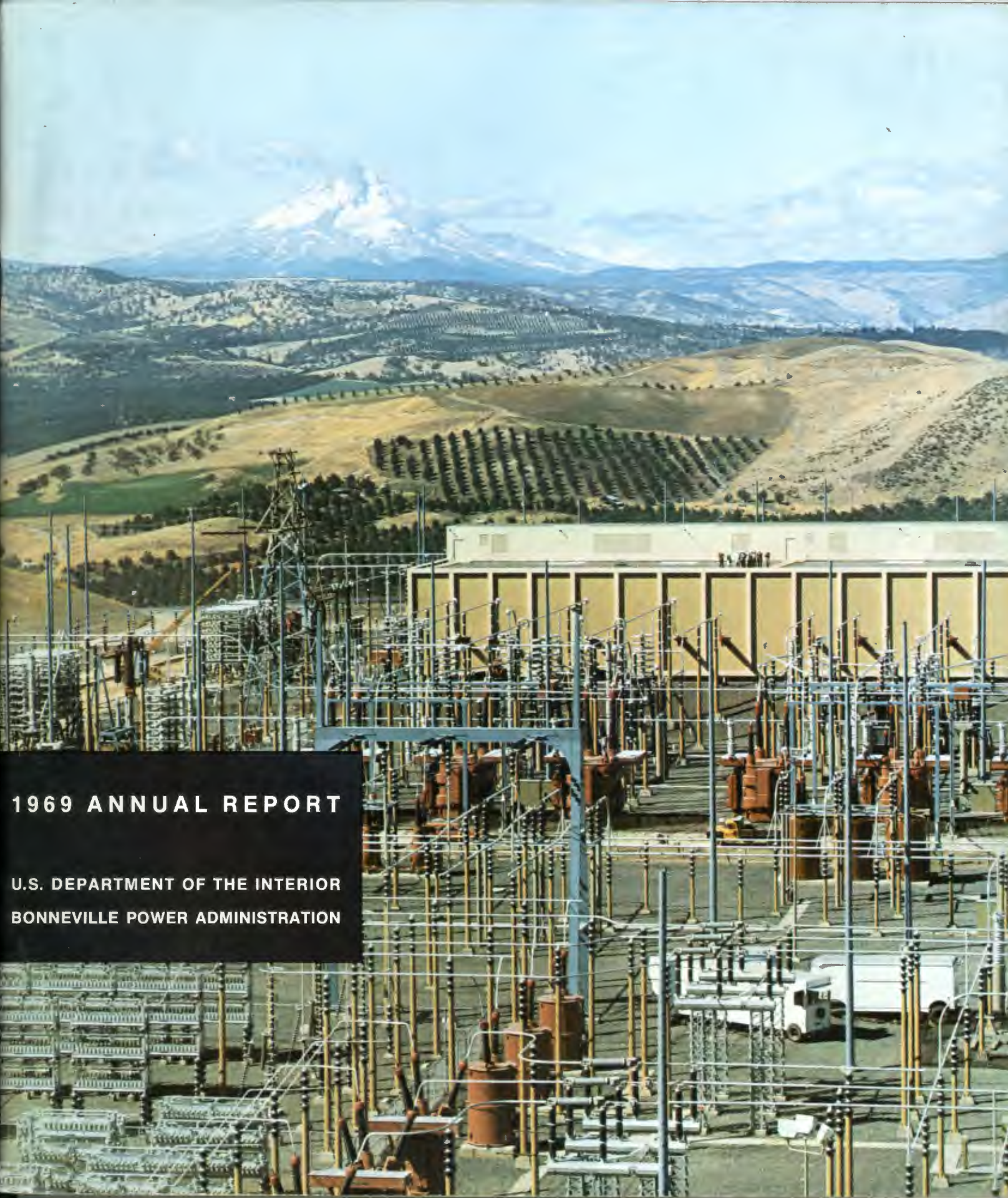

1969 ANNUAL REPORT

U.S. DEPARTMENT OF THE INTERIOR

BONNEVILLE POWER ADMINISTRATION

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FEDERAL COLUMBIA RIVER POWER SYSTEM

1969 ANNUAL REPORT

U.S. DEPARTMENT OF THE INTERIOR

Walter J. Hickel, Secretary

BONNEVILLE POWER ADMINISTRATION

H. R. Richmond, Administrator

Opposite— Valve Room, Celilo Converter Station

Cover— View of Celilo Converter Station Switchyard

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Joint Power Planning Council in session

LETTER TO THE SECRETARY

December 31, 1969

Honorable Walter J. Hickel
Secretary of the Interior
Washington, D.C. 20240

Dear Mr. Secretary:

This is Bonneville Power Administration's thirty-second Annual Report on the Federal Columbia River Power System. The report covers events of fiscal year 1969 and significant developments that have occurred since the fiscal year ended June 30. It has been one of the most eventful periods in Bonneville's history.

Hydro-Thermal Power Program Approval

The capstone event was the approval of the joint Hydro-Thermal Power Program for the Pacific Northwest by President Richard M. Nixon's Administration. Passage of the fiscal year 1970 Public Works Appropriations Bill provided congressional endorsement of the Hydro-Thermal Power Program principle as well. The program will ensure optimum combination of the region's generating and transmission resources—Federal and non-Federal, public and private, existing and planned—to fulfill two key objectives.

First, it will permit timely and orderly development of an adequate and reliable supply of power for the Northwest at the lowest practicable cost. Second, it will meet future power requirements with maximum attention to the importance of preserving environmental quality.

Our commitment to these twin objectives is emphatic. We are determined that each be achieved with the highest concern for the other.

Commitment Policy

A key element in the Hydro-Thermal Power Program is Bonneville's policy of entering into commitments for the sale of power. The ability to make long-range commitments enables Bonneville to engage in meaningful planning. It assures the utilities in the region of the role the Federal system will play and enables them to plan with certainty the development of their own systems. Successful implementation of

Secretary of the Interior, Walter J. Hickel

the Hydro-Thermal Power Program hinges on a workable BPA commitment policy.

In April, the national Administration formally approved our policy on commitments for the sale of power from Federal hydroelectric projects. Essentially, except for sales or exchanges of peaking capacity from authorized projects, the policy permits us to commit power from Federal projects which are existing or for which construction funds have been appropriated. Approval of this policy provides a solid foundation from which to launch the Hydro-Thermal Power Program.

Cooperation

If there is one characteristic of the Hydro-Thermal Power Program which transcends all others, it is the high degree of cooperation achieved among all 108 participating utilities and between them and BPA. To produce and deliver power most efficiently in the Pacific Northwest requires integrating thermal power with hydro power. Markets must be assured for the output of the largest and most economical thermal plants. Each participant has demonstrated willingness to accept a responsible role in the unique undertaking.

Bulk transmission, peaking capacity, forced outage reserves, fuel displacement energy, and reserves for unanticipated regional load growth are required. These will be Federal responsibilities to be borne jointly by the Army Corps of Engineers, the Bureau of Reclamation, and the Bonneville Power Administration.

Building the largest and most economical thermal plants, timed, sized, and located to meet regional as well as owner needs is the key responsibility to be borne by private and public utilities.

This specialization and division of responsibilities is clearly efficient. But it also increases interdependence and obliges each participant to fulfill its part of the cooperative plan. It is a tribute to the utilities of the Northwest that they, together with Bonneville, have forged a strong and effective mechanism for interutility cooperation, the Joint Power Planning Council.

The region's utilities, individually and collectively, have also developed productive relationships with Federal and state agencies responsible for protection of the environment. These environmental agencies, in turn, have been involved in the planning of the region's power system.

Hydro-Thermal Power Program Status

Construction of the first large thermal plant of the Hydro-Thermal Power Program is underway near Centralia, Washington. It is a coal-fired plant being built by Pacific Power and Light Company and The Washington Water Power Company, and shared in by other utilities.

The second large thermal plant in the program is in the advanced planning stage. It will be a nuclear plant built by Portland General Electric Company at Rainier, Oregon, and also shared in by other utilities.

We are discussing plans and marketing arrangements with other utilities for a series of additional thermal plants to be built on schedules closely tied to forecasts of power requirements. The third plant, coal-fired, will be built by Pacific Power and Light Company near Rock Springs, Wyoming. The next four thermal plants will be built by Eugene Water and Electric Board, the Washington Public Power Supply System, Seattle City Light and Snohomish County PUD, and Puget Sound Power and Light Company. Output of each of these plants will be shared with other participating utilities.

At the same time, the Corps of Engineers and the Bureau of Reclamation are proceeding with construction of multipurpose hydro plants (including Libby, Dworshak, Lower Granite, and Little Goose) and with installation of additional generators at existing plants (such as Grand Coulee, The Dalles, John Day, and Lower Monumental).

System Development

During fiscal year 1969, the Federal Columbia River Power System added 1.2 million kilowatts of generating capacity, increasing the number of Federal dams producing electricity to 25 and their combined nameplate rating to more than 8 million kilowatts.

Two of the four Canadian Treaty dams, Duncan and Keenleyside (formerly Arrow), are already operational and contributing to the power system's performance. Construction of the two remaining Treaty projects, Mica Dam in British Columbia and Libby Dam in Montana, is proceeding on schedule.

Bonneville Power Administration built more than 400 miles of 500,000-volt transmission lines during fiscal year 1969, increasing total circuit miles on our system to more than 11,000.

Power Sales and Financial Results

Our energy sales increased 15.8 percent during the fiscal year, reaching a new high of 51.8 billion kilowatt-hours.

Revenues increased 16.4 percent to a new high of $137.3 million. Net revenues, after all expenses including interest on the Federal investment, totaled $28.1 million.

As required by Public Law 89-448, this annual report presents a financial statement on a payout basis for the Federal Columbia River Power System. The statement shows that BPA's present power rate levels will continue to be adequate through 1974; power revenues will repay all costs of generating and transmitting electric energy (including repayment of investment plus interest) and also help repay irrigation costs beyond the ability of water users to repay.

Power Rates

The repayment analysis reflects the new higher interest rate policy for new construction announced October 27, 1969. The analysis was presented to the Federal Power Commission for that agency's review of your decision to maintain present BPA power rates for the 5-year rate period ending December 20, 1974. On December 5, 1969, the FPC approved this decision.

Power Operations

During December 1968 and January 1969, the power system experienced unusually heavy power demands occasioned by exceptionally low temperatures. Every available generator operated to the maximum extent possible. The power situation was aggravated by the temporary unavailability of power from the Hanford project and by delays in Federal generator installation schedules. We imported

James R. Smith, Assistant Secretary of the Interior for Water and Power Development

"Your regional approach to solve power problems is unique in the United States and is extremely effective."

as much as 700,000 kilowatts of power into the region and curtailed as much as 400,000 kilowatts of interruptible industrial loads during peak periods on the coldest days. Operations returned to normal in February and continued normal for the balance of the fiscal year.

Accelerated snowmelt and early runoff from a warm spring led to abnormally low streamflows by midsummer at the start of the new fiscal year. A severe shortage of hydro energy developed. By early September 1969, streamflows were at record lows for that time of year.

Exports of surplus energy over the Intertie were stopped. Secondary energy sales to public and private utilities and for interruptible industrial loads ceased. Sales of provisional energy to industry were cut back, first to 70 percent and then to 60 percent of interruptible load.

The situation improved during the last two weeks of September when heavy rains replenished streamflows and reservoirs. Service to secondary and interruptible loads was resumed October 1.

Intertie

Throughout fiscal year 1969, the Pacific Northwest-Pacific Southwest Intertie, consisting thus far of two 500-kilovolt alternating-current lines, was undergoing successful break-in operations. The Intertie is now being operated at a top limit of 1,400,000 kilowatts. As operating experience is accumulated and equipment problems eliminated, it is planned to gradually bring the two a-c lines up to their design capability of about 2,000,000 kilowatts.

During the year, the Intertie contributed significantly to the stability of electrical systems in both the Northwest and Southwest. On one occasion, when 1¼ million kilowatts being produced at 11 of Grand Coulee's 18 generator units were suddenly lost, power flow on the Intertie was reversed and a widespread blackout in the Northwest was averted. And during the cold weather spell, the Intertie brought sizable blocks of power to the Northwest.

The Intertie is performing valuable services for the two regions it interconnects. It is enabling the marketing of surplus Northwest energy to California. It enables Northwest utilities to sell Canada's share of Canadian Treaty power to California. It makes it possible for Northwest industries to maintain production by purchasing energy from California to replace curtailed interruptible deliveries from Bonneville. It permitted importation from California of up to 700,000 kilowatts during the 1968-69 winter cold snap to meet record high Northwest loads. And it tends to speed restoration of system stability following loss of major generation. It is expected that surplus sales on the

Intertie will increase significantly as experience is gained with operations of interconnected power systems.

Meanwhile, construction of America's first—and the world's largest—long-distance, high-voltage direct-current transmission line, which is a key part of the Intertie, proceeded apace. The converter stations at each end of the line are undergoing tests. The 800,000 volt, 846-mile line is now scheduled to carry power commercially between The Dalles Dam on the Columbia River and the City of Los Angeles beginning about March 1970.

System Control

The program to automate system control and dispatch, essential for efficient operation of an increasingly complex power system, is moving steadily forward. Adoption of this dramatic new technology is expected to yield substantial improvements in the control of streamflows and electrical operations. By employing high-speed, special-purpose computers to schedule generation and control transmission, the Northwest power system will be taking a giant step towards optimizing power production, assuring that regional power requirements are met with a minimum investment of resources and improving reliability of electric service.

Power Outlook

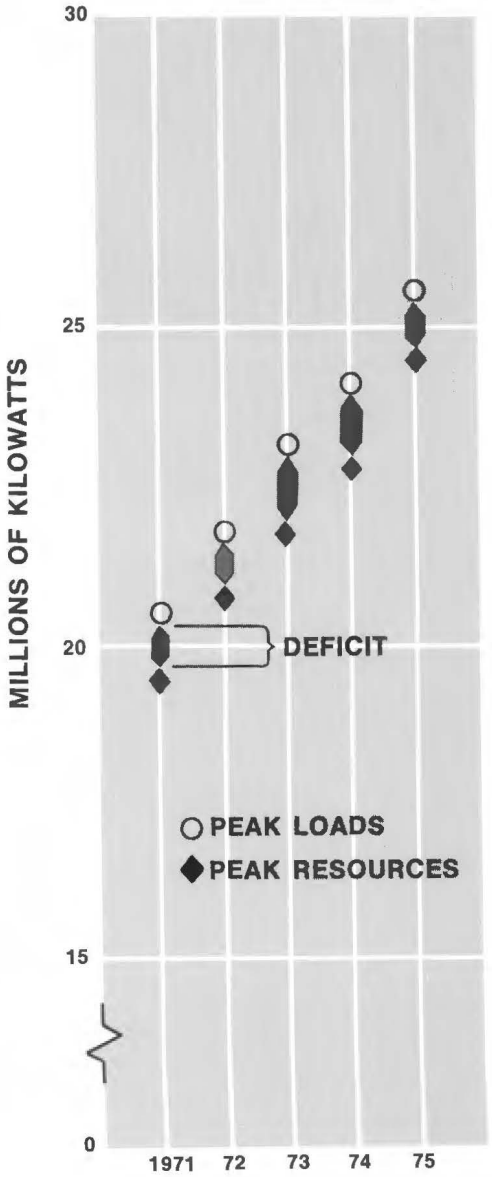
We are approaching a serious power supply situation in the Pacific Northwest over the next five years. Repeated delays in generator unit installation schedules at key Federal hydro projects in the region will result in utility loads outstripping resources during the years 1970-75. The following table shows the resulting deficits.

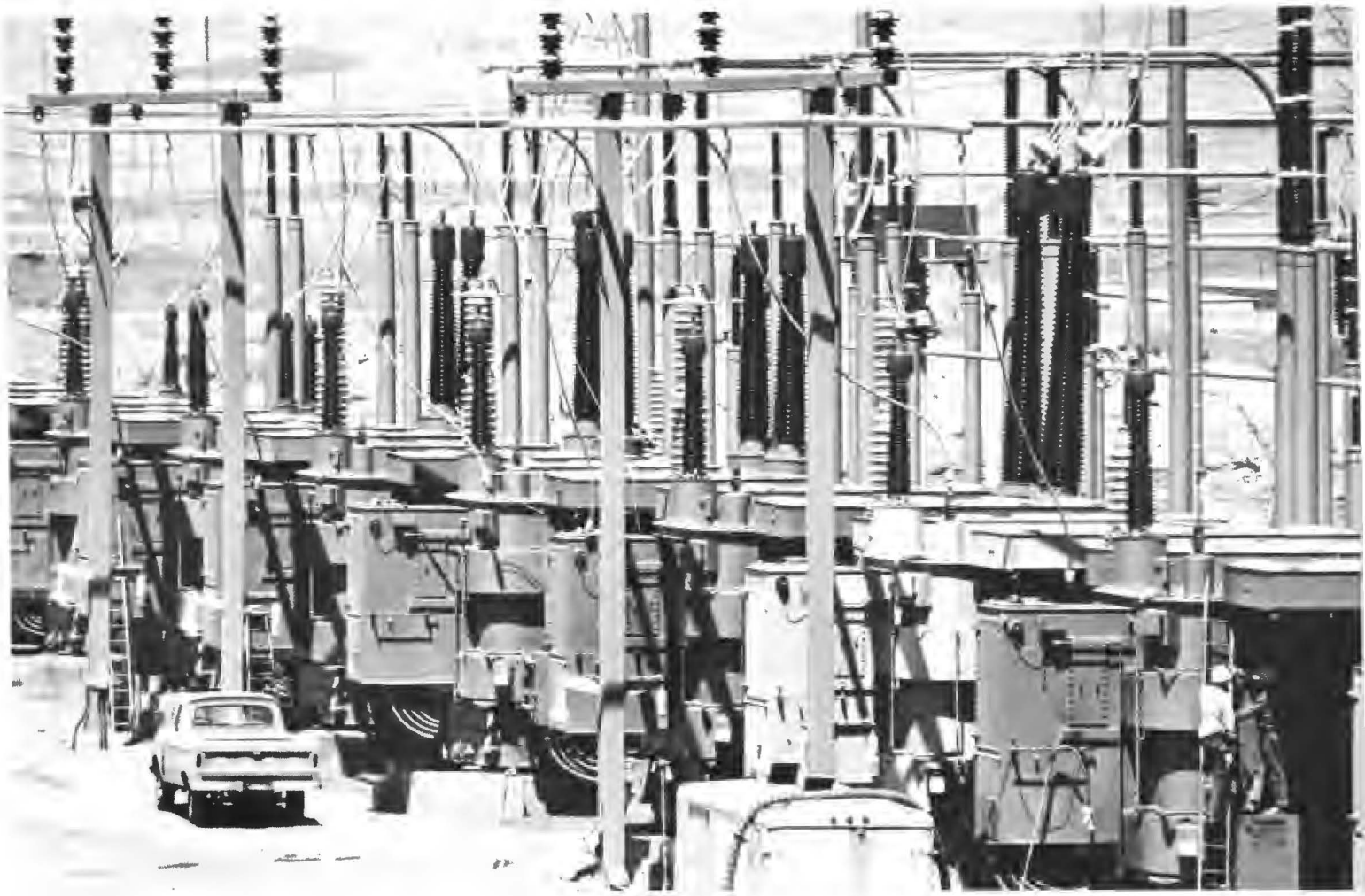
Peak Loads and Resources
West Group Area
(Thousands of Kilowatts)

	1970-71	1971-72	1972-73	1973-74	1974-75
Loads	20,159	21,472	22,777	24,076	25,449
Resources	19,734	20,992	21,757	22,922	24,840
(Deficit)	(425)	(480)	(1,020)	(1,154)	(609)

The deficit of 1,154,000 kilowatts shown for 1973-74 is equivalent to more than the combined peak loads of the cities of Tacoma and Eugene. Even with the elimination of interruptible industrial loads, the

PEAK LOAD DEFICIT
WEST GROUP AREA





Celilo Converter Station switchyard

1973-74 firm peak deficit will reach 262,000 kilowatts. This means that under certain conditions, we will be short of necessary reserves and it will be necessary to cut off firm loads. We have not yet decided which firm loads will have to be dropped under these circumstances.

The situation is even more alarming than suggested by the table. Any significant delay in installation schedules of Federal generation will compound the seriousness of the problem and force additional firm loads to be cut off under adverse circumstances. Moreover, the table assumes some resources which are highly problematical. For example, because of air pollution problems in the Los Angeles basin, it is now uncertain that Southern California Edison will be able to advance construction of its Huntington Beach thermal plant six months ahead of its own needs. This will deprive the Northwest of 790,000 kilowatts we expected to import over the Intertie in the winter of fiscal year 1974. Without this import, the projected January 1974 peak deficit will approach 2 million kilowatts.

Any combination of adverse events—a harsh winter, unanticipated load growth, delay in installation schedules, unscheduled generator outages, or critical hydro conditions—could leave the region vulnerable to serious power shortages. Makeshift emergency arrangements

to secure power from outside the region are being explored. Whether or not we will be successful in making such arrangements is uncertain.

Much of this bleak short-run outlook stems from the very long lead time required for construction of hydroelectric projects and large modern steamplants. When generator installation schedules are slipped, it becomes difficult or impossible to accelerate construction of alternative resources to meet forecasted loads. Power shortages result.

Long-Range Outlook

The Administration's approval of the Northwest Hydro-Thermal Power Program brightens the prospects for meeting regional loads after 1975. Without the Hydro-Thermal Power Program, one of two things would happen. Either (1) the region's forecasted power requirements would not be met or (2) loads would be met but at excessively high costs to society.

By simulating conditions which would prevail under a single ownership, the Hydro-Thermal Power Program not only holds the promise that loads will be met but that they will be met by an efficient power system which closely approximates the ideal model—minimum capital requirements, lowest rates to consumers, and minimum impact on the environment.

Implementation of Hydro-Thermal Power Program

Approval of the Hydro-Thermal Power Program will not permit any slackening of effort. Quite the contrary. Although the Program provides the framework in which the region's future power system will develop, implementation will confront us with formidable challenges.

A major problem will be protecting the quality of our environment. As an agency in the Department of the Interior, we recognize our responsibility to safeguard the environment. The utilities of the Northwest are increasingly sensitive to this problem. We are determined that no power facility be developed without careful evaluation of environmental consequences and that effective steps be taken to minimize potential environmental damage.

Another problem of implementation is to ensure that the critical timetable schedules for installation of hydro and thermal generating resources and transmission needed to integrate those resources to serve growing loads are observed. Any serious delay will result in greater power deficits than now anticipated.

The planning of a regional power system is a dynamic process and this too presents problems. Forecasts of loads and resources must be

Congressman Wendell Wyatt

"To meet the power needs of the Northwest, we have achieved enlightened progress — an accord between man and an accommodation with our environment."

continuously up-dated to reflect changing conditions. To assure least-cost development, it will be necessary for the Federal system and the region's utilities to be alert and responsive to changes in these critical forecasts.

Implementation of the Hydro-Thermal Power Program will also require continuation and extension of the high degree of interutility cooperation which has been manifested by the Joint Power Planning Council. Existing cooperative arrangements will have to be maintained and strengthened. Development of additional modes of cooperation will be required to fully integrate the views and interests of other agencies and the public at large.

I would like to add one thought on power supply reliability. We can no longer speak of just regional reliability; instead we must refer to interregional reliability. Disturbances on the Northwest power system can affect electrical service outside the region and vice versa. Utilities in the Western United States must carefully coordinate their planning and operation. This is being done through the Western Systems Coordinating Council.

Budget Restraint

In operating the Federal Columbia River Power System over the past year, we have had to be mindful of two countervailing forces. On the one hand, the Nation has been confronted with serious price inflation which has resulted in the imposition of stringent budgetary constraints on our program. On the other hand, increasing electric power loads of the Pacific Northwest have had to be met by joint cooperative action of Federal and non-Federal entities to achieve minimum environmental damage and an ample and dependable supply of low-cost power. In this setting we have endeavored to strike the appropriate balance between our dual responsibilities — to the national fiscal policy and to the regional power system.

Inauguration of the Hydro-Thermal Power Program does not relieve us of these immediate problems. It does, however, focus our attention on the future. It is the challenge of this program to which we now address ourselves.

Sincerely yours,

H R Richmond

H. R. Richmond
Administrator

Model of Portland General Electric's Nuclear Plant

HYDRO-THERMAL POWER PROGRAM: A PROGRESS REPORT

The Pacific Northwest's Hydro-Thermal Power Program was officially approved by President Richard M. Nixon's Administration on October 27, 1969. Secretary of the Interior Walter J. Hickel announced "a new accord in power planning between the Federal Government and public and private utilities through greater pooling of all facilities, existing or to be built."

In December 1969, Congress went on record formally endorsing the Hydro-Thermal Power Program principle by passage of the fiscal year 1970 Public Works Appropriations Bill. Language contained in the bill confirmed BPA's authority to acquire some of the output from non-Federally financed thermal generating plants by net billing. Under this arrangement, BPA payment obligations would be liquidated by net billing against amounts due to BPA from thermal plant participants under their other obligations to Bonneville. All net billing arrangements, before they are put into effect, will be subject to approval of the Department of the Interior and to review by the Bureau of the Budget and the congressional appropriations committees.

Secretary Hickel defined the program as a long-range plan to assure low-cost electricity for the Northwest by blending the resources of hydroelectric systems with those of non-Federal thermal generating plants.

Arrangements for the Hydro-Thermal Power Program will be based on agreements among the utilities and Bonneville Power Administration. The output of each thermal generating plant will be shared by a number of utilities, both public and private, with BPA providing reserves, peaking capacity from Federal hydro plants, and most of the high-voltage transmission.

Private and public utilities will build the thermal plants. None will be constructed by the Federal Government.

Some of the new thermal plants will be owned jointly by public and private utilities. Others will be wholly publicly or privately owned.

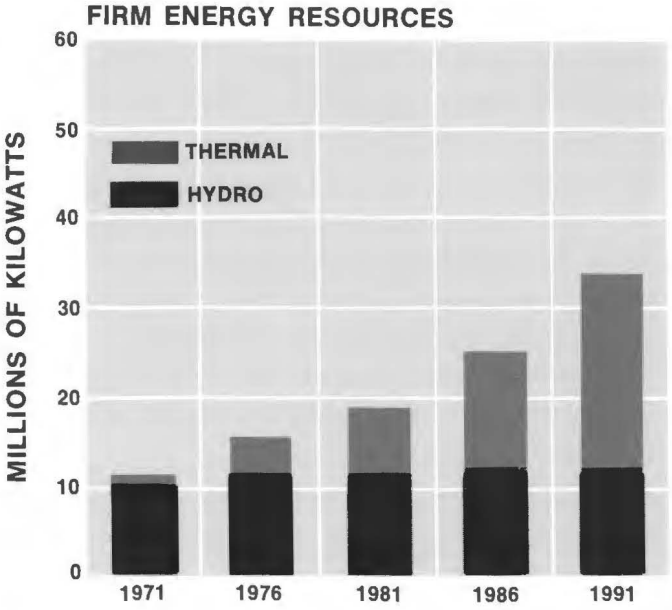
As a key element in the hydro-thermal plan, Bonneville will acquire thermal-generated electricity and combine it with the peaking capacity from the extensive Federal Columbia River Power System to assure low rates for BPA's customers. Secretary Hickel's announcement cleared the way for BPA to participate in the program. The first two thermal plants are underway.

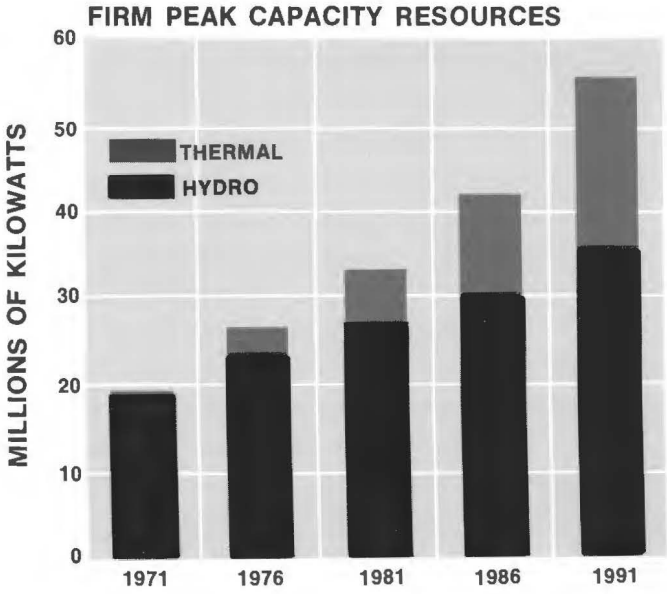
By October 1969, about 10 percent of the work had been completed on Pacific Power & Light and Washington Water Power Companies' 1.4-million kilowatt, coal-fired generating plant. The plant is beginning to rise above the floor of the Hanaford Valley five miles northeast of Centralia, Washington.

The first of two 700,000-kilowatt generating units at Centralia is to begin producing electricity in September 1971, and the second a year later.

Under arrangements agreed to during the year, BPA will acquire some of the power from the Centralia plant until 1974 through a net-billing arrangement. The power will be used to help meet loads between 1971 and 1974. Ultimately, 28 percent of the power from the Centralia plant will be distributed to public utilities (Snohomish County PUD, City of Seattle, City of Tacoma, and Grays Harbor County PUD). Beginning in 1982, BPA may obtain the public utilities' share of the plant's output under the net-billing concept. Or, at their option, BPA may wheel this power to the participants' load centers. The remaining 72 percent of Cen-

HYDRO & THERMAL POWER RESOURCES WEST GROUP AREA





tralia's output will go to the two sponsors, PP&L and WWP, and to Puget Sound Power & Light Company and Portland General Electric Company.

Meteorological and other testing has begun at the site of the program's second large thermal plant near Rainier, Oregon, where Portland General Electric Company plans to construct a 1.1-million kilowatt generating unit powered with nuclear fuel. Contracts have been let for the power-supply units and for enough nuclear fuel for the first five years of operation. The plant is to come on the line in September 1974.

Portland General Electric Company will own 60 percent of the plant, and Pacific Power & Light Company 10 percent. About 30 percent of the nuclear plant at Rainier will be owned by the Eugene Water & Electric Board, which expects to sell about half of its portion of the output to nine public utilities and cooperatives (City of Canby, Clatskanie PUD, Consumers Power, City of Forest Grove, City of McMinnville, City of Milton-Freewater, Salem Electric, City of Springfield, and Umatilla Electric Cooperative). BPA, in turn, may acquire the power from Eugene and the other nine public utilities through net billing.

Plans for the third thermal plant also took shape during the year. These plans call for a plant to be built in the coal fields near Rock Springs, Wyoming, by Pacific Power & Light Company. It will be 100 percent privately owned, by PP&L and Idaho Power Company. Three 500,000-kilowatt generating units will ultimately give the plant a total capacity of 1.5 million kilowatts, 1 million of which will produce power for utilities in the West Group Area of the Northwest Power Pool. The first unit will serve Wyoming and Idaho loads. The West Group is to get power from the second unit beginning in 1975, and the third in 1979.

Plant No. 4 is scheduled to be built by Eugene Water &

Electric Board. During the past year, Eugene has been investigating sites in southwest Oregon for a large nuclear plant. It is to begin producing electricity in 1976. The City's voters passed a $225 million bond issue in November 1968 to finance the plant. Other participants in the Eugene plant will include PGE and PP&L. About 15 public agency utilities and cooperatives will participate in Eugene's ownership share. This latter group is expected to obtain power from Eugene and deliver it to BPA under the net-billing concept. Tacoma City Light may participate during the first few years of the plant.

Plant No. 5 is scheduled to be built by the Washington Public Power Supply System. WPPSS' present plans provide for construction of a 1-million kilowatt or larger nuclear plant somewhere in southwest Washington. It will be 100 percent publicly owned and it is

Howard Elmore, Manager, Chelan County Public Utility District

Glenn Jackson, Chairman, and Don Frisbee, President of PP&L

expected that most of the 104 public agency members of the Joint Power Planning Council will be participants in the plant. Production at the plant would begin in 1978 and the entire output will probably go to BPA under net billing.

Of the next two thermal plants, both of which will probably be nuclear, one is to be jointly sponsored by Seattle City Light and Snohomish County PUD. The other plant would be built by Puget Sound Power & Light Company. Both are expected to come on the line before 1981. Again, other utilities are expected to participate in the ownerships and outputs of these plants.

Plans for this series of thermal generating plants are being coordinated through the Joint Power Planning Council composed of 108 public and private utilities and BPA. The JPPC developed the Hydro-Thermal Power Program as the most economical means of providing future power requirements, recognizing that the cost of power from these plants will be largely determined by location, size, and the time each goes into production. The plants will be built to meet the load growth of the entire region rather than just the requirements of smaller areas served by individual utilities.

To be more specific, under the program BPA will:

- Acquire surplus energy from that share of a plant's

output owned by private utilities under exchange agreements on a short-term withdrawable basis.

- Acquire power from the public utilities' share of thermal generation by net billing.
- Provide peaking capacity, bulk transmission, and generation reserves for forced outages, plus surplus hydro power, when available, for thermal plant fuel displacement. (BPA will provide these services under long-term exchange agreements and will accept off-peak energy or cash in payment.)
- Carry reserves for unanticipated regional load growth, equivalent to one-half-year's growth of utility-type loads, for all participants.
- Strengthen its transmission system to accommodate new generation.
- Use the energy it acquires to serve the load growth of public agencies, renew existing industrial contracts, maintain reserves, and, to the extent possible, provide a modest amount of firm power to industry for future expansion.
- Set up a new class of power (and rate) for industry, subject to the approval of the Federal Power Commission, under which BPA industrial customers would (a) take 25 per cent of their load as nonfirm energy, (b) accept the interruption at any time of one-half their load for up to two hours and thus provide forced-outage reserves for the system, and (c) accept the interruption at any time of all their loads for up to five minutes to maintain system stability.

The Federal Government will continue its program to provide more hydro peaking power. The bulk of this added capacity will be in the form of additional generators installed at existing Federal hydro projects, the cheapest source of peaking power within the region. (A more detailed discussion of future hydro generation appears in this report on page 19.)

Alan Jones, Chairman, Public Power Council

On April 21, 1969, the Administration formally approved a policy for the commitment by BPA of power generated at Federal hydroelectric projects. In addition to energy sales, commitments also include wheeling arrangements, provisions for reserves, surplus energy for fuel displacement, and exchange arrangements to supply peaking capacity. The ability of BPA to make long-term commitments is an indispensable ingredient of the Hydro-Thermal Power Program. Without it, neither BPA nor the participating utilities would know what functions each is expected to perform. Long-range power planning would be rendered impossible. And a principal objective of the Hydro-Thermal Power Program—adequate, reliable power to meet regional loads at lowest practicable cost—would be imperiled. In short, a meaningful BPA commitment policy is essential to implement the Hydro-Thermal Power Program.

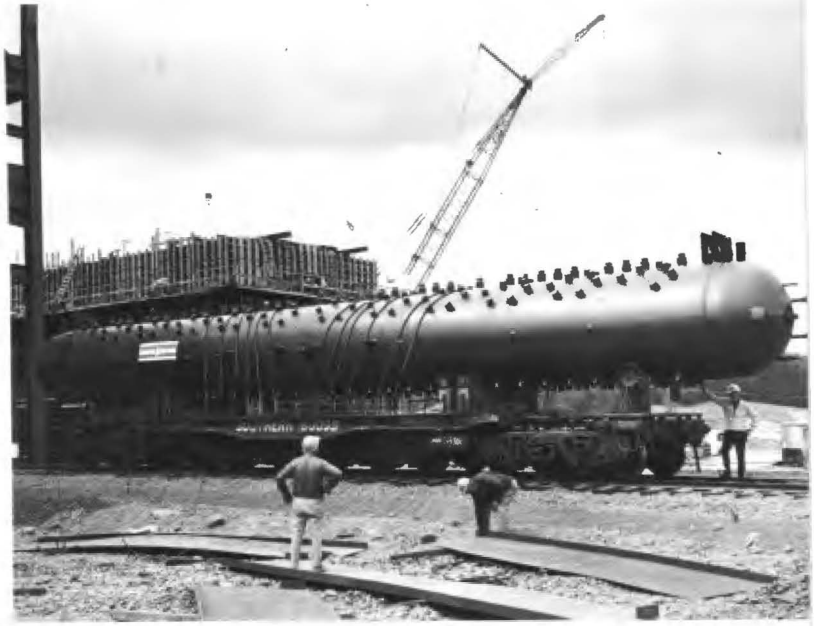
The approved policy on commitments provides that BPA can commit power from existing Federal hydro projects and from Federal hydro projects for which construction funds have been appropriated. The only exception to this policy would be in the case of con-

tracts such as exchange agreements and net-billing arrangements where commitments can be made further in advance. Under the Hydro-Thermal Power Program, a net-billing arrangement is considered an assured resource available for commitment at the time BPA and the owners of a thermal plant contract for the plant's construction and the purchase of power.

Conforming to law, the approved BPA commitments policy provides first priority for the power requirements of preference customers. Additional assured Federal capability, after subtracting other BPA firm sales or exchange contracts with private and public utilities and reserves for unanticipated load growth for all utilities, will be made available to electroprocess industries and private utilities. With respect to exports, only energy and peaking capacity which is surplus to the needs of the Pacific Northwest will be sold outside the region. (Details of the approved BPA commitments policy appear as an appendix to this report.)

The Hydro-Thermal Power Program will be implemented through a number of contractual agreements. The various utilities involved and BPA are drafting these contracts in the same atmosphere of cooperation that has marked previous mutual efforts such as the Northwest Power Pool, Coordination Agreement, Canadian Treaty, and Pacific Northwest-Pacific Southwest Intertie.

In addition to providing sufficient reliable power to meet regional power requirements with a minimum investment of resources, another principal objective of the Hydro-Thermal Power Program is to minimize the effect on the environment in meeting future electric power needs. Both objectives are important. And neither will be sacrificed for the other. The substantial versatility of the Hydro-Thermal Power Program, derived from coordinated planning, improves the likelihood that both objectives will be satisfactorily met.



This 210-ton drum will collect steam to drive the turbine generators at the Centralia Plant.

With the Hydro-Thermal Power Program, power will be transmitted at the lowest cost per unit by use of extra-high transmission voltages. This will also mean that given transmission capacity can be achieved with minimum space requirements. The program also contemplates extensive utilization of existing transmission rights-of-way by replacing existing lines with extra-high voltage circuits.

The fact that peaking generator units will be installed primarily at existing hydro powerplants (both Federal and non-Federal) or at plants already under construction means more extensive use of existing plant potential with correspondingly reduced environmental impact. The fact that the Hydro-Thermal Power Program permits construction of the largest feasible thermal powerplants means avoidance of a proliferation of plants to serve growing regional loads. And the fact that thermal plants can be sited to take advantage of the BPA high-voltage transmission network means improved siting flexibility to accommodate environmental problems.

The Joint Power Planning Council established an Environmental Committee in March 1968. The Committee

Larry Bradley, Secretary, Washington State Thermal Power Plant Site Evaluation Council

Byron Price, General Manager, Eugene Water and Electric Board

has since worked closely and cooperatively with Federal and state agencies to define problems, suggest research, and recommend solutions.

BPA is the marketing agent for power from Federal dams in the Northwest and operates the region's main transmission grid. At the same time, of course, BPA is an agency of the Department of the Interior and as such is fully cognizant of its responsibilities to help fulfill the precepts of such legislation as the Federal Water Pollution Control Act, the Water Quality Act, and the Air Quality Act. We participate prominently in power planning sessions for the region and in these meetings and elsewhere we will continue to emphasize the importance of the natural environment and the tremendous obligation upon all power system participants to preserve and protect it.

POWER RATES AND REPAYMENT OF POWER INVESTMENT

Two major actions regarding BPA's wholesale power rates marked 1969 as a year of significance. These were:

1. The decision by the Secretary of the Interior to continue BPA's existing wholesale power rates with no change for the next five years and the approval of that decision by the Federal Power Commission.

2. The Secretary's decision to adopt a new interest rate policy for new Federal power projects.

BPA is required under the Bonneville Project Act to review the adequacy of its power rates at least every five years and to obtain approval of the rates from the Federal Power Commission. BPA power sales contracts permit the rates to be changed only on December 20 of every fifth year. December 20, 1969, was such an adjustment date. It was thus necessary to first determine whether any change in the power rates was warranted, and then obtain FPC approval of the recommended rates for the ensuing 5-year period.

The law requires that BPA set its rates at a level sufficient to bring in enough revenues to pay all Federal

Columbia River Power System expenses and fully repay the Government's investment in the power facilities, with interest, within specified time limitations. BPA must be able to demonstrate that revenues from the rates proposed for approval will be sufficient to meet this objective.

Intensive study was given, therefore, to the revenues BPA could expect to receive from the existing power rates and to projections of power costs to determine whether the rates would continue to be adequate. These studies showed that all power costs could be recovered by existing rates with a comfortable margin.

However, it was also apparent that the cost of interest to the Government had increased substantially in recent years, and that there was reason for concern as to whether the existing policy for establishing the rate of interest to be paid on the Federal investment in power facilities was appropriate in view of current interest costs.

BPA, as well as the other Interior Department power marketing agencies, had been following a policy of paying a rate of interest on each new power project and each year's increment of investment in the transmission system, based upon the average interest rate paid by the Treasury on all outstanding long-term Treasury bonds. This rate had been 3¼ percent for the past two years. The policy had been approved by Congress in the authorization of the Grand Coulee Third Powerplant in June 1966.

This policy does not reflect the higher interest rates of recent years, however, because the maximum interest the Treasury is legally permitted to pay on long-term bonds is 4¼ percent. The prevailing yield on outstanding long-term Treasury bonds in the money market has exceeded that level—at one time reaching as high as 6½ percent. Thus, no new long-term Treasury bonds have been issued for several years. Short-term Treasury borrowing, which is not encumbered by a 4¼ percent ceiling and which now accounts for all of the Government's current borrowing, has also been at a similarly high interest rate. Consequently, it has become more and more apparent that the interest rate policy has not reflected the actual cost to the Government of borrowing money.

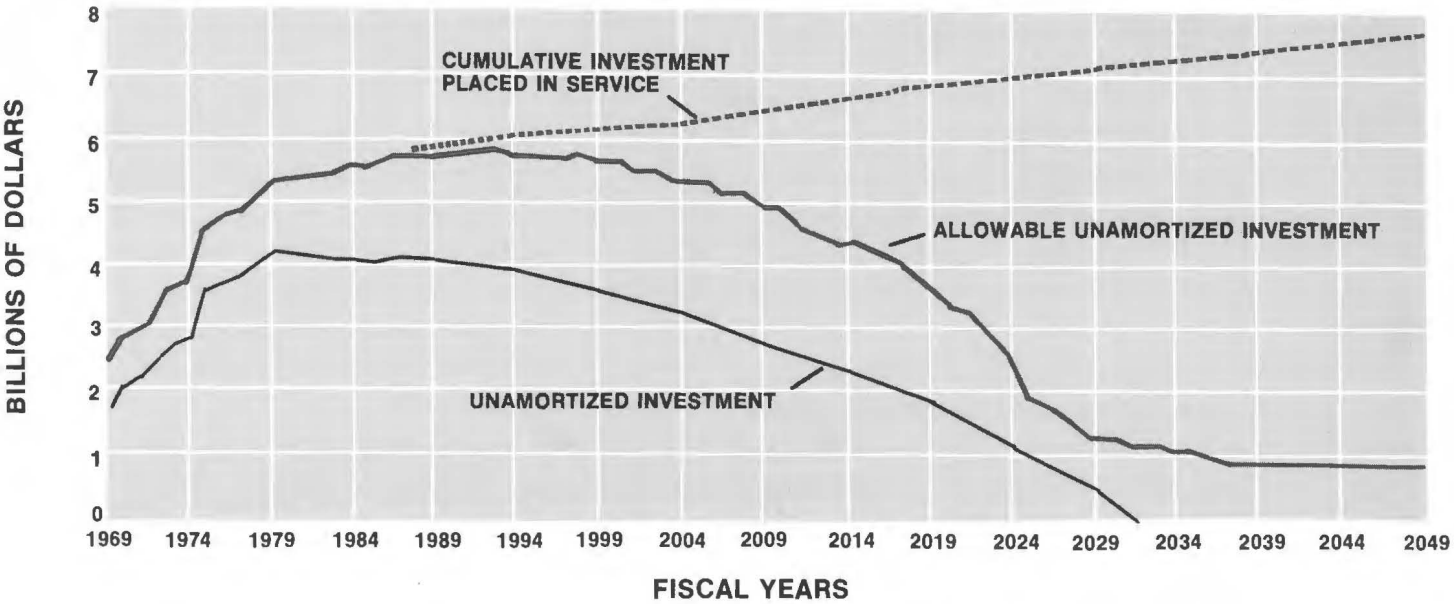
This recognition led to the Secretary's decision, which he announced on October 27, 1969, to issue an order establishing a new interest rate policy for the Federal power projects subject to his jurisdiction. The new policy is designed to provide an interest rate for new projects which more closely approximates the actual current interest cost to the Treasury.

Under the new policy, new project construction started in fiscal year 1970 will bear an interest rate of 4⅞ percent. This basic rate is the same as prescribed by the Water Resources Council for the economic evaluation of proposed new projects. The policy further provides that the interest rate for repayment of new projects started in each fiscal year thereafter shall be adjusted upward or downward from the preceding year's rate by up to one-half percentage point based upon the average yield in the bond market on outstanding long-term Treasury bonds for the preceding 12 months.

Following the Secretary's announcement of the new interest rate policy, BPA prepared and submitted to the FPC an updated repayment study applying the new interest rate policy. This study demonstrated that the existing wholesale power rate level would still continue to be adequate to meet all power costs, including the higher interest rates on future construction, for the next five years.

On December 5, 1969, the Federal Power Commission approved continuance of the existing BPA rates for

REPAYMENT OF PLANT INVESTMENT ALLOCATED TO COMMERCIAL POWER
FEDERAL COLUMBIA RIVER POWER SYSTEM—AUTHORIZED PROJECTS AS OF JUNE 30, 1969



the 5-year period extending to December 20, 1974.

The power system repayment study is shown in Table 7 and is also graphically illustrated above. In addition to demonstrating the adequacy of the power rate level to the FPC, this study is also responsive to the requirement for a consolidated Federal Columbia River Power System financial statement contained in Public Law 89-448.

The repayment study demonstrates that BPA's power rates are adequate to provide sufficient revenues to meet the following repayment criteria:

1. Pay all costs of operating and maintaining the power system.

2. Pay the cost of obtaining power through purchase and exchange agreements with other utilities.

3. Pay interest on the unamortized portion of the commercial power investment at the interest rates established for each project.

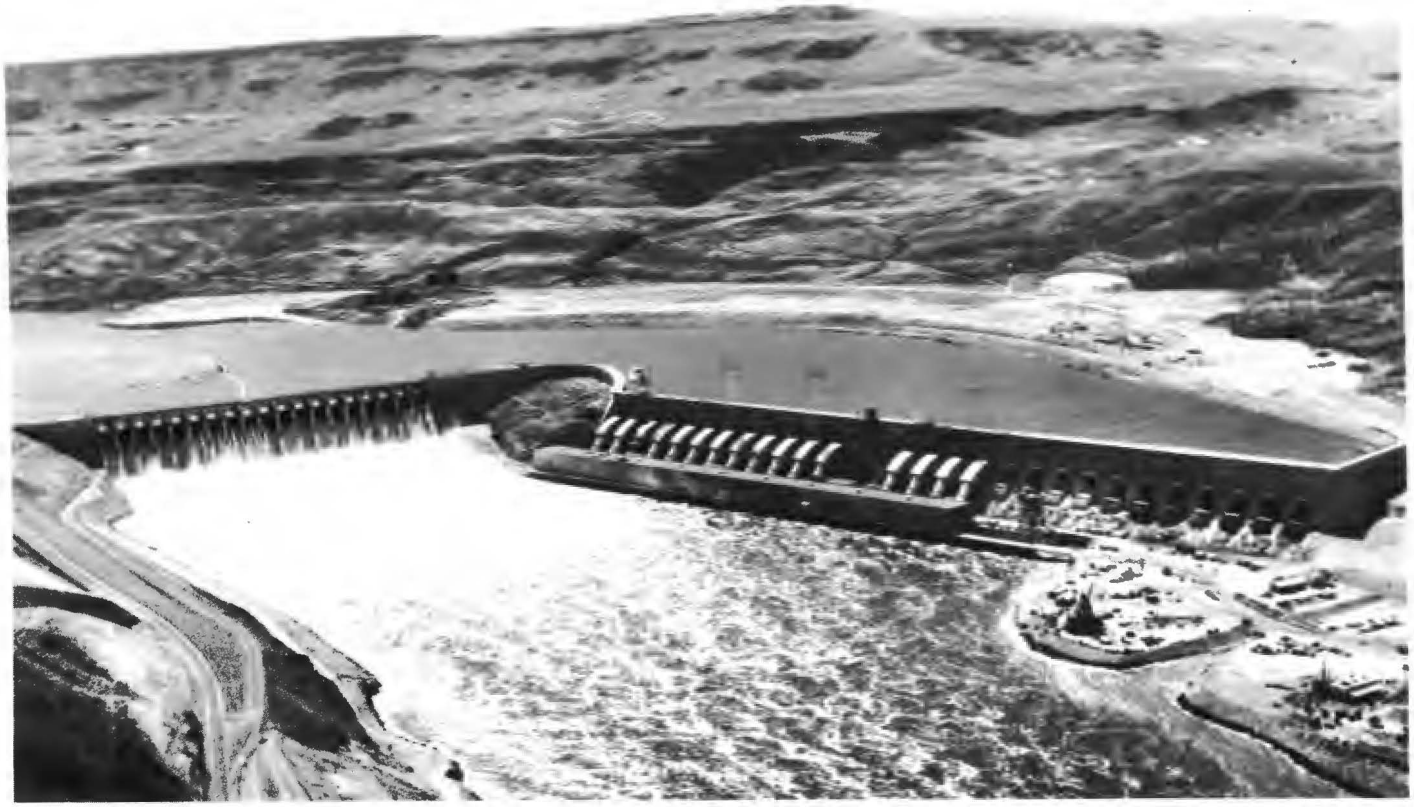
4. Repay the capital investment allocated to commercial power at the generating projects within 50 years after each project is completed.

5. Repay each increment of capital investment in the transmission system within the average service life of the transmission facilities (currently 45 years).

6. Repay the investment in each replacement of a facility at a generating project or on the transmission system within its service life.

7. Repay the portion of construction costs at Federal reclamation projects which is beyond the repayment ability of the irrigators, and which is assigned for repayment from commercial power revenues, within the same overall period available to the irrigation water users for making their payments. These periods range from 40 to 66 years with 60 years being applicable to most of the irrigation assistance.

(Although power rate levels are set on the basis of meeting repayment requirements as described above, BPA is also required to keep books on a cost accounting basis to comply with accounting policies prescribed by the Comptroller General. Therefore, financial results for fiscal year 1969 on the cost accounting basis are presented in another part of this report under "Financial Results.")



Empty Slots at Chief Joseph Dam Await the Installation of Additional Generators

GENERATION

During fiscal year 1969, the Federal Columbia River Power System added 1,235,000 kilowatts of generating capacity.

This additional capacity consists of 135,000 kilowatts at Lower Monumental Dam, the first eight units totaling 1,080,000 kilowatts at John Day Dam, and 20,000 kilowatts at Foster Dam.

There are now 25 Federal dams producing electricity in the Pacific Northwest. These Federal hydro projects are built and operated by the Bureau of Reclamation or the U.S. Army Corps of Engineers. They have an installed capacity of 8,074,150 kilowatts.

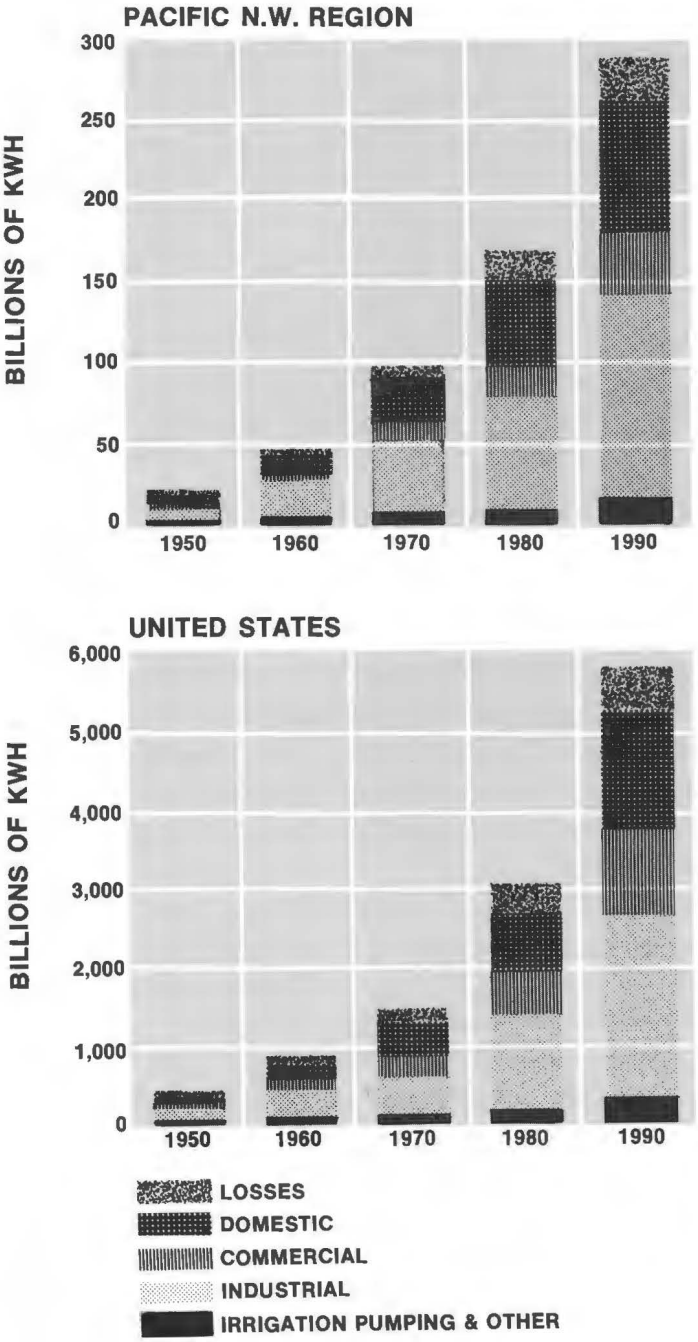
The non-Federal generating plants in the region have a total installed capacity of 10,680,822 kilowatts. Included in this amount are 800,000 kilowatts at Hanford Generating Plant and 437,819 kilowatts at old steamplants.

Thus, the combined generating capacity at all Northwest plants stands now at 18,754,972 kilowatts.

Federal capacity under construction totals 7,685,000 kilowatts. This includes six Federal dams — Libby, Little Goose, Lower Granite, Dworshak, Lost Creek, and Teton — which will have a combined nameplate rating of 1,695,000 kilowatts. The large balance of the capacity under construction is being installed at existing projects.

These additional generators — to be added at The Dalles, Grand Coulee, John Day, and Lower Monumental — will have a combined capacity of 5,990,000 kilowatts. This figure includes 3,600,000 kilowatts for the Third Powerhouse and 97,000 kilowatts for two pump-generator units, all of which are in initial phases of construction at Grand Coulee. If Congress so authorizes, the number of turbine-generator units in the Third Powerhouse may be increased and its capacity raised to 7.2 million kilowatts. Grand Coulee would then have a total capacity of about 10 million kilowatts, more than any existing dam in the world.

LOAD GROWTH FORECAST



Space for additional generators at The Dalles Dam

Between now and 1980, public and private non-Federal utilities plan to add 11,129,370 kilowatts of generating capacity in the Northwest. This figure includes 7,906,000 kilowatts of capacity to be installed at thermal plants, principally nuclear.

Northwest utilities estimate that electric power requirements in the region will almost triple in the next 20 years.

The region is running out of feasible hydro sites, although a few remain which can be developed. Turbine-generators may be added at other projects.

Between 1974 and 1991, the Northwest will require steamplants to meet the base load at an average of more than one 1-million-kilowatt plant a year. The amount of additional new steam generating capacity required each year will increase as regional loads grow. The Federal Columbia River Power System will support these plants with peaking capacity, reserves, and transmission capacity—via the BPA grid.

Congress has authorized two Federal hydro projects not yet under construction: Asotin, with a nameplate rating of 540,000 kilowatts, and Strube, with a rating of 4,500 kilowatts. Authorized additions at Bonneville, Chief Joseph, and Ice Harbor Dams could add another 1,702,000 kilowatts to the system in the next 10 years.

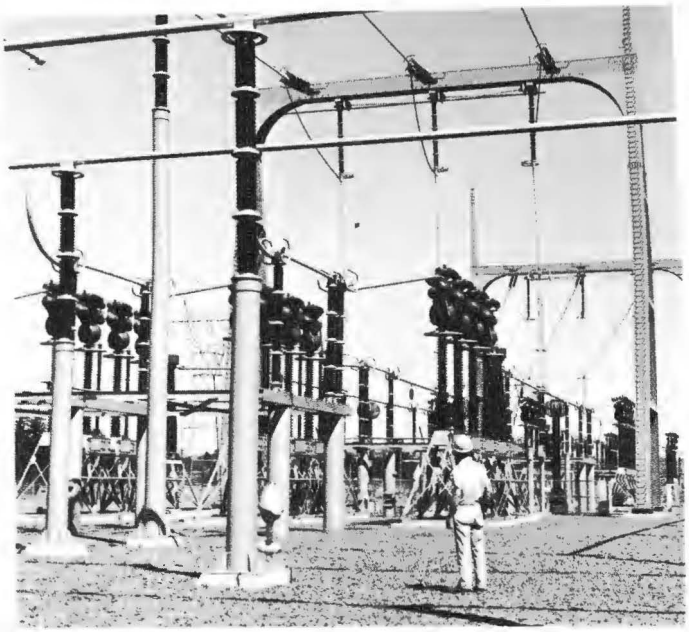
TRANSMISSION CONSTRUCTION

During fiscal 1969, BPA added 507 circuit miles to its system of transmission lines. Four hundred two miles were 500,000-volt lines, the highest voltage on the system until the first direct-current 800,000-volt Intertie line is completed in 1970.

This raised the total number of circuit miles on the system to 11,151, and the total mileage of 500,000-volt lines to 1,315.

System transformer capacity as of June 30 totaled 28,401,062 kilovolt-amperes.

Present plans call for another 1,566 miles of 500,000-volt lines, partly to strengthen service to western Montana and to integrate the output of new dams on the Lower Snake River. BPA is already operating one of the largest 500,000-volt grids in the United States. The use of these large lines requires significantly less land for rights-of-way per unit of power transmitted.

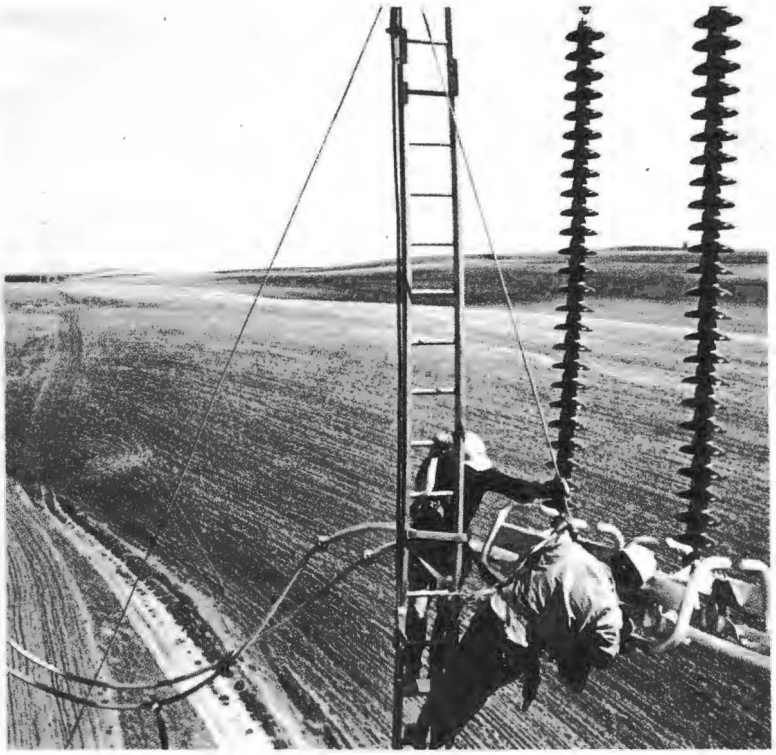


New 500,000 volt substation near Oregon City

A key line among those to be constructed is a 123-mile 500,000-volt line from Chief Joseph Dam in north central Washington to Monroe Substation northeast of Seattle. When this line is energized, it will provide capacity to serve growing loads in western Washington at a time when loads are reaching critically heavy levels. Part of the electricity ultimately to be moved over this line will come from the new Third Powerhouse at Grand Coulee Dam.

BPA's construction plans are meshed with those for new large thermal generating plants now under construction or projected for the future. Because these thermal units will eventually supply base power while hydro plants supply peaking power, new transmission must be planned accordingly.

For example, the 116-mile 500,000-volt Raver-Paul-Allston line is being built to connect the Seattle and Portland areas. This line is a main link in the 500,000-volt grid. It will also integrate into the grid power from the coal-fired generating plant under construction near Centralia by the Pacific Power & Light and Washington Water Power Companies.



Linemen expand 500,000 volt grid

SALES

Energy sales in fiscal 1969 increased 15.8 percent over the previous year and reached a new high of 51.8 billion kilowatt-hours.

The amount of power used by the aluminum industry increased 19 percent, or 3 billion kilowatt-hours. The 20.2 billion kilowatt-hours sold to the aluminum industry in fiscal 1969 accounted for 39 percent of all BPA's energy sales. Most of the increase was used by new potlines at the Anaconda, Intalco, and Reynolds plants.

Publicly owned utilities bought 18.9 billion kilowatt-hours in the fiscal year; 36.5 percent of the energy sold.

Investor-owned utilities purchased 7.2 billion kilowatt-hours (13.9 percent), Federal agencies 1.6 billion kilowatt-hours (3.1 percent), and industries other than aluminum 2.4 billion kilowatt-hours (4.6 percent). One and one-half billion kilowatt-hours (2.9 percent) were sold outside the Pacific Northwest.

Power sales brought an average of 2.39 mills per kilowatt-hour, exclusive of capacity sales and other revenues.

By class of customer, the average revenue per kilowatt-hour was: aluminum industry 2.03 mills, other industries 2.22 mills, investor-owned utilities 2.21 mills, public agencies 2.92 mills, Federal agencies 2.44 mills, and sales of surplus energy outside the Pacific Northwest 2 mills.

Eighty-nine out of the 104 public agencies served by Bonneville buy all of their power, including peak needs, from BPA. This results in a slightly higher-than-average cost of energy, as compared with the industrial and investor-owned purchasers.

FINANCIAL RESULTS

From a cost accounting standpoint, fiscal year 1969 was one of the best years in BPA's history.

Revenues increased $19 million, or 16.4 percent, over fiscal 1968 and totaled $137.3 million.

System costs were up $10.1 million, or 10.2 percent.

Net revenues after all expenses, including operation, maintenance, purchase and exchange, depreciation, and interest, totaled $28.1 million. Net revenues accumulated since the beginning of operations now exceed $322 million.

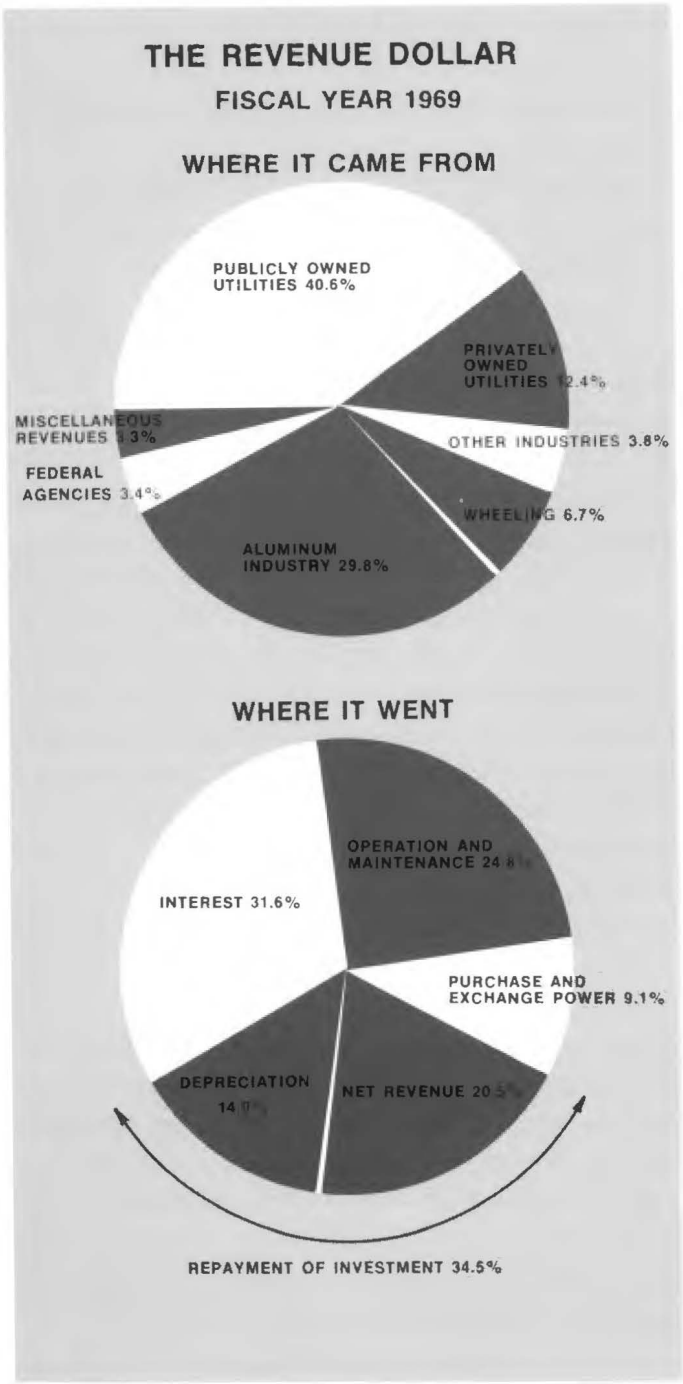
Revenues from the sale of power outstripped estimates by $7 million. The estimates, of course, were based on normal weather conditions. However, severe cold weather in December and January boosted the demand for power to a new high for BPA. As a result, sales to publicly owned utilities were 13.5 percent higher than the year before and were well above the public utilities' normal rate of increase.

A gain of $6.7 million in revenues from the aluminum industry was the largest for any group of customers. It reflects a new record in aluminum production for the Northwest. Total sales to this group were $40.8 million.

The Pacific Intertie brought BPA $3.1 million from the sale of energy surplus to Northwest needs and $1 million for wheeling. For operating reasons and by agreement of utilities using the lines, capacity on the intertie was limited to 400 megawatts early in the fiscal year, but was raised to 800 megawatts on September 12, 1968, and to 1,400 megawatts April 1, 1969. These capacity limitations restricted potential Intertie sales.

Total system revenues included $3 million received directly by generating projects for headwater benefits and irrigation pumping power.

Each year BPA pays in full the costs for operation



and maintenance, interest, and the purchase and exchange of power. The balance of its revenues is used to pay back that portion of the Government's investment allocated to power facilities in the Federal Columbia River Power System. This sum was $47.3 million in fiscal year 1969.

Cost increases were moderate. The largest, for interest, was up $5.7 million. This increase stemmed mainly from the addition of $200 million for power facilities at John Day Dam which became part of the system early in the fiscal year. John Day also contributed to an increase in operation and maintenance costs. Additional details on revenues and costs for the power system as compared with last year are shown in Table 6. The chart on this page shows where revenues came from and how they were applied.

Table 8 contains an account of the trends in revenues by class of customer for the years 1960 through 1969. This was a decade of consistent growth. For example, sales to the aluminum industry for fiscal 1969 are 134 percent greater than for 1960. The sales to public utilities are up 95 percent.

Since the beginning of operations in fiscal year 1939, BPA has returned $1,623,100,000 in revenues to the U.S. Treasury. Of this total, $575,059,000 has gone to repay the capital investment in the power system and $551,139,000 to pay interest costs. Thus, 69 percent of our revenues, or more than $1.1 billion, has been returned to the U.S. Treasury to pay the debt incurred to finance the power system. The remaining 31 percent, $496,902,000, has paid for operation, maintenance, and power purchased.

Financial statements for the Federal Columbia River Power System and an opinion letter of the Comptroller General of the United States appear in this report beginning on page 39.

THE OPERATING YEAR AND ITS PROBLEMS

BPA encountered severe operating conditions during and after fiscal year 1969. Despite adversities, the system performed well although there were times when service reliability was marginal.

During the last few days of December 1968, one of the most severe outbreaks of winter weather in Northwest history invaded the Pacific Northwest region. On December 30, average temperatures for major load centers were the lowest of any December day in recorded history. Demand for power soared to record peaks. Northwest powerplants were running at the maximum capacity permitted by available water. Temperatures remained abnormally low and demand for power high during January, especially the period from January 20 to 29. In addition, the Hanford plant was inoperative during this period, further reducing generating capability of the system by 800,000 kilowatts. The power situation was aggravated still further by delays in Federal generator schedules at Lower Monumental and John Day Dams.

Despite maximum plant output and streamflows which ranged near or above median, it was necessary, in order to meet firm loads, to import power from outside the region and to curtail up to 400 megawatts of interruptible industrial loads. This was the first time since 1957 that actual load curtailments were necessary because there was insufficient power available from other utilities to displace curtailed interruptible loads.

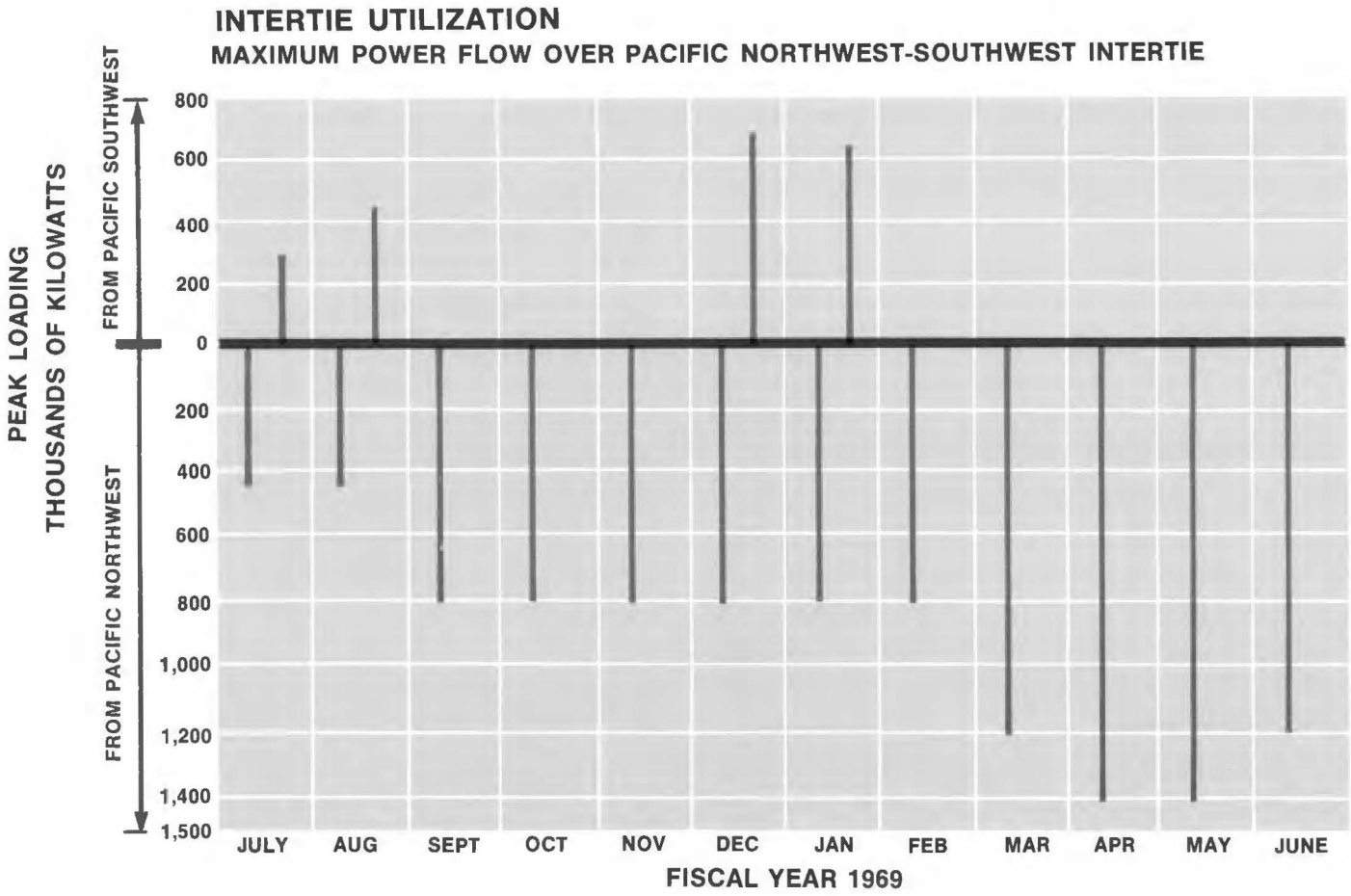
Were it not for the Intertie over which energy was imported from California, reaching a maximum of 700,000 kilowatts, BPA would have had to curtail additional interruptible sales to industry as well as some of its modified firm power sales to industry. Power was also imported from the Missouri Basin, eastern Montana, and Utah.

Fortunately, the severe weather eased and after February 1 we began once again to carry all interruptible loads through the periods of peak demand.

Compounding the seriousness of the region's chronic shortage of peak power reserves was a scheduled draft of the Grand Coulee reservoir later in the year. The reservoir was drafted down to 38 feet below its normal bottom elevation to accommodate Third Powerplant construction. The reservoir had to reach this low level by April 1, 1969, and it had to be held at or below this elevation for a month-and-a-half. While the additional draft below normal bottom elevation increased the energy capability at Grand Coulee and at downstream plants, it greatly reduced the peaking capability at Grand Coulee. This caused the power situation to remain tight until mid-May. To compensate for this reduced peaking capability, we made arrangements with the Atomic Energy Commission to avoid refueling shutdowns of the Hanford steamplant during the deep draft period. Our planning also incorporated the use of Keenleyside (Arrow) Dam storage made possible by the Canadian Treaty.

Accelerated snowmelt and early runoff from a warm spring led to abnormally low streamflows by midsummer. A severe shortage of hydro energy for secondary loads developed in late July 1969 as a result of exceptionally low flows on the Columbia River. The drop in streamflows continued throughout August, falling below critical levels, and by early September had reached record minimums for that time of year.

Export of surplus energy over the Intertie to California



utilities was stopped July 25. Secondary energy sales to private utilities and for interruptible industrial loads were discontinued July 31 (although interruptible industrial loads were served with provisional energy). Secondary sales to public agencies were curtailed August 4. By August 21, BPA was compelled to cut back deliveries of provisional energy to industry by 30 percent. As a result, these customers purchased higher cost power from outside the region rather than curtail production. The cutback in provisional energy was increased to 40 percent early in September.

Substantial rainfall during the last two weeks of September increased streamflows above median levels and reservoirs recovered to above rule curves. Service to secondary and interruptible loads was resumed October 1, 1969.

The Northwest power situation was aggravated during fiscal year 1969 by a shortage of reserve generators. The Federal Columbia River Power System did not have all the reserves it needed because of delays in installing generators at two projects. This cut our

peaking capacity by 776,000 kilowatts. (Three units capable of producing 466,000 kilowatts at Lower Monumental Dam had been delayed from December 1967 and were not on the line until June 1969. And only five units instead of seven were ready in January at John Day, reducing the capacity of that plant from 1,085,000 to 775,000 kilowatts.)

Most of our customers received reliable service during fiscal 1969. However, some industrial customers were sometimes an exception. They were dropped occasionally to protect against area blackouts. This was done automatically by relays which open preselected circuits when certain emergency conditions occur.

Cutting off firm loads to maintain service to other customers is an expediency and reflects less than adequate reliability. We will be forced to continue to cut firm loads during unusual conditions because the construction of new lines that would give us adequate capacity for reliable operations has not kept pace with the growth of loads.

A number of equipment failures and operating problems during the year indicated our preventive maintenance program also has slipped below acceptable standards. Consequences so far have been minor. Nevertheless, it is apparent we have been handicapped in attempting to achieve satisfactory maintenance standards by not having enough personnel to accomplish all the work that should have been done.

The strong electrical ties created with other regions proved to be a boon, especially to the Northwest, and helped us avert at least one major blackout when newly installed equipment was being tested near Grand Coulee Dam. On August 7, 1969, a relay operated inadvertently, causing other relays to trip 11 generators at the dam which had been producing 1,250,000 kilowatts of electricity. As the machines dropped off the line, the flow of power over the Intertie reversed. The Intertie lines, which had been carrying 480,000 kilowatts south, began bringing 325,000 kilowatts north. An industrial load at Spokane was temporarily dropped under the load-shedding scheme. Reserve generators in the Northwest picked up the balance of the load. The system then returned to normal.

The Intertie supported California systems during similar incidents, when those systems suddenly lost the production of large steam units with capacities of up to 750,000 kilowatts.

In addition to our good experience with the Intertie, it should be noted that at 9:05 a.m., October 20, 1969, the Hanford nuclear generating plant passed the production mark of 10 billion kilowatt-hours. It was the first U.S. nuclear plant to reach this mark.

CANADIAN TREATY

The first two dams built under terms of the Columbia River Treaty with Canada have been operating successfully for some time. Construction on the two remaining dams is well underway.

On June 9, 1969, British Columbia's Prime Minister W. A. C. Bennett presided at the dedication of Arrow Dam five miles above Castlegar on the Columbia River. He announced then that the dam henceforth would be known as the Hugh Keenleyside Dam in honor of the man who was charged with its successful construction. For Dr. Keenleyside the dedication was his last official ceremony before retiring as Co-Chairman of British Columbia Hydro and Power Authority.

The Canadians completed both Keenleyside and Duncan Dams ahead of schedule. Keenleyside was de-

Construction at Mica Dam, Canadian Treaty Project

Libby Dam in Montana

clared operational on October 10, 1968, six months ahead of schedule, and Duncan on July 31, 1967, eight months early.

Work is now proceeding on Mica Dam in British Columbia and Libby Dam in Montana.

Giant strides have been made on the enormous task of placing 42 million cubic yards of fill material required for Mica. When completed by the spring of 1973, Mica, an earth and rockfill structure, will rise 800 feet above bedrock and will have a crest 2,600 feet long.

The Columbia has been diverted around the Mica site through two 3,000-foot tunnels so that the dam can be built on a dry riverbed. The tunnels took two years to build and were ready in 1967.

By early fall 1969, about 8.6 million cubic yards of fill had been dumped in place by a fleet of fifty huge trucks. The construction of a 1,950-foot spillway on the left abutment is well underway. Workmen in September began pouring some 60,000 cubic yards of concrete to line the spillway, which is to be finished in 1971.

The reservoir behind Mica will create a new lake extending 80 miles upstream. One arm of the lake will run 55 miles up the Canoe River Valley.

Libby Dam, which the Corps of Engineers is building in the United States under the Treaty, is now more than 50 percent complete. Libby, 420 feet high and 3,055 feet long, will create a lake extending 90 miles up the Kootenay River in western Montana and southeast British Columbia. The dam will back water 42 miles into Canada. Libby is to begin generating electricity in 1974.

Duncan Dam added 1.4 million acre-feet of usable storage, and Keenleyside 7.1 million acre-feet. Mica will add 7 million acre-feet initially and Libby 5 million acre-feet. This will double the usable storage capacity on the Columbia and its tributaries. The Treaty provides for 15.5 million acre-feet of storage in Canada, of which 8.5 million acre-feet will be usable for flood control.

The four Treaty projects together with other hydro plants on the river will make it possible to control a flood as great as any man has observed on the Columbia since he began to measure the river's flow before the turn of the century.

Water released from the Canadian projects will increase the dependable capacity at 11 U.S. dams downstream by 2.8 million kilowatts. The additional power produced with this capacity is being shared equally by Canada and the United States. Canada has sold her share to purchasers in the United States for 30 years.

Proposed Control Center—Ross Substation

CONTROL & DISPATCH

In 1967, BPA launched a program to prepare the power system to meet the anticipated rigorous demands of the region for dependable electric power. We recognized then that the growing complexities of the far-flung power transmission system were outstripping man's ability to respond to system conditions within tolerable time limits. We knew we would have to turn to high-speed, special-purpose computers which could quickly detect impending trouble and react with split-second timing to initiate corrective action. We also knew we would have to develop new computer programs which would optimize our use of power resources.

To take advantage of the most advanced skills and the highest available technology, we secured the assistance of North American-Rockwell Corporation, prime contractors of the Apollo space program. It was anticipated that spin-off knowledge gained from the aerospace program would find successful application in the electric power field.

This new technology will come to fruition in the new System Control Center at Bonneville's Ross Substation (Vancouver, Washington). Experience and technology from the NASA mission control center, from advanced research by BPA consultants, including universities, and from our own staff of engineers, mathematicians, and computer specialists have been applied to design a plan for a new control center adequate to handle system problems and growth as foreseen for the next twenty years.

The Advanced Control and Dispatch program will provide new techniques that will give us better control of electrical operations and greater system stability. We are compressing margins for error allowed in the past. We are gaining greater control over streamflows by refining the rough approximations of earlier methods. Thus, we are achieving more efficient, economical electrical operations and squeezing more kilowatts, and hence more revenues, out of streamflows.

In many ways the program is a push into the unknown. Many of the methods and some of the equipment required are still in the developmental stage.

The cornerstone of this program will be the construction, by 1973, of the new System Control Center at Ross. The new building is expected to cost about $5 million. It will house sophisticated special-purpose computers and data-storage banks. Information will flow automatically into these machines from power-

houses, substations, and hydrometeorological stations. The control equipment will be able to act on information as it is received or forward it for display so it can be used by men operating the system. In turn, this will lead to more precise control over such system elements as generation, transmission line loadings, and bus-voltage levels.

Engineers and programmers are already developing the special purpose computer program ("software") that will assist dispatchers to perform scheduling, arrange outages for construction or maintenance work, achieve system stability, monitor operations, and expedite service restoration in emergencies.

Facilities for the remote control of substations will be centralized at Ross and computer-directed. The center will control BPA's 500,000-volt and most of the 230,000-volt transmission system. The subtransmission system west of the Cascades will also be controlled from Ross. Another control center, to be located near Pasco, Washington, will control the east subtransmission system and serve as a backup for critical functions performed at and controlled from Ross.

We are modifying our present control center at Portland to prepare for the transition to a more automated system. A special-purpose computer has been installed and is undergoing tests. We have also installed prototype displays for the dispatchers, including an animated wall-type diagram of the Pacific Northwest-Pacific Southwest Intertie system, and a computer-driven color cathode-ray tube display console.

The Advance Control and Dispatch program will culminate a major effort to extract the greatest return from the investment in the Federal Columbia River Power System by development and application of the most modern power system control technology.

INTERTIE CONSTRUCTION

Soon after this report is published, the United States' first, and the world's largest, high-voltage direct-current line will go into commercial operation. The terminal equipment and the 800,000-volt line have been undergoing final tests.

The line's northern terminal, Celilo Converter Station, stands on a bare hill above the Columbia River near The Dalles, Oregon. The line itself stretches 853 miles across Oregon, Nevada, and California. It ends at Sylmar Converter Station, near Los Angeles.

BPA built the Celilo terminal and the line across Oregon to the Nevada border. The City of Los Angeles constructed the line from there south, plus Sylmar, and has shared the costs and ownership equally with the Southern California Edison Company.

The direct-current line will be the third of four large lines included in the original concept of the Pacific Intertie. Two 500,000-volt alternating-current lines are in operation. The fourth line, an 820-mile, 800,000-volt direct-current transmission line, to operate between Celilo and a terminal near Hoover Dam has been postponed until 1977 or later.

The Intertie carries power both north and south and has improved the stability of electrical systems in the Pacific Northwest and the Southwest. The Northwest has received substantial revenues from the sale of secondary power surplus to the region's needs.

These exchanges of power and secondary power revenues will increase after the first d-c line goes into operation. Celilo will convert a-c power from Northwest dams to d-c power, sending it south. Sylmar will convert the power back to a-c and dispatch it to consumers in the Southwest. When power flows north over

Floyd L. Goss, Chief Electrical Engineer and Assistant Manager, Los Angeles Department of Water and Power

the line, the conversion roles of the two terminals will be reversed.

When the Intertie's two a-c lines were completed, the first in May 1968 and the second in December 1968, the capacity of the lines was limited to 400,000 kilowatts. This was due to a lack of generating capacity and backup lines. As we began to overcome these deficiencies and accumulate operating experience, the Intertie's capacity was expanded to 800,000 kilowatts. New generation at John Day Dam has since made it possible to boost this capacity to 1.4 million kilowatts. Ultimately, the two a-c lines will carry 2 million kilowatts and the d-c line 1.4 million kilowatts.

Thus, we have reached the point in the development of transmission technology when two major regional systems will be linked with both a-c and d-c lines. It will mark the realization of a dream born more than 30 years ago.

Surplus Northwest power can now be transmitted to the Southwest to meet requirements that would otherwise be met with power from generating plants burning fossil fuels. The Intertie results in the better use of renewable resources in the West and the conservation of exhaustible fuels.

Meanwhile, d-c's importance looms larger, for researchers in this country and abroad are perfecting solid-state rectifiers that may displace the mercury arc valves.

The two a-c lines are proving invaluable assets for both the Pacific Northwest and the Pacific Southwest. Over six billion kilowatt-hours of energy were delivered over the Intertie to California during calendar year 1969. About two-thirds was Canadian Entitlement energy, the disposition of which makes implementation of the Treaty possible. Most of the balance was surplus energy.

The Intertie also served other valuable functions. Periods of low streamflow in the Northwest in the fall of 1968 and again in the fall of 1969 required Bonneville to curtail interruptible deliveries to industries we serve. By using energy purchased from California over the Intertie, these industries were able to continue operations.

The Intertie was also instrumental in permitting Bonneville and Northwest utilities to meet the record high loads which the Northwest experienced during the cold spell which gripped the region in late December 1968 and January 1969. Northwest resources loaded to capacity were inadequate to meet loads. Substantial power imports from California over the Intertie enabled Northwest firm utility and industrial loads to be met without disruption.

Finally, by making some of the power resources of one region available to serve loads in another region, the Intertie assisted in maintaining power system stability in both the Northwest and in California. The two regions have been enabled to exchange energy and capacity to assist one another in emergencies.

TABLES

TABLE 1
ELECTRIC ENERGY SALES TO CUSTOMERS OF THE BONNEVILLE POWER ADMINISTRATION
Fiscal Year Ended June 30, 1969

Customer	Energy Delivered for Year (000) KWH	Revenue from Sales of Energy
NORTHWEST AREA		
Publicly Owned Utilities		
Municipalities		
Albion, Idaho	2,489	$ 8,099
Bandon, Oregon	36,195	125,957
Blaine, Washington	17,972	58,980
Bonners Ferry, Idaho	9,750	53,825
Burley, Idaho	56,880	184,936
Canby, Oregon	35,842	131,028
Cascade Locks, Oregon	15,882	42,192
Centralia, Washington	52,519	283,174
Cheney, Washington	58,383	192,066
Consolidated Irrigation District #19	896	4,678
Coulee Dam, Washington	23,661	91,067
Declo, Idaho	1,468	5,012
Drain, Oregon	23,042	77,273
Ellensburg, Washington	112,734	365,353
Eugene, Oregon	957,893	2,317,053
Forest Grove, Oregon	92,956	311,701
Grand Coulee, Washington	34,891	122,685
Heyburn, Idaho	47,888	142,680
Idaho Falls, Idaho	160,721	511,917
McCleary, Washington	25,225	84,191
McMinnville, Oregon	132,683	476,505
Milton Freewater, Oregon	79,928	256,849
Minidoka, Idaho	675	2,501
Monmouth, Oregon	43,995	154,978
Port Angeles, Washington	374,783	1,013,498
Richland, Washington	273,254	900,876
Rupert, Idaho	34,806	112,136
Seattle, Washington	671,617	1,518,430
Springfield, Oregon	184,386	577,370
Sumas, Washington	175	660
Tacoma, Washington	1,075,495	2,375,830
Vera Irrigation District #15	64,042	208,186
Washington Public Power Supply System	9,502	23,758
Total Municipalities (33)	4,712,628	$ 12,730,444
Public Utility Districts		
Benton Co. PUD No. 1	506,843	$ 1,562,427
Central Lincoln PUD	699,515	2,115,373
Chelan Co. PUD No. 1	244,853	738,148
Clallam Co. PUD No. 1	172,985	536,238
Clark Co. PUD No. 1	1,405,561	4,395,009
Clatskanie PUD	575,558	1,463,407
Cowlitz Co. PUD No. 1	1,724,543	4,225,809
Douglas Co. PUD No. 1	269,058	748,345
Ferry Co. PUD No. 1	29,460	90,366
Franklin Co. PUD No. 1	294,682	930,855
Grant Co. PUD No. 2	343,441	1,110,465
Grays Harbor Co. PUD No. 1	807,204	2,497,978
Kittitas Co. PUD No. 1	22,114	71,119
Klickitat Co. PUD No. 1	124,965	385,181
Lewis Co. PUD No. 1	304,094	956,830
Mason Co. PUD NO. 1	24,584	78,509
Mason Co. PUD No. 3	196,535	614,661
Northern Wasco Co. PUD	50,922	172,727
Okanogan Co. PUD No. 1	251,361	762,880
Pacific Co. PUD No. 2	158,155	533,067
Pend Oreille Co. PUD No. 1	5,727	11,103
Skamania Co. PUD No. 1	62,621	212,050
Snohomish Co. PUD No. 1	2,758,039	8,346,659
Tillamook PUD	229,512	785,669
Wahkiakum Co. PUD No. 1	30,474	103,348
Whatcom Co. PUD No. 1	86,826	205,588
Total Public Utility Districts (26)	11,379,132	$ 33,653,811
Cooperatives		
Benton Rural Elec. Assn.	99,978	$ 308,781
Big Bend Elec. Coop.	179,522	483,561
Blachly Lane Co. Coop.	68,277	227,870
Central Elec. Coop.	65,536	189,323
Clearwater Power Co.	84,237	282,375
Columbia Basin Elec. Coop.	64,160	199,508
Columbia Power Coop. Assn.	27,625	95,389
Columbia Rural Elec. Assn.	56,223	164,589
Consumers Power	199,049	656,172
Coos Curry Elec. Coop.	185,855	630,270
Douglas Elec. Coop.	71,299	241,017
East End Mutual Elec. Co.	3,659	12,309
Fall River Elec. Coop.	37,107	122,794
Farmers Elec. Coop.	2,930	9,539
Flathead Elec. Coop.	47,347	147,008
Harney Elec. Coop.	76,272	194,659
Hood River Elec. Coop.	55,343	182,407
Idaho Co. L&P Coop. Assn	25,187	85,435
Inland Power & Light Co.	204,447	667,675
Kootenai Elec. Coop.	44,973	143,864
Lane Co. Elec. Coop.	186,653	616,767
Lincoln Elec. Coop. Montana	47,194	153,371
Lincoln Elec. Coop. Washington	65,262	187,130
Lost River Elec. Coop.	17,516	50,238
Lower Valley Power & Light	70,441	$ 237,216
Midstate Elec. Coop.	42,617	118,580
Missoula Elec. Coop.	34,976	105,509
Nespelem Valley Elec. Coop.	19,373	62,976
Northern Lights	63,083	205,593
Okanogan Co. Elec. Coop.	14,218	45,860
Orcas Power & Light Co.	47,128	156,838
Prairie Power Coop.	2,133	7,687
Raft River Rural Coop.	87,563	230,179
Ravalli Co. Elec. Coop.	34,561	113,803
Riverside Elec. Coop.	2,816	9,722
Rural Elec. Co.	25,361	82,729
Salem Electric	131,573	442,508
Salmon River Elec. Coop.	15,676	44,555
South Side Elec. Lines	8,745	26,796
Surprise Valley Elec. Coop.	34,648	108,217
Tanner Electric	7,129	23,985
Umatilla Elec. Coop. Assn.	100,895	303,657
Unity Light & Power Co.	19,339	63,232
Vigilante Elec. Coop.	31,989	97,268
Wasco Elec. Coop.	60,750	209,237
West Oregon Elec. Coop.	38,410	125,700
Total Cooperatives (46)	2,809,075	$ 8,873,988
Total Publicly Owned Utilities	18,900,835	$ 55,258,243
Federal Agencies (9)	1,601,314	$ 3,914,671
Privately Owned Utilities		
California Pacific Utilities	20,437	$ 69,899
Idaho Power Co.	128,548	330,329
Montana Power Co.	833,275	1,924,648
Pacific Power & Light Co.	2,731,632	6,887,049
Portland General Electric Co.	3,136,152	6,909,626
Puget Sound Power & Light Co.	43,806	104,009
Utah Power Co.	0	0
Washington Water Power Co.	286,008	668,959
Total Privately Owned Utilities (8)	7,188,858	$ 15,894,519
Industries		
Aluminum Co. of America		
Vancouver Plant	2,088,524	$ 4,316,416
Wenatchee Plant	1,226,521	2,568,942
Anaconda Aluminum Co.	3,010,260	5,737,297
Harvey Aluminum (Inc.)	1,597,452	2,730,236
Intalco Aluminum Co.	3,158,673	6,728,020
Kaiser Aluminum & Chemical Co.		
Spokane Reduction Plant	3,839,291	7,886,888
Spokane Rolling Mill	432,571	1,044,611
Tacoma Reduction Plant	969,777	2,009,639
Reynolds Metals Co.		
Longview Plant	2,333,648	4,796,579
Troutdale Plant	1,508,306	3,053,327
Other Industries		
Carborundum Co.	218,278	478,006
Cominco American Inc.	11,972	57,847
Crown Zellerbach Corp.	99,267	218,037
Foote Mineral Co. – Kemco Opr	109,755	241,220
Georgia Pacific Corp.	178,133	392,476
Hanna Nickel Smelting Co.	715,103	1,592,754
ITT Rayonier, Incorporated	44,180	97,707
Pacific Carbide & Alloys Co.	57,562	128,819
Pennwalt Corp.	349,998	730,241
Stauffer Chemical Works	460,605	1,026,614
Stewart Elsner	32	210
Union Carbide Corp., M&M Div.	160,690	369,794
Total Industries (22)	22,570,598	$ 46,205,640
Total Northwest Area	50,261,605	$121,273,073
OUTSIDE NORTHWEST AREA		
British Columbia Hydro & Power Authority	176	$ 352
Sacramento Municipal Utility District	138,915	277,830
Pacific Gas & Electric Co.	354,694	709,388
San Diego Gas & Electric Co.	46,017	92,034
Southern California Edison Co.	551,147	1,102,294
U.S. Bureau of Reclamation		
Central Valley Authority	389,009	778,018
State of California	60,612	121,224
Total Outside Northwest Area (7)	1,540,570	$ 3,081,140
Total Sales of Electric Energy (151)	51,802,175	$124,354,213[1]

[1] Differs from the $123,585,000 shown on Table 6 because of statistical adjustments.

TABLE 2

FEDERAL COLUMBIA RIVER POWER SYSTEM

General Specifications, Projects Existing, Under Construction and Authorized
June 30, 1969

				Existing			Under Construction		Authorized		Other Potential		Total	
Project	Operating Agency[1]	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			6	324,000	–		16	842,400
Grand Coulee	BR	Washington	Columbia	Sept. 1941	18	2,025,000[2]	6	3,855,000[3]		–)	6	3,600,000)	36	9,771,000
Grand Coulee (Pump Turbines)		Washington	Columbia		–	–	2	97,000	4	194,000)	–	–)		
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	-		-		6	420,000	20	1,400,000
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	12,000	–	–				–	2	12,000
The Dalles	CE	Ore.-Wash.	Columbia	May 1957	16	1,119,000	8	688,000	–				24	1,807,000
Roza	BR	Washington	Yakima	Aug. 1958	1	11,250	–		–				1	11,250
Ice Harbor	CE	Washington	Snake	Dec. 1961	3	270,000			3	332,880	–		6	602,880
Hills Creek	CE	Oregon	M.Fk. Willamette	May 1962	2	30,000	–		–			–	2	30,000
Minidoka	BR	Idaho	Snake	May 1909	7	13,400	–		–				7	13,400
Boise Diversion	BR	Idaho	Boise	May 1912	3	1,500	–		–				3	1,500
Black Canyon	BR	Idaho	Payette	Dec. 1925	2	8,000	–		–		–		2	8,000
Anderson Ranch	BR	Idaho	S. Fk. Boise	Dec. 1950	2	27,000			1	13,500			3	40,500
Palisades	BR	Idaho	Snake	Feb. 1957	4	114,000	–		–		2	135,000	6	249,000
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	8	1,080,000	8	1,080,000	4	540,000			20	2,700,000
Lower Monumental	CE	Washington	Snake	May 1969	1	135,000	2	270,000	3	405,000		–	6	810,000
Little Goose	CE	Washington	Snake		–	–	3	405,000	3	405,000			6	810,000
Lower Granite	CE	Washington	Snake				3	405,000	3	405,000			6	810,000
Teton	BR	Idaho	Teton		–	–	2	16,000					2	16,000
Lost Creek	CE	Oregon	Rogue				2	49,000					2	49,000
Dworshak	CE	Idaho	N.Fk. Clearwater		–	–	3	400,000	3	660,000			6	1,060,000
Strube	CE	Oregon	S.Fk. McKenzie		–	–	–		1	4,500			1	4,500
Libby	CE	Montana	Kootenai		–	–	4	420,000	4	420,000			8	840,000
Asotin	CE	Wash. Ida.	Snake		–		–		4	540,000			4	540,000
Total installed capacity						8,074,150		7,685,000		5,323,880		5,728,000		26,811,030
Total number of projects						25		6		2		0		33

[1] CE Corps of Engineers; BR Bureau of Reclamation.
[2] Includes three service units and increase of 17,000 kw each for three rewound main units.
[3] Includes an increase of 17,000 kw each for 15 units to be rewound and six 600,000 kw units being installed at the Third Powerplant.

TABLE 3

PACIFIC NORTHWEST GENERATION

Nameplate Rating in Kilowatts of Plants Existing, Under Construction and Authorized or Licensed

June 30, 1969

Ownership	Existing		Under Construction		Authorized or Licensed		Total	
	No. of Plants	Nameplate Rating	No. of Plants	Nameplate Rating	No. of Plants	Nameplate Rating	No. of Plants	Nameplate Rating
Federal Columbia River Power System								
Hydro	25	8,074,150	6	7,685,000[1]	2	5,323,880[1]	33	21,083,030[1]
Publicly Owned Agencies								
Hydro	43	5,510,461	1	503,600[1]	3	1,976,850[1]	47	7,990,911[1]
Thermal	20	986,651	0	0	3	3,300,000[2]	23	4,286,651[2]
Total Publicly Owned Agencies	63	6,497,112	1	503,600[1]	6	5,276,850[1 2]	70	12,277,562[1 2]
Privately Owned Agencies								
Hydro	93	3,932,542	0	0	0	743,920[1]	93	4,676,462[1]
Thermal	11	251,168	2	2,505,000	2	2,100,000[2]	15	4,856,168[2]
Total Privately Owned Agencies	104	4,183,710	2	2,505,000	2	2,843,920[1 2]	108	9,532,630[1 2]
Pacific Northwest Agencies								
Hydro	161	17,517,153	7	8,188,600[1]	5	8,044,650[1]	173	33,750,403[1]
Thermal	31	1,237,819	2	2,505,000	5	5,400,000[2]	38	9,142,819[2]
Total Pacific Northwest Agencies	192	18,754,972	9	10,693,600[1]	10	13,444,650[1 2]	211	42,893,222[1 2]

[1] Includes additions to projects existing or under construction.

[2] Includes projects not presently licensed, but scheduled as part of the Pacific Northwest Hydro-Thermal Power Program.

TABLE 4

ELECTRIC ENERGY ACCOUNT FOR BONNEVILLE POWER ADMINISTRATION FISCAL YEAR 1969

Energy Received (millions of kilowatt-hours)	
Energy Generated for BPA	
Bureau of Reclamation	15,215
Corps of Engineers	35,540
Washington Public Power Supply System	3,884
Power interchanged in	35,726
Total received	90,365
Energy Delivered (millions of kilowatt-hours)	
Sales	51,802
Power interchanged out	34,857
Used by the Administration	51
Total delivered	86,710
Energy losses in transmission and transformation	3,655
Total (kilowatt-hours)	90,365
Losses in percent of total received	4.0%
Maximum demand on Federal plants (kilowatts)	
January 11, 1969, 5–6 p.m. PST	8,433,000
Load factor in percent of total generated for BPA	74.0%

TABLE 5

GENERATION BY THE PRINCIPAL ELECTRIC UTILITY SYSTEMS OF THE PACIFIC NORTHWEST[1]

Fiscal Year 1969

Utility	Kilowatt-hours (Billion)	Of Total Generation (Percent)
Publicly Owned:		
Federal Columbia River Power System[2]	54.1	49.8
Grant County PUD	10.6	9.7
Chelan County PUD	6.5	6.0
Seattle City Light	6.2	5.7
Douglas County PUD	3.9	3.6
Tacoma City Light	2.4	2.2
Eugene Water & Electric Board	0.4	0.4
Pend Oreille County PUD	0.4	0.4
Total Publicly Owned	84.5	77.8
Privately Owned:		
Idaho Power Company	7.6	7.0
Montana Power Company	4.6	4.2
Pacific Power and Light Co.	4.4	4.1
Washington Water Power Co.	3.8	3.5
Portland General Electric Co.	2.4	2.2
Puget Sound Power and Light Co.	1.3	1.2
Total Privately Owned	24.1	22.2
Total Generation	108.6	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 & 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 steam plant (NPR).

TABLE 6

FEDERAL COLUMBIA RIVER POWER SYSTEM

Operating Results on the Repayment Basis

Fiscal Years 1969 and 1968

(In thousands of dollars)

	F.Y. 1969	F.Y. 1968	Increase (Decrease) Amount	Increase (Decrease) Percent
REVENUES				
Bonneville Power Administration				
Sales of electric energy:				
Publicly owned utilities	55,752	49,135	6,617	13.5
Privately owned utilities	16,967	12,516	4,451	35.6
Federal agencies	4,662	5,474	(812)	(14.8)
Aluminum industry	40,871	34,202	6,669	19.5
Other industry	5,333	5,296	37	.7
Total	123,585	106,623	16,962	15.9
Other operating revenues:				
Wheeling revenues	9,160	6,363	2,797	44.0
Other revenues	1,574	1,689	(115)	(6.8)
Total	10,734	8,052	2,682	33.3
Total Bonneville Power Administration Revenues	134,319	114,675	19,644	17.1
Associated Projects				
Other operating revenues	2,958	3,213	(255)	(7.9)
Total power system operating revenues	137,277	117,888	19,389	16.4
EXPENSES				
Purchase and exchange power	12,526	12,755	(229)	(1.8)
Operating expenses	23,473	20,504	2,969	14.5
Maintenance and other expenses	10,612	11,075	(463)	(4.2)
Total power system expenses	46,611	44,334	2,277	5.1
INTEREST				
Interest on Federal investment	49,005	42,240	6,765	16.0
Less interest charged to construction	5,681	4,648	1,033	22.2
Total power system interest	43,324	37,592	5,732	15.2
Total power system expenses and interest	89,935	81,926	8,009	9.8
BALANCE AVAILABLE FOR REPAYMENT OF POWER SYSTEM INVESTMENT AND REPLACEMENTS	47,342	35,962	11,380	31.6

TABLE 7

FEDERAL COLUMBIA RIVER POWER SYSTEM REPAYMENT STUDY FOR F.Y. 1969

AUTHORIZED PROJECTS

(All Amounts in $1,000)

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
					Plant Allocated to Commercial Power											Irrigation Assistance				
					Investment Placed in Service			Cumulative Investment Placed in Service					Allowable Unamortized Investment							
Fiscal Year Ending June 30	Revenues	Operation and Maintenance Expense	Purchase and Exchange Power	Interest Expense	Initial Project	Replace-ments	Total	Initial Project	Replace-ments	Total	Amorti-zation	Unamortized Investment	Initial Project	Replace-ments	Total	Cumulative Amount in Service	Amorti-zation	Unamor-tized Amount	Allowable Unamor-tized Amount	Cumulative Surplus Revenues
Cumulative to 6-30-69	1,623,100	445,439	51,463	551,139	2,399,249		2,399,249	2,399,249		2,399,249	575,059	1,824,190	2,399,249		2,399,249	386,943		386,943	386,943	
1970	145,000	40,880	11,248	58,200	397,901	3,289	401,190	2,797,150	3,289	2,800,439	34,672	2,190,708	2,789,351	5,819	2,795,170	422,100		422,100	422,100	
1971	168,100	43,415	13,676	64,800	202,132	3,133	205,265	2,999,282	6,422	3,005,704	46,209	2,349,764	2,991,483	8,952	3,000,435	422,100		422,100	422,100	
1972	173,500	44,477	25,091	64,700	174,984	3,593	178,577	3,174,266	10,015	3,184,281	39,232	2,489,109	3,166,467	12,545	3,179,012	422,100		422,100	422,100	
1973	194,000	47,947	44,121	67,714	389,234	3,899	393,133	3,563,500	13,914	3,577,414	34,218	2,848,024	3,555,701	16,444	3,572,145	427,542		427,542	427,542	
1974	203,400	51,143	35,074	83,550	183,643	4,378	188,021	3,747,143	18,292	3,765,435	33,633	3,002,412	3,739,344	20,822	3,760,166	451,924		451,924	451,924	
1975	224,300	53,686	25,116	85,269	748,530	9,629	758,159	4,495,673	27,921	4,523,594	60,229	3,700,342	4,487,874	30,432	4,518,306	486,379		486,379	486,379	
1976	232,500	55,912	27,116	105,090	187,000	5,468	192,468	4,682,673	33,389	4,716,062	44,382	3,848,428	4,674,874	35,908	4,710,782	494,102		494,102	494,102	
1977	243,100	57,713	26,242	109,295	191,809	8,078	199,887	4,874,482	41,467	4,915,949	49,850	3,998,465	4,866,683	43,987	4,910,670	506,288		506,288	506,288	
1978	248,100	60,367	25,375	113,556	232,000	6,139	238,139	5,106,482	47,606	5,154,088	48,802	4,187,802	5,098,683	50,116	5,148,799	516,748		516,748	516,748	
1979	255,000	62,727	25,147	118,934	299,184	8,164	307,348	5,405,666	55,770	5,461,436	48,192	4,446,958	5,397,867	58,273	5,456,140	533,358		533,358	533,358	
1980	276,300	64,138	24,545	143,192		12,057	12,057	5,405,666	67,827	5,473,493	44,425	4,414,590	5,397,867	70,245	5,468,112	561,773		561,773	561,773	
1981	280,400	64,138	24,860	142,150		8,266	8,266	5,405,666	76,093	5,481,759	49,252	4,373,604	5,397,867	78,488	5,476,355	590,766		590,766	590,766	
1982	284,600	64,138	24,791	140,830		9,629	9,629	5,405,666	85,722	5,491,388	54,841	4,328,392	5,397,867	88,105	5,485,972	613,273		613,273	613,273	
1983	284,900	64,138	24,764	139,374		10,850	10,850	5,405,666	96,572	5,502,238	56,624	4,282,618	5,397,867	99,055	5,496,922	630,616		630,616	630,616	
1984	291,000	64,758	24,764	137,900	68,713	11,942	80,655	5,474,379	108,514	5,582,893	63,578	4,299,695	5,465,033	110,997	5,576,030	645,962		645,962	645,962	
1985	293,200	65,262	24,764	139,740		13,696	13,696	5,474,379	122,210	5,596,589	63,434	4,249,957	5,461,349	124,206	5,585,555	657,258		657,258	657,258	
1986	299,700	66,017	24,764	138,124	91,447	15,604	107,051	5,565,826	137,814	5,703,640	70,795	4,286,213	5,540,459	140,130	5,680,589	680,323		680,323	680,323	
1987	309,400	67,851	24,764	139,302	148,496	13,600	162,096	5,714,322	151,414	5,865,736	77,483	4,370,826	5,678,750	153,559	5,832,309	706,955		706,955	706,955	
1988	311,800	69,076	24,764	142,052	50,332	16,725	67,057	5,764,654	168,139	5,932,793	75,908	4,361,975	5,724,077	170,141	5,894,218	713,074		713,074	713,074	
1989	312,200	69,521	24,764	141,764	41,000	16,326	57,326	5,805,654	184,465	5,990,119	76,151	4,343,150	5,731,471	185,995	5,917,466	738,625		738,625	738,625	
1990	312,200	69,941	24,764	145,496		25,194	25,194	5,805,654	209,659	6,015,313	71,999	4,296,345	5,720,929	223,751	5,944,680	756,762		756,762	756,762	
1991	312,200	69,941	24,764	143,928		19,633	19,633	5,805,654	229,292	6,034,946	73,567	4,242,411	5,714,175	243,637	5,957,812	763,911		763,911	763,911	
1992	312,800	69,941	24,764	142,121		30,402	30,402	5,805,654	259,694	6,065,348	75,974	4,196,839	5,706,796	273,367	5,980,163	785,358		785,358	785,358	
1993	313,200	69,941	24,764	140,594		19,024	19,024	5,805,654	278,718	6,084,372	77,901	4,137,962	5,694,130	293,772	5,987,902	813,292		813,292	813,292	
1994	313,800	69,941	24,764	138,622		29,411	29,411	5,805,654	308,129	6,113,783	80,473	4,086,900	5,621,499	321,456	5,942,955	844,668		844,668	844,668	
1995	314,300	69,941	24,764	136,911		34,112	34,112	5,805,654	342,241	6,147,895	82,684	4,038,328	5,586,586	344,544	5,931,130	858,966		858,966	858,966	
1996	314,800	69,941	24,764	135,284		21,385	21,385	5,805,654	363,626	6,169,280	84,811	3,974,902	5,562,040	365,981	5,928,021	874,323		874,323	874,323	
1997	308,000	69,941	7,127	133,159		32,510	32,510	5,805,654	396,136	6,201,790	86,776	3,920,636	5,530,884	395,438	5,926,322	896,035	10,997	885,038	885,038	
1998	307,400	69,941	3,600	131,341		22,842	22,842	5,805,654	418,978	6,224,632	102,518	3,840,960	5,475,830	418,055	5,893,885	917,747		906,750	906,750	
1999	307,500	69,941	3,600	128,672		28,928	28,928	5,805,654	447,906	6,253,560	105,287	3,764,601	5,430,809	446,499	5,877,308	937,341		926,344	926,344	
2000	307,500	69,941	3,600	126,114		32,593	32,593	5,805,654	480,499	6,286,153	107,845	3,689,349	5,395,782	479,764	5,875,546	965,143		954,146	954,146	
2001	307,600	69,941	3,600	123,593		26,151	26,151	5,805,654	506,650	6,312,304	93,032	3,622,468	5,355,260	501,901	5,857,161	983,810	17,434	955,379	955,379	
2002	307,900	69,941	3,600	121,353		25,653	25,653	5,805,654	532,303	6,337,957	113,006	3,535,115	5,156,262	524,418	5,680,680	1,002,080		973,649	973,649	
2003	307,900	69,941	3,600	118,426		25,375	25,375	5,805,654	557,678	6,363,332	115,933	3,444,557	5,123,969	550,032	5,674,001	1,027,234		998,803	998,803	
2004	308,400	69,941	3,600	115,393		25,843	25,843	5,805,654	583,521	6,389,175	118,685	3,351,715	4,983,056	570,644	5,553,700	1,055,830	781	1,026,618	1,026,618	
2005	308,400	69,941	3,600	112,282		28,467	28,467	5,805,654	611,988	6,417,642	122,577	3,257,605	4,931,980	593,918	5,525,898	1,073,570		1,044,358	1,044,358	
2006	308,400	69,941	3,600	109,130		30,195	30,195	5,805,654	642,183	6,447,837	125,729	3,162,071	4,875,435	621,197	5,496,632	1,105,873		1,076,661	1,076,661	
2007	308,400	69,941	3,600	105,929		28,461	28,461	5,805,654	670,644	6,476,298	128,930	3,061,602	4,582,509	644,230	5,226,739	1,120,568		1,091,356	1,091,356	
2008	308,400	69,941	3,600	102,564		32,407	32,407	5,805,654	703,051	6,508,705	129,449	2,964,560	4,554,838	665,205	5,220,043	1,135,528	2,846	1,103,470	1,103,470	
2009	308,400	69,941	3,600	99,313		56,176	56,176	5,805,654	759,227	6,564,881	129,270	2,891,466	4,382,137	703,019	5,085,156	1,148,366	6,276	1,110,032	1,110,032	
2010	308,400	69,941	3,600	96,864		45,068	45,068	5,805,654	804,295	6,609,949	137,995	2,798,539	4,348,932	739,043	5,087,975	1,161,204		1,122,870	1,122,870	
2011	308,400	69,941	3,600	93,751		49,320	49,320	5,805,654	853,615	6,659,269	141,108	2,706,751	4,089,547	782,636	4,872,183	1,172,727		1,134,393	1,134,393	
2012	308,400	69,941	3,600	90,676		28,034	28,034	5,805,654	881,649	6,687,303	143,637	2,591,148	3,939,802	800,337	4,740,139	1,172,727	546	1,133,847	1,133,847	
2013	308,400	69,941	3,600	86,803		29,265	29,265	5,805,654	910,914	6,716,568	112,040	2,508,373	3,823,415	816,880	4,640,295	1,172,727	36,016	1,097,831	1,097,831	
2014	308,400	69,941	3,600	84,030		47,381	47,381	5,805,654	958,295	6,763,949	112,967	2,442,787	3,695,374	865,532	4,560,906	1,172,727	37,862	1,059,969	1,059,969	
2015	308,400	69,941	3,600	81,833		33,424	33,424	5,805,654	991,719	6,797,373	116,688	2,359,523	3,529,374	887,582	4,416,956	1,172,727	36,338	1,023,631	1,023,631	
2016	308,400	69,941	3,600	79,044		38,309	38,309	5,805,654	1,030,028	6,835,682	109,214	2,288,618	3,449,374	915,749	4,365,123	1,172,727	46,601	977,030	977,030	
2017	308,400	69,941	3,600	76,669		24,248	24,248	5,805,654	1,054,276	6,859,930	120,425	2,192,441	3,285,705	928,833	4,214,538	1,172,727	37,765	939,265	939,265	
2018	308,400	69,941	3,600	73,447		25,465	25,465	5,805,654	1,079,741	6,885,395	142,287	2,075,619	3,176,705	944,164	4,120,869	1,172,727	19,125	920,140	920,140	
2019	308,400	69,941	3,600	69,533		28,366	28,366	5,805,654	1,108,107	6,913,761	113,994	1,989,991	2,899,405	960,421	3,859,826	1,172,727	51,332	868,808	868,808	
2020	308,400	69,941	3,600	66,665		33,883	33,883	5,805,654	1,141,990	6,947,644	146,874	1,877,000	2,575,504	975,426	3,550,930	1,172,727	21,320	847,488	847,488	
2021	308,400	69,941	3,600	62,880		33,674	33,674	5,805,654	1,175,664	6,981,318	161,073	1,749,601	2,402,372	988,695	3,391,067	1,172,727	10,906	836,582	836,582	
2022	308,400	69,941	3,600	58,612		27,471	27,471	5,805,654	1,203,135	7,008,789	165,196	1,611,876	2,277,388	1,000,008	3,277,396	1,172,727	11,051	825,531	825,531	
2023	308,400	69,941	3,600	53,998		29,417	29,417	5,805,654	1,232,552	7,038,206	174,715	1,466,578	1,905,154	1,012,061	2,917,215	1,172,727	6,146	819,385	819,385	
2024	308,400	69,941	3,600	49,130		37,567	37,567	5,805,654	1,270,119	7,075,773	169,968	1,334,177	1,649,511	1,028,152	2,677,663	1,172,727	15,761	803,624	803,624	
2025	308,400	69,941	3,600	44,695		28,956	28,956	5,805,654	1,299,075	7,104,729	167,684	1,195,449	992,981	1,036,647	2,029,628	1,172,727	22,480	781,144	781,144	
2026	308,400	69,941	3,600	40,048		30,176	30,176	5,805,654	1,329,251	7,134,905	179,348	1,046,277	856,981	1,046,593	1,903,574	1,172,727	15,463	765,681	765,681	
2027	308,400	69,941	3,600	35,050		34,893	34,893	5,805,654	1,364,144	7,169,798	197,533	883,637	747,172	1,052,118	1,799,290	1,172,727	2,276	763,405	763,405	
2028	308,400	69,941	3,600	29,602		29,355	29,355	5,805,654	1,393,499	7,199,153	188,210	724,782	607,172	1,058,602	1,665,774	1,172,727	17,047	746,358	746,358	
2029	308,400	69,941	3,600	24,280		35,436	35,436	5,805,654	1,428,935	7,234,589	199,108	561,110	358,988	1,061,249	1,420,237	1,172,727	11,471	734,887	734,887	
2030	308,400	69,941	3,600	18,797		40,571	40,571	5,805,654	1,469,506	7,275,160	207,530	394,151	358,988	1,063,316	1,422,304	1,172,727	8,532	726,355	726,355	
2031	308,400	69,941	3,600	13,204		27,067	27,067	5,805,654	1,496,573	7,302,227	221,655	199,563	307,988	1,066,342	1,374,330	1,172,727		726,355	726,355	
2032	308,400	69,941	3,600	6,685		28,426	28,426	5,805,654	1,524,999	7,330,653	227,989		215,988	1,067,282	1,283,270	1,172,727		726,355	726,355	185
2033	308,400	69,941	3,600			26,564	26,564	5,805,654	1,551,563	7,357,217	26,564		215,988	1,068,502	1,284,490	1,172,727		726,355	726,355	208,480
2034	308,400	69,941	3,600			25,203	25,203	5,805,654	1,576,766	7,382,420	25,203		147,275	1,069,053	1,216,328	1,172,727	10,472	715,883	715,883	407,664
2035	308,400	69,941	3,600			28,297	28,297	5,805,654	1,605,063	7,410,717	28,297		147,275	1,069,337	1,216,612	1,172,727	12,898	702,985	702,985	601,328
2036	308,400	69,941	3,600			25,579	25,579	5,805,654	1,630,642	7,436,296	25,579		106,828	1,069,049	1,175,877	1,172,727	24,360	678,625	678,625	786,248
2037	308,400	69,941	3,600			30,298	30,298	5,805,654	1,660,940	7,466,594	30,298		50,332	1,069,367	1,119,699	1,172,727	8,996	669,629	669,629	981,813
2038	308,400	69,941	3,600			24,765	24,765	5,805,654	1,685,705	7,491,359	24,765			1,069,064	1,069,064	1,172,727	9,935	659,694	659,694	1,181,972
2039	308,400	69,941	3,600			29,139	29,139	5,805,654	1,714,844	7,520,498	29,139			1,068,347	1,068,347	1,172,727	16,252	643,442	643,442	1,371,440
2040	308,400	69,941	3,600			35,732	35,732	5,805,654	1,750,576	7,556,230	35,732			1,067,576	1,067,576	1,172,727	28,415	615,027	615,027	1,542,152
2041	308,400	69,941	3,600			28,360	28,360	5,805,654	1,778,936	7,584,590	28,360			1,066,784	1,066,784	1,172,727	33,066	581,961	581,961	1,715,585
2042	308,400	69,941	3,600			28,694	28,694	5,805,654	1,807,630	7,613,284	28,694			1,066,010	1,066,010	1,172,727	22,507	559,454	559,454	1,899,243
2043	308,400	69,941	3,600			29,002	29,002	5,805,654	1,836,632	7,642,286	29,002			1,065,266	1,065,266	1,172,727	17,343	542,111	542,111	2,087,757
2044	308,400	69,941	3,600			54,878	54,878	5,805,654	1,891,510	7,697,164	54,878			1,064,582	1,064,582	1,172,727	15,346	526,765	526,765	2,252,392
2045	308,400	69,941	3,600			35,749	35,749	5,805,654	1,927,259	7,732,913	35,749			1,063,960	1,063,960	1,172,727	11,296	515,469	515,469	2,440,206
2046	308,400	69,941	3,600			45,975	45,975	5,805,654	1,973,234	7,778,888	45,975			1,063,414	1,063,414	1,172,727	23,065	492,404	492,404	2,606,025
2047	308,400	69,941	3,600			24,723	24,723	5,805,654	1,997,957	7,803,611	24,723			1,062,953	1,062,953	1,172,727	26,632	465,772	465,772	2,789,529
2048	308,400	69,941	3,600			24,842	24,842	5,805,654	2,022,799	7,828,453	24,842			1,062,581	1,062,581	1,172,727	6,119	459,653	459,653	2,993,427
2049	308,400	69,941	3,600			28,328	28,328	5,805,654	2,051,127	7,856,781	28,328			1,062,286	1,062,286	1,172,727	25,551	434,102	434,102	3,174,407
2050	308,400	69,941	3,600			31,940	31,940	5,805,654	2,083,067	7,888,721	31,940			1,062,054	1,062,054	1,172,727	18,137	415,965	415,965	3,359,189
TOTALS	25,495,500	5,889,144	928,488	6,673,196	5,805,654	2,083,067	7,888,721				7,888,721						756,762			

NOTE:
This repayment study is similar to those included in the BPA Annual Reports since fiscal year 1965. However, several changes in this year's study are of sufficient significance to warrant explanation. These are:

1. The Bureau of Reclamation updated its estimates of the cost to complete reclamation projects which are authorized to receive repayment assistance from Federal Columbia River Power System revenues. This study reflects that increase, which totals $420 million more than such assistance included in the F.Y. 1968 Annual Report.

2. Previously, the cost of obtaining power through purchase and exchange agreements had been included in operation and maintenance costs. Inasmuch as the amount of purchase and exchange power has increased in recent years, this study shows it in a separate column.

3. The fiscal year 1968 study ran through the year 2056, as that was the final date for payment of the last increment of authorized irrigation assistance. The latest schedule provided by the Bureau of Reclamation for the irrigation assistance extends the authorized repayment period for the last increment to the year 2071. This extension is due to the stretch-out of the reclamation construction program. The repayment study, however, shows ample net revenues to repay all authorized irrigation assistance following complete repayment of the power investment well ahead of the last year of the allowable irrigation repayment period. Consequently, there is no necessity to extend the repayment study to 2071. As a result, 2050 was selected as a reasonable termination point. The study shows that all power costs are fully repaid prior to that date, and that there are more than enough surplus revenues to cover all remaining irrigation costs.

TABLE 8

BONNEVILLE POWER ADMINISTRATION REVENUE AND REVENUE TRENDS

Sales of energy, firm and nonfirm
by class of customer and miscellaneous power revenues

(In thousands of dollars)

Class of Customer	F.Y. 1960	F.Y. 1961	F.Y. 1962	F.Y. 1963	F.Y. 1964	F.Y. 1965	F.Y. 1966	F.Y. 1967	F.Y. 1968	F.Y. 1969
Aluminum Industry										
Firm	$15,293	$14,978	$14,341	$14,382	$15,733	$16,068	$ 17,299	$ 21,652	$ 27,530	$ 32,156
Nonfirm	2,168	1,982	3,042	3,715	5,297	6,930	8,994	8,719	6,672	8,715
Total aluminum industry	17,461	16,960	17,383	18,097	21,030	22,998	26,293	30,371	34,202	40,871
Trend percentages[1]	100%	97%	100%	104%	120%	132%	151%	174%	196%	234%
Other Industry										
Firm	3,163	3,205	3,194	2,927	3,431	3,608	3,801	3,776	4,334	4,426
Nonfirm	868	613	855	625	1,064	1,342	1,569	1,129	962	907
Total other industry	4,031	3,818	4,049	3,552	4,495	4,950	5,370	4,905	5,296	5,333
Trend percentages[1]	100%	95%	100%	88%	112%	123%	133%	122%	131%	132%
Publicly Owned Utilities										
Firm	28,304	29,520	32,598	35,466	36,965	41,231	46,643	50,215	41,931	54,719
Nonfirm	357	583	1,340	682	746	507	1,873	911	7,204	1,033
Total publicly owned utilities	28,661	30,103	33,938	36,148	37,711	41,738	48,516	51,126	49,135	55,752
Trend percentages[1]	100%	105%	118%	126%	132%	146%	169%	178%	171%	195%
Privately Owned Utilities										
Firm	9,907	8,338	5,678	6,900	4,974	4,874	7,743	11,062	8,418	13,799
Nonfirm	2,659	1,301	1,536	332	781	663	1,519	1,691	4,098	3,168
Total privately owned utilities	12,566	9,639	7,214	7,232	5,755	5,537	9,262	12,753	12,516	16,967
Trend percentages[1]	100%	77%	57%	58%	46%	44%	74%	101%	100%	135%
Federal Agencies										
Firm	5,986	6,194	6,217	6,646	7,088	5,874	3,346	5,199	5,132	3,528
Nonfirm	239	281	253	303	183	872	2,225	111	342	1,134
Total Federal agencies	6,225	6,475	6,470	6,949	7,271	6,746	5,571	5,310	5,474	4,662
Trend percentages[1]	100%	104%	104%	112%	117%	108%	89%	85%	88%	75%
Sales of Electric Energy										
Firm	62,653	62,235	62,028	66,321	68,191	71,655	78,832	91,904	87,345	108,628
Nonfirm	6,291	4,760	7,026	5,657	8,071	10,314	16,180	12,561	19,278	14,957
Total sales of electric energy	68,944	66,995	69,054	71,978	76,262	81,969	95,012	104,465	106,623	123,585
Trend percentages[1]	100%	97%	100%	104%	111%	119%	138%	151%	155%	179%
Miscellaneous Revenues										
Wheeling revenues	1,798	2,317	4,019	3,878	4,359	4,397	4,314	4,504	6,363	9,160
Downstream benefits	--	--	1,100	1,460	1,881	112	271	103	160	153
All other	256	390	310	388	349	807	864	1,092	1,529	1,421
Total miscellaneous revenues	2,054	2,707	5,429	5,726	6,589	5,316	5,449	5,699	8,052	10,734
Trend percentages[1]	100%	131%	264%	279%	321%	259%	265%	277%	392%	523%
Total Revenues	$70,998	$69,702	$74,483	$77,704	$82,851	$87,285	$100,461	$110,164	$114,675	$134,319
Trend percentages[1]	100%	98%	105%	109%	117%	123%	141%	155%	162%	189%

[1] F.Y. 1960 base year.

FINANCIAL STATEMENTS

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

B-114858

December 23, 1969

Dear Mr. Secretary:

The General Accounting Office has examined the accompanying financial statements prepared by the Bonneville Power Administration (BPA), Department of the Interior, for the Federal Columbia River Power System for fiscal year 1969.

The designation "Federal Columbia River Power System" is used to describe the integrated Federal power system in the Pacific Northwest comprising the (1) power generating facilities of the Corps of Engineers (Civil Functions), Department of the Army, and of the Bureau of Reclamation, Department of the Interior, and (2) transmission facilities of BPA. BPA markets the power generated by the integrated System. Our examination was made pursuant to the Budget and Accounting Act, 1921 (31 U.S.C. 53), and the Accounting and Auditing Act of 1950 (31 U.S.C. 67).

The statements present the financial results of operations and the source and application of funds in the generating, transmitting, and marketing of electric power for fiscal year 1969 and the financial position of the System at June 30, 1969.

Our examination of the financial statements was made in accordance with generally accepted auditing standards and included tests of the accounting records of the Corps of Engineers, the Bureau of Reclamation, and BPA and such other auditing procedures as we considered necessary in the circumstances. Our preceding examination of financial statements of the System was made for fiscal year 1968.

The accompanying financial statements for the System were prepared on a cost-accounting basis. They do not show the financial results on a repayment basis, either for the fiscal year or cumulatively. (See note 2 to the financial statements.) A separate repayment analysis is prepared by BPA for the System for repayment purposes. Depreciation for cost-accounting purposes is based on an average composite life of 64 years for the entire System whereas a repayment period of 50 years for the generating projects and 45 years for the transmission system is used for repayment purposes. Wholesale power rates are based upon this repayment analysis rather than the cost-based statements.

Our report for fiscal year 1968 stated that the rental costs of space provided by the General Services Administration to BPA were not included in the financial statements for fiscal years 1963 through 1967 but were included for fiscal year 1968. During fiscal year 1969 BPA made a retroactive adjustment, charging $1,162,000 to accumulated net revenues and $1,404,000 to construction, for rental costs for fiscal years 1963 through 1967.

During fiscal year 1969 BPA also treated the cost of the annual System audit, furnished without reimbursement by the General Accounting Office, as an operating cost and made a retroactive adjustment to accumulated net revenues for such costs for fiscal years 1963 through 1968. (See note 7 to the financial statements.) We concur in these adjustments. Also during fiscal year 1969, BPA recorded as assets and as liabilities, for the first time, the costs of "constructively received" material as required by Bureau of the Budget Bulletin 68-10, dated April 26, 1968. This amounted to $9,531,000 at June 30, 1969. (See note 5.e. to the financial statements.)

The accounts and financial statements are subject to retroactive adjustment, because firm allocations of the cost of joint-use facilities to power and other purposes were not made for 5 of the 19 generating projects in service as of June 30, 1969. (See note 3 to the financial statements.) The costs of joint-use facilities of the five projects amounted to about $480 million at June 30, 1969, of which about $337 million was tentatively allocated to power. In prior years, such changes in allocations have sometimes resulted in significant adjustments to (1) the cost of joint-use facilities allocated to power and (2) the reported results of power operations. Note 3 to the financial statements discloses the impact of the changes in the allocations of the five projects for which firm allocations were adopted during fiscal year 1969.

Three of the five projects for which firm allocations had not been made at the end of fiscal year 1969 were placed in service in recent years. The other two proj-

ects—Chief Joseph and Palisades—however, were placed in service in 1955 and 1957, respectively. The Corps of Engineers advised us during our fiscal year 1968 and 1969 audits that it considered the cost allocation for the Chief Joseph project to be firm. The Department of the Interior, however, advised us in connection with our fiscal year 1968 audit that it expected the cost allocation for this project to be firmed up in fiscal year 1969.

The required action was not taken by the Department in fiscal year 1969 to arrive at a firm allocation of costs for the Chief Joseph project. With regard to the Palisades project, the Department informed us that a firm allocation of costs was dependent on the Corps' approval of the costs allocable to flood control. Because cost allocations are such an important factor in the preparation of the financial statements and repayment analyses for the System, we recommend that appropriate action be taken to see that firm cost allocations are arrived at promptly for these two projects which were placed in service more than 10 years ago.

In addition to the need for firm cost allocations, there are other matters discussed in the notes to the financial statements that remain to be resolved for improved disclosure of the financial position and results of operations of the integrated power system. These other matters include inconsistencies (1) in computing interest expense on the Federal investment and in capitalizing interest costs during construction, (2) in capitalizing preliminary survey and investigation costs, and (3) in reporting accrued annual leave as a liability. The General Accounting Office is currently reviewing these matters with a view toward determining the feasibility of uniform treatment.

As shown in note 4 to the financial statements, interest on the Government's unrepaid investment, to be repaid from power revenues, is computed at rates ranging from 2-1/2 to 3-1/4 percent. The rates were established for individual projects on the basis of legislative requirements or administrative policies.

On October 27, 1969, the Department of the Interior announced that interest rates on new Federal power projects in fiscal year 1970—for projects where the interest rate is subject to administrative determination—would be increased from 3-1/4 to 4-7/8 percent and that in subsequent years the rate would be based on the average yields on long-term obligations but would be adjusted by not more than one half of 1 percent each July 1. The change, which was announced by the Department in a press release, will result in interest costs more nearly comparable to the Government's financing costs for new projects. However, a secretarial order directing that the change be made had not been issued at the time our review was completed.

Subject to the financial effects of future adjustments related to adoption of firm cost allocations and of the resolution of other matters described above, the accompanying financial statements, in our opinion, present fairly the assets and liabilities of the Federal Columbia River Power System at June 30, 1969, the financial results of its power operations, and the source and application of its funds for the year then ended, in conformity with accounting principles and standards prescribed for executive agencies of the Federal Government by the Comptroller General of the United States. These accounting principles and standards were applied on a basis consistent with that of the preceding period, except for the cost of "constructively received" materials, rental costs, and the cost of audit services explained above.

Copies of this report are being sent to the Director, Bureau of the Budget; 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

The Honorable
The Secretary of the Interior

EXHIBIT 1

UNITED STATES OF AMERICA

FEDERAL COLUMBIA RIVER POWER SYSTEM

STATEMENT OF COMMERCIAL POWER REVENUES AND EXPENSES
FOR THE FISCAL YEARS ENDED JUNE 30, 1969 AND JUNE 30, 1968

(NOTES 1 AND 2)

(In thousands)

	Fiscal Year 1969	Fiscal Year 1968
OPERATING REVENUES:		
Sales of electric energy by Bonneville Power Administration:		
Publicly owned utilities	$ 55,752	$ 49,135
Privately owned utilities	16,967	12,516
Federal agencies	4,662	5,474
Aluminum industry	40,871	34,202
Other industry	5,333	5,296
Total	123,585	106,623
Other operating revenues:		
Wheeling revenues	9,160	6,363
Other revenues	4,532	4,902
Total	13,692	11,265
Total operating revenues	137,277	117,888
OPERATING EXPENSES:		
Purchase and exchange power	12,526	12,755
Operation	23,473	20,504
Maintenance	11,053	10,796
Depreciation	19,228	17,116
Total operating expenses	66,280	61,171
Net operating revenues	70,997	56,717
INTEREST AND OTHER DEDUCTIONS (Notes 4 & 5)		
Interest on Federal investment	49,005	42,240
Interest charged to construction	5,681*	4,648*
Miscellaneous income deductions, net	441*	279
Net interest and other deductions	42,883	37,871
NET REVENUES	$ 28,114	$ 18,846
ACCUMULATED NET REVENUES:		
Balance at beginning of year	$296,557	$278,336
Net revenues — current year	28,114	18,846
Prior years adjustments (Note 10)	2,087*	625*
Balance at end of year	$322,584	$296,557

*Denotes deduction

"Notes to the financial statements" are an integral part of this statement.

UNITED STATES OF AMERICA

FEDERAL COLUMBIA RIVER POWER SYSTEM

STATEMENT OF ASSETS AND LIABILITIES
OF THE COMMERCIAL POWER PROGRAM
AS OF JUNE 30, 1969 AND JUNE 30, 1968

(NOTES 1 AND 2)

(In thousands)

ASSETS

	June 30	
	1969	1968
FIXED ASSETS:		
Completed plant (Schedule A)	$2,362,822	$1,988,280
Retirement work in progress	11,861	9,380
	2,374,683	1,997,660
Less accumulated depreciation	217,401	199,562
	2,157,282	1,798,098
Construction work in progress (Schedule A)	803,190	894,884
Total fixed assets	2,960,472	2,692,982
CURRENT ASSETS:		
Unexpended funds	141,784	121,236
Special funds	3,314	4,101
Accounts receivable	21,856	17,119
Materials and supplies	13,942	11,388
Total current assets	180,896	153,844
DEFERRED CHARGE FOR PAYMENT OF IRRIGATION ASSISTANCE (Schedule A) (Note 6)	386,943	370,544
OTHER ASSETS AND DEFERRED CHARGES:		
Trust funds	1,092	1,346
Other assets and deferred charges (Note 5)	13,586	3,078
Total other assets and deferred charges	14,678	4,424
TOTAL ASSETS	$3,542,989	$3,221,794

*Denotes deduction

"Notes to the financial statements" are an integral part of this statement.

EXHIBIT 2

LIABILITIES

	June 30 1969	June 30 1968
INVESTMENT OF U.S. GOVERNMENT:		
Congressional appropriations	$3,587,005	$3,268,890
Revenues transferred to continuing fund	3,909	3,909
Transfers from other Federal agencies, net	23,799	22,462
Interest on Federal investment (Notes 4 and 5)	705,432	639,561
Gross Federal investment	4,320,145	3,934,822
Less funds returned to U.S. Treasury	1,557,948	1,437,669
Net investment of U.S. Government	2,762,197	2,497,153
ACCUMULATED NET REVENUES:		
Balance at beginning of year	296,557	278,336
Net revenues current year (Exhibit 1)	28,114	18,846
Prior years adjustments (Note 10)	2,087*	625*
Balance at end of year	322,584	296,557
CURRENT LIABILITIES:		
Accounts payable	61,352	49,428
Employees accrued leave (Note 5)	3,937	3,691
Total current liabilities	65,289	53,119
LIABILITY OF U.S. GOVERNMENT FOR PAYMENT OF IRRIGATION ASSISTANCE (Schedule A) (Note 6)	386,943	370,544
OTHER LIABILITIES AND DEFERRED CREDITS:		
Trust fund advances	1,156	1,346
Other deferred credits	4,820	3,075
Total other liabilities and deferred credits	5,976	4,421
TOTAL LIABILITIES	$3,542,989	$3,221,794

EXHIBIT 3

UNITED STATES OF AMERICA

FEDERAL COLUMBIA RIVER POWER SYSTEM

STATEMENT OF SOURCE AND APPLICATION OF FUNDS
OF COMMERCIAL POWER PROGRAM
FOR FISCAL YEAR ENDING JUNE 30, 1969

(NOTES 1 AND 2)

(In thousands)

SOURCE OF FUNDS:		
Congressional appropriations	$318,115	
Transfers from other Federal agencies	1,337	
Gross investment		$319,452
Revenue from sale of electric energy, including adjustment for prior year of $601	124,186	
Other operating revenue	13,692	
Total revenues		137,878
Total source of funds		$457,330
APPLICATION OF FUNDS:		
Operation and maintenance expense, purchase and exchange power, miscellaneous income deductions and adjustment for prior years of $681		$ 47,292
Investment in electric utility plant (Does not include capitalized interest of $20,707)		266,178
Return of funds to U.S. Treasury for:		
Operation, maintenance, and miscellaneous expense	$ 47,292	
Interest on Federal investment, including adjustment for prior years of $1,840	45,164	
Repayment of capital investment	27,823	
Total funds returned to U.S. Treasury		120,279
Increase in current assets and liabilities, net		14,882
Increase in other assets and deferred charges, net of other liabilities and deferred credits (excluding irrigation assistance)		8,699
Total application of funds		$457,330

"Notes to the financial statements" are an integral part of this statement.

Centralia Thermal Plant
under Construction

UNITED STATES OF AMERICA

FEDERAL COLUMBIA RIVER POWER SYSTEM

AMOUNT AND ALLOCATION OF PLANT INVESTMENT
AS OF JUNE 30, 1969

(NOTES 1 AND 3)

PROJECTS IN SERVICE AND UNDER CONSTRUCTION

(In thousands)

SCHEDULE A

Project	Total	COMMERCIAL POWER: Completed Plant (Notes 3 and 5)	COMMERCIAL POWER: Construction Work in Progress	COMMERCIAL POWER: Total	ALLOCATED TO: IRRIGATION f: Returnable from Commercial Power Revenues	IRRIGATION: Returnable from Other Sources (Note 6)	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)	$1,027,560	$ 866,283	$161,277	$1,027,560									100.0
Albeni Falls (CE)	32,768	31,896		31,896				$ 134	$ 173		$ 565		97.3
Boise (BR)	65,570	4,835	53	4,888	$ 10,994	$ 34,731	$ 45,725		14,957				24.2
Bonneville (CE)	90,897	61,344	1,304	62,648				28,111			138		68.9
Chief Joseph (CE)	156,740	155,592	972	156,564							176		99.9
Columbia Basin (BR)	646,431	165,564	57,132 (a)	222,696	319,016	60,108	379,124	1,000	43,071			$ 540	83.8
Cougar (CE)	57,190	17,666		17,666		3,080	3,080	513	35,931				30.9
Detroit-Big Cliff (CE)	66,360	41,979		41,979		3,399	3,399	132	20 439			411	63.3
Green Peter-Foster (CE)	86,236	46,588		46,588		6,393	6,393	355	30,897		333	1,670	54.0
Hills Creek (CE)	48,761	17,302		17,302		4,583	4,583	626	26,250				35.5
Hungry Horse (BR)	102,140	77,472	4	77,476					24,664				75.9
Ice Harbor (CE)	138,809	93,574	688	94,262				43,662			885		67.9
John Day (CE)	462,761	190,785	151,684	342,469				79,009	13,347		3,671	24,265 (b)	74.0
Lookout Point-Dexter (CE)	94,432	45,568	25	45,593		1,410	1,410	704	46,530		195		48.3
Lower Monumental (CE)	178,081	49,857	82,591	132,448				45,085			548		74.4
McNary (CE)	304,341	256,407	235	256,642				47,204			495		84.3
Minidoka (BR)	36,756	2,241	93	2,334		34,101	34,101				27	294	6.3
Palisades (BR)	60,028	10,535	81	10,616	17,469	9,343	26,812		22,455		145		46.8
The Dalles (CE)	270,033	222,777	4,894	227,671				41,800			540	22	84.3
Yakima (BR)	63,391	4,557	44	4,601	9,837	47,800	57,637			$1,153			22.8
Projects under Construction													
Dworshak (CE)	104,955		94,934	94,934				3,568	5,547		906		90.5
Libby (CE)	156,917		122,953	122,953					33,964				78.4
Little Goose (CE)	134,929		94,691	94,691				40,076			162		70.2
Lost Creek (CE)	5,205		642	642		82	82		1,995	882	1,298	306	12.3
Lower Granite (CE)	34,225		28,893	28,893				5,291			41		84.4
Irrigation assistance at 11 projects having no power generation	28,768				28,768		28,768						100.0
Subtotal plant investment	4,454,284	2,362,822	803,190	3,166,012	386,084	205,030	591,114	337,270	320,220	2,035	10,125	27,508	79.8
Repayment obligation retained by Columbia Basin Project (c)	2,211	1,352		1,352	859		859						100.0
Total	$4,456,495	$2,364,174	$803,190	$3,167,364	$386,943	$205,030	$591,973	$337,270	$320,220	$2,035	$10,125	$27,508	79.8

BPA – Bonneville Power Administration
CE – Corps of Engineers Project
BR – Bureau of Reclamation Project

(a) Includes $53,702 construction costs of third power plant
(b) Nonreimbursable road costs
(c) Joint facilities transferred to Bureau of Sports Fisheries and Wildlife. Power portion is included in the Balance Sheet as a deferred item.

"Notes to the financial statements" are an integral part of this statement.

UNITED STATES OF AMERICA

FEDERAL COLUMBIA RIVER POWER SYSTEM

NOTES TO THE FINANCIAL STATEMENTS

Note 1. Composition of the Federal Columbia River Power System

The Federal Columbia River Power System (FCRPS) is the name applied to the facilities and operations of the Bonneville Power Administration (BPA) and the hydroelectric generating plants constructed and operated by the Corps of Engineers (Corps) or the Bureau of Reclamation (Bureau) for which BPA transmits and markets the power. The projects in service and under construction at June 30, 1969, are listed in Schedule A.

The three agencies are separately managed and financed, and each has its own accounting system. However, the facilities are operated as an integrated power system, and the financial statements for the three agencies are consolidated under the name Federal Columbia River Power System.

Note 2. Basis of Financial Reporting

The accompanying financial statements for the FCRPS are prepared on the cost accounting basis which includes depreciation by the compound interest method as one element of cost. The statements do not show financial results on a repayment basis either for the fiscal year or cumulatively.

The average depreciation life of fixed assets allocated to power is about 85 years for the generating projects and 46 years for the transmission system. The average composite life for the entire system is about 64 years. A separate repayment analysis is prepared for the FCRPS based upon repayment periods of 50 years for the generating projects and 45 years for the transmission system. As a result of the difference between depreciation and repayment periods, depreciation charges accumulated during the repayment periods are much less than repayment requirements for the same periods. Wholesale power rates are based upon the repayment analysis rather than these cost based statements.

Note 3. Cost Allocations

The term "cost allocation" is used to describe the process of assigning the costs of a multipurpose project to the individual purposes it serves. In such a process, joint-use costs of plant and operations are allocated among the purposes served such as power, irrigation, navigation, and flood control. The portion of total project costs allocated to power is included in the FCRPS financial statements.

Cost allocations are designated as tentative or firm. A tentative allocation of costs among purposes may be adjusted retroactively when it is replaced with a firm allocation. A firm allocation may be adjusted, if conditions warrant, but only on a prospective basis.

Firm cost allocations have been adopted for all of the 19 projects in service at June 30, 1969, except the following:

Chief Joseph	Lower Monumental
Green Peter-Foster	Palisades
John Day	

The Corps considers the cost allocation for the Chief Joseph Project to be a firm allocation because all plant costs are allocated to power except for $176,000 of specific recreation facilities. However, the amount allocated to commercial power is subject to revision because the Department of the Interior has not yet firmed up the suballocation to irrigation pumping power. Therefore, the Department of the Interior considers that the Chief Joseph allocation is tentative.

On July 8, 1968, firm allocations were adopted for Hills Creek, The Dalles, Lookout Point-Dexter, and Cougar Projects. As a result, the allocation of plant investment to power for the four projects increased $6,948,000, and Accumulated Net Revenues decreased $1,157,000.

On June 6, 1969, a firm allocation was adopted for the Detroit-Big Cliff Project, too late to be reflected in year-end accounts. Retroactive adjustments will be made in fiscal year 1970. Plant investment allocated to power will decrease about $1,650,000 (4.0%) and Accumulated Net Revenues at June 30, 1969, will increase about $1,070,000.

Note 4. Interest Rates

An interest rate of 2-1/2% is applied to the unpaid Federal investment for the majority of the projects. The projects which use a rate higher than 2-1/2% are as follows: Bureau projects in service, all using a 3% rate, are: Boise, Columbia Basin, Hungry Horse, Minidoka, Palisades, and Yakima-Roza Division. The Bureau's Grand Coulee Third Powerplant, which is under construction, carries a 3-1/8% rate.

Corps projects which are under construction and which use rates higher than 2-1/2% are:

Dworshak	2-5/8%
Libby	3-1/8%
Lost Creek	3-1/8%

BPA used the 2-1/2% rate through fiscal year 1963. Subsequently, the following rates were used:

Fiscal Year 1964	2-7/8%
Fiscal Year 1965	3%
Fiscal Years 1966 through 1968	3-1/8%
Fiscal Year 1969	3-1/4%

Variations in rates applicable to individual projects are the result of legislative requirements or administrative policies adopted by the various entities.

Note 5. Variations in Practices Among Reporting Entities

The entities of FCRPS each maintain a separate accounting system designed to meet its particular requirements, and variations in reporting practices exist among the entities. However, cooperation among the entities in prior years has led to the adoption of standard practices such as use of the compound interest method of depreciation. The unresolved variations existing during fiscal year 1969 are as follows:

a. The Corps and BPA include interest during construction and other items such as working capital in the base for computation of interest expense. The Bureau does not include in its base interest during construction for four projects and one division of a fifth, and it also excludes other items such as working capital. In addition, the Bureau's interest base does not include interest from the period of initial allocation to fiscal year 1963 on plant costs of the Columbia Basin Project allocated to future downstream river regulation.

   The Bureau excluded these elements based on its interpretation of Federal reclamation law. However, had the Bureau included these elements in its interest base and computed interest at the rate of 2-1/2% for the Columbia Basin and Hungry Horse Projects (the two principal projects involved) accumulated net revenues at June 30, 1969, would have been reduced about $21,600,000.

b. All entities currently capitalize interest during construction. However, the Bureau was not required to include capitalized interest for four projects and one division of a fifth. Had the Bureau capitalized interest during construction at a rate of 2-1/2% for the Columbia Basin and Hungry Horse Projects, plant costs, net of depreciation, would be increased by about $11,700,000 at June 30, 1969. The Bureau computed interest expense at a rate of 3% upon completion of these projects. At that time the Corps and BPA used a 2-1/2% interest rate.

c. The Bureau includes in the costs of its projects, general investigation and development costs which are incurred prior to project authorization. It is the policy of the Corps not to include for FCRPS purposes such costs which are incurred prior to project authorization. The Corps had excluded about $2,100,000 of such costs at June 30, 1969.

d. The accounts of the Corps and BPA properly reflect the liability for accrued but unused annual leave. However, the accounts of the Bureau projects do not include an amount for unused annual leave, estimated to be $666,000 as of June 30, 1969.

e. As of June 30, 1969, BPA recorded $9,531,000 in Accounts Payable, representing the liability for "constructive receipt" of materials being fabricated for BPA in accordance with its specifications. The offsetting entry was made to Other Assets and Deferred Charges. This entry was made to conform to new Federal concepts for recording such items. A corresponding item for BPA was omitted from the financial statements last year pending full development of the new procedures. The Corps and the Bureau have recorded such liabilities in previous years with offsetting entries principally made to Construction Work in Progress.

Note 6. Repayment Responsibility for Irrigation Costs

The revenues of the FCRPS must repay to the United States Treasury the cost of irrigation facilities which benefiting water users in the FCRPS area are unable to repay. At June 30, 1969, this amount was $386,943,000.

Joint project costs of $18,865,000 for the Cougar, Detroit-Big Cliff, Hills Creek, Lookout Point-Dexter, and Green Peter-Foster Projects have been allocated to irrigation pursuant to project authorizations. A determination of water users' repayment ability will be made at the time the irrigation facilities are proposed for authorization and development. If water users' repayment ability is insufficient to meet the repayment requirements, irrigation assistance may be required from power revenues, if authorized by Congress. These costs are not included in the accompanying statements because a final determination as to potential repayment from power revenues has not been made.

Note 7. Costs Incurred by Other Agencies

The estimated costs of office space provided without charge to BPA by the General Services Administration were not included in the financial statements for the period July 1, 1962, through June 30, 1967. In fiscal year 1969, BPA recorded costs for that period as a charge to Accumulated Net Revenues in the amount of $1,162,000 and $1,404,000 was charged to Construction.

The costs of the annual FCRPS audit, furnished without charge by the General Accounting Office, were not included in the financial statements for the period July 1, 1962, through June 30, 1968. BPA recorded the costs applicable to this period in fiscal year 1969 as a charge to Accumulated Net Revenues in the amount of $336,000. The fiscal year 1969 operating costs include $79,000 for the cost of the audit.

Estimated costs of rental services furnished to the Corps and the Bureau, and other services furnished by other Federal agencies to BPA, the Corps, and the Bureau which are not included in the financial statements are considered to be minor.

Note 8. Hanford Steam Plant

BPA, the Washington Public Power Supply System (WPPSS), and 76 utility participants have executed agreements under which BPA receives the electric power generated by the Hanford Steam Plant which was constructed by WPPSS. In return BPA furnishes the participants an amount of power equal in value, at BPA rates, to the annual costs of operating the steam plant and retiring the bonds issued in 1963 to construct the plant. At June 30, 1969, $87,675,000 of the bonds were outstanding and scheduled to be fully retired by 1996. The agreements call for payments to WPPSS by each participant for its portion of the costs of the project based on the Annual Operating Budget. For the year ending June 30, 1969, the participants' shares of the Annual Operating Budget totaled $7,930,000.

BPA will be required to make the required power deliveries until 1996 even if the Hanford Steam Plant becomes inoperable. However, the Government may acquire ownership of the plant, subject to Congressional approval. Ownership may be acquired after 1996 without cost, with the assumption of all project assets and liabilities. BPA engineers have estimated that by 1996 the plant will have only a net salvage value.

Note 9. Contingent Liabilities

Contingent liabilities applicable to commercial power at June 30, 1969, totaled approximately $17,300,000; $12,200,000 representing claims under the Federal Tort Claims Act (of which $9,700,000 is a claim against the Bonneville Dam by the Yakima Tribe of Indians); and $5,100,000 representing various contractor claims.

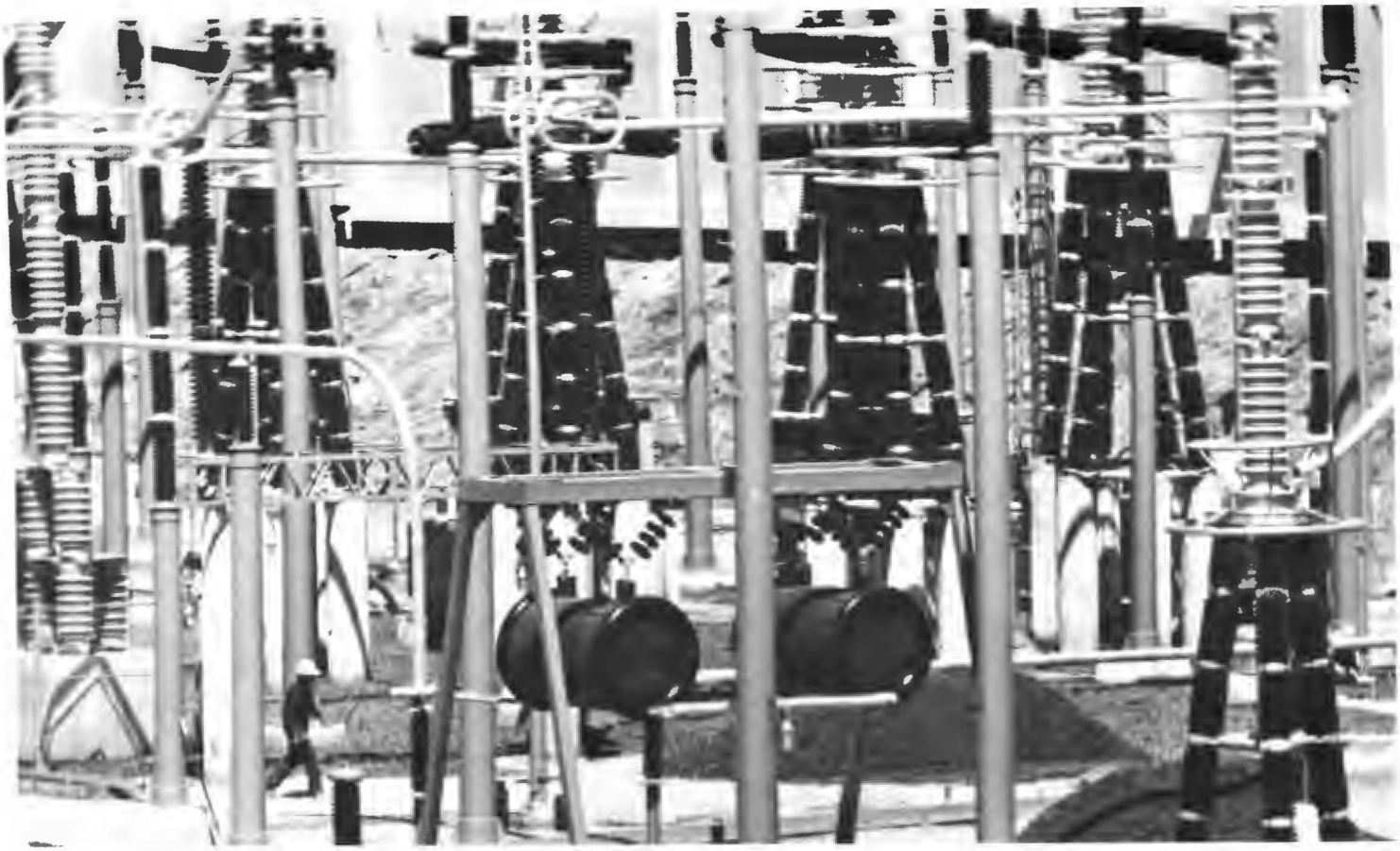
Note 10. Adjustments to Accumulated Net Revenues

The following table explains the adjustments which have caused the net decrease in Accumulated Net Revenues of $2,087,000 shown on Exhibits 1 and 2:

	In Thousands
1. Recognition of prior years' expenses (net) for four Corps projects due to adoption of firm cost allocations in fiscal year 1969	$(1,157)
2. Recognition of imputed rental costs for fiscal years 1963 through 1967 and costs of the GAO audit for fiscal years 1963 through 1968 not previously reported on FCRPS financial statements	(1,498)
3. Adjustment for BPA revenues not recorded in prior years	601
4. Miscellaneous minor adjustments	(33)
Total	$(2,087)

Grand Coulee with third powerhouse under construction

At Malin—Frank H. Warren, PGE—H. R. Richmond, BPA—Al Ullman, Oregon Congressman—E. Robert de Luccia, PP&L



Celilo Converter Station Switchyard

Don Hodel, right, Deputy Administrator, sworn in by Judge Gus Solomon

Valve Room, Celilo Converter Station

New Intalco Aluminum Plant near Bellingham, Wash.

APPENDIX

BPA Policy on Commitments

Defined below is the BPA policy on commitments related to power sales to preference customers, electroprocess industries, and private utilities. Policies concerning exchange arrangements with private utilities and sales and exchanges involving areas outside the Pacific Northwest are also stated.

Available Firm Power

The total amount of firm power available for sale or exchange by BPA is derived from assured capability. BPA considers its assured capability as power, after deduction of appropriate forced-outage reserves, from (1) existing Federal projects, (2) Federal projects for which initial construction funds have been appropriated, and (3) contracts such as exchange agreements and net billing arrangements. Under the hydro-thermal program a net billing arrangement is considered an assured resource at the time BPA and the owners contract for the construction of the plant and the purchase of the power.

Preference Customers

BPA will meet on a first-priority basis all the power requirements of preference customers. Such customers will receive at least five years' notice in advance of the time that BPA no longer will have sufficient assured capability to meet all their power requirements and its other firm commitments as defined below.

Electroprocess Industries

The amount of firm power BPA will have available for industry is the balance remaining after subtracting from BPA's assured capability the total of (1) the projected loads of preference customers for a reasonable period in the future, (2) other BPA firm sales or exchange contracts, and (3) reserves for unanticipated load growth.

Reserves for unanticipated load growth under the hydro-thermal program will amount to one-half the annual preference customer and private utility load growth.

The amount of firm power available from BPA to serve new or additional industrial loads will be obtained from new thermal capability over and above that needed together with Federal hydro assured capability to provide for items (1), (2), and (3) immediately above.

Private Utilities

BPA sales of firm hydro power to private utilities will be made after meeting other firm commitments. These sales will terminate in a few years except for the reservation of power for sale in Montana. The amount will be the difference between assured capability and the total of preference customer requirements and other BPA firm sales or exchange contracts. The amount of BPA's sales of peaking capacity, including such sales for forced-outage reserves, will be determined by the balance remaining after subtracting the total of firm loads and reserves for unanticipated load growth from the total of assured capability and the capacity which can be made available by the addition of units at authorized Federal projects. Sales contracts will contain a provision for withdrawal on five years' notice if the power is needed to serve preference customers.

Long-term exchange arrangements under which BPA will supply peaking capacity, including use for forced-outage reserves, in exchange for off-peak energy will be made if such capacity can be made available from BPA's assured capability and by the addition of units at authorized Federal projects.

Power Marketed Outside Pacific Northwest

Power is marketed outside the Pacific Northwest in accordance with Public Law No. 88-552. Only energy and peaking capacity surplus to the needs of the Pacific Northwest will be sold outside that region. Under existing contracts energy is withdrawable on not to exceed seven days' notice and peaking capacity is withdrawable on five years' notice* if the power is needed in the Pacific Northwest.

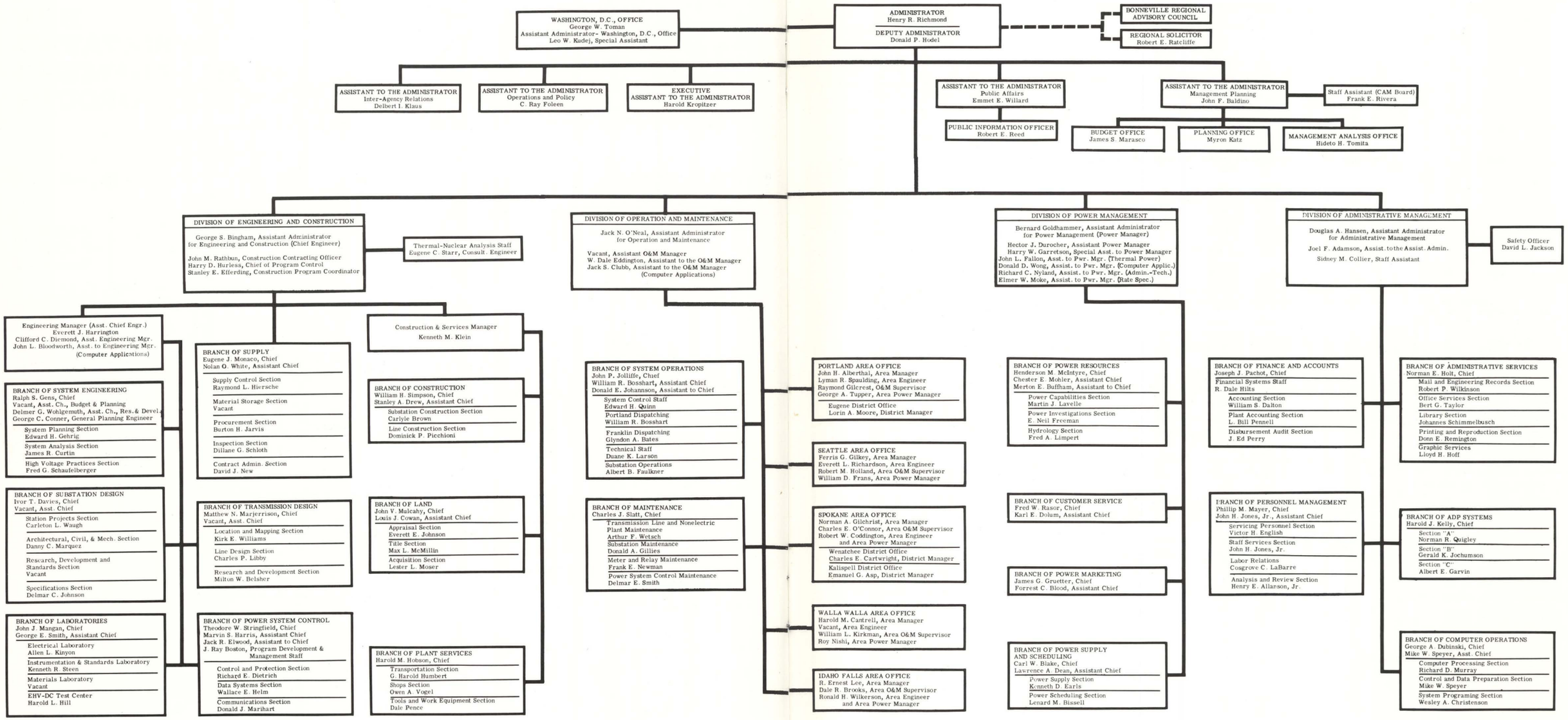
*There are two exceptions to the right to withdraw on five years' notice, both dealing with power exchanges:

(a) Agreements for the use of the direct current line from Celilo to Los Angeles provide for the exchange of 1050 megawatts of peaking capacity from the Pacific Northwest for off-peak energy from California on a 20-year basis with a possible 20-year renewal. During the renewal period the peaking capacity is withdrawable on five years' notice if it is needed in the Pacific Northwest.

(b) Diversity exchanges over the Celilo-Hoover line will be for 20 years and on a firm exchange basis.

BPA ASSOCIATED & MANAGEMENT GROUPS

BPA ORGANIZATION CHART



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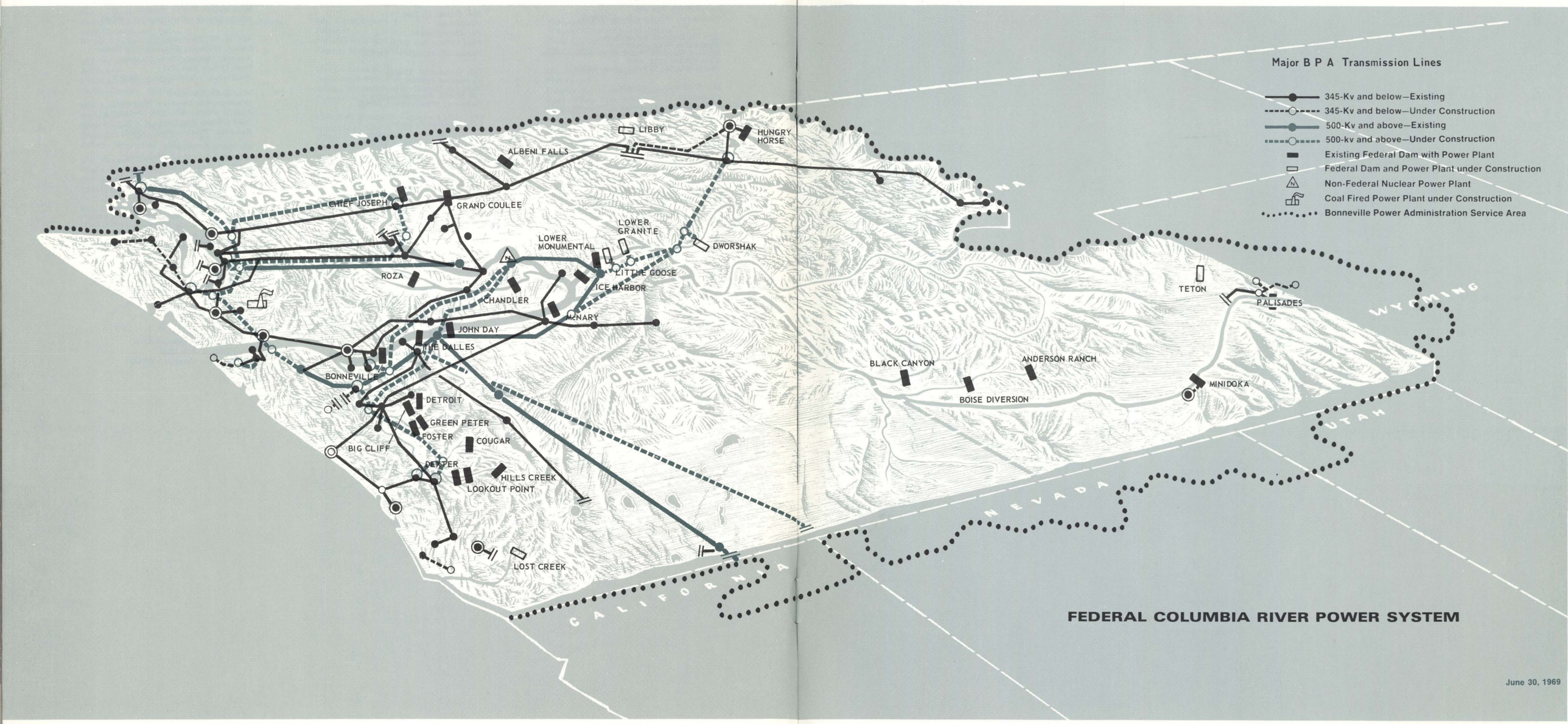
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345-Kv and below—Under Construction
500-Kv and above—Existing
500-kv and above—Under Construction
Existing Federal Dam with Power Plant
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June 30, 1969

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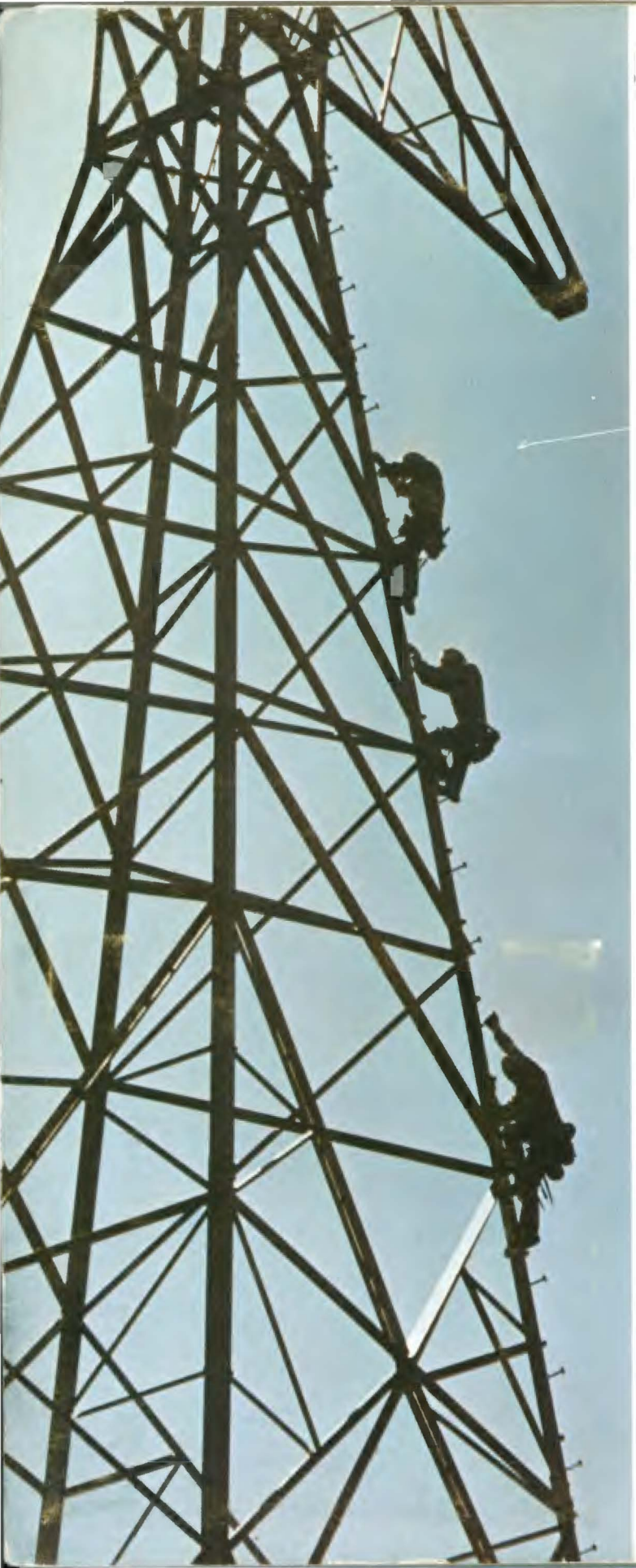

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