418	4,694,991
Vera Irrigation District, Washington	111,045	457,805
Wash. Public Power Supply System	22,633	87,600
Total Municipalities (36)	7,936,512	$ 28,767,617
PUD's		
Benton County PUD #1	939,101	$ 3,556,225
Central Lincoln PUD	1,016,205	3,930,470
Chelan County PUD #1[2]	299,247	1,024,170[1]
Clallam Co. PUD #1	356,708	1,450,644
Clark Co. PUD #1	2,136,734	8,495,005
Clatskanie PUD	548,904	2,024,779
Cowlitz Co. PUD #1	2,700,512	9,112,216[1]
Douglas Co. PUD #1	486,115	1,803,680[1]
Ferry Co. PUD #1	47,066	193,644
Franklin Co. PUD #1	440,333	1,693,461
Grant Co. PUD #2	803,495	2,938,362[1]
Grays Harbor Co. PUD #1	1,083,275	4,034,377
Kittitas Co. PUD #1	29,869	126,878[1]
Klickitat Co. PUD #1	202,739	766,336
Lewis Co. PUD #1	549,473	2,116,007
Mason Co. PUD #1	47,780	199,831
Mason Co. PUD #3	314,055	1,236,920
Northern Wasco Co. PUD	70,012	300,850
Okanogan Co. PUD #1	391,241	1,568,430
Pacific Co. PUD #2	239,734	1,034,011
Pend Oreille Co. PUD #1	2,077	5,195
Skamania Co. PUD #1	92,221	393,918
Snohomish Co. PUD #1	3,831,147	14,603,884
Tillamook PUD	316,837	1,367,891
Wahkiakum Co. PUD #1	43,920	183,709
Whatcom Co. PUD	117,720	384,601
Total Public Utility Districts (26)	17,106,520	$ 64,545,494
Cooperatives		
Alder Mutual Light Co.	2,074	$ 8,847
Benton Rural Elec. Assn.	189,967	714,223
Big Bend Elec. Coop.	309,530	1,060,180
Blachly-Lane Co. Coop.	99,624	424,451
Central Electric Coop.	171,729	675,016
Clearwater Power Co.	135,190	581,343
Columbia Basin Electric Coop.	120,018	418,453
Columbia Power Coop. Assn.	35,543	136,017
Columbia Rural Electric Assn.	145,725	534,331
Consumers Power	255,831	1,084,593
Coos-Curry Electric Coop.	245,698	1,011,475
Douglas Electric Coop.	124,531	529,937
East End Mutual Elec. Co. Ltd.	9,305	37,201
Elmhurst Mutual Power & Light Co.	123,641	516,827
Fall River Electric Coop.	83,893	352,226
Farmers Electric Co.	6,718	29,076
Flathead Electric Coop.	87,673	341,526
Harney Electric Coop.	111,272	357,182
Hood River Electric Coop.	75,254	309,717
Idaho Co. Light & Power Coop. Assn.	35,421	151,906
Inland Power & Light Co.	350,369	1,439,249
Kootenai Electric Coop., Inc.	119,109	481,115
Lakeview Light & Power Co.[1]	174,774	714,023
Lane Co. Electric Coop.	273,257	1,200,869
Lincoln Electric Coop. — Montana	48,572	202,981
Lincoln Electric Coop. — Washington	106,075	376,120
Lost River Electric Coop.	38,558	127,993
Lower Valley Power & Light Co.	180,743	760,860
Midstate Electric Coop.	108,424	408,918
Missoula Electric Coop.	75,578	300,239
Nespelem Valley Electric Coop.	31,471	134,833
Northern Lights	109,113	448,906
Ohop Mutual Light Co.	22,177	95,860
Okanogan Co. Electric Coop.	21,386	85,924
Orcas Power & Light Co.	89,874	382,043
Parkland Light & Power Co.	94,608	394,321
Peninsula Light Co.[2]	178,927	739,083
Prairie Power Coop.	5,917	24,559
Raft River Electric Coop.	166,246	571,919
Ravalli Co. Electric Coop.	57,921	242,525
Riverside Electric Co.	5,665	24,299
Rural Electric Co.	57,711	233,353
Salem Electric	194,058	803,045
Salmon River Electric Coop.	29,525	99,176
South Side Electric Lines	22,916	93,247
Surprise Valley Electric Corp.	66,598	242,999
Tanner Electric	14,498	64,813
Umatilla Electric Coop.	502,344	1,818,131
Unity Light & Power Co.	39,110	160,627
Vigilante Electric Coop.	64,021	238,972
Wasco Electric Coop.	76,860	323,492
Wells Rural Electric Co.	18,264	66,314
West Oregon Electric Coop.	60,862	255,350
Total Cooperatives (53)	5,774,168	$ 22,830,685
Total Publicly Owned Utilities (115)	30,817,200	$116,143,796
Federal Agencies		
U.S. Energy Research Development Adm.	326,987	$ 1,067,598
U.S. Bureau of Mines	7,701	42,186
U.S. Bureau of Reclamation-Roza Project	1,987	7,738
Fairchild Air Base	23,954	88,092
U.S. Bureau of Indian Affairs	86,031	362,542
U.S. Navy	190,299	776,013
Total Federal Agencies (6)	639,959	$ 2,344,169
Privately-Owned Utilities		
California-Pacific Utilities Co.	7,917	$ 24,435
Idaho Power Co.	3,939	13,787
Montana Power Co.	930,304[1]	2,913,588
Pacific Power & Light Co.	1,482,144	8,629,587[1]
Portland General Electric Co.	3,347,643	20,859,684[1]
Puget Sound Power & Light Co.	654,530	3,217,838[1]
Utah Power Co.	689,307	2,441,586
Washington Water Power Co.	544,479	1,694,283
Total Privately-Owned (8)	7,660,263	$ 39,794,788
Aluminum		
Aluminum Co. of America (combined)[2][3]	3,066,274	10,325,689
Anaconda Aluminum Co.	2,210,337	6,714,803
Intalco Aluminum Co.	3,532,780	11,162,091
Kaiser Alum. & Chem. Corp. (combined)[3]	4,605,901	14,808,234
Martin Marietta Aluminum Inc.		
The Dalles, Oregon	1,494,676	4,148,500
Goldendale, Washington	1,802,615	4,990,922
Reynolds Metals Co. (combined)[3]	5,971,411	18,992,215
Other Industries		
The Carborundum Co.	195,923	650,206
Cominco American, Inc.	0	0
Crown Zellerbach Corp.	96,651	338,985
Georgia Pacific Corp.	169,535	573,863
Hanna Nickel Smelting Co.	878,284	2,698,275
Oregon Metallurgical Corp.	31,259	137,727
Pacific Carbide & Alloys Co.	63,996	214,550
Pennwalt Corporation	378,877	1,231,171
Stewart Elsner	54	814
Stauffer Chemical Works	429,150	1,504,733
Union Carbide Corp.	134,871	442,178
Total Industries (17)	25,062,594	$ 78,934,956
OUTSIDE NORTHWEST REGION		
British Columbia Hydro & Power	89,238	284,833
Burbank, California	230,978	859,168
Glendale, California	211,571	810,844
Los Angeles, California	2,816,878	10,513,098
Pasadena, California	166,638	623,598
Sacramento, California	0	0
Pacific Gas & Electric Co.	4,126,770	16,609,164
San Diego Gas & Electric Co.	398,458	1,259,795
Southern California Edison Co.	3,768,997	13,513,531
State of California	0	0
USBR-Mid-Pacific Region	1,459,297	5,542,316
USBR-Lower Colorado Region	0	0
USBR-Upper Colorado Region	25,250	74,076
Total Outside Northwest Region (12)	13,294,075	$ 50,090,423
Total Sales of Electric Energy (158)	77,471,091	$287,308,132

[1] Includes capacity sales
[2] Includes preliminary data
[3] Billing is by company. Pro-rata break by plant

		Pro-rata MWH	break by plant Revenue
Alcoa—	Vancouver	1,765,432	$ 5,950,318
	Wenatchee	1,241,711	4,168,041
	Addy	59,131	207,330
Kaiser—	Spokane Reduction	2,897,840	9,317,229
	Spokane Rolling	421,788	1,357,511
	Tacoma Reduction	1,286,273	4,133,494
Reynolds—	Longview	3,584,050	11,393,756
	Troutdale	2,387,361	7,598,459

Federal Columbia River Power System

Table 5

Bonneville Power Administration Fund

Monthly Detail of Estimated Cash Receipts and Disbursements
(In Millions of Dollars)

	Cash Receipts	Cash Disbursements	Cash Balance Increase or (Decrease)	Cash Balance Cumulative	Bonds and Notes Outstanding
From June 30, 1976				35	
Transition Quarter					
July	20	17	3	38	
August	52	17	35	73	
September	23	52[1]	(29)	44	
FY 1977					
October	20	19	1	45	
November	23	18	5	50	
December	20	17	3	53	
January 1977	17	18	(1)	52	
February	27	17	10	62	
March	30	18	12	74	
April	29	16	13	87	
May	23	15	8	95	
June	24	17	7	102	
July	22	16	6	108	
August	22	17	5	113	
September	73	186[1]	(113)	0	53
FY 1978					
October	19	19	0	0	56
November	21	21	0	0	59
December	18	18	0	0	58
January 1978	18	18	0	0	55
February	19	19	0	0	53
March	20	20	0	0	48
April	22	22	0	0	45
May	21	21	0	0	39
June	20	20	0	0	36
July	17	17	0	0	37
August	19	19	0	0	33
September	217	217[1]	0	0	234

[1] The large disbursements at the end of each fiscal year result from BPA scheduling its annual repayments to the Treasury at that time.

Federal Columbia River Power System

Table 6

Repayment Study for Fiscal Year 1976

Authorized Projects *(All Amounts in $1,000)*

1 Fiscal Year	2 Revenues	3 O/M Expense	4 Purchase Power Expense	5 Interest Expense (Net)	6 Investment Placed In Service	7 Cumulative Investment In Service	8 Amortization	9 Unamortized Investment	10 Allowable Unamortized Investment
Cumulative to 6-30-76	2,999,851	846,439	266,807	1,072,605	5,260,344	5,260,344	814,000	4,446,344	5,258,188
T/Q	71,800	20,476	8,000	29,201	49,519	5,309,863	14,123	4,481,740	5,307,707
1977	319,600	87,418	75,000	129,923	470,053	5,779,916	27,259	4,924,534	5,777,466
1978	325,200	92,830	109,300	157,683	662,835	6,442,751	34,613-	5,621,982	6,440,301
1979	342,300	99,439	114,200	169,857	298,807	6,741,558	41,196-	5,961,985	6,738,822
1980	358,800	101,939	116,100	187,253	341,612	7,083,170	46,492-	6,350,089	7,076,974
1981	367,700	103,539	155,745	207,195	432,254	7,515,424	98,779-	6,881,122	7,483,319
1982	378,500	105,211	159,742	225,815	441,161	7,956,585	112,268-	7,434,551	7,909,096
1983	386,600	105,331	169,146	238,234	75,584	8,032,169	126,111-	7,636,246	7,963,968
1984	408,700	105,988	149,771	256,936	311,569	8,343,738	103,995-	8,051,810	8,267,552
1985	407,700	106,348	148,592	259,484	26,744	8,370,482	106,724-	8,185,278	8,284,740
1986	413,900	106,468	149,594	259,704	32,833	8,403,315	101,866-	8,319,977	8,307,880
1987	419,700	106,568	150,199	259,512	28,642	8,431,957	96,579-	8,445,198	8,326,249
1988	424,600	107,588	150,217	264,650	153,111	8,585,068	97,855-	8,696,164	8,458,440
1989	425,100	108,588	150,052	269,296	77,909	8,662,977	102,836-	8,876,909	8,514,636
1990	429,100	108,588	151,775	274,771	63,233	8,726,210	106,034-	9,046,176	8,546,299
1991	427,500	108,588	152,183	278,119	59,524	8,785,734	111,390-	9,217,090	8,567,870
1992	426,500	108,588	152,262	281,773	110,628	8,896,362	116,123-	9,443,841	8,596,450
1993	425,100	108,588	146,368	283,310	66,463	8,962,825	113,166-	9,623,470	8,596,009
1994	423,700	108,588	145,300	285,069	80,564	9,043,389	115,257-	9,819,291	8,586,291
1995	422,300	108,588	145,300	285,914	68,954	9,112,343	117,502-	10,005,747	8,633,818
1996	423,300	108,588	145,300	288,850	82,383	9,194,726	119,438-	10,207,568	8,671,036
1997	430,900	108,588	145,300	291,501	80,864	9,275,590	114,489-	10,402,921	8,714,123
1998	431,400	108,588	145,300	294,592	57,247	9,332,837	117,080-	10,577,248	8,677,890
1999	432,600	108,588	145,300	297,667	88,984	9,421,821	118,955-	10,785,187	8,733,584
2000	434,800	108,588	145,300	301,003	92,309	9,514,130	120,091-	10,997,587	8,782,569
2001	434,900	108,588	145,300	306,810	82,977	9,597,107	125,798-	11,206,362	8,786,398
2002	435,000	108,588	145,300	313,224	86,566	9,683,673	132,112-	11,425,040	8,823,229
2003	435,800	108,588	145,300	320,039	72,763	9,756,436	138,127-	11,635,930	8,841,034
2004	437,500	108,588	145,300	327,619	87,558	9,843,994	144,007-	11,867,495	8,750,386
2005	437,500	108,588	145,300	335,186	87,301	9,931,295	151,574-	12,106,370	8,656,919
2006	437,500	108,588	145,300	350,173	101,652	10,032,947	166,561-	12,374,583	8,594,660
2007	437,100	108,588	145,300	358,224	111,586	10,144,533	175,012-	12,661,181	8,557,768
2008	435,700	108,588	145,300	365,956	87,645	10,232,178	184,144-	12,932,970	8,416,465
2009	435,700	108,588	145,300	374,441	98,199	10,330,377	192,629-	13,223,798	8,339,862
2010	434,500	108,588	145,300	389,719	96,582	10,426,959	209,107-	13,529,487	8,218,701
2011	430,300	108,588	145,300	399,942	113,713	10,540,672	223,530-	13,866,730	8,246,346
2012	429,300	108,588	125,300	409,614	108,031	10,648,703	214,202-	14,188,963	8,162,745
2013	429,300	108,588	125,300	444,675	98,075	10,746,778	249,263-	14,536,301	8,101,009
2014	424,900	108,588	125,300	457,994	110,945	10,857,723	266,982-	14,914,228	8,099,918
2015	409,700	108,588	125,300	471,831	93,567	10,951,290	296,019-	15,303,814	8,043,426
2016	408,500	108,588	7,400	553,192	136,130	11,087,420	260,680-	15,700,624	7,984,325
2017	408,500	108,588	7,400	569,440	106,531	11,193,951	276,928-	16,084,083	7,837,146
2018	408,500	108,588	7,400	585,492	96,110	11,290,061	292,980-	16,473,173	7,752,223
2019	408,500	108,588	7,400	601,452	116,681	11,406,742	308,940-	16,898,794	7,387,885
2020	408,500	108,588	7,400	697,845	107,957	11,514,699	405,333-	17,412,084	6,987,294
2021	408,500	108,588	7,400	720,675	92,685	11,607,384	428,163-	17,932,932	6,835,714
2022	408,500	108,588	7,400	744,561	105,360	11,712,744	452,049-	18,490,341	6,831,298
2023	408,500	108,588	7,400	768,831	101,373	11,814,117	476,319-	19,068,033	6,822,582
2024	408,500	108,588	7,400	793,669	95,444	11,909,561	501,157-	19,664,634	6,813,691
2025	408,500	108,588	7,400	912,030	90,920	12,000,481	619,518-	20,375,072	6,653,317
2026	408,500	108,588	7,400	947,716	129,603	12,130,084	655,204-	21,159,879	5,830,127
2027	408,500	108,588	7,400	1,184,177	109,725	12,239,809	891,665-	22,161,269	5,594,617
2028	408,500	108,588	7,400	1,242,831	88,733	12,328,542	950,319-	23,200,321	5,060,273
2029	408,500	108,588	7,400	1,304,928	103,071	12,431,613	1,012,416-	24,315,808	4,920,985
2030	408,500	108,588	7,400	1,600,178	89,940	12,521,553	1,307,666-	25,713,414	4,915,849
2031	408,500	108,588	7,400	1,696,490	103,557	12,625,110	1,403,978-	27,220,949	4,719,976
2032	408,500	108,588	7,400	1,800,674	93,926	12,719,036	1,508,162-	28,823,037	4,394,472
2033	408,500	108,588	7,400	1,910,800	69,048	12,788,084	1,618,288-	30,510,373	4,427,332
2034	408,500	108,588	7,400	2,028,156	80,246	12,868,330	1,735,644-	32,326,263	4,222,572
2035	408,500	108,588	7,400	2,154,203	69,886	12,938,216	1,861,691-	34,257,840	4,241,241
2036	408,500	108,588	7,400	2,289,429	83,586	13,021,802	1,996,917-	36,338,343	4,240,052
2037	408,500	108,588	7,400	2,435,447	59,816	13,081,618	2,142,935-	38,541,094	4,221,795
2038	408,500	108,588	7,400	2,591,025	49,586	13,131,204	2,298,513-	40,889,193	4,204,564
2039	408,500	108,588	7,400	2,757,239	58,394	13,189,598	2,464,727-	43,412,314	4,193,444
2040	408,500	108,588	7,400	2,934,993	62,850	13,252,448	2,642,481-	46,117,645	4,176,580
2041	408,500	108,588	7,400	3,125,722	65,417	13,317,865	2,833,210-	49,016,272	4,119,747
2042	408,500	108,588	7,400	3,333,342	87,142	13,405,007	3,040,830-	52,144,244	4,078,874
2043	408,500	108,588	7,400	3,553,866	53,480	13,458,487	3,261,354-	55,459,078	4,057,969
2044	408,500	108,588	7,400	3,787,371	59,314	13,517,801	3,494,859-	59,013,251	4,028,239
2045	408,500	108,588	7,400	4,038,324	69,584	13,587,385	3,745,812-	62,828,647	4,023,248
2046	408,500	108,588	7,400	4,305,659	76,948	13,664,333	4,013,147-	66,918,742	4,017,418
2047	408,500	108,588	7,400	4,591,544	64,879	13,729,212	4,299,032-	71,282,653	4,010,788
2048	408,500	108,588	7,400	4,896,848	60,029	13,789,241	4,604,336-	75,947,018	3,976,582
2049	408,500	108,588	7,400	5,225,954	80,352	13,869,593	4,933,442-	80,960,812	3,931,524
2050	408,500	108,588	7,400	5,578,973	64,759	13,934,352	5,286,461-	86,312,032	3,900,870
TOTALS	33,539,451	8,828,038	6,050,653	91,038,440	13,934,352		72,377,680-		

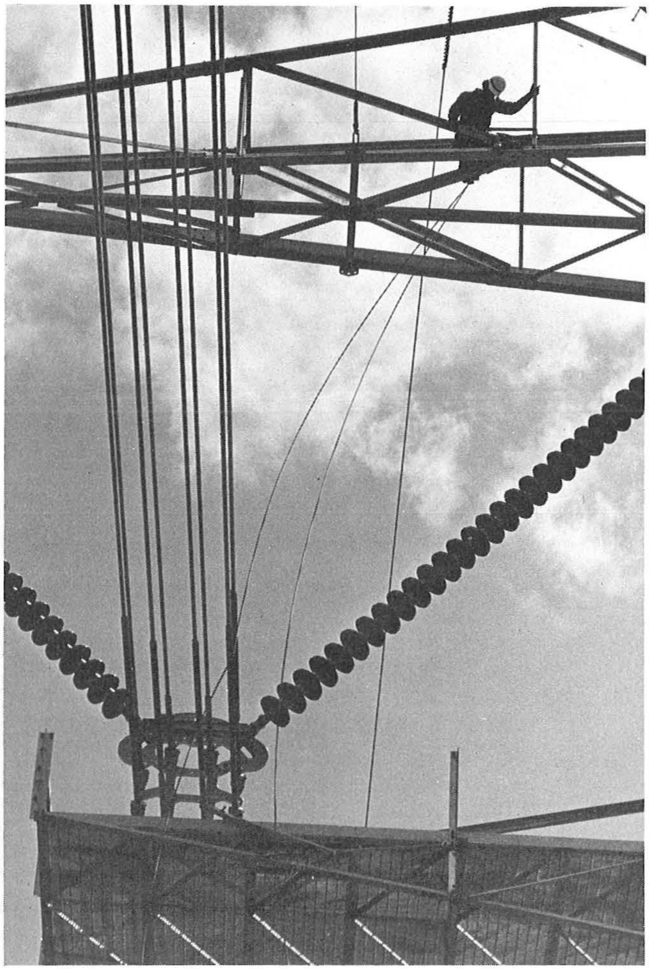
Federal Columbia River Power System

Repayment Policy

Revenues must be sufficient to satisfy the following repayment criteria:

1. Pay the cost of operating and maintaining the power system.
2. Pay the cost of obtaining power through purchase and exchange agreements.
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).
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 40 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.



Mechanical test assembly for ultra-high-voltage test facility.

The FY 1976 Repayment Study (Table 6, page 25), prepared in accordance with the foregoing criteria, shows that cumulative revenues through June 30, 1976, totaled $3.000 billion. These have been applied to pay purchase and exchange power costs of $267 million, operation and maintenance costs of $846 million, interest costs of $1.073 billion, with $814 million having been applied to amortization of the investment in power facilities. The $814 million amortization includes $35 million which was invested in Treasury securities as of the end of the fiscal year and $42 million which was used to pay current construction program. Cumulative investment to be repaid from power revenues totaled $5.260 billion with the unamortized balance totaling $4.446 billion.

Starting with these cumulative results, the repayment study forecasts future revenues and costs over the balance of the repayment period. Costs and

Bonneville Regional Advisory Council meetings stimulate dialog on regional power supply planning.

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. Projects that are authorized but not scheduled for construction at this time are Cougar added units, Strube, John Day added units, Dworshak added units and reregulating dam, and Ice Harbor added units. The total estimated investment in these projects amounts to $444 million. The repayment study also includes BPA power purchase costs which will commence within the 5-year period from December 20, 1974, to December 20, 1979, for which the Federal Power Commission has approved BPA's present wholesale power rates.

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.

Letter from the Comptroller General

COMPTROLLER GENERAL OF THE UNITED STATES
WASHINGTON, D.C. 20548

B-114858 — *December 23, 1976*

The Honorable
The Secretary of the Interior

Dear Mr. Secretary:

We have examined the statement of assets and liabilities of the Federal Columbia River Power System (see note 1 to the financial statements) as of June 30, 1976 and 1975, and the related statements of revenues and expenses and of changes in financial position for the years then ended. We made our examination in accordance with generally accepted auditing standards and included tests of the accounting records of the Corps of Engineers, the Bureau of Reclamation, and the Bonneville Power Administration and such other auditing procedures as we considered necessary in the circumstances.

The accompanying financial statements were prepared on a cost-accounting basis which included depreciation. The statements do not present the financial results on a basis designed to show whether power rates are adequate to repay the Federal investment in the System, for the fiscal year or cumulatively, on the basis of established repayment periods. (See note 1 to the financial statements.)

As described in note 9 to the financial statements, a breach occurred in the Teton Dam on June 5, 1976, causing extensive damage to the project and downstream from the resulting flood. The Congress has enacted legislation to pay the costs of any claims of non-Federal entities and individuals resulting from the damage caused by the flood; thus the System will not be required to pay them (Public Law 94-400, 90 Stat. 1211, September 7, 1976). At the time of our review no decision had been made regarding the future of the project. Until that decision is made, the $13.1 million project investment allocated to power is shown as a Deferred Charge; the $40.1 million irrigation investment repayable from power revenues is included in the repayable irrigation costs described in note 4.

In our opinion, the accompanying financial statements (exhibits 1, 2, and 3), subject to the financial effects of future adjustments related to the adoption of firm cost allocations and the effect of the financial decision on Teton Dam, as explained in notes 3 and 9, present fairly the financial position of the System at June 30, 1976 and 1975, the financial results of its power operations, and the changes in financial position for the years then ended, in conformity with accounting principles and standards prescribed by the Comptroller General of the United States.

We are sending copies of this report to the Director, Office of Management and Budget; the Chairman, Federal Power Commission; the Administrator, Bonneville Power Administration; the Commissioner of Reclamation; the Secretary of the Army; and the Chief of Engineers.

Sincerely yours,

Comptroller General
of the United States

Enclosures - 6

Federal Columbia River Power System **Exhibit 1**

Statement of Revenues and Expenses

For the Fiscal Years ended
June 30, 1976 and June 30, 1975

	1976	1975
	(in thousands)	
OPERATING REVENUES:		
Bonneville Power Administration		
Sales of electric energy:		
Publicly owned utilities	$126,772	$ 99,127
Privately owned utilities	57,395	44,382
Federal agencies	7,975	6,700
Aluminum industry	70,927	56,469
Other industry	7,976	6,239
Total	**271,045**	**212,917**
Other operating revenues:		
Wheeling revenues	17,531	16,321
Other revenues	3,646	5,180
Total	**21,177**	**21,501**
Total Bonneville Power Administration revenues	**292,222**	**234,418**
Associated projects		
Other operating revenues	4,776	2,729
Total power system operating revenues	**296,998**	**237,147**
OPERATING EXPENSES:		
Operation and maintenance expense:		
Operation expense	48,775	45,318
Maintenance expense	30,516	26,005
Total operation and maintenance expense	**79,291**	**71,323**
Purchase and exchange power	7,692	19,347
Depreciation	38,785	34,976
Total operating expenses	**125,768**	**125,646**
Net operating revenues	171,230	111,501
INTEREST:		
Interest on Federal investment (Note 7)	145,826	128,404
Interest charged to construction	35,561*	33,656*
Interest income	6,161*	5,565*
Net interest expense	104,104	89,183
NET REVENUE (Schedule B)	**$ 67,126**	**$ 22,318**

* Denotes deduction

"Notes to the Financial Statements" are an integral part of this statement.

Federal Columbia River Power System **Exhibit 2**

Statement of Assets and Liabilities

As of June 30, 1976 and June 30, 1975

ASSETS

	June 30 1976	June 30 1975
	(in thousands)	
FIXED ASSETS:		
Completed plant (Schedule A) (Note 8)	$4,578,669	$3,890,363
Retirement work in progress	34,137	33,226
	4,612,806	3,923,589
Less accumulated depreciation	381,684	350,925
	4,231,122	3,572,664
Construction work in progress (Schedule A)	759,576	1,079,220
Total fixed assets (Note 8)	**4,990,698**	**4,651,884**
CURRENT ASSETS:		
Unexpended funds	56,046	129,798
Investments in Government securities, at cost	34,237	11,011
Special funds	5,203	7,002
Accounts receivable	59,931	48,791
Materials and supplies	25,373	22,857
Total current assets	**180,790**	**219,459**
OTHER ASSETS AND DEFERRED CHARGES:		
Trust funds construction work in progress	54,566	16,899
Other assets and deferred charges (Note 1)	45,405	30,465
Investment in Teton Dam (Note 9)	13,090	—
Total other assets and deferred charges	**113,061**	**47,364**
TOTAL ASSETS	$5,284,549	$4,918,707

* Denotes deduction

LIABILITIES

	June 30 1976	June 30 1975
	(in thousands)	
PROPRIETARY CAPITAL:		
Investment of U.S. Government in power facilities:		
Congressional appropriations	$5,841,080	$5,577,537
Revenues transferred to Continuing Fund	7,005	7,005
Transfers from other Federal agencies, net	39,489	37,996
Interest on Federal investment (Note 7)	1,433,451	1,287,590
Gross Federal investment	7,321,025	6,910,128
Less funds returned to U.S. Treasury	2,564,707	2,412,854
Net investment of U.S. Government	4,756,318	4,497,274
Accumulated net revenues:		
Balance at beginning of year	312,389	290,588
Net revenues — current year (Exhibit 1)	67,126	22,318
Prior years adjustment (Notes 8 and 10)	440*	517*
Balance at end of year	379,075	312,389
Total proprietary capital in power facilities before irrigation assistance	5,135,393	4,809,663
Irrigation assistance (1976, $542 million; 1975, $511 million) (Schedule A) (Note 4)		
Total proprietary capital	**5,135,393**	**4,809,663**
COMMITMENTS AND CONTINGENCIES (Notes 5 and 6)		
CURRENT LIABILITIES:		
Accounts payable	69,595	60,241
Employees accrued leave	7,362	7,051
Total current liabilities	**76,957**	**67,292**
OTHER LIABILITIES AND DEFERRED CREDITS:		
Trust fund advances	61,546	19,585
Other deferred credits	10,653	22,167
Total other liabilities and deferred credits	**72,199**	**41,752**
TOTAL LIABILITIES	$5,284,549	$4,918,707

"Notes to the Financial Statements" are an integral part of this statement.

Federal Columbia River Power System **Exhibit 3**

Statement of Changes in Financial Position

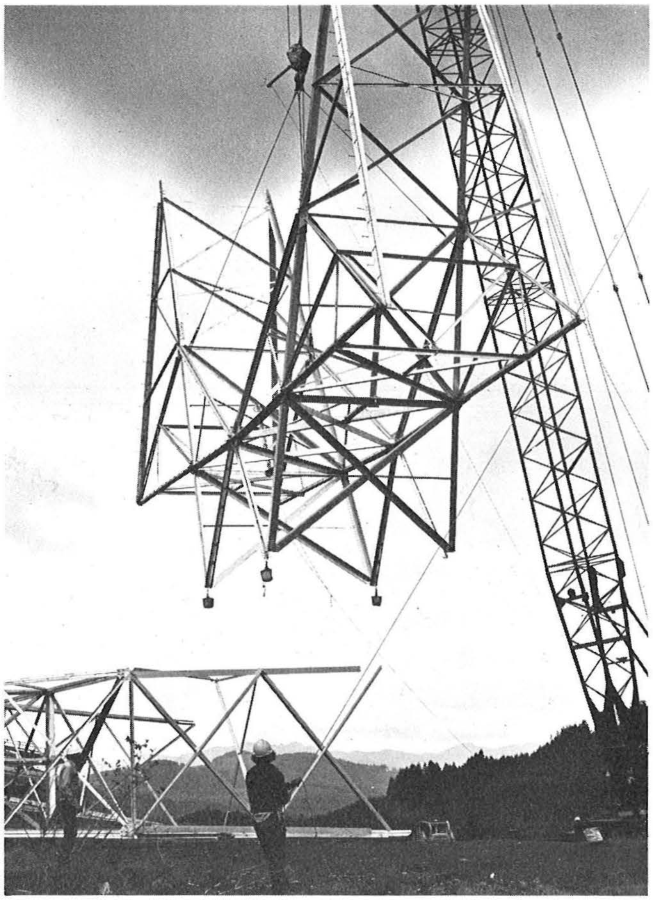
For the Fiscal Years Ending June 30, 1976 and June 30, 1975

	1976	1975
	(in thousands)	
FINANCIAL RESOURCES PROVIDED FROM:		
Operations:		
Net revenues (Exhibit 1)	$ 67,126	$ 22,318
Expenses not requiring repayment	38,785	34,976
Net revenues available for repayment	105,911	57,294
Prior years adjustments (Note 10)	440*	517*
Resources provided from operations	105,471	56,777
Federal investment:		
Congressional appropriations	263,543	379,297
Transfers from other Federal agencies, net	1,493	1,392
Interest on Federal investment	145,861	127,089
Resources provided from Federal investment	410,897	507,778
Other resources:		
Decrease in current assets net of current liabilities	48,334	27,121*
Total resources provided	**$564,702**	**$537,434**
FINANCIAL RESOURCES USED:		
Investment in electric utility plant and facilities, net	$377,599	$338,193
Funds returned to U.S. Treasury	151,853	185,362
Other uses:		
Increase in other assets net of other liabilities	35,250	13,879
Total resources used	**$564,702**	**$537,434**

* Denotes deduction

"Notes to the Financial Statements" are an integral part of this statement.

Installing steel plate footing of a transmission tower leg.



Crane hoists a steel bridge to top-off a transmission tower.

Federal Columbia River Power System

Schedule A

Amount and Allocation of Plant Investment

As of June 30, 1976
(All dollar amounts in thousands)

ALLOCATED TO:

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)	$1,719,245	$1,487,674	$231,571	$1,719,245									100.0
Albeni Falls (CE)	33,454	32,063		32,063				$ 134	$ 174		$ 1,083		95.8
Boise (BR)	66,987	5,138	517	5,655	$ 11,007	$ 35,317	$ 46,324		15,008				24.9
Bonneville (CE)	161,811	61,807	65,456	127,263				32,845			1,279	$ 424	78.6
Chief Joseph (CE)	238,537	155,011	82,492	237,503	723		723				255	56	99.9
Columbia Basin (BR)	1,153,075	335,909	300,248	636,157	401,583	68,093	469,676	1,000	45,715			527	90.0
Cougar (CE)	59,746	18,258	1	18,259		3,025	3,025	539	37,715			208	30.6
Detroit-Big Cliff (CE)	66,611	40,459		40,459		4,764	4,764	220	20,877			291	60.7
Dworshak (CE) (a)	317,956	281,214	38	281,252				9,838	20,549		6,317		88.5
Green Peter-Foster (CE)	89,800	49,639		49,639		5,776	5,776	363	30,107		1,854	2,061	55.3
Hills Creek (CE)	48,840	17,313	60	17,373		4,312	4,312	625	26,257			273	35.6
Hungry Horse (BR)	101,286	76,686	8	76,694					24,592				75.7
Ice Harbor (CE)	173,610	126,704		126,704				44,598			2,308		73.0
John Day (CE) (a)	521,343	381,636	18	381,654				87,461	14,691		11,128	26,409	73.2
Libby (CE) (a)	513,382	398,727	2,426	401,153					81,390			30,839	78.1
Little Goose (CE) (a)	193,595	118,570	21,830	140,400				46,861			3,736	2,598	72.5
Lookout Point-Dexter (CE)	95,251	45,842	7	45,849		1,324	1,324	709	46,798		477	94	48.1
Lower Granite (CE) (a)	332,400	242,726	22,717	265,443				53,762			4,975	8,220	79.9
Lower Monumental (CE) (a)	207,165	150,205	6,723	156,928				47,628			2,192	417	75.8
McNary (CE)	317,115	261,633	544	262,177				53,375			1,563		82.7
Minidoka-Palisades (BR)	97,215	13,357	27	13,384	10,092	43,412	53,504		29,860		173	294	24.1
The Dalles (CE)	319,803	273,527	1,979	275,506				42,433			1,842	22	86.1
Yakima (BR)	65,378	4,571		4,571	10,428	48,673	59,101		316	$ 1,152	238		22.9
Projects Under Construction (a)													
Lost Creek (CE)	120,990		22,914	22,914		1,878	1,878		45,573	20,849	17,693	12,083	18.9
Irrigation Assistance at 11 Projects Having No Power Generation	67,331				67,331		67,331						100.0
Subtotal plant investment	7,081,926	4,578,669	759,576	5,338,245	501,164	216,574	717,738	422,391	439,622	22,001	57,113	84,816(c)	82.5
Repayment obligation retained by Columbia Basin Project	2,211	1,352		1,352(b)	859		859						100.0
Investment in Teton Project (d) (See Note 9)	68,887		13,090	13,090	40,102	3,533	43,635		10,377		1,785		77.2
Total	$7,153,024	$4,580,021	$772,666	$5,352,687	$542,125	$220,107	$762,232	$422,391	$449,999	$22,001	$58,898	$84,816(c)	82.4

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

"Notes to the Financial Statements" are an integral part of this schedule.

(a) Projects in service that have tentative cost allocations at June 30, 1976. Projects under construction have tentative cost allocations (Note 3).

(b) Joint Facilities transferred to Bureau of Sport Fisheries and Wildlife. This portion is included in Exhibit 2 as a Deferred item.

(c) Included in this amount are nonreimbursable road costs amounting to $70.2 million.

(d) Commercial Power portion of Teton included in Exhibit 2 as a Deferred item.

Federal Columbia River Power System

Schedule B

Reconciliation of Cost Accounting Financial Statements to Repayment Study

For the Fiscal Year Ended June 30, 1976
(All dollar amounts in thousands)

	Cumulative Balance June 30, 1975	Fiscal Year 1976 Operations	Prior Years Adjustments	Cumulative Balance June 30, 1976	Cumulative Adjustment to Repayment Basis	Cumulative Data Through June 30, 1976 on Repayment Study
		(Exhibit 1)	(Note 10)		(Note 1)	
OPERATING REVENUES	$2,702,853	$296,998		$2,999,851		$2,999,851
EXPENSES:						
Purchase and exchange power	221,383	7,692		229,075	$ 37,732	266,807
Operation and maintenance expense	766,761	79,291	$387	846,439		846,439
Interest expense	968,466	104,104	35	1,072,605		1,072,605
Depreciation	433,854	38,785	18	472,657	472,657*	
Total expense	2,390,464	229,872	440	2,620,776	434,925*	2,185,851
NET REVENUES (Exhibit 2)	$ 312,389	$ 67,126	$440*	$ 379,075		
RECONCILIATION TO CUMULATIVE AMORTIZATION				$ 379,075	$434,925	$ 814,000
PLANT INVESTMENT						
Completed plant (Exhibit 2)				$4,578,669		
Retirement work in progress (Exhibit 2)				34,137		
Repayment obligation retained by Columbia Basin Project (Schedule A)				1,352		
Repayment obligation for Teton Project (Exhibit 2)				13,090		
Irrigation Assistance (Schedule A)				542,125		
Net retirements					$ 90,971	
				$5,169,373	$ 90,971	$5,260,344
Less amortization						814,000 (a)
Unamortized plant investment						$4,446,344

(a) CHANGES IN CUMULATIVE AMORTIZATION:

Cumulative amortization through June 30, 1975 (including $11,152 invested in government securities)	$ 731,802
Fiscal year 1976	
Depreciation	38,803
Net revenues	67,126
Prior years adjustments	440*
Purchase and exchange power-adjustment	23,291*
Amortization for the year	82,198
Cumulative amortization through June 30, 1976	$ 814,000

* Denotes deduction

"Notes to the Financial Statements" are an integral part of this schedule.

Notes to the Financial Statements

Note 1. Major Accounting Considerations

The Federal Columbia River Power System (FCRPS) consists of the Bonneville Power Administration (BPA) and the generating facilities of the Corps of Engineers (Corps) and the Bureau of Reclamation (Bureau) for which BPA is the power marketing agent. Each entity is separately managed and financed, but the facilities are operated as an integrated power system with the financial results consolidated under the FCRPS title.

These financial statements are prepared on a cost accounting basis including compound interest depreciation and interest on the unamortized Federal investment.

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. Schedule A lists the projects included in FCRPS and the allocation of plant investment to the various purposes.

BPA wholesale power rates are established by using a separate repayment analysis. The differences between the financial statements and the historical data on the repayment analysis are the treatment of fixed assets, purchased power, and amortization. In the accompanying statements, the depreciation life for fixed assets allocated to power averages about 62 years, with the transmission system averaging 40 years and generating projects averaging 88 years. However, the repayment periods used to establish power rates are 50 years for the generating projects and 40 years for the transmission system, for an average of 47 years.

The purchase and exchange power costs in the cost accounting financial statements reflect the expense on a revenue and expense matching basis, while the figures in the repayment study are on a cash basis. The difference occurs when, for example, net billing for a thermal plant commences before the commercial operation date, such as the Trojan Nuclear Plant. The statement line item "Other assets and deferred charges" on Exhibit 2 for fiscal years 1976 and 1975 includes $38.0 million and $21.1 million respectively, of accumulated Trojan Nuclear Plant costs which were accumulated prior to the plant operation date. These costs will be amortized against revenues produced from that project over the life of the project.

Schedule B provides a correlation between the accompanying costs statements and cumulative totals shown in the first line of the separate repayment analysis.

Note 2. Financing of BPA's Construction Program

The Federal Columbia River Transmission System Act approved October 18, 1974, authorized BPA to use operating receipts and proceeds from sales of revenue bonds for further construction of the Federal transmission system in the Pacific Northwest. The transmission system construction program was financed through the appropriation process for fiscal year 1975 and all prior years. In fiscal year 1976, BPA expended the last of the unused portions of the fiscal year 1975 and prior construction appropriation and began using operating receipts. Current receipts of $61.7 million were used for construction of BPA facilities during the fiscal year.

Note 3. Tentative Cost Allocations

Plant cost and operation and maintenance expenses based on tentative allocations between power and nonpower purposes are included for seven of the projects listed in Schedule A. In the past, adjustments have been made to plant cost and accumulated net revenues when firm allocations were adopted. At June 30, 1976, total joint plant costs for these seven projects were about $1.4 billion of which $1.1 billion were tentatively allocated to power and subject to retroactive adjustment. The amount of adjustments that may be necessary when the allocations become firm is not determinable at this time.

Note 4. Repayment Responsibility for Irrigation Costs

Legislation requires that FCRPS net revenues will be used to repay to the U.S. Treasury the cost of Bureau irrigation facilities which benefiting water users are unable to repay. The use of power revenues for such repayments 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. The irrigation assistance payments will be shown as reductions of accumulated net revenues at the time future payments are made. The first payment is scheduled to be made in 1997. The 1997 and other future payments are disclosed in the FCRPS repayment studies which are used to establish BPA's power rates. Investment made in irrigation facilities through June 30, 1976, results in estimated irrigation assistance of $542 million. This compares to $511.5 million at June 30, 1975.

Not included in the above irrigation assistance costs, is any portion of $21 million of original project facility costs allocated to irrigation at six Corps projects. If completion of irrigation facilities is ever proposed for authorization and development at these six projects, a determination of water users' repayment ability will probably be made which might result in additional irrigation assistance being required from power revenues.

Note 5. Commitments to Exchange Power and Acquire Project Capability

BPA has made commitments to acquire all or part of the generating capability of various thermal power plants, listed in the table below. BPA is obligated to pay by exchange and net-billing agreements its share of the project costs whether or not the project is completed, operable, or operated. The "Present Termination Commitment" represents those project financing costs (without credit for assets) which would have been payable over the varied financing repayment periods if the project had terminated at June 30, 1976.

		Estimated BPA Portion		
Project Name	Commitment Period	Capacity	Total Capital Cost	Present Termination Commitment
		(Megawatts)	(in thousands)	(in thousands)
Hanford	Present, for project life	800	$ 68,000	$ 58,900
Trojan Nuclear Plant	Present, for project life	339	144,500	144,500
WPPSS* Nuclear Project #1	Start 12/79 for project life	850	1,217,100	355,000
WPPSS Nuclear Project #2	Start 12/76 for project life	1,100	998,700	600,000
WPPSS Nuclear Project #3	Start 12/80 for project life	868	1,016,500	250,000

*Washington Public Power Supply System

BPA has also entered into agreements with 41 utilities to exchange an agreed amount of power for their rights to the Canadian Entitlement. The Canadian Entitlement is one-half of the additional power benefits realized from three Canadian Treaty dams. It was purchased for a 30-year period by the 41 utilities with a $314.1 million bond issue. BPA furnishes a specified amount of power regardless of the actual additional power generated.

Note 6. Contingent Liabilities

Contingent liabilities other than those liabilities relating to the failure of Teton Dam, which are discussed in Note 9, total approximately $40.4 million of which $32.9 million represent various contractor claims and $7.5 million represent claims under the Federal Tort Claims Act.

Note 7. Interest Rates

Rates of interest applied to the unamortized Federal investment for each generating project and for each year's investment in the transmission system range from 2-1/2% to 6-5/8%. The rates have been set either by law, by administrative order pursuant to law, or by administrative policies. They have not necessarily been designed to recover the interest costs to the U.S. Treasury to finance the investment.

Note 8. Imputed Rent

The General Services Administration (GSA) provides facilities to BPA, the Corps, and the Bureau. Beginning in fiscal year 1975, all three agencies were required by law to pay GSA approximate commercial rental rates. Prior to fiscal year 1975, BPA and the Bureau imputed the rental cost, but the Corps did not because they believed the costs were insignificant. The Corps has estimated these rental costs at $1.7 million for fiscal years 1972-74 of which $.5 million would be written off against accumulated net revenues and $1.2 million would be added to completed plant.

Note 9. Teton Dam

On June 5, 1976, 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 gross investment in the project at June 30, 1976 was $68.9 million. The amount of investment allocated to power was $13.1 million, and the amount of investment allocated to irrigation but repayable from power revenues, was $40.1 million.

Disposition of the project costs and final decision on the repayment obligation are dependent upon Department of the Interior administrative action and/or Congressional action. The most severe impact on the financial position of the Federal Columbia River Power System would be if the total reimbursable project investment became due and payable immediately and the asset cost allocated to power was written off against accumulated net revenues.

Until a decision is made regarding the future of the project, the investment allocated to power is included as a deferred charge on the Statement of Assets and Liabilities and the costs of irrigation assistance are included with the other irrigation costs, described in Note 4.

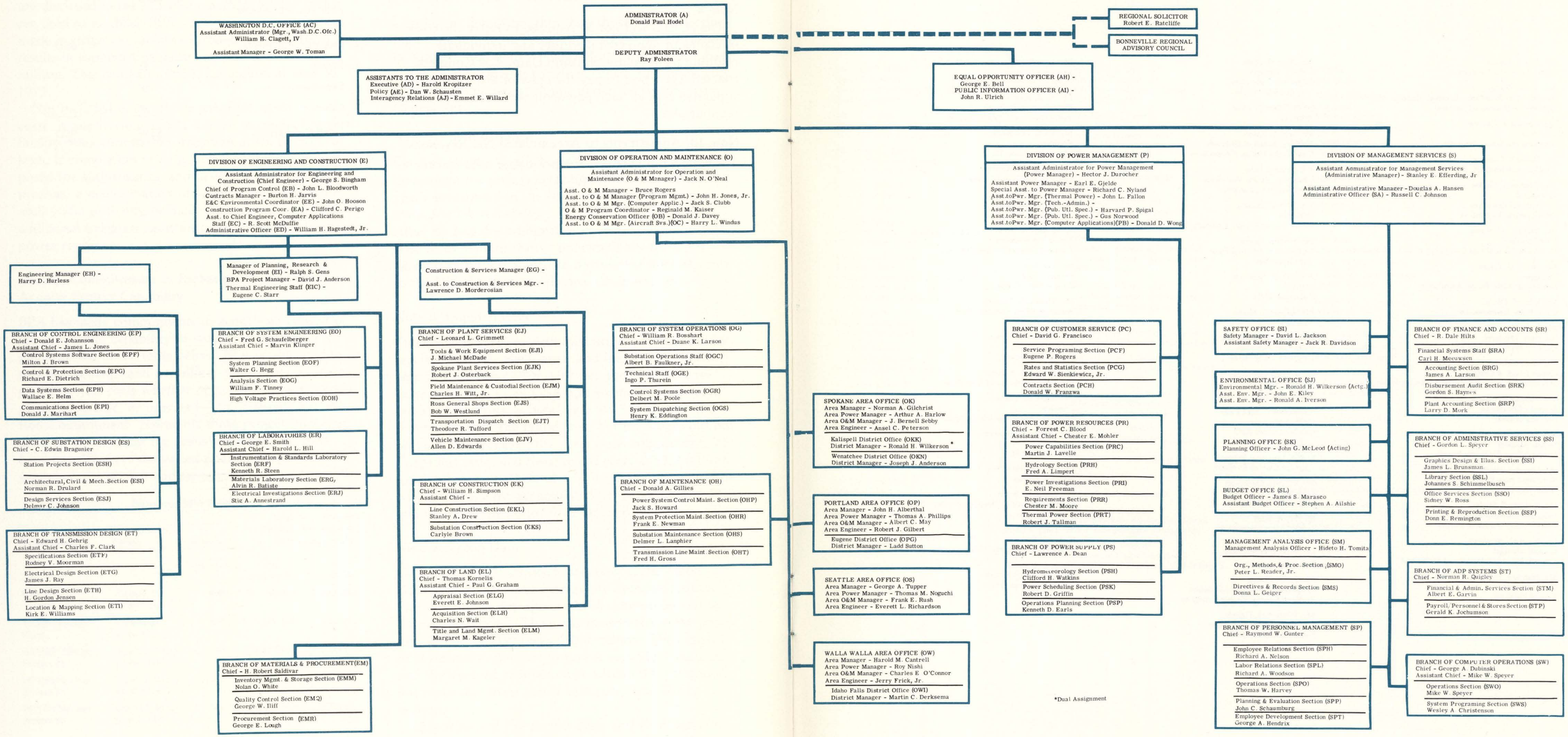
The FCRPS will not be required to repay the costs of claims of non-Federal entities and individuals resulting from failure of Teton Dam. The Congress enacted legislation to pay the costs of these claims and stipulated that all such payments would be non-reimbursable.

Note 10. Adjustments to Accumulated Net Revenues

The following table lists the prior year adjustments deducted from Accumulated Net Revenues as shown in Exhibit 2 and Schedule B.

	Fiscal Year 1976	Fiscal Year 1975
	(in thousands)	
1. Adjustment to write-off prior year's employee compensation.	$368	–
2. Property retirements	–	$517
3. Interest	35	–
4. Depreciation	18	–
5. Other	19	–
Net Decrease	$440	$517

BPA Organization Chart
Management Analysis Office
November 1, 1976



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