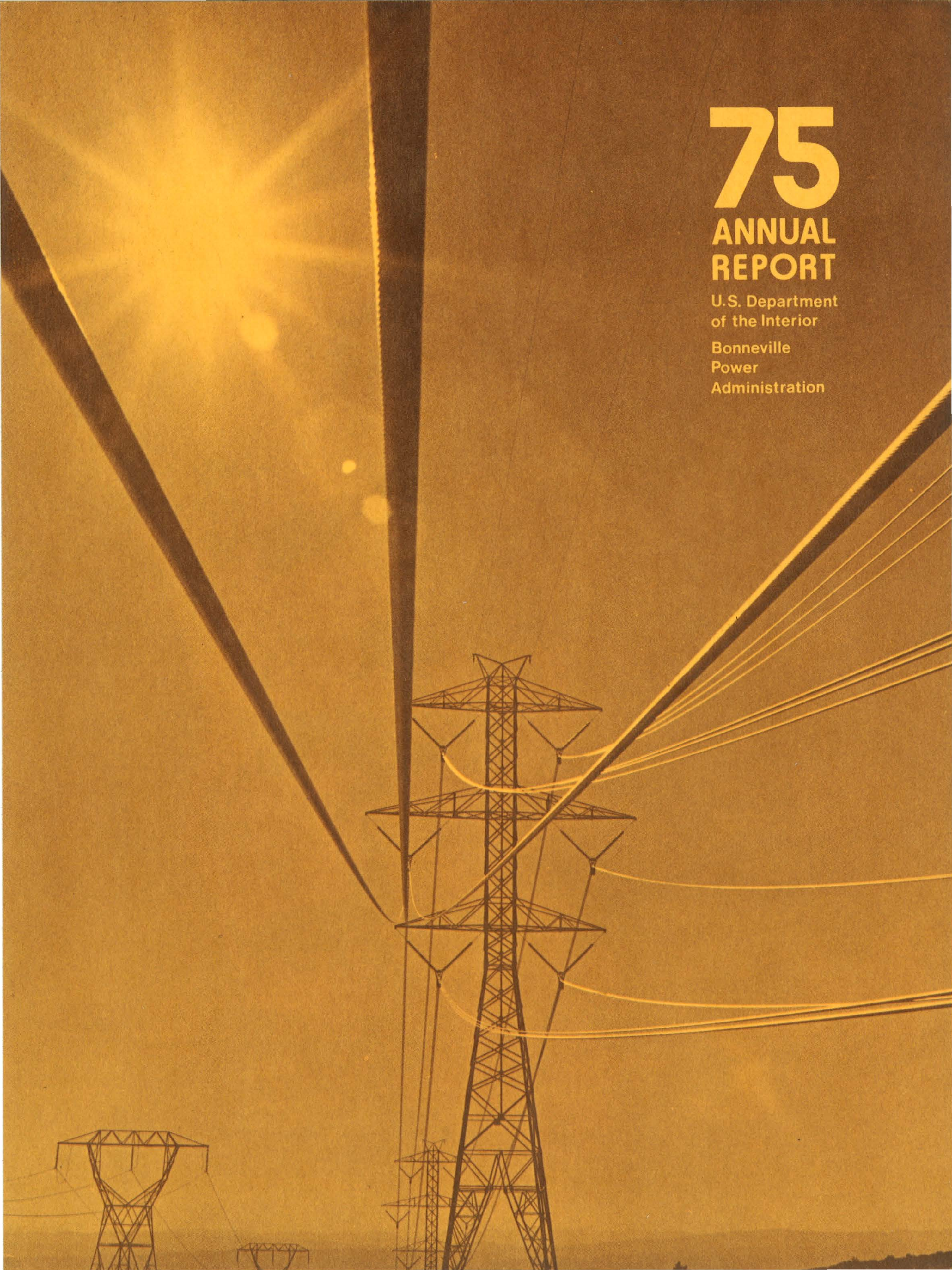

75 ANNUAL REPORT

U.S. Department of the Interior

Bonneville Power Administration

U.S. DEPARTMENT OF THE INTERIOR

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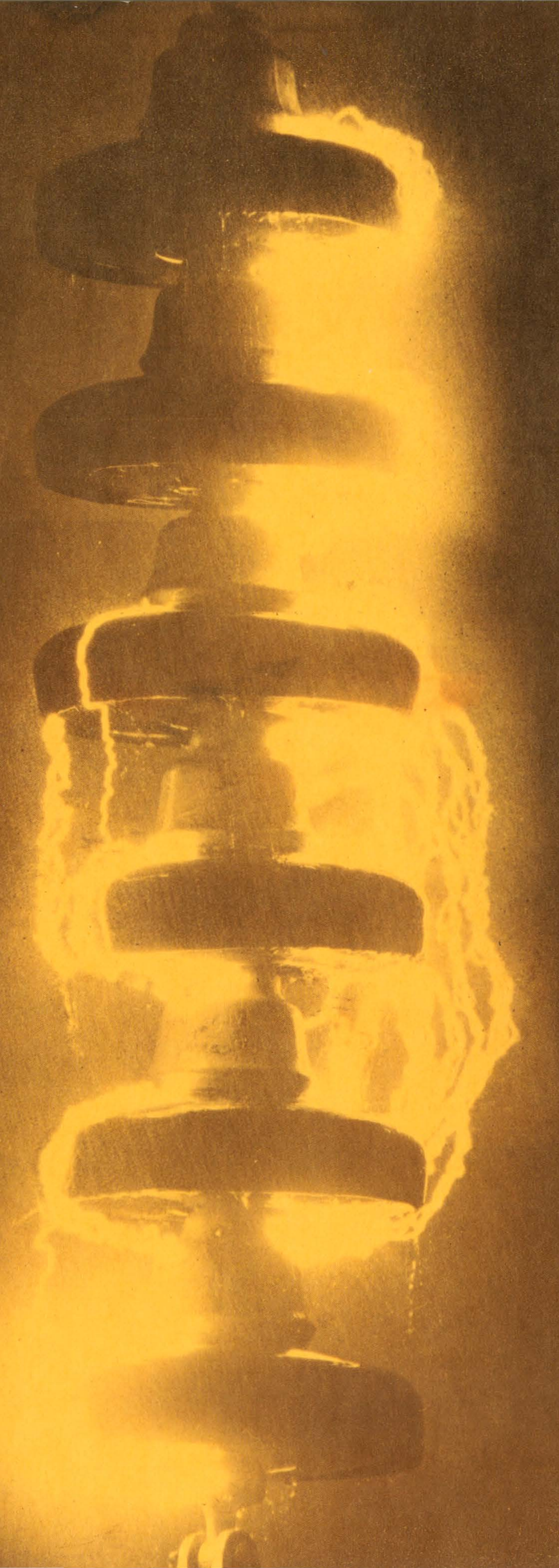

Federal Columbia River Power System

December 31, 1975

1975 ANNUAL REPORT

U.S. Department of the Interior

Thomas S. Kleppe
Secretary

Bonneville Power Administration

Donald Paul Hodel
Administrator

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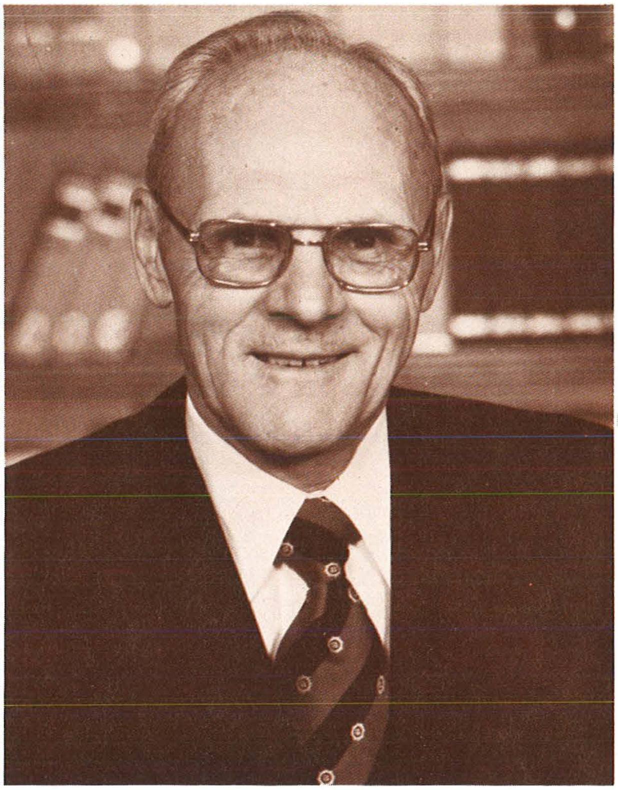


Secretary of the Interior Thomas S. Kleppe.

Letter to the Secretary

December 31, 1975

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

Dear Mr. Secretary:

This is the Bonneville Power Administration's 38th Annual Report on the Federal Columbia River Power System. It covers events of fiscal year 1975 plus significant developments since the fiscal year ended on June 30.

This has been a year of excellent progress on some fronts, but frustration and setbacks on others.

On the bright side, implementation of the Federal Columbia River Transmission System Act, which was approved October 18, 1974, proceeded smoothly. As a result, BPA is now on a fully self-financing basis, and we are beginning to benefit from the more businesslike procedures and assured financing that this has made possible. Also, after some controversy and delay, we obtained final Federal Power Commission approval of new wholesale power rates. This effectuated an average rate increase of approximately 27 percent. The rates were approved for a full 5-year period extending to December 20, 1979. We were also fortunate in having generous precipitation and streamflows during the year, thus providing an adequate power supply.

Consequently, our financial results improved dramatically. Revenues reached a record high of $237.1 million, up 28 percent over the previous year. As anticipated, net revenues on the cost accounting basis totaled $22.3 million, thus reversing the deficit trend of the previous 2 years.

Streamflows currently continue to run above median and our storage reservoirs are at or above normal levels. The short-term power outlook is thus excellent. We anticipate being able to serve all of our Pacific Northwest loads over the balance of the current operating year plus being able to sell considerable quantities of oil-conserving surplus power to Southwest utilities.

The longer range regional power supply situation, however, is not good. Based on the best currently available analysis, the Pacific Northwest faces the potential of serious electric energy shortages. Depending on the regional and national rate of economic recovery, this could last for much of the next decade. The amount of shortage will depend on many variables which affect both supply and requirements; i.e., temperatures, rainfall, the rate of load growth, conversions to electric energy from other fuels, the overall level of economic activity, etc. Based on present planning criteria, the supply of electric energy in any one year may fall as much as 12 percent short of the presently forecasted requirements. Furthermore, the recent trend has been for each year's new forecast of energy supply and requirements to show an increasing imbalance due to the occurrence of additional delays in the completion of new thermal generating plants. Hence, the potential electric energy shortage could possibly worsen. The one bright spot in this picture was provided by the initial startup in December 1975 of Portland General Electric Company's 1100 MW Trojan Nuclear Plant.

There is insufficient time available to bring new generators on the line to avert the potential power shortage. The Pacific Northwest, therefore, is directing its attention to an intensified energy conservation effort, plus development of specific plans for load curtailment. The impact of this situation will be far reaching.

Two years ago we reported that an accord had been reached in the Pacific Northwest to implement Phase 2 of the Hydro-Thermal Power Program to assure an adequate power supply through the balance of the 1970's and the 1980's. In last year's report, we stated that the many complex agreements and other actions needed to implement Phase 2 were progressing, and that we hoped to be able to report this year the successful conclusion of those arrangements.

Regrettably, we are not able to do that. Because of a Federal court decision in the "Alumax case"—a complex lawsuit involving the location of a proposed new aluminum plant which would be served by BPA under a contract signed nearly 10 years ago—we are now precluded from signing any of the contracts needed to implement Phase 2. The Alumax decision has been appealed by all parties involved. Unless this decision is reversed, our current situation will prevail until we have completed and the court has accepted a comprehensive environmental impact statement covering BPA's role in the Pacific Northwest power systems, including its participation in the Hydro-Thermal Power Program. Preparing such an EIS is a substantial task which is expected to cost up to $4 million. The final version would not be completed until late 1977.

Other litigation which conceivably could impact the implementation of future power supply development plans has also been initiated by various parties.

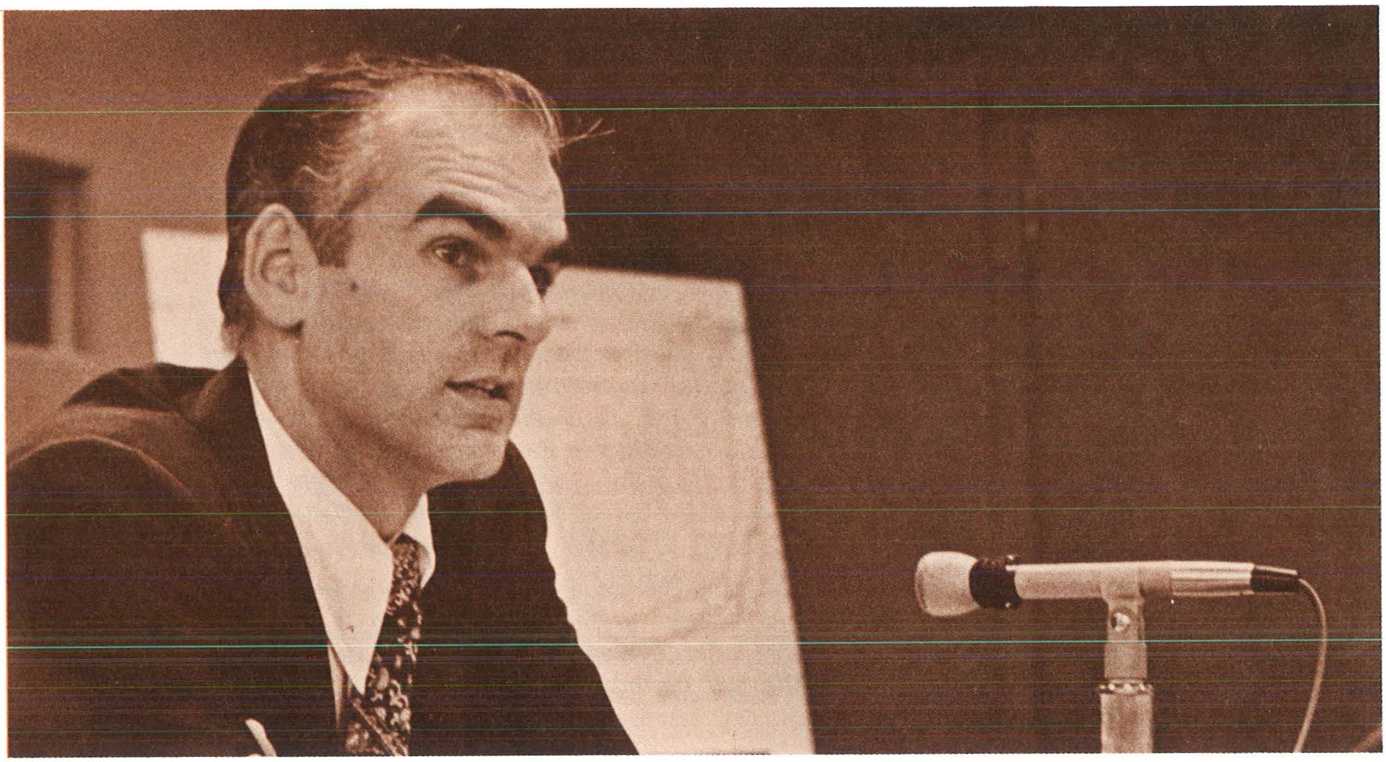
In summary, the future power situation is poor, the region is preparing for electric energy shortages, and the Bonneville Power Administration is not able to implement fully its role in Pacific Northwest power matters pending the outcome of a comprehensive environmental impact statement.

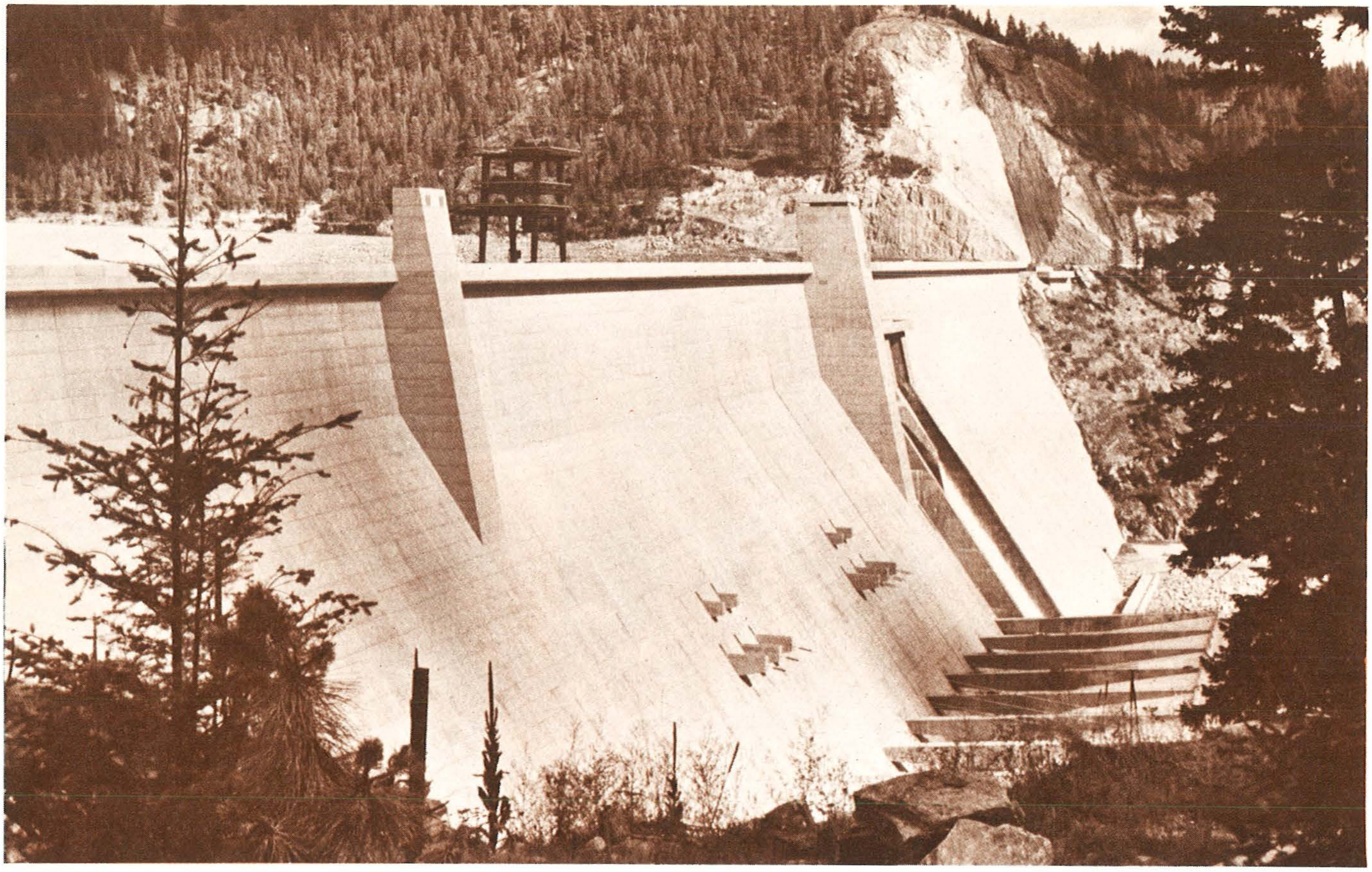
Sincerely yours,

Donald Paul Hodel

Donald Paul Hodel
Administrator

Bonneville Power Administrator Don Hodel.





Overview

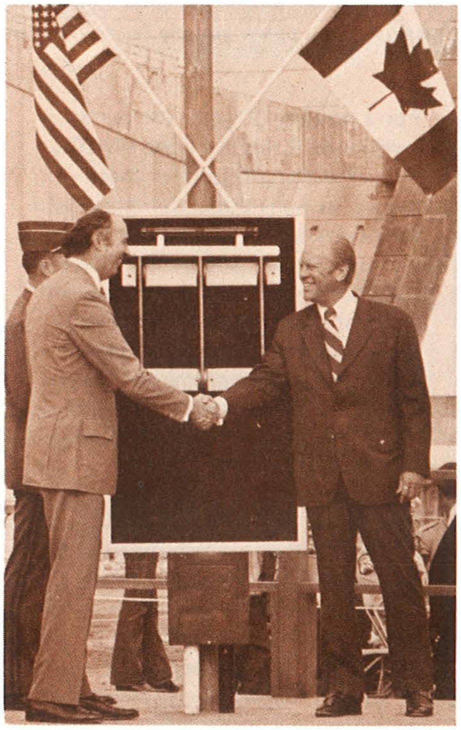
President Ford and The Honorable Donald S. MacDonald, Canadian Minister of Energy, Mines and Resources, complete switch-throwing ceremony to put power from Libby Dam into BPA's grid on August 24, 1975.

During Fiscal Year 1975, the Bonneville Power Administration took a long, hard look at electrical power shortages impending in the Pacific Northwest in the next decade.

Electric Energy to be in Short Supply in Northwest

For decades BPA has shaped its planning on the basis of a continuing need to develop new generation as well as new transmission facilities in the region. In the seventies the character of this need changed. Up to the present decade, the Pacific Northwest has depended on installing new hydrogeneration to meet almost all of its energy requirements.

Generators are still being added at existing dams to provide short-term peaking power. But few undeveloped, economically feasible, and socially acceptable sites for getting significantly more energy,



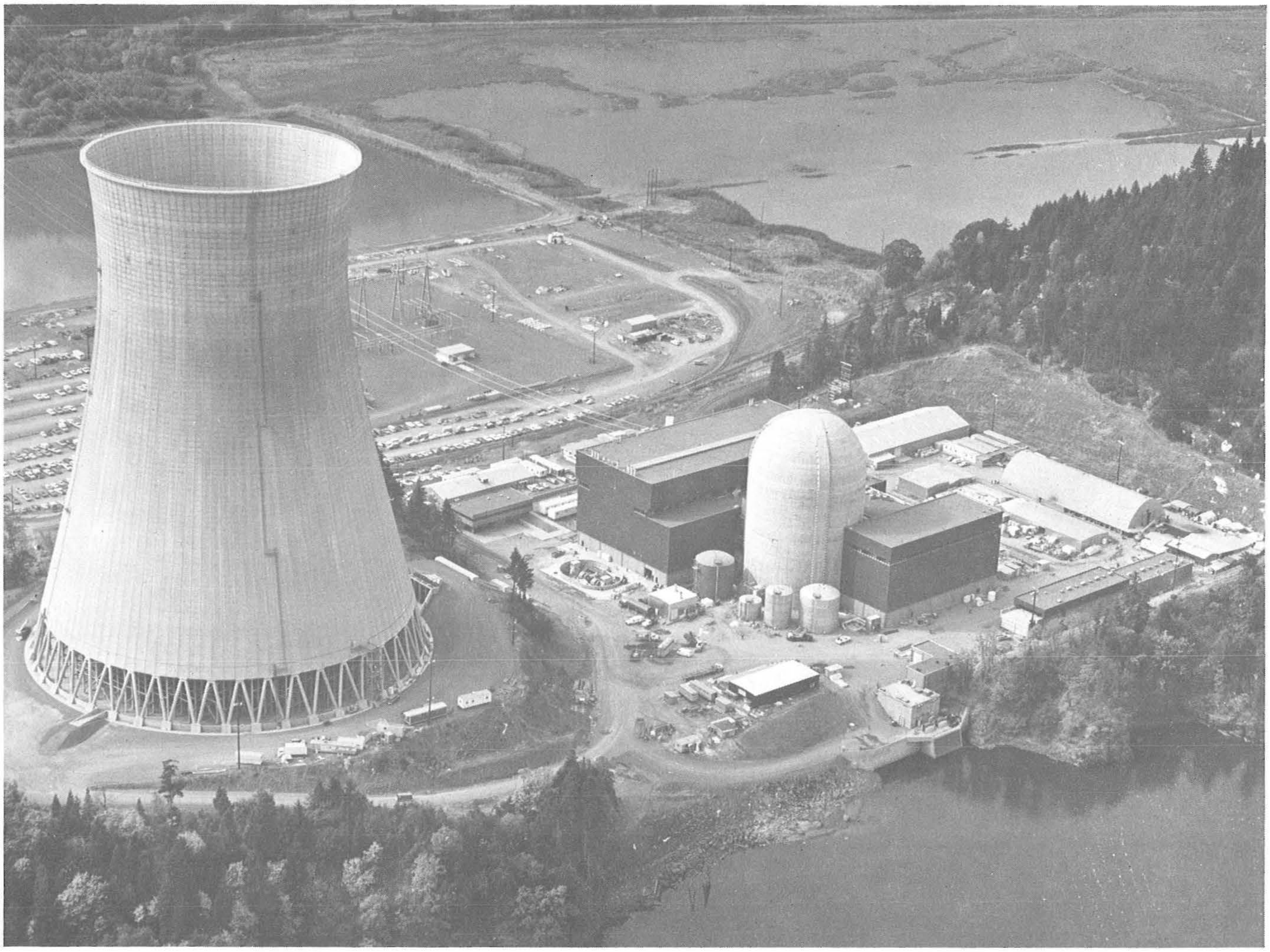
(Photo courtesy of Western News)

or continuously available power, out of streamflows remain in the Pacific Northwest. So the region must now turn to thermal sources to meet nearly all of its future energy requirements.

According to the latest report by the region's long-range electrical planning group, the Pacific Northwest Utilities Conference Committee (PNUCC), generation of firm energy to meet the region's loads must more than double from about 15 million to about 35 million average kilowatts in the next 20 years. More than 90 percent of the added energy must come from thermal projects, including both nuclear and coal-fired plants.

The energy needs of a region or a nation depend largely upon the size of its population, the standard of living of its people, and the character of its economy.

In the Northwest, electrical demand



The 1,130,000-kilowatt Trojan Nuclear Plant, which first put power into the Pacific Northwest grid in December 1975.
(Photo courtesy of PGE)

is particularly affected by the demographic fact that the number of people entering the job market in the next 20 years will exceed people retiring from jobs by 800,000. This number is a 26 percent increase over the present labor force, and it is going to take a lot of kilowatts to develop the industry to provide those jobs.

Shortages Due to Construction Delays

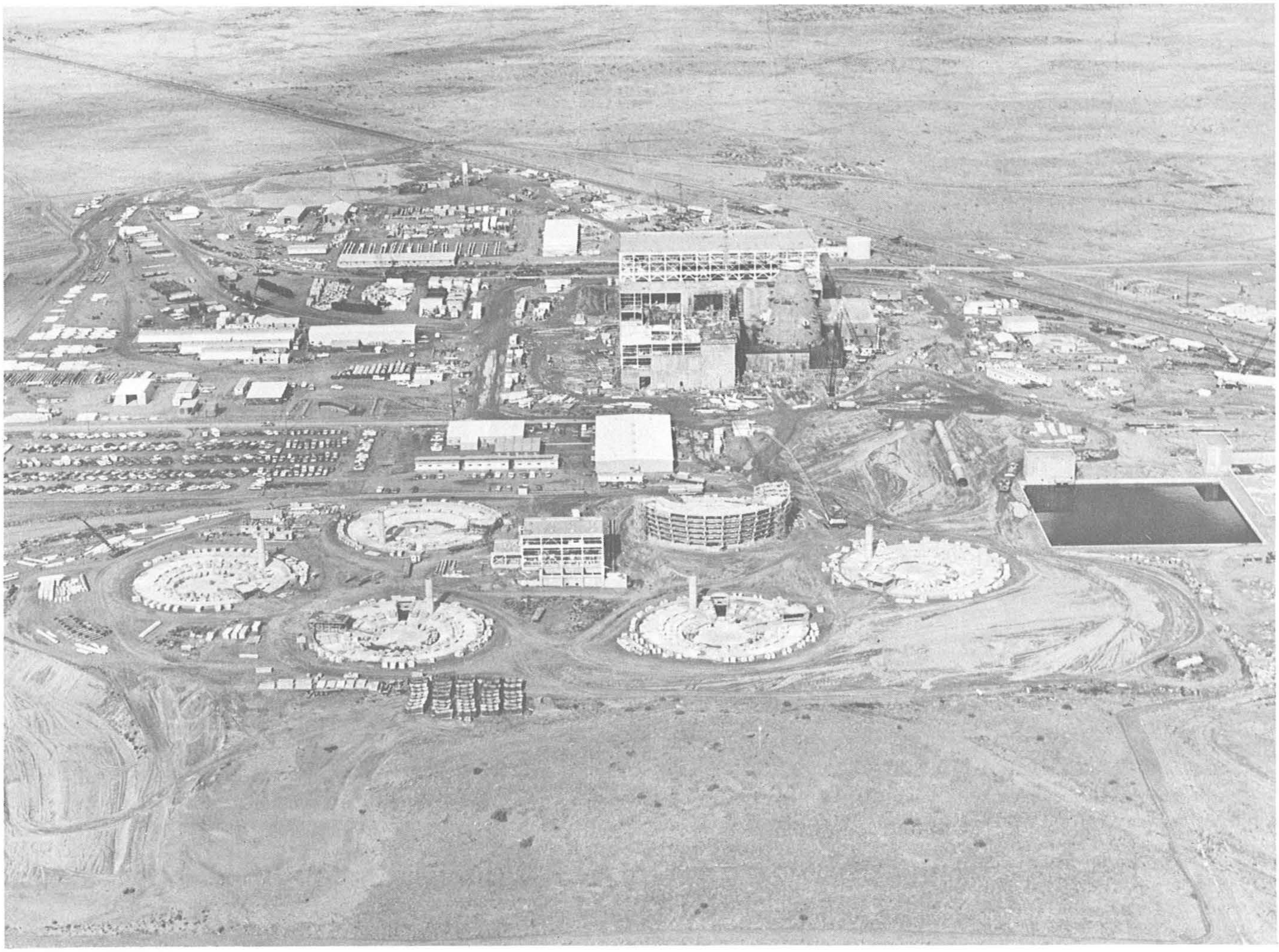
In 1968, BPA and over 100 Northwest utilities first outlined the Hydro-Thermal Power Program to supply the region with needed power through the year 1981. But planning for both this early Phase 1 and the later Phase 2, established in 1973 to continue the Program beyond 1981, has been plagued by schedule slippages.

For a number of years the annual long-range forecast by the PNUCC indicated that, in spite of these delays, no substantial deficits would be incurred. In 1974, however, the picture changed, and the PNUCC load-resource projections showed several years of shortages in which energy loads would exceed resources. In 1975, prospects became even more cheerless. Projections based on March 1975 PNUCC data showed shortages in all years through 1982-83.

The energy deficits reported by PNUCC—deficits which measure as much as four times the energy capability of Bonneville Dam—were forecast with the assumption of the most adverse, or lowest, streamflow of record—admittedly an event that has a low probability of occurrence. Deficits, however, are foreseen even with higher streamflows, and from the year 1978-79 on into the 1980's, it will take better than median streamflows as well as loads not significantly greater than those presently forecast to avoid regional energy shortages.

The energy deficits, which became so apparent in 1975, could result in mandatory curtailments of electrical service in the Northwest. Accordingly, BPA, other Federal agencies, and the region's utilities and large electroprocess industries, who shared in the intricate planning and the enormous financial burden of the Hydro-Thermal Power Program, have now turned their attention to searching for solutions to the problem of delays and shortages.

Financing difficulties are immediately seen as one cause of



By the end of October 1975 overall construction of Washington Public Power Supply System's Nuclear Project No. 2 was about 26 percent complete. Plant's six circular cooling towers are being constructed in the foreground. (Photo courtesy of WPPSS)

delays. Financing is aggravated by inflation, high interest rates, lagging utility revenues, and the pernicious cycle of delays leading to cost escalations and cost escalations leading to further delays. By the end of 1975, the total budgets of Northwest thermal plants had escalated by approximately 50 percent above original estimates, while budgets for hydrogeneration had escalated by a similar amount during the same span of time.

Many Factors Involved in Shortages

Certainly the causes of shortages are rooted in broader ground than BPA and the utilities themselves. In Fiscal Year 1975, for example, it became apparent that special interest groups, the general public, and the courts play a significant role in the scheduling of new generation.

Two lawsuits particularly illustrate this point. The first was filed on April 17, 1975, in U.S. District Court by the Natural Resources Defense Council, The Sierra Club, and other environmental interests against BPA and the Department of the Interior. The plaintiffs alleged that BPA failed to file an environmental statement on Phase 2 of the Hydro-Thermal Power Program and requested that any action taken toward developing Phase 2, including the execution of contemplated industrial power sales contracts, construction of related transmission facilities, and requests for installation of additional Federal hydrogenerating capability on the Federal Columbia River Power System, be declared unlawful and void. The plaintiffs also asked that BPA be required to prepare, publicly circulate, file, and consider a final and adequate environmental statement on the Hydro-Thermal Power Program. For the most part, the progress of this litigation has been slow.

Settlement of this April 17 case, however, may come with the preparation of a general environmental statement on BPA's role in supplying power in the Pacific Northwest. This statement was required by the court's decision in the so-called "Alumax case." The "Alumax case" refers to a lawsuit filed on April 18, 1975, against BPA or more specifically the Port of Astoria *et al* v. Hodel *et al*. The litigation led to a September 18, 1975, ruling by the U.S. District Court that a new power sales contract

Pacific Northwest Governors Bob Straub, Dan Evans, and Cecil Andrus are greeted at Vancouver, Washington, on December 10, 1975, by BPA Administrator Don Hodel (third from left). Conference of governors held that day led to setting up of Northwest Energy Policy Project, to study energy options available to the region.

to serve the Alumax Pacific Corporation's proposed aluminum plant in the Hermiston-Umatilla area of Eastern Oregon signed on April 18, 1975, is *valid but unenforceable*, pending the preparation and acceptance of an adequate final environmental impact statement (EIS). BPA and Alumax signed the new contract to replace a 20-year contract signed in 1966, after the location of the proposed plant was changed from a site near Astoria in northwestern Oregon, a change supported by Governor Straub of Oregon.

The Court determined that the final EIS to be prepared by BPA must assess the primary, or direct, impact of BPA's construction of transmission facilities to serve the proposed plant, and the secondary, or indirect, socio-economic impact of the proposed plant on the Hermiston-Umatilla community. In addition, it was adjudged that an impact assessment of those aspects of the Alumax contract which relate to Phase 2 of the Hydro-Thermal Power Program must be made and documented.

"Alumax Case" EIS Could Cost $4 Million

Subject to final determination on appeal, BPA is complying with the District Court's decision in the Alumax case, and has begun work on environmental impact statements on the Alumax service and on BPA's role in helping provide the region's future supply. BPA estimates that preparation of these EIS's will take up to 2 years and could cost about $4 million. Moreover, during these 2 years, the execution of Phase 2 contracts will be held in abeyance, thus causing additional problems for utilities constructing the region's thermal plants.

A third 1975 lawsuit was also filed which could have added to the region's difficulties in getting adequate electrical power. In this action, the Emerald Peoples' Utility District Committee Inc. from west-central Oregon and other parties filed suit on October 10, 1975, in the U.S. District Court to prevent BPA from signing renegotiated power sales contracts with industrial customers. This suit claimed that BPA rates and the extension of contracts with direct service industrial customers from the mid-1980's, when most present contracts expire, to the mid-1990's violated "sound business principles" and denied preference to public and peoples' utility districts and rural cooperatives.[1]

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[1] *On January 19, 1976, subsequent to the cutoff date of this report, this suit was dismissed on stipulation of the parties, primarily on the basis that new contracts with industrial customers would await completion of the EIS.*

Public Also Involved in Problem

It is clear that the building of new generation in the Northwest has many facets which reflect beyond the electrical agencies and utilities themselves into the whole of the society and economy. Accordingly, BPA and Northwest utilities launched a broad campaign in 1975 to bring the problem to the attention of state and local governments, business groups, and the general public. The public must ultimately make the decisions that will determine our energy future—a future which could demand extensive changes in life-styles or at least a new energy ethic.

Conservation is seen by BPA as the key to any viable new energy ethic. In fact, since it does give us additional breathing time for developing new energy sources, conservation—a voluntary one which depends on public cooperation—has become an important first step in our national and the Pacific Northwest energy strategy.

Thus, BPA continued its commitment to an energy conservation program initiated during the acute Pacific Northwest water shortage of the fall and early winter of 1973. While the good water conditions of 1974 and 1975 have understandably lessened the urgency of conservation of electricity, BPA continues to encourage regional elimination of waste and more efficient use of electricity. The BPA internal energy conservation program has been particularly successful. During Fiscal Year 1974, the program yielded total savings of 15 percent as compared to FY 1973. Fiscal Year 1975 showed an even more substantial saving of energy when consumption was reduced 23 percent as compared to FY 1973.

New BPA Rates Reviewed with Much Court and Public Visibility

Obviously, since BPA rates determine income of the Federal Columbia River Power System and power costs of its customers, BPA's rates are of keen interest in the region. But in 1975, BPA's rates were reviewed and finally approved in an unusual scenario where the courts and the public again played major parts.

Effective December 20, 1974, the Federal Power Commission confirmed and approved the BPA proposal for a revision of its rate schedules and the second general rate increase in BPA's history. The proposal provided for a 27 percent average increase in wholesale electric power rates. Calculations indicate the increase could bring in revenues in excess of $60 million a year. The FPC, however, stated that the approval was an interim one, for a period of not more than one year, and was subject to FPC hearings and possible refunds or credits to BPA customers.

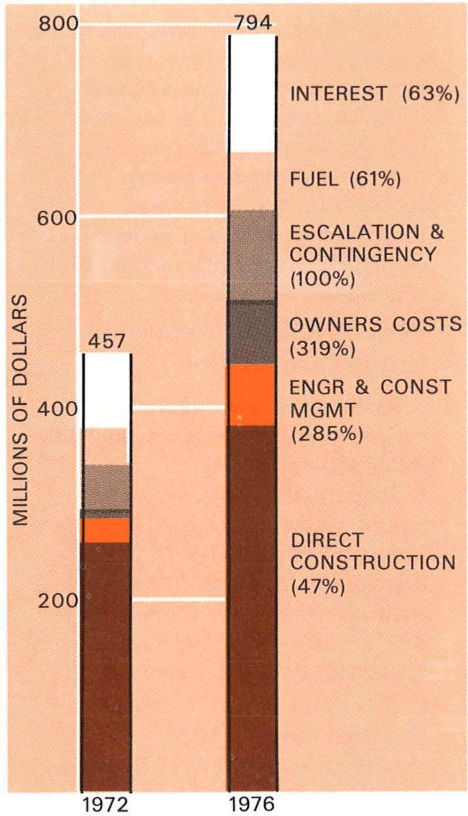
Four pre-hearing conferences and two hearings—in which a number of intervenors (including California and Northwest utilities) participated—were held before an administrative law judge. The Department of the Interior advised the administrative law judge that it would not participate in the proceedings and adhered to that position. Finally, 8 months after the interim approval, the FPC issued an order approving the rate schedules to December 20, 1979. This order included the additional provision that BPA should expeditiously examine time-of-day pricing as an adjunct to the rate design changes already in force.

To permit a more flexible development of rates to meet rapidly changing conditions, BPA plans to revise its power sales contract provisions to permit *annual* rate reviews after December 20, 1979. Rates are currently reviewed every 5 years.

New Avenues of Cooperation Opened

In this overview, then, 1975 can be seen as a year of encounter. But perhaps because of encounter, 1975 also became a year when new avenues of cooperation and participation were opened among the public, governmental agencies and electrical power groups in the Northwest.

For example, when faced with rapidly declining upstream chinook salmon and steelhead runs, the fishery agencies, the Federal and non-Federal dam operators, and BPA cooperated successfully in 1975 to control spills at Columbia and Snake River projects to aid fish passage. This effort marked the first time that a coordinating mechanism, comprising all entities concerned with river management, operated to assist fish migration. The results were encouraging, and all parties involved agreed that the cooperative effort is well worth continuing.



Comparison of 1972 and 1976 budgets above gives some clue to cause of rising costs on Washington Public Power Supply System Nuclear Plant No. 2.

Broad, Independent Regional Energy Study Planned

The future infrastructure for cooperation in this part of the country may be set by the results of a 2-year study being planned by the Pacific Northwest Regional Commission, a Federal-state partnership consisting of the Governors of Idaho, Oregon and Washington and a Federal representative appointed by the President.

Known as the Northwest Energy Policy Project, the study, funded up to $1 million, will assess future energy demands; the social, economic, and environmental impacts of meeting or failing to meet these demands; opportunities for energy conservation; and other matters that can assist states, energy suppliers (including utilities), local governments, and Federal agencies in energy planning on a coordinated regional basis.

BPA Invites Environmental Group Participation

In keeping with the mood of public participation, BPA formally invited active and "affirmative" contributions by environmental groups, such as the Natural Resources Defense Council (NRDC), in the preparation of the proposed environmental impact statement on BPA's role in supplying Pacific Northwest power through the Hydro-Thermal Power Program.

In a December 16, 1975, letter to the attorney for the NRDC inviting participation in preparing the proposed EIS, the BPA Administrator explained the special importance he attached to the word "affirmative:"

> "We would ask particularly that all comments be affirmative. By this, we mean that if a discrepancy or concern is noted, the commentator would do more than call attention to that fact. Rather, an affirmative identification or suggestion is needed which would show what needed to go in that portion of the EIS. It is of no significant service to characterize something as inadequate without offering a suitable solution or alternative to the condition identified."

The Administrator concluded his letter with a suggestion than "an arrangement be established on a long-term basis to permit interaction and an exchange of views between BPA and environmental organizations." "We think it . . . important," continued the Administrator, "that we establish a forum in which candid comments can be exchanged, in which views reflecting BPA's positions, policies, and directives can be made known to you, and in which a meaningful dialogue can take place."

The Operating Year

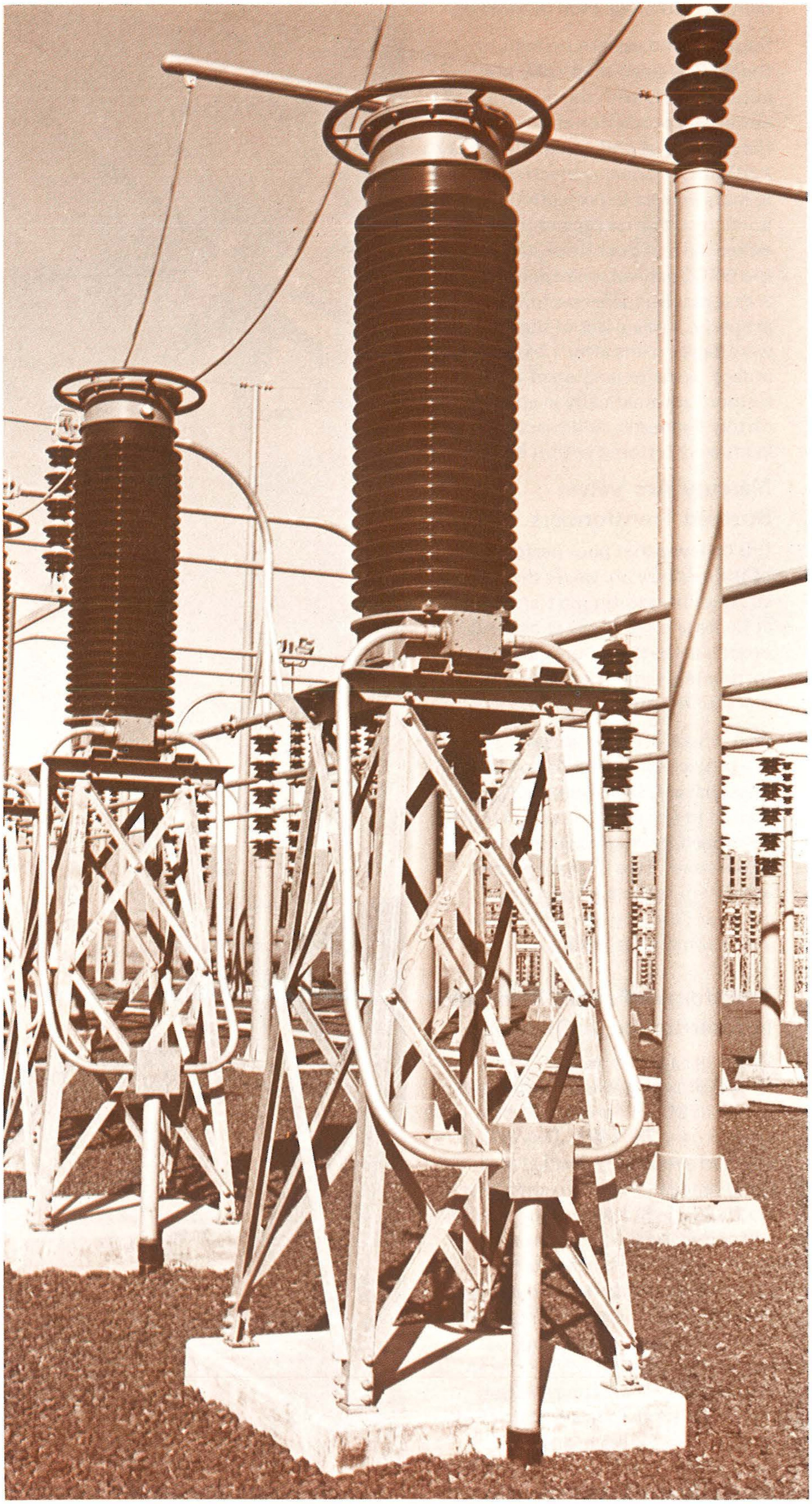
The calendar year 1975 saw few BPA system disturbances. On two occasions, however, disturbances did lead to service interruptions.

The Silent Blackout

The most widespread interruption came on March 21, 1975, with the so-called "Silent Blackout." Barely noticed in the Northwest, a BPA system disturbance resulted in extensive shedding of loads in other sectors of the Western Systems Coordinating Council (WSCC) region which covers the western third of the United States and British Columbia in Canada.

The first in the sequence of incidents leading to load dropping occurred with the failure of a "grid-timing" transformer at the Celilo Converter Station near The Dalles Dam which serves as the northern terminus of the d-c leg of the Pacific Northwest-Pacific Southwest Intertie. "Grid-timing" transformers determine the output level of the mercury arc valves which convert alternating to direct current at Celilo. As a result of the failure of the transformer at Celilo the Intertie system had to operate in a reduced mode.

Subsequently, at 0055 hours on March 21, while the system was operating in this vulnerable mode, a braided copper jumper failed at Celilo, resulting in total loss of the d-c line. Normally the load from the d-c leg would have transferred to the two 500-kilovolt a-c legs of the Intertie with a concurrent dropping of some generation at The Dalles Dam to minimize the shock to the a-c lines. The generator dropping scheme, however, failed to function. The reason was later determined to be an error in the wiring of the logic circuits that controlled the scheme. Without dropping the generation, the two a-c lines became unstable and opened at the Malin Substation in southern Oregon. As a result, the systems on the southern end of the Intertie were deprived of power



Failure of a Celilo grid-timing transformer, such as the one pictured here, cascaded into Western Systems Coordinating Council area "Silent Blackout" of March 21, 1975.

deliveries totaling 3400 megawatts.

Southern and eastern systems in the WSCC region shed 1665 MW automatically with the operation of automatic protection schemes such as the tripping of underfrequency relays. All WSCC regional protection schemes in fact, worked to perfection. The quick-insert series capacitors at Bakeoven and Fort Rock, Oregon, and the WSCC generator dropping and area separation schemes functioned properly. The a-c legs of the Intertie were back on line after a 14-minute outage. A major portion of the loads restored automatically in approximately 4 minutes, and practically all loads were restored within 15 minutes.

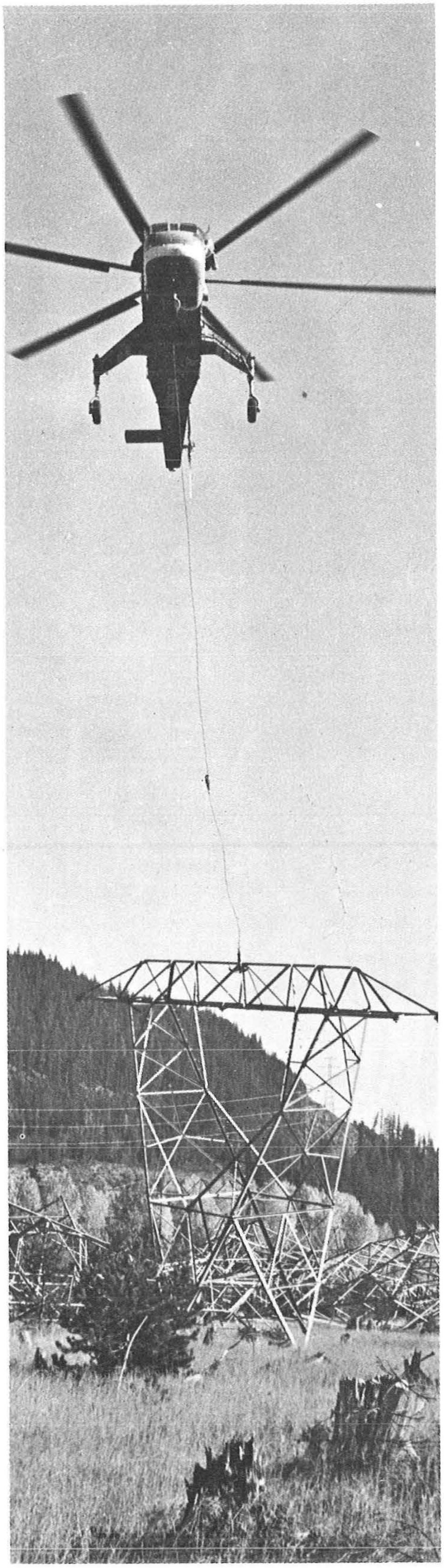
Mercury Arc Valves Stressed Transformers

It is believed that poor performance of the mercury arc valves themselves stressed the grid-timing transformers at Celilo and led to the above and other less serious failures, which fortunately did not cascade into any load dropping.

BPA, therefore, is now taking part in a project sponsored by the Energy Research and Development Administration to test a plasma valve recently developed by Hughes Research Laboratory. Two of these plasma valves will replace mercury-arc valves at Celilo by late 1976 for a year's commercial evaluation.

Transformer Failure Also Leads to Interruption at Okanogan

One other system incident which led to load dropping was a transformer failure at BPA's Tonasket Substation on February 25, 1975. This failure affected a relatively small area—the Okanogan Valley in northeastern Washington—but service to residents and commercial enterprises was interrupted for a substantially long time during particularly cold weather. Approximately 75 percent of the total load in the valley was restored by supplying power from sources other than Tonasket Substation in less than seven hours. Full restoration of service, however, came 19 hours and 8 minutes after failure with the installation of a portable transformer delivered from Wenatchee, 120 miles away.



Helicopter removes tower of BPA 230,000-volt line which is being replaced by a higher-capacity double-circuit 500,000-volt line.

Building the Transmission System

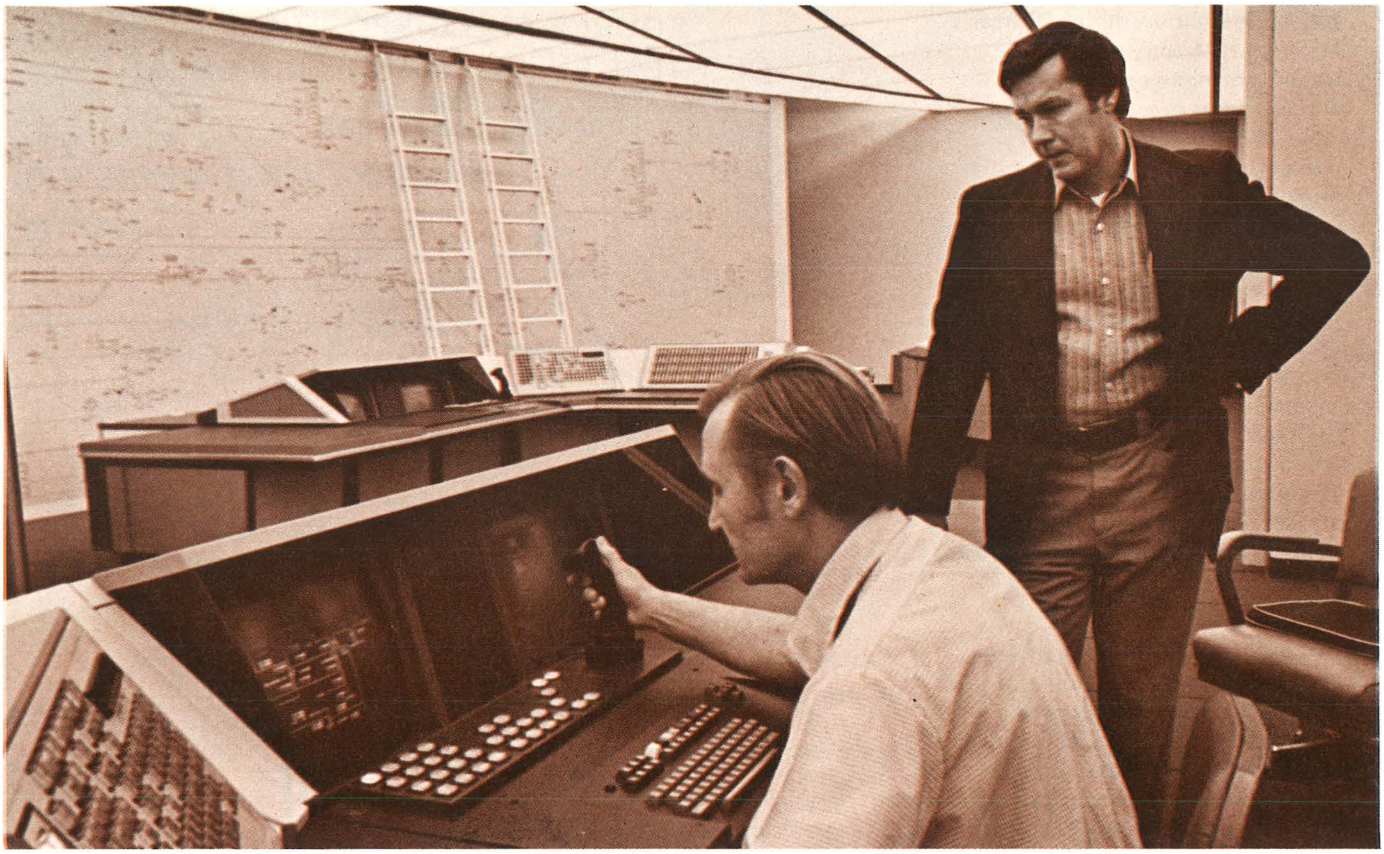
As part of its ongoing activity in Fiscal Year 1975, BPA energized 322 miles of new transmission lines, 100 miles of which operate at 500,000 volts. BPA energized its first 500,000-volt line in 1967. By the end of 1975, BPA had 2,555 circuit miles of such lines, which totals about 20 percent of the 12,325 circuit miles for all BPA lines. In Fiscal Year 1975 BPA also energized 5 new substations, raising the number of its substations to 340.

Another significant statistic for FY 1975 is that BPA removed 71 circuit miles of lower voltage lines from service. Because the need to increase system capacity competes with other land uses, higher voltage lines are replacing lines of lower voltage. This is because more kilowatts per foot of right-of-way can be moved over higher voltage lines. For example, a single-circuit 500,000-volt line can carry five times as much power as a 230,000-volt line on virtually the same right-of-way.

One of the larger projects completed in 1975 was the 96-mile, 500,000-volt line from the vicinity of Grand Coulee Dam to BPA's Hanford Substation. A 65-mile section of the line was built on right-of-way made available by removing one of two Midway-Grand Coulee 230,000-volt lines. The Grand Coulee-Hanford line integrates new generation being added at the dam's third powerplant into the Northwest power grid and provides the added capacity needed to strengthen electrical ties between Grand Coulee and the southern part of the Northwest transmission grid.

Two Double-Circuit Line Construction Contracts Awarded

In 1975 BPA completed contracting for the construction of the 174-mile trans-Cascade, Grand Coulee-Raver line with the award of two contracts, totaling $9.3 million, for building the eastern 73 miles of the line. The new double-circuit, 500,000-volt line will use right-of-way from



Engineer calls up TV-type display in Eastern Control Center now under test at Moses Lake, Washington. (Photo courtesy of Boeing)

which lower-voltage lines are being removed. Capable of carrying 5 million kilowatts of power, this Grand Coulee-Raver line, scheduled to be in service in October 1977, will have the highest capacity of any known line in the world.

An unusual provision in the two Grand Coulee-Raver contracts calls for the salvage of wood poles and part of the conductor from the old lines. Such recycling obviously suggests itself as a strategy for offsetting shortages and price increases in materials. But, previously, salvage was not economical on any significant scale because comparatively few lines were taken down and per-unit handling costs were high. Now, however, cheaper and better methods for recycling materials are being found and more lines are being retired.

BPA also let a smaller, $2.8 million contract for the construction of 18 miles of another double-circuit, 500,000-volt line. This line will loop the existing 500,000-volt Raver-Monroe line into BPA's Maple Valley Substation just outside of Seattle. Scheduled for energization in October 1976, the loop will contribute to a program jointly planned and executed by BPA, Seattle City Light, Snohomish County PUD, and Puget Sound Power & Light Company to meet growing loads in the Seattle and lower Puget Sound areas.

Fluctuating Market Expected in Procuring Equipment

The inflationary "sellers' market" of fiscal 1974 prevailed into this year as prices for major items of equipment continued to climb. Late in fiscal 1975, however, the rate of price increase slowed and vendors were scheduling shorter delivery times as a result of a general slowdown in purchases and even the cancellation of orders by utilities.

As the economy recovers, however, the competition for equipment will intensify somewhat and put a greater strain on manufacturing capability. Accordingly, BPA anticipates a return of the accelerated upward trend in prices and longer delivery times, which in turn can be expected to have an adverse affect on completion dates of future projects. If an inflationary and material shortage market returns, BPA expects it will be able to adjust more quickly than in 1974 because of flexibilities available under the BPA self-financing law.

Dittmer Completes Over a Year of Operation

Hailed on its December 1, 1974, full-energization date as a culmination of some of the world's most advanced electric utility control-dispatch concepts, the William A. Dittmer BPA System Control Center in Vancouver, Washington, has more than met expectations in its first year of operation.

Utilizing over $15 million worth of special electronic equipment, the control center has increased the efficiency and reliability of the day-to-day operation of BPA's Pacific Northwest transmission system. In addition, during Dittmer's first year, BPA engineers and technicians incorporated many improvements over original design. As a result, the performance of the control center has exceeded the original, overall design goals—goals which called for 99.9 percent availability.

Moreover, on-line, computer-supported security assessment of the main grid is being developed for early utilization. This program will enable BPA dispatchers to evaluate the impact of one or a series of potential disturbances on the system. The dispatchers can then correct or prevent the conditions that might otherwise make the system vulnerable.

SCADA to be Extended

Part of the success of the first year of Dittmer is attributed to the Center's SCADA I (Supervisory Control and Data Acquisition) system which provides centralized supervision of 30 main grid substations and remote control of over 900 circuit breakers and transformers in these substations. As a result, BPA will extend SCADA by putting 20 additional main grid substations under SCADA I control at Dittmer, by constructing a SCADA II system with master control at the BPA Eastern Control Center (ECC) near Moses Lake, Washington, and by planning a SCADA III system for energization between 1979 and 1981.

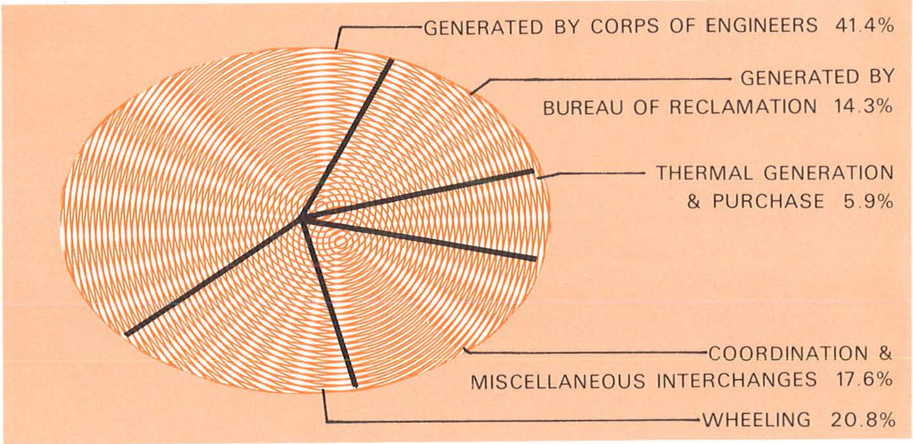
The SCADA III system, to be installed at Dittmer, will bring centralized control initially to 42 substations in the region's western subtransmission grid. (As compared to a main grid whose high-voltage facilities provide for the broad movement of power throughout a region, a subtransmission grid essentially consists of the lower-voltage equipment which interfaces with customer service facilities.)

New ECC Also to Provide Dittmer Backup

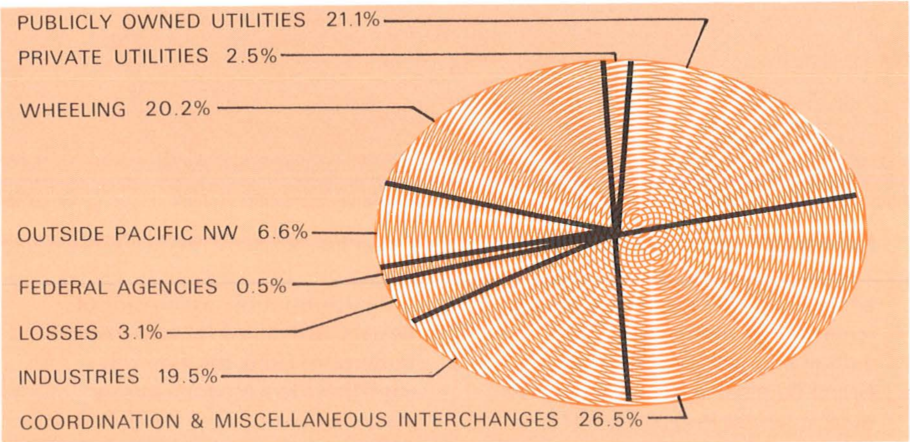
The SCADA II system master at the ECC is scheduled for operation in July 1976. Some $6 million in telecommunications and control equipment were delivered and installed by late 1975 and are now

SOURCE AND DISPOSITION
OF TOTAL ENERGY HANDLED BY BPA

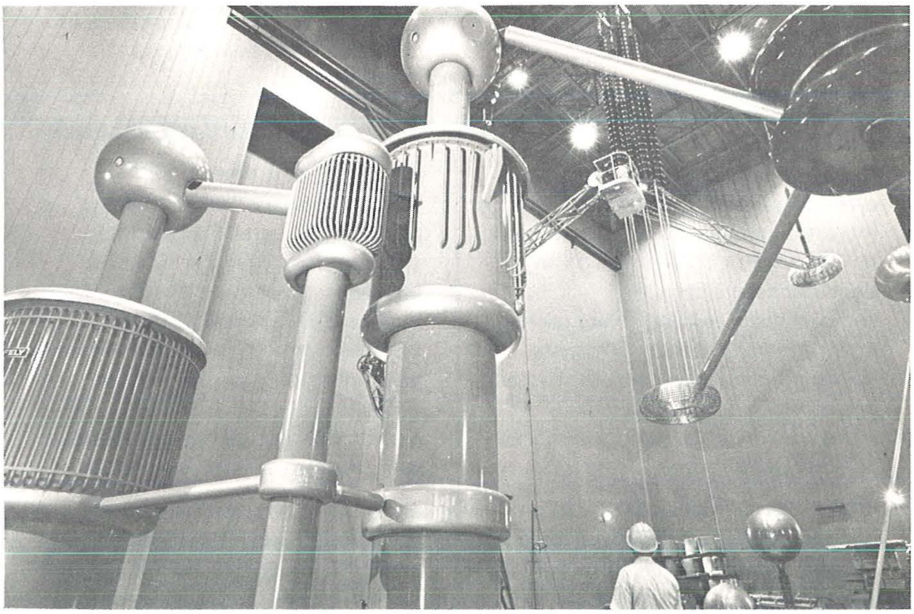
FISCAL YEAR 1975
TOTAL 131.0 BILLION KWH



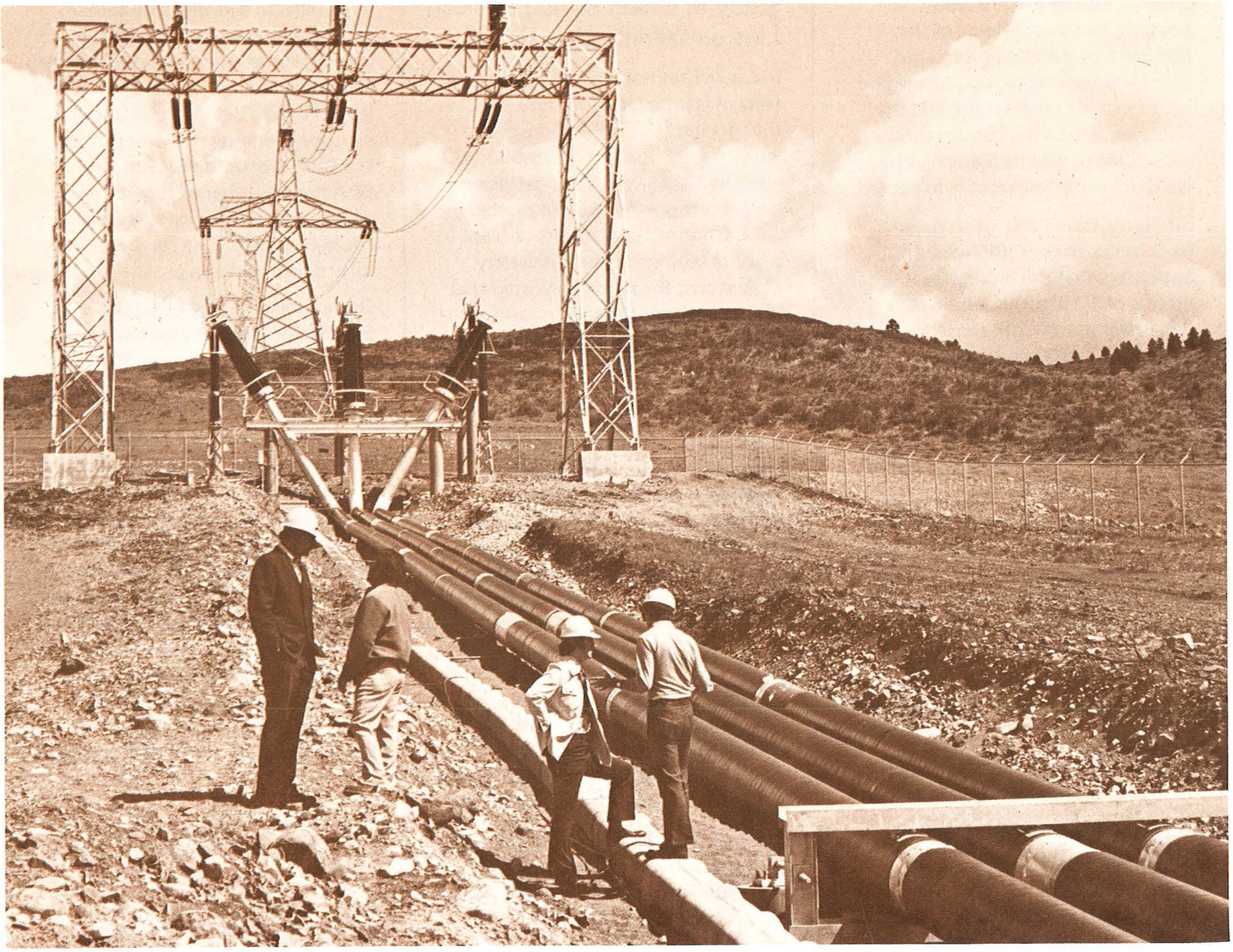
WHERE IT CAME FROM



WHERE IT WENT



BPA Laboratory at Vancouver, Washington, for testing ultra-high voltage components for future 1,100,000-volt transmission lines.



BPA and contractor personnel examine completed runs of underground compressed gas insulated transmission system, energized August 13, 1975. System will be covered over after a period of trial operation.

being checked out. The center occupies 18,000 square feet of floor space in a remodeled Air Force building. Operating personnel at BPA's ECC will be able to control all of BPA's eastern subtransmission grid in northern Idaho, western Montana, and east of the Cascade Mountains in Washington and Oregon. The new center will also have the capability of backing up critical functions of Dittmer in case of an emergency.

CGITS Energized

A noteworthy milestone in its continuing technical research and development program was reached when BPA energized the first 500,000-volt Compressed Gas Insulated Transmission System (CGITS) in the United States on August 13, 1975. As part of the Sickler-Raver line, the CGITS carries power underground for 600 feet, where the line formerly crossed several other lines near Ellensburg, Washington.

Operational tests of the system which consists of three conductors, each sheathed in its own 22-inch pipe containing sulfur hexafluoride gas under 60 pounds pressure, were completed successfully 3 months after energization.

R&D on UHV Transmission to Include Biological Tests

In Fiscal Year 1975, BPA, supported by the Department of the Interior and Congress, began a program to develop and test prototype ultra-high-voltage (UHV) transmission. After a final environmental statement was submitted through the Department of the Interior and filed with the President's Council on Environmental Quality during 1975, BPA can now begin building two 1,100,000-volt test facilities scheduled for completion by late 1976.

At Moro, Oregon, where the weather produces extremes of wind and ice, a mechanical facility will be built to evaluate "worst case" physical conditions, such as loads, wind-induced oscillations, and vibrations on bundle conductors, towers, insulators, spacers and other hardware.

The other UHV facility, a 1.3-mile line and substation near Lyons, Oregon, will be used to study possible electrical effects of the line, such as audible noise, radio and TV interference, and ozone and nitrous oxide production, and the line's impact on the comfort and well-being of people living nearby. No detrimental effects are expected.

Similarly, based on research and its own experience, BPA does not anticipate that the biological effects of 1,100,000-volt lines will differ much from those for existing 500,000-volt lines. Nonetheless, BPA will conduct a testing program to determine any possible effects of 1,100,000-volt transmission on vegetation, wildlife, and domestic animals.

Only field observations will be made at Lyons. BPA will use the information collected at Lyons to supplement the findings of research, such as that sponsored by the Electric Power Research Institute (EPRI), under way elsewhere in the United States.

Study of Effect of 500,000-volt Line on Wildlife Completed

In the context of the UHV biological tests, it is interesting to note that during 1975 BPA sponsored a study on the impacts of the 500,000-volt Dworshak-Hot Springs line on elk and other wildlife. Conducted by John Goodwin, a graduate student in wildlife biology at the University of Arizona, the study indicated that the presence of the towers, audible noise from the line, and the electric and magnetic fields recorded near the line did not adversely influence elk or deer behavior. Bighorn sheep, black bear, bobcat and mountain lion, as well as elk and deer, used the transmission line right-of-way to feed. They also used the access roads to the line as travel lanes, sometimes following them for miles.

Energy Ethic Leads to Other BPA R&D Efforts

Pursuing a conservation ethic, BPA is designing a system to retrieve waste energy from large transformers to heat nearby substation buildings.

The energy presently is lost to the atmosphere in the form of heat dissipated by cooling systems and large fans. In summer, the winter heating system would be complemented by an air conditioning system using solar energy. A contract will be let in 1976 to develop and install a prototype energy retrieval system at a BPA substation by late 1977. BPA has a number of substations where energy retrieval systems could be used if they can be successfully developed and prove economical.

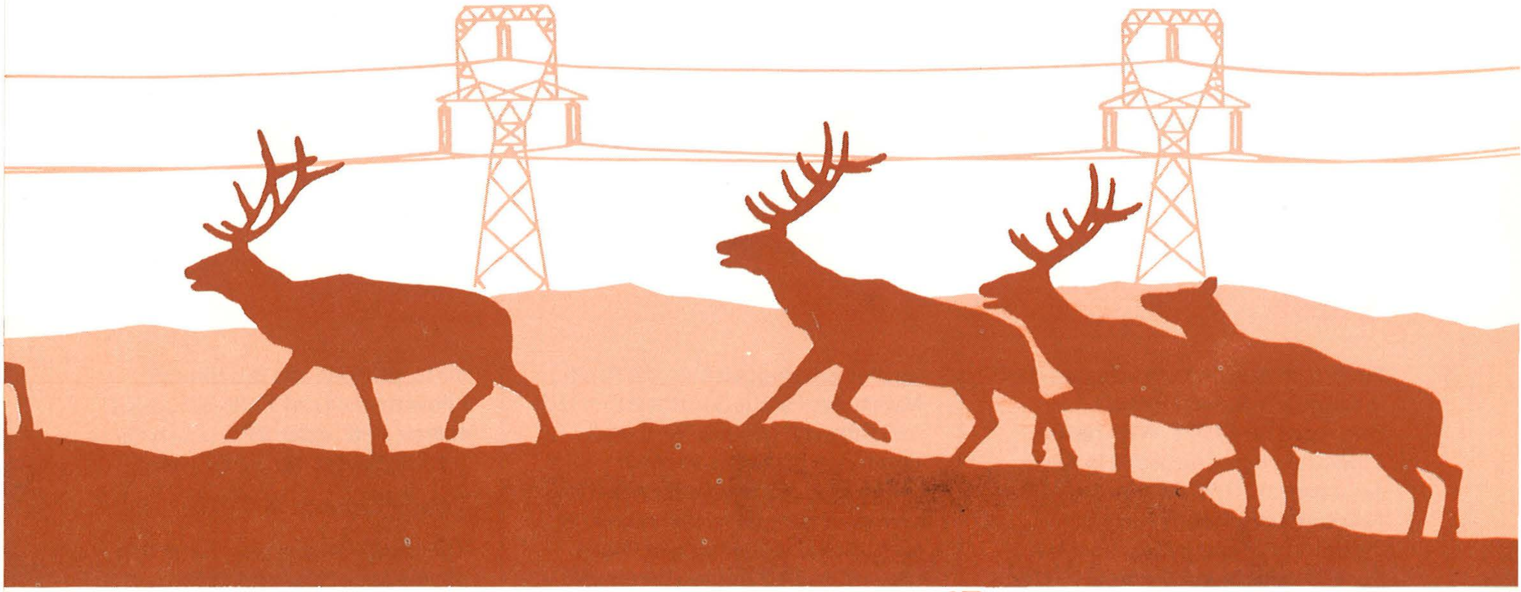
Our national energy ethic also calls for development of alternate energy sources. Thus, the Energy Research and Development Agency (ERDA) is currently funding and managing a Research, Development and Demonstration Program for all types of alternate energy resources, including wind energy as a part of its Solar Energy Program. BPA is cooperating with ERDA in locating suitable Pacific Northwest sites for the installation and operation of one of ERDA's demonstration Wind Energy Conversion Systems. In this regard, BPA is making available wind data, which it has collected for the design of transmission lines.

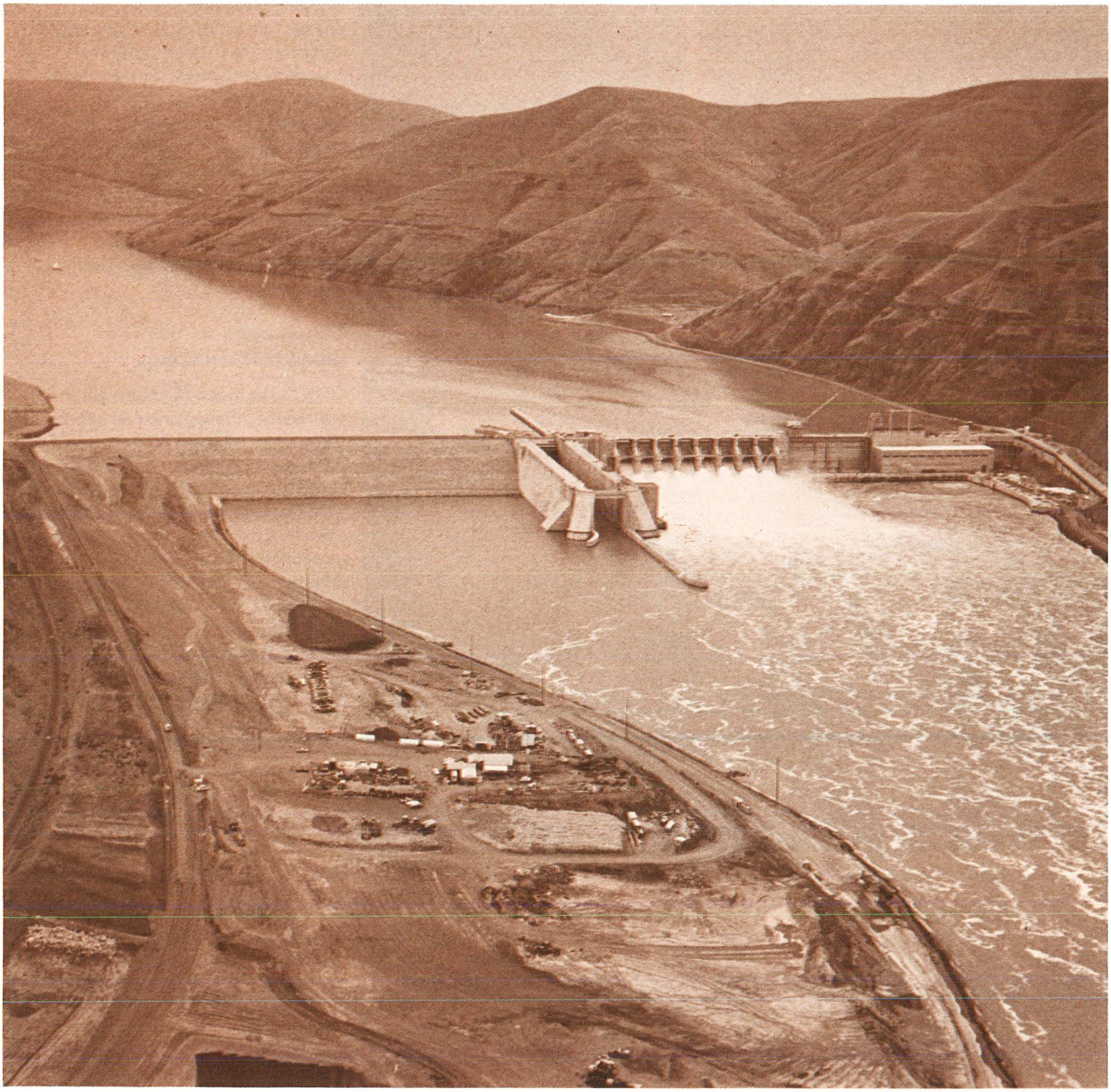
Fertilizing after seeding to provide browse for wildlife on BPA's Carlton-Tillamook right-of-way.

It is possible that some day wind energy may be integrated on a large scale with the Federal Columbia River Power System. One difficulty is that wind varies, so the energy it produces must be stored. The large reservoirs in the FCRPS can ideally supply the storage capacity needed by turbine generators. The energy from the wind turbine generators could supplement hydropower and help keep the reservoirs full.

Cooperation is Also the Mood of Technology

In 1975 the mood of cooperation underwrote the technical as well as the general policy of BPA. In February BPA technologists and other United States scientists and engineers participated with Russian experts in a Washington, D.C., symposium on extra-high-voltage, alternating current transmission. The subject of the next Russian-American power symposium will be high voltage direct-current transmission. BPA's Chief Engineer, George S. Bingham, has served as the Chairman for the U.S. technical exchange team on Ultra-High-Voltage Transmission Technology and High-Voltage-Direct-Current Transmission System Experience and Design.





By early summer, 1975, the first three units installed at the Lower Granite Dam, pictured here, added 405,000 kilowatts to Northwest power resources.
(Photo courtesy Army Corps of Engineers)

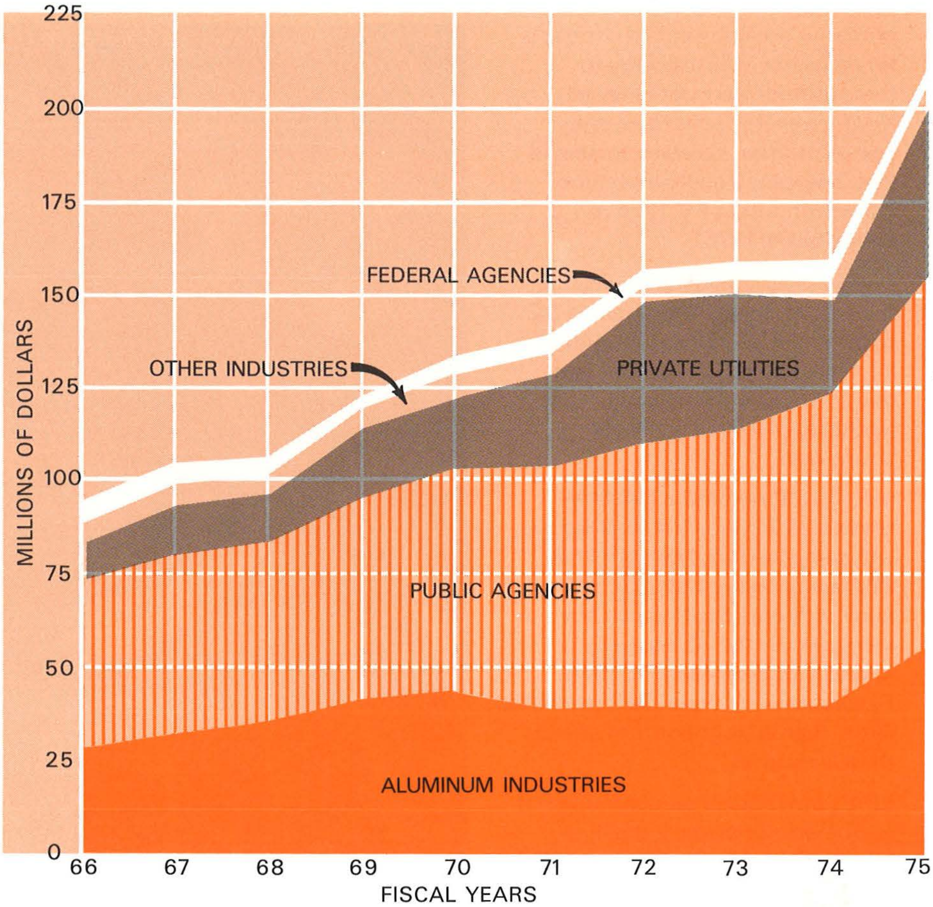
Power Sales

Favorable water conditions reported in last year's Annual Report continued into 1975. With heavy snowpacks being recorded in the early part of 1975, Bonneville Power Administration made surplus hydroelectric energy available from Federal dams in mid-February. This surplus was shipped over the Pacific Northwest-Pacific Southwest Intertie to Southwest utilities, who used the energy to replace thermal generation, resulting in substantial savings of non-renewable resources such as oil. For example, it would have taken 14.2 million barrels of oil to generate the 8.5 billion kilowatt-hours of Federal surplus energy sold under BPA contracts to the Southwest during FY 1975.

Loads Lighter in 1975

The good power supply condition was sustained through 1975 by continually favorable weather—heavy fall rains, for instance, with one of the wettest Novembers ever recorded in the Pacific Northwest. Another reason that power was in good supply was that loads for 1975 were substantially less than estimates. Low loads were ascribed to temperate weather, energy conservation, and depressed economic conditions. BPA's nonfirm industrial loads, for example, dropped from an average of 743 megawatts in the early fall of 1974 to an average of 394 megawatts during June 1975.

BPA SALES OF ELECTRIC ENERGY



Generation Sets New Records in the Fall of 1975

About one and a half million kilowatts of new generation came on line in 1975 with the completion of Lower Granite and Libby dams, the addition of a generating unit at Dworshak Dam, and the installation of the first of six super, 600,000 and 700,000-kilowatt generators in the third powerplant of the Grand Coulee Dam.

Since November 1, 1975, the new generation, the favorable water which enabled BPA to deliver to Southwest utilities energy assigned to them by Northwest entities and the ability of BPA to market large amounts of secondary hydroenergy to replace expensive thermal generation in the Northwest allowed new records to be set almost daily by the Federal Columbia River Power System. Between 8 and 9 a.m., December 19, 1975, for example, the 1-hour generation averaged 13,141,000 kilowatts, a record that exceeded last winter's high by more than a million kilowatts.

Because of the propitious power supply, BPA began to ship Federal surplus energy to the Southwest in the first week of December. Surplus energy is usually not made available until snowpack readings are taken in January or February, and is generally curtailed during the summer when normal seasonal recession of streamflows occurs.

Sales Grow at Moderate Rate

Energy sales during Fiscal Year 1975 totaled 65.7 billion kilowatt-hours, an increase of 3.5 percent from FY 1974 sales. Firm energy sales decreased by 3 percent, but a 42.4 percent increase in nonfirm sales made for the overall 3.5 percent increase.

The average revenue from the sale of energy to all classes of customers was 2.92 mills per kilowatt-hour. (Sales of capacity and revenues from other services, were not considered in computing this figure.) The 2.92 mills, a 19.6 percent increase over the 2.44 mills for FY 1974, is largely the result of a rate increase averaging 27 percent which became effective about half way through the fiscal year on December 20, 1974.

Revenues from sales of capacity during FY 1975 totaled $6.8 million, a 49.3 percent increase over FY 1974. Any energy associated with the delivery of this capacity is returned to BPA during the recipient's off-peak hours. Investor-owned utilities increased their purchases of capacity by 88 percent and took 82 percent of the total capacity sold by BPA. The remainder was purchased by the Bureau of Reclamation, Mid-Pacific (California) Region, as forced outage reserves.

In the Northwest public agencies, including public and peoples' utility districts, cooperatives, and municipal systems purchased 27.7 billion kilowatt-hours of energy during the fiscal year. Public purchases accounted for 42.1 percent of total BPA energy sales and amounted to a 4 percent increase over public purchases in FY 1974.

BPA sold a total of 3.3 billion kilowatt-hours of energy to investor-owned utilities in the Northwest during FY 1975, a decrease of 51 percent from the prior year. Firm sales to the private utilities declined 78 percent from 6.2 billion kilowatt-hours in FY 1974 to 1.3 billion kilowatt-hours in FY 1975, primarily because expired contracts for deliveries of firm energy to these utilities were not renewed. Nonfirm energy sales to investor-owned utilities, however, increased 294.3 percent from half a billion kilowatt-hours in FY 1974 to 1.9 billion in FY 1975.

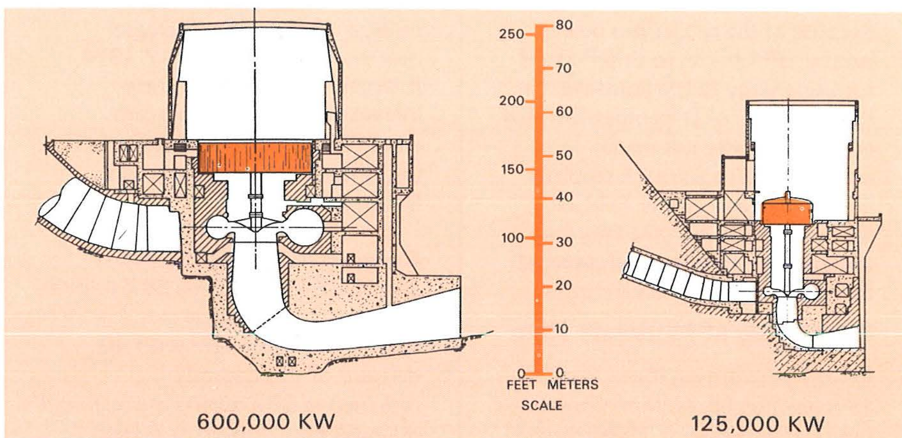
Energy sales to Federal agencies in the Pacific Northwest increased 3.8 percent in FY 1975 to 599 million kilowatt-hours. The increase was due principally to increased needs by the U.S. Navy in the Puget Sound area.

Sales to the aluminum industry totaled 23.2 billion kilowatt-hours and comprised 35.4 percent of all BPA energy sales. The 23.2 billion kilowatt-hours is a 14.3 percent increase over the 20.3 billion kilowatt-hours sold in FY 1974. Favorable water conditions permitted larger than average nonfirm sales to these industries.

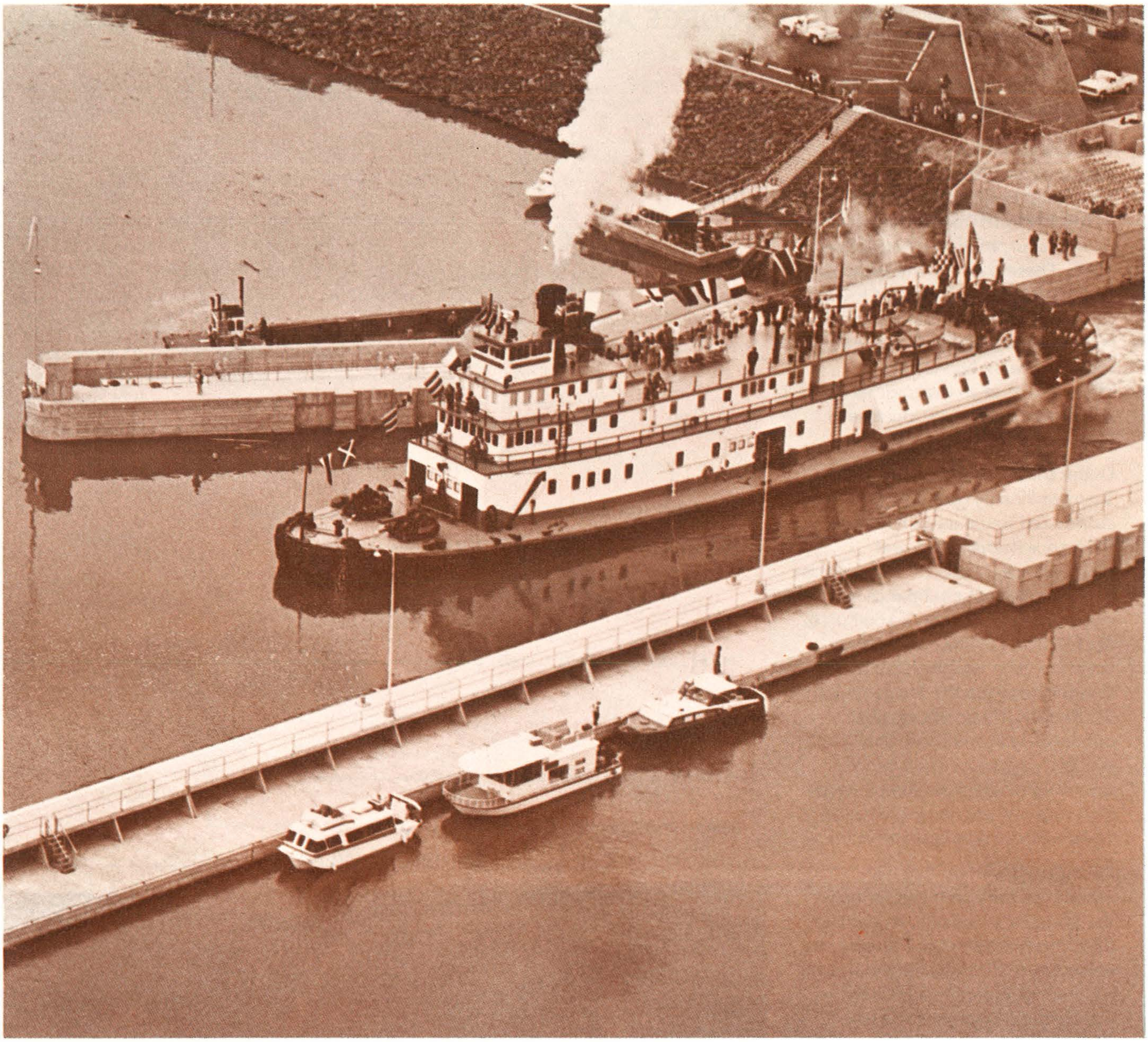
BPA's other direct service industrial customers purchased 2.3 billion kilowatt-hours in FY 1975, an 8.3 percent increase over the 2.1 billion kilowatt-hours purchased in FY 1974. These sales comprise 3.5 percent of total BPA energy sales.

In FY 1975 surplus energy sales to the Pacific Southwest, as the result of favorable water conditions, increased 19.4 percent to 8.5 billion kilowatt-hours. Surplus sales to the Southwest made up 13.1 percent of total FY 1975 energy sales.

Workmen installing half-ton coupling bolt in Grand Coulee Third Powerplant.
(Photo courtesy of Bureau of Reclamation)



First 600,000-kw unit installed in 1975 in Third Powerplant at Grand Coulee dwarfs previously installed 125,000-kw units.



Sternwheeler, Portland, goes through locks on Lower Monumental Dam. Completion of Lower Snake River dams in 1975 provides a 465-mile, "slack-water" route for navigation from the Pacific to Lewiston, Idaho.

The Financial Year

Federal Columbia River Power System revenues totaled $237.1 million during Fiscal Year 1975, up 28 percent over the previous year. This substantial increase, coupled with a large decrease in purchased power expense, produced net revenues for the year of $22.3 million.

The FCRPS thus finished the year "in the black" for the first time in 3 years. The $22.3 million net revenues compare to deficits of $37.9 million and $24 million in Fiscal Years 1974 and 1973, respectively.

These results are based on the accrued cost accounting method of financial reporting customarily used by commercial enterprises. Costs include all elements of operation and maintenance, the purchase of power, interest, and depreciation of facilities over their useful service lives. These financial statements are audited in accordance with generally accepted standards by the General Accounting Office under the direction of the Comptroller General. The complete financial statements together with the Comptroller General's opinion appear on pages 26 through 37.

Significant Developments

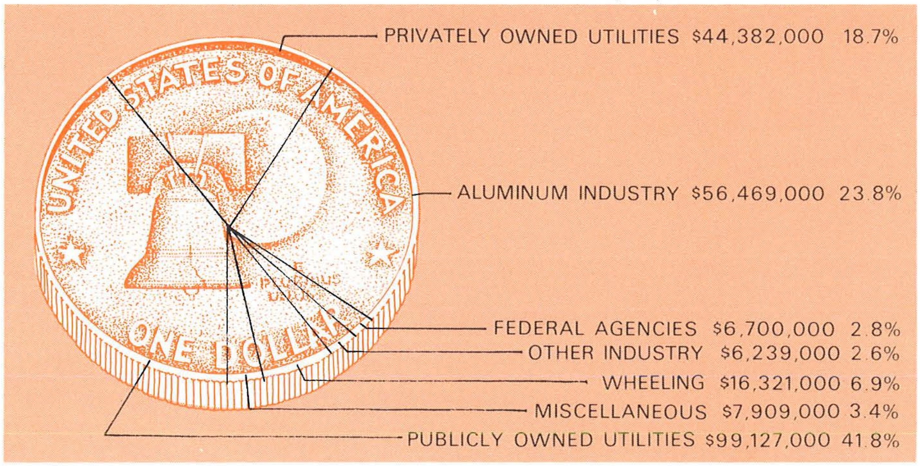
These results were achieved in conjunction with two other significant events affecting the power system's financial situation which occurred during Fiscal Year 1975. These were (1) the approval on October 18, 1974, of the Federal Columbia River Transmission System Act, which placed BPA on a self-financing basis, and (2) the effectuation of an approximately 27 percent power rate increase in January 1975.

Under the Federal Columbia River Transmission System Act, BPA is now authorized to use its cash receipts to finance its operation and maintenance, to pay for the purchase of power and to help finance its construction program. To complete the financing of the construction program, BPA is authorized to sell revenue bonds to the Treasury. Up to $1.25 billion in bonds may be outstanding at any time. This authority provides much better assurance of adequate financing for BPA than the previous reliance on Congressional appropriations.

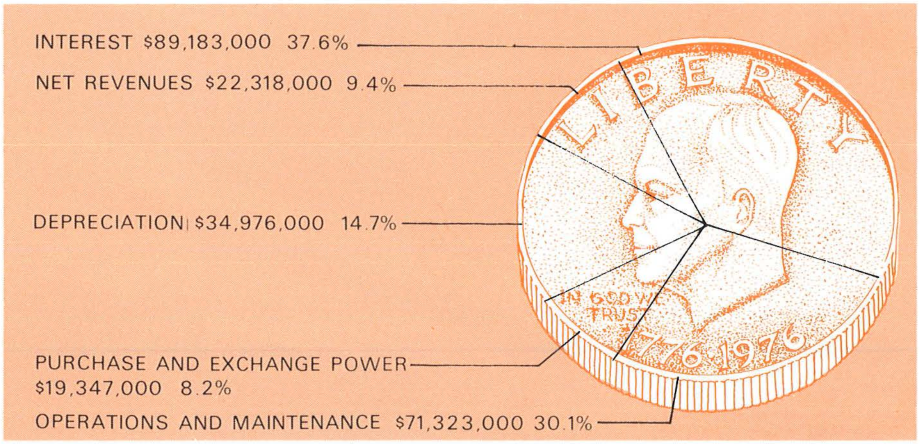
Receipts are also used to pay interest on the bonds and to repay the principal when due. In addition, BPA must repay to the Treasury the operating costs of the hydroelectric generating projects constructed by the Corps of Engineers and the Bureau of Reclamation for which BPA serves as the power marketing agent. (These costs continue to be financed by appropriations enacted by Congress. Appropriations also are used to Finance the construction of Federal hydroelectric generation.) Finally, BPA receipts also must repay to the Treasury interest on the unamortized investment in such power facilities (including BPA transmission facilities previously financed with appropriated funds), amortize such investments within prescribed periods, and repay a portion of the construction costs of certain Federal irrigation projects which are beyond the water users' repayment ability.

SOURCE AND DISPOSITION OF THE REVENUE DOLLAR

FISCAL YEAR 1975 TOTAL $237,147,000

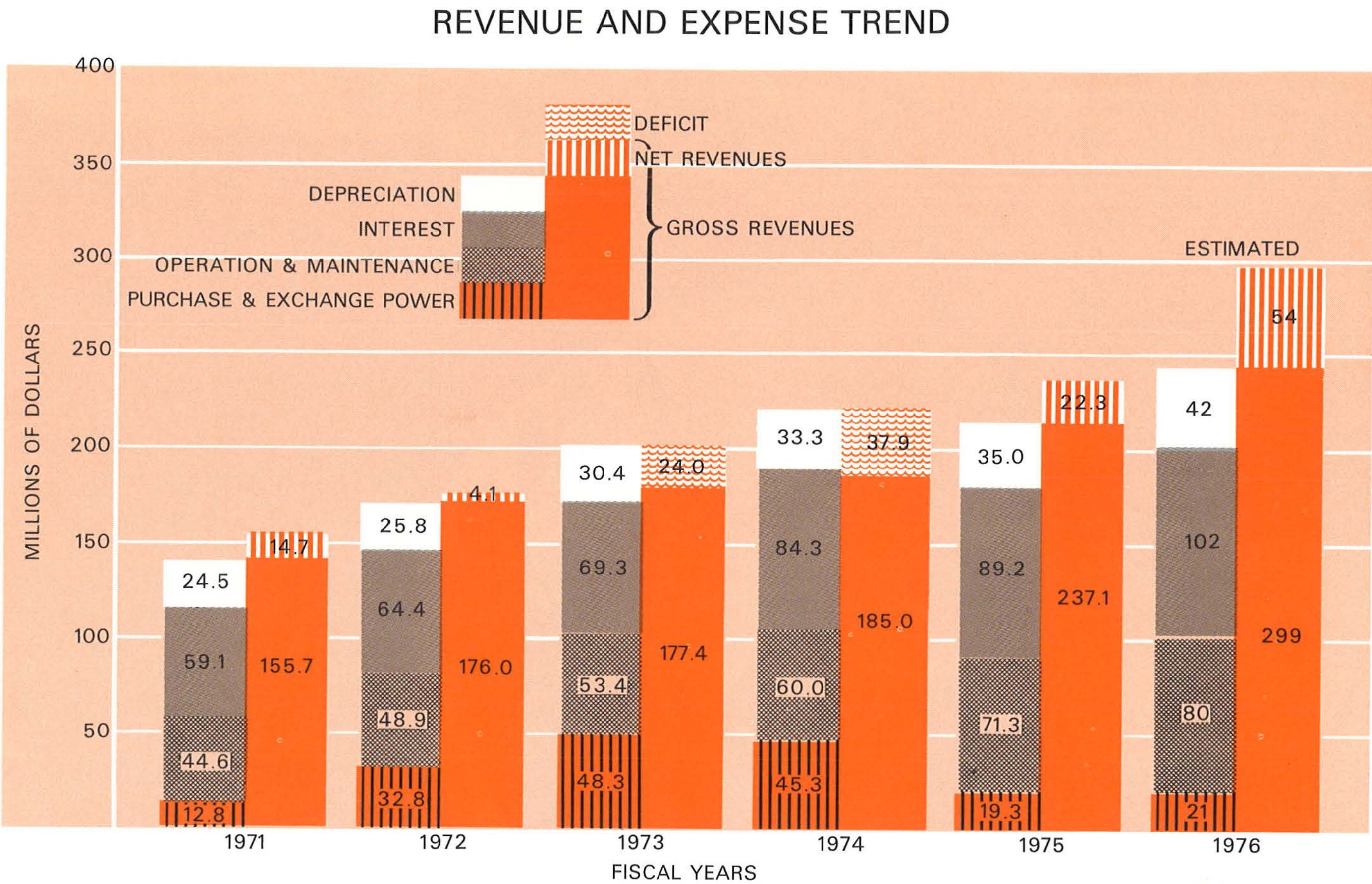


WHERE IT CAME FROM



WHERE IT WENT

Electric car which is under test at BPA for practicality.



The Act authorized the establishment in the Treasury of the Bonneville Power Administration Fund. Receipts from all sources are deposited into the Fund, including the proceeds from bond sales. All disbursements, including the repayments to the Treasury, are made from the Fund. The Act further authorizes BPA to invest, in Treasury securities, receipt balances in the Fund which are temporarily excess to current needs.

The BPA Fund was officially established as of the date of approval of the Act and at that time all balances of previously approved but unexpended appropriations were transferred into the Fund together with the balance of power receipts, trust funds, and other miscellaneous amounts then on deposit with the Treasury. The investment of temporarily excess funds commenced on January 2, 1975, following establishment of necessary procedures with the Treasury.

The power rate increase, as discussed at length in last year's report, was determined necessary to increase power revenues to the extent required to assure meeting the power system's obligations to fully recover all costs in accordance with the repayment policy established by the Secretary of the Interior pursuant to statutory requirements. This increase contributed significantly to the power system's return to a net revenue situation compared to the deficits of the previous 2 years.

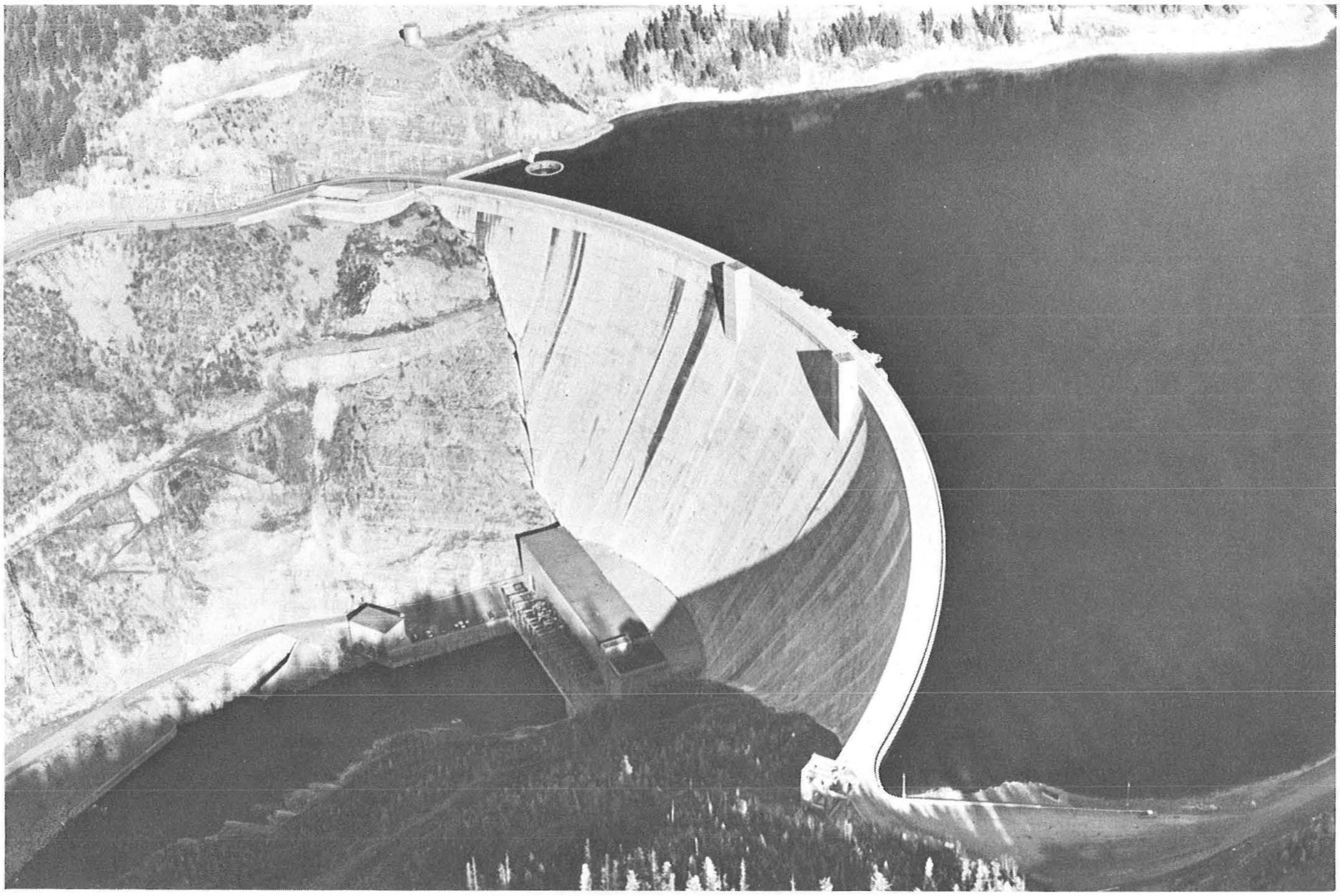
Wheeling rates (charges for transmitting power for others) were not increased in January 1975 as had been contemplated. BPA studies had indicated a need to increase revenues from this source to match increasing costs. The Federal Columbia River Transmission System Act, however, added a requirement that Federal Power Commission approval be obtained of BPA's wheeling rates. Delays in obtaining final FPC approval of the power rates resulted in postponement of the submission of the wheeling rates to FPC. Current plans are to submit increased wheeling rates to FPC during Fiscal Year 1976.

Cost Accounting and Repayment Reporting

This report includes both the cost accounting financial statements discussed above and the repayment study which constitutes the basis for determining the adequacy of the power rate level. The cost accounting statements present financial results on an annual basis. The repayment study, on the other hand, consists of long-range forecasts of future revenues and expenses and the repayment of the investment in power facilities. The two sets of financial reports, therefore, seek to measure two different things, i.e., current financial results on the one hand and future financial requirements on the other.

The repayment study, in summarized form, is found on page 42, with an explanation of the repayment policy on page 43.

It should be noted that the cost accounting financial statements include depreciation of the power facilities over their expected useful



Hungry Horse Dam, South Fork Flathead River, Montana.

lives, which extend up to 100 years in some cases. The repayment policy, however, requires that the investment in such facilities be fully repaid within not-to-exceed 50 years following each facility being placed in service. Consequently, the rate level and hence the level of revenues required to meet the repayment requirement is higher than that needed to cover costs on the cost accounting basis. Therefore, the normal situation with a rate level sufficient to meet the repayment requirement will be for the FCRPS to produce net revenues, i.e., operate "in the black." With the rate level now in effect, which is approved by the Federal Power Commission through December 20, 1979, prospects are for substantial net revenues over the next several years. This trend is illustrated graphically by the chart on page 21.

Another noteworthy difference between the cost accounting statements and the repayment study is that the latter reflects costs, such as for purchased power, on a cash payments basis. The cost accounting statements, on the other hand, record such costs on the accrual basis. This results in different amounts being shown in the two sets of reports in some cases for the same item. This is especially true of purchased power expense, where the contracts through which BPA is purchasing the capacity of certain thermal plants commits BPA to paying for such capacity beginning on a specified date in advance of the plant commencing operation. In this situation the repayment study shows the amount of the cash payments, but the cost accounting statements defer charging such amounts to purchased power expense until the plant starts operating. This explains, for example, the different amounts shown for purchased power in Fiscal Year 1976 in the repayment study (page 42) and the forecast of cost accounting results (graph on page 21).

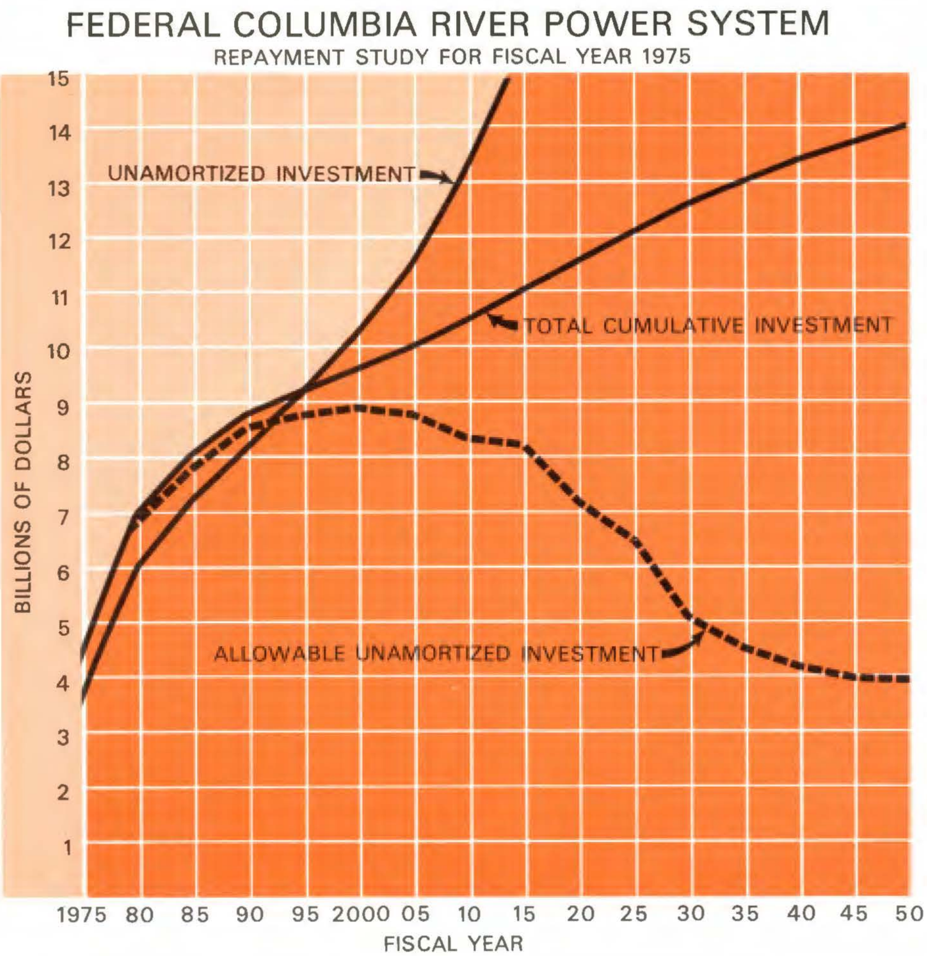
Prospects for Future Rate Increases

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

1. The purchase of the capacity of various thermal plants, which is more costly than hydroelectric power;
2. Inflation;
3. Higher interest rates on new construction.

All of these factors contributed to the necessity for the 27 percent rate increase placed into effect in January 1975.

The repayment study included in



this report is an updated version of the study which documented the need for the aforementioned increase. The new study includes more recent cost estimates which reflect additional escalation which has occurred since the preceding study was prepared. It also reflects for the first time the future impact of self-financing for BPA, which will entail somewhat higher interest costs. This study shows that the revenues that can be expected from the current wholesale power rates will fall short of meeting all repayment requirements, thus indicating the need for a future rate adjustment. (This result is illustrated graphically by the repayment study chart above.)

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

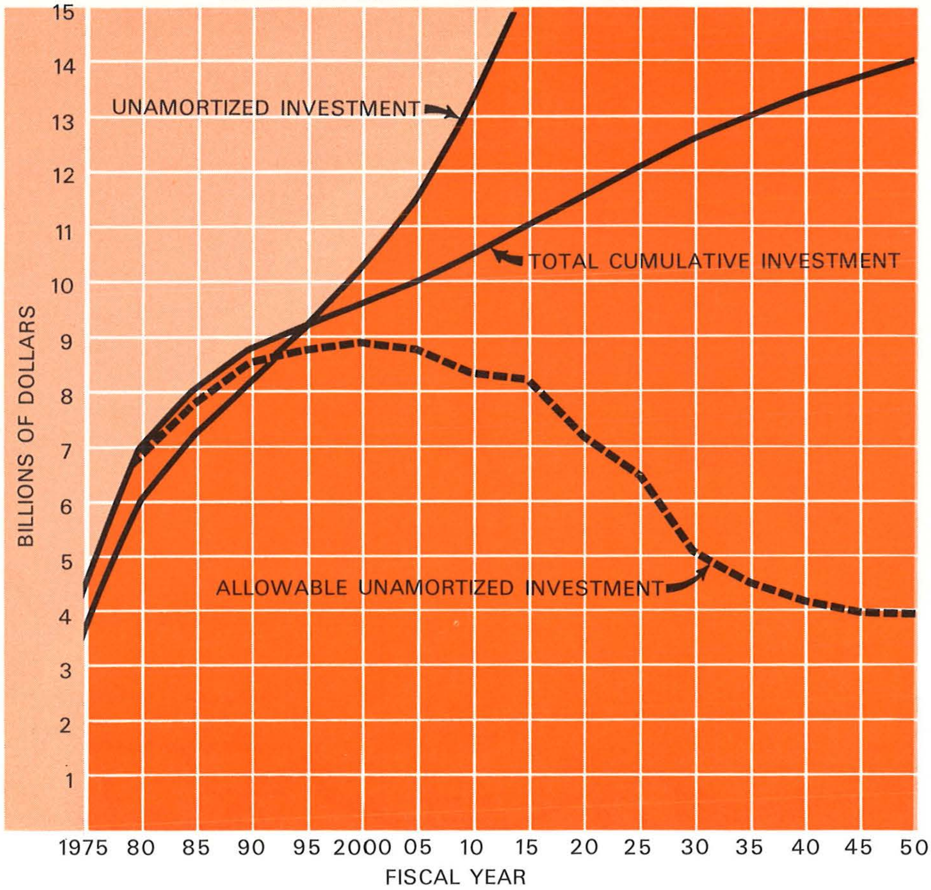
Cash Flow Forecast

Now that BPA is on a fully self-financing basis, the BPA cash flow takes on particular significance. First, effective cash management will minimize net interest costs. Secondly, the balance between cash receipts and outlays will determine the amount and timing of future BPA bond sales to the Treasury. The estimated BPA cash flow through Fiscal Year 1979 is shown in the tabulation on page 41. (Forecasting cash flow beyond 1979 is impractical because of the present uncertainty regarding the amount and timing of future rate increases.)

It will be noted in the cash flow forecast that the first bond sales are anticipated commencing in October 1977 (the first month of Fiscal Year 1978). Because BPA entered the transition to self-financing with a substantial cash balance due to the availability of previously approved appropriations which had not yet been expended, that initial balance together with the substantial cash receipts generated through its operations is expected to provide BPA sufficient cash to meet all requirements through the end of Fiscal Year 1977. Thereafter, BPA anticipates an increasing volume of bond sales to the Treasury to complete the financing of its construction program.

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

FEDERAL COLUMBIA RIVER POWER SYSTEM
REPAYMENT STUDY FOR FISCAL YEAR 1975



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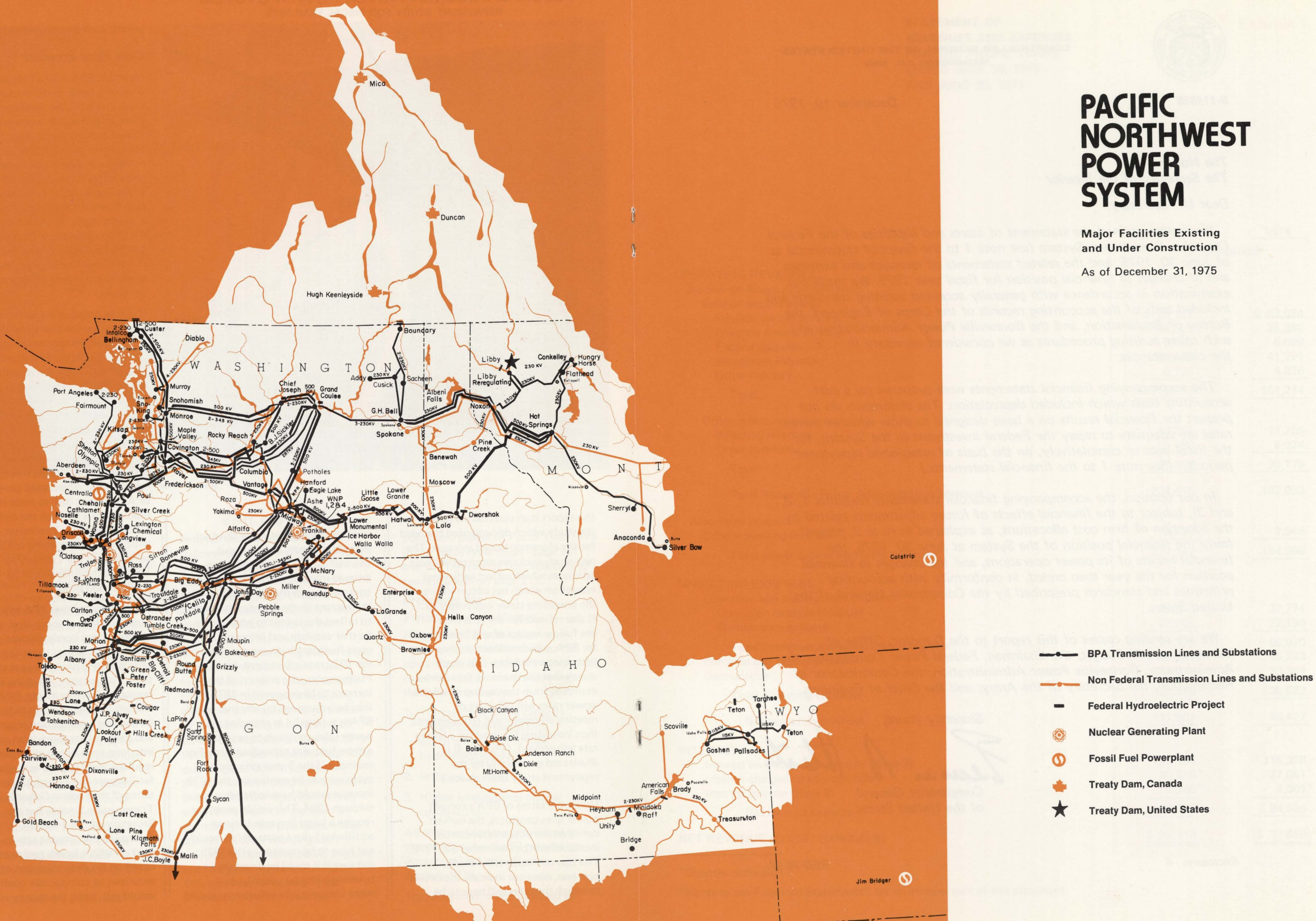
PACIFIC NORTHWEST POWER SYSTEM

Major Facilities Existing and Under Construction

As of December 31, 1975



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

B-114858

December 19, 1975

The Honorable
The Secretary of the Interior

Dear Mr. Secretary:

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

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

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

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

Sincerely yours,

Thomas B. Staats

Comptroller General
of the United States

Enclosures - 6

RED-76-57

Federal
Columbia
River
Power
System

STATEMENT OF
REVENUES AND EXPENSES
FOR THE FISCAL YEARS
ENDED JUNE 30, 1975
AND JUNE 30, 1974

Exhibit 1

	1975	1974
	(In thousands)	
OPERATING REVENUES:		
Bonneville Power Administration		
Sales of electric energy:		
Publicly owned utilities	$ 99,127	$ 83,034
Privately owned utilities	44,382	25,380
Federal agencies	6,700	6,699
Aluminum industry	56,469	41,291
Other industry	6,239	4,870
Total	212,917	161,274
Other operating revenues:		
Wheeling revenues	16,321	14,705
Other revenues	5,180	6,074
Total	21,501	20,779
Total Bonneville Power Administration revenues	234,418	182,053
Associated projects		
Other operating revenues	2,729	2,946
Total power system operating revenues	237,147	184,999
OPERATING EXPENSES:		
Operation and maintenance expense:		
Operation expense (Note 9)	45,318	37,774
Maintenance expense	26,005	22,196
Total operation and maintenance expense	71,323	59,970
Purchase and exchange power	19,347	45,243
Depreciation	34,976	33,309
Total operating expenses	125,646	138,522
Net operating revenues	111,501	46,477
INTEREST:		
Interest on Federal investment (Note 2)	128,404	115,388
Interest charged to construction	33,656*	27,051*
Interest income (Note 2)	5,565*	4,001*
Net interest expense	89,183	84,336
NET REVENUE (LOSS) (Schedule B)	$ 22,318	($ 37,859)

*Denotes deduction

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

Federal Columbia River Power System

STATEMENT OF ASSETS AND LIABILITIES AS OF JUNE 30, 1975 AND JUNE 30, 1974

ASSETS

	June 30 1975	June 30 1974
	(In thousands)	
FIXED ASSETS:		
Completed plant (Schedule A)	$3,890,363	$3,580,636
Retirement work in progress	33,226	20,677
	3,923,589	3,601,313
Less accumulated depreciation	350,925	320,689
	3,572,664	3,280,624
Construction work in progress (Schedule A)	1,079,220	1,068,043
Total fixed assets (Note 9)	4,651,884	4,348,667
CURRENT ASSETS:		
Unexpended funds (Note 7)	129,798	135,258
Investments (Notes 2 and 7)	11,011	0
Special funds	7,002	8,893
Accounts receivable	48,791	35,721
Materials and supplies	22,857	17,054
Total current assets	219,459	196,926
OTHER ASSETS AND DEFERRED CHARGES:		
Trust funds construction work in progress (Note 7)	16,899	18,184
Other assets and deferred charges (Note 1)	30,465	13,918
Total other assets and deferred charges	47,364	32,102
TOTAL ASSETS	$4,918,707	$4,577,695

*Denotes deduction

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

Exhibit 2

LIABILITIES

	June 30 1975	June 30 1974
	(In thousands)	
PROPRIETARY CAPITAL:		
Investment of U.S. Government in power facilities:		
Congressional appropriations	$5,577,537	$5,198,240
Revenues transferred to Continuing Fund	7,005	7,005
Transfers from other Federal agencies, net	37,996	36,604
Interest on Federal investment (Note 8)	1,287,590	1,160,501
Gross Federal investment	6,910,128	6,402,350
Less funds returned to U.S. Treasury	2,412,854	2,227,492
Net investment of U.S. Government	4,497,274	4,174,858
Accumulated net revenues:		
Balance at beginning of year	290,588	328,546
Net revenues — current year (Exhibit 1)	22,318	37,859*
Prior years adjustment (Note 10)	517*	99*
Balance at end of year	312,389	290,588
Total proprietary capital in power facilities before irrigation assistance	4,809,663	4,465,446
Irrigation assistance (1975, $511 million; 1974, $474 million) (Schedule A) (Note 4)		
Total proprietary capital	4,809,663	4,465,446
COMMITMENTS AND CONTINGENCIES (Notes 5 and 6)		
CURRENT LIABILITIES:		
Accounts payable	60,241	65,560
Employees accrued leave	7,051	6,320
Total current liabilities	67,292	71,880
OTHER LIABILITIES AND DEFERRED CREDITS:		
Trust fund advances (Note 7)	19,585	21,296
Other deferred credits	22,167	19,073
Total other liabilities and deferred credits	41,752	40,369
TOTAL LIABILITIES	$4,918,707	$4,577,695

Federal
Columbia
River
Power
System

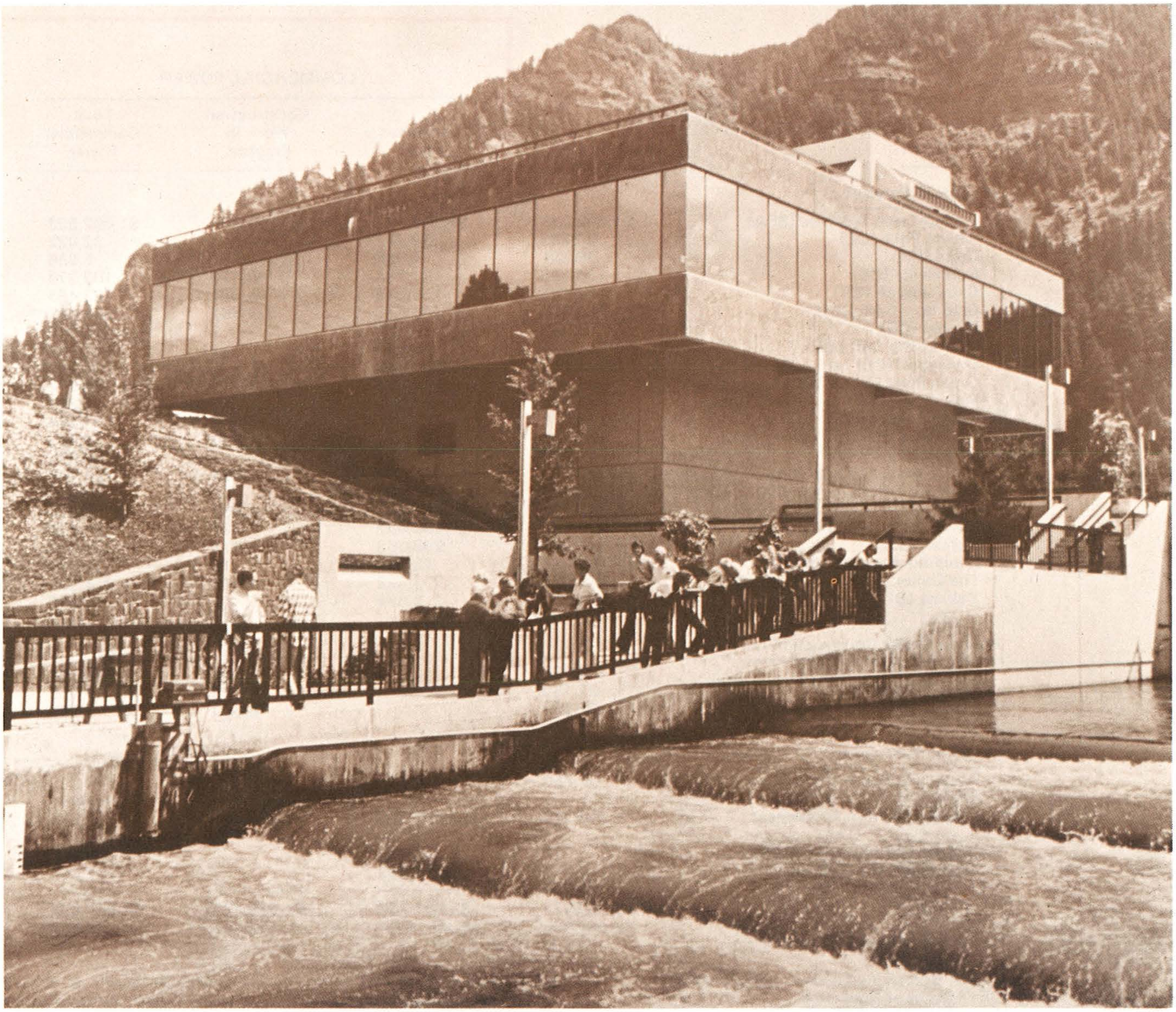
STATEMENT OF CHANGES IN FINANCIAL POSITION FOR THE FISCAL YEARS ENDING JUNE 30, 1975 AND JUNE 30, 1974

Exhibit 3

	1975	1975
	(In thousands)	
FINANCIAL RESOURCES PROVIDED FROM:		
Operations:		
Net revenues	$ 22,318	$ 37,859*
Expenses not requiring repayment	34,976	33,309
Net revenues available for repayment	57,294	4,550*
Prior years adjustments (Note 10)	517*	99*
Resources provided from operations	56,777	4,649*
Federal investment:		
Congressional appropriations	379,297	310,002
Transfers from other Federal agencies, net	1,392	3,548
Interest on Federal investment	127,089	111,352
Transfers to Continuing Fund	0	2,615
Resources provided from Federal investment	507,778	427,517
Total resources provided	$564,555	$422,868
FINANCIAL RESOURCES USED:		
Investment in electric utility plant and facilities, net	$338,193	$287,596
Funds returned to U.S. Treasury	185,362	141,322
Other uses:		
Increase in current assets net of current liabilities	27,121	663*
Increase in other assets net of other liabilities	13,879	5,387*
Total other uses	41,000	6,050*
Total resources used	$564,555	$422,868

*Denotes deduction

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



New visitor's center and fish ladder at Bonneville Dam.
(Photo courtesy of Army Corps of Engineers)

Federal Columbia River Power System

AMOUNT AND ALLOCATION OF PLANT INVESTMENT AS OF JUNE 30, 1975

Schedule A

(All dollar amounts in thousands)

Project	Total	Commercial Power: Completed Plant	Commercial Power: Construction Work in Progress	Commercial Power: Total Commercial Power	Allocated to Irrigation: Returnable From Commercial Power Revenues	Allocated to Irrigation: Returnable From Other Sources	Allocated to 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)	$1,592,593	$1,392,895	$ 199,698	$1,592,593									100.0
Albeni Falls (CE)	33,262	32,022		32,022				$ 134	$ 173		$ 933		96.3
Boise (BR)	66,331	4,995	361	5,356	$ 10,737	$ 35,281	$ 46,018		14,957				24.3
Bonneville (CE)	136,350	61,783	40,596	102,379				32,320			1,632	$ 19	75.1
Chief Joseph (CE)	184,487	155,012	28,441	183,453	723		723				255	56	99.8
Columbia Basin (BR)	1,060,758	186,776	372,867	559,643	385,921	68,092	454,013	1,000	45,575			527	89.1
Cougar (CE)	58,791	18,039	1	18,040		2,967	2,967	529	37,047			208	30.7
Detroit-Big Cliff (CE)	66,624	40,462		40,462		4,766	4,766	220	20,886			290	60.7
Dworshak (CE) (a)	312,852	280,140		280,140				9,759	18,789		4,164		89.5
Green Peter-Foster (CE)	89,689	49,614	1	49,615		5,772	5,772	363	30,087		1,791	2,061	55.3
Hills Creek (CE)	48,794	17,311	14	17,325		4,313	4,313	625	26,258			273	35.5
Hungry Horse (BR)	101,971	77,341	3	77,344					24,627				75.9
Ice Harbor (CE)	170,701	96,223	27,900	124,123				44,371			2,207		72.7
John Day (CE) (a)	515,672	378,357	2	378,359				85,581	14,478		10,844	26,410	73.4
Little Goose (CE) (a)	173,798	118,590	2,532	121,122				46,498			3,593	2,585	69.7
Lookout Point-Dexter (CE)	95,209	45,832	1	45,833		1,324	1,324	709	46,774		475	94	48.1
Lower Granite (CE) (a)	303,273	234,933	4,082	239,015				52,469			3,678	8,111	78.8
Lower Monumental (CE) (a)	200,377	150,022	402	150,424				47,504			2,032	417	75.1
McNary (CE)	313,226	258,563	971	259,534				52,601			1,091		82.9
Minidoka-Palisades (BR)	97,013	13,359	13	13,372	10,039	43,399	53,438		29,731		178	294	24.1
The Dalles (CE)	318,231	273,523	814	274,337				42,063			1,809	22	86.2
Yakima (BR)	65,231	4,571		4,571	10,615	48,429	59,044		226	$ 1,152	238		23.3
Projects Under Construction (a)													
Libby (CE)	493,733		373,834	373,834					76,449			43,450	75.7
Lost Creek (CE)	97,152		18,018	18,018		1,545	1,545		37,494	17,166	13,923	9,006	18.5
Teton (BR)	52,592		8,669	8,669	31,013	3,539	34,552		8,580		791		75.5
Irrigation Assistance at 11 Projects													
Having No Power Generation	61,550				61,550		61,550						100.0
Subtotal Plant Investment	6,710,260	3,890,363	1,079,220	4,969,583	510,598	219,427	730,025	416,746	432,131	18,318	49,634	93,823 (c)	81.7
Repayment Obligation Retained by Columbia Basin Project	2,211	1,352		1,352 (b)	859		859						100.0
Total	$6,712,471	$3,891,715	$1,079,220	$4,970,935	$511,457	$219,427	$730,884	$416,746	$432,131	$18,318	$49,634	$93,823 (c)	81.7

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

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

(a) Projects in service that have tentative cost allocations at June 30, 1975. Projects under construction have tentative cost allocations (Note 3).

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

(c) Included in this amount are nonreimbursable road costs amounting to $82.7 million.

RECONCILIATION OF COST ACCOUNTING FINANCIAL STATEMENTS TO REPAYMENT STUDY

FOR THE FISCAL YEAR ENDED JUNE 30, 1975
(All dollar amounts in thousands)

	Cumulative Balance June 30, 1974	Fiscal Year 1975 Operations (Exhibit 1)	Prior Years Adjustments (Note 10)	Cumulative Balance June 30, 1975	Cumulative Adjustment to Repayment Basis (Note 1)	Cumulative Data Through June 30, 1975 on Repayment Study
OPERATING REVENUES	$2,465,706	$237,147		$2,702,853		$2,702,853
EXPENSES:						
Purchase and exchange power	202,036	19,347		221,383	$ 14,441	235,824
Operation and maintenance expense	695,438	71,323		766,761		766,761
Interest expense	879,283	89,183		968,466		968,466
Depreciation	398,361	34,976	$517	433,854	433,854*	
Total expenses	2,175,118	214,829	517	2,390,464	419,413*	1,971,051
NET REVENUES (Exhibit 2)	$ 290,588	$ 22,318	$517*	$ 312,389		
RECONCILIATION TO CUMULATIVE AMORTIZATION				$ 312,389	$419,413	731,802
Revenues not available for amortization and carried as investment in U.S. Government securities to provide working capital						11,152*
CUMULATIVE AMORTIZATION						$ 720,650 (a)

(a) CHANGES IN CUMULATIVE AMORTIZATION:

Cumulative amortization through June 30, 1974	$ 691,777
Fiscal year 1975	
Depreciation, including property retirements	35,493
Net revenues	22,318
Prior years adjustments	517*
Purchase and exchange power-adjustment	17,269*
Revenues invested in lieu of amortization	11,152*
Amortization for the year	28,873
Cumulative amortization through June 30, 1975	$ 720,650

*Denotes deduction

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

Federal Columbia River Power System

NOTES TO THE FINANCIAL STATEMENTS

Note 1. Major Accounting Considerations

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

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

Costs of multi-purpose Corps and Bureau projects are assigned to the individual purposes through a cost allocation process. The portion of total project costs allocated to power is included in these statements. Schedule A lists the projects included in FCRPS and the allocation of plant investment to the various purposes.

BPA wholesale power rates are established by using a separate repayment analysis. The differences between the financial statements and the historical data on the repayment analysis are the treatment of fixed assets, purchased power, and amortization. In the accompanying statements, the depreciation life for fixed assets allocated to power averages about 61 years, with the transmission system averaging 40 years and generating projects averaging 87 years. However, the repayment periods used to establish power rates are 50 years for the generating projects and 40 years for the transmission system for an average of 46 years.

The purchase and exchange power costs in the cost accounting financial statements reflect the expense on a revenue and expense matching basis, while the figures in the repayment study are on a cash basis. The difference occurs when, for example, net billing for a thermal plant commences before the commercial operation date, such as the Trojan Nuclear Plant. The statement line item "Other assets and deferred charges" on Exhibit 2 for fiscal years 1975 and 1974 includes \$21.1 million and \$8.6 million, respectively, of accumulated Trojan Nuclear Plant costs which will be matched and amortized against revenues produced from that project when it starts operation.

The amount of cumulative amortization shown on the repayment study through fiscal year 1975, \$731.8 million, includes \$720.7 million available for repayment of the U.S. Government investment in power facilities and \$11.1 million of revenues invested in U.S. Government securities.

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

Note 2. Investment and Interest Income

The Federal Columbia River Transmission System Act approved October 18, 1974, authorized BPA to request the Secretary of the Treasury to invest BPA's temporarily excess funds in securities guaranteed by the United States Government. BPA does not include any appropriated funds as temporarily excess funds available for investment.

Prior to passage of this Act and agreement with the U.S. Treasury on implementing investment arrangements, BPA imputed an interest income credit on revenues and other non-appropriated funds held on deposit with the U.S. Treasury. In fiscal year 1974 and prior fiscal years, "Interest on federal investment" on Exhibit 1, was reported net of this interest income credit. Beginning in fiscal year 1975, the Exhibit 1 format has been changed to show all interest income as a separate line item. The fiscal year 1974 amounts shown for comparative purposes in "Interest on federal investment" and "Interest income" have accordingly been restated.

The fiscal year 1975 investments are reported at cost after being adjusted to reflect accrued interest income. It is anticipated that investments will be held until maturity.

Note 3. Tentative Cost Allocations

Plant cost and operation and maintenance expenses based on tentative allocations between power and nonpower purposes are included for eight of the projects listed in Schedule A. In the past, adjustments have been made to plant cost and accumulated net revenues when firm allocations were adopted. At June 30, 1975, total joint plant costs for these eight projects are about \$1.3 billion of which \$1.1 billion are tentatively allocated to power and subject to retroactive adjustment. The amount of adjustments that may be necessary when the allocations become firm is not determinable at this time.

Note 4. Repayment Responsibility For Irrigation Costs

Legislation requires that FCRPS net revenues will be used to repay to the U.S. Treasury the cost of Bureau irrigation facilities which benefiting water users are unable to repay. The use of power revenues for such repayments represents a payment for irrigation assistance to the benefiting water users and, while paid by power rate payers, such costs do not represent a regular operations cost of the power program. The irrigation assistance payments will be shown as reductions of accumulated net revenues at the time future payments are made. The first payment is scheduled to be made in 1997. The 1997 and other future payments are disclosed in the FCRPS repayment studies which are used to establish BPA's power rates. Investment made in irrigation facilities through June 30, 1975, results in estimated irrigation assistance of $511.5 million. This compares to $474.5 million at June 30, 1974.

Not included in the above irrigation assistance costs, is any portion of $20.7 million of original project facility costs allocated to irrigation at six Corps projects. If completion of irrigation facilities is ever proposed for authorization and development at these six projects, a determination of water users' repayment ability will probably be made which might result in additional irrigation assistance being required from power revenues.

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

BPA has made commitments to acquire all or part of the generating capability of various thermal power plants, listed in the table below. BPA is obligated to pay by exchange and net-billing agreements its share of the project costs whether or not the project is completed, operable, or operated. The "Present Termination Commitment" represents those project financing costs (without credit for assets) which would have been payable over the varied financing repayment periods if the project had terminated at June 30, 1975.

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

Note 6. **Contingent Liabilities**

Contingent liabilities total approximately $73.8 million of which $67.0 million represent various contractor claims and $6.8 million represent claims under the Federal Tort Claims Act.

Note 7. **Trust Funds**

For comparative purposes the fiscal year 1974 amounts shown on Exhibit 2 for "Unexpended funds" and "Trust fund advances" have been restated to conform with a new financial presentation for fiscal year 1975. In the new presentation, BPA includes appropriate asset and off-setting liability amounts for unexpended and invested trust funds which are now a part of the "BPA Fund" established by passage of the Federal Columbia River Transmission System Act mentioned in Note 2. Previously, BPA reported only trust fund construction work in progress as the appropriate balance for trust fund asset and liability accounts.

		Estimated BPA Portion		
Project Name	Commitment Period	Capacity	Total Capital Cost	Present Termination Commitment
		(Megawatts)	(In thousands)	(In thousands)
Hanford	Present, for project life	800	$ 68,000	$ 60,000
Trojan Nuclear Plant	Present, for project life	339	134,500	122,500
WPPSS* Nuclear Project #1	Start 12/79 for project life	850	1,147,000	102,000
WPPSS Nuclear Project #2	Start 12/76 for project life	1100	794,000	480,000
WPPSS Nuclear Project #3	Start 12/80 for project life	868	952,000	29,000

*Washington Public Power Supply System

Note 8. **Interest Rates**

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

Note 9. **Imputed Rent**

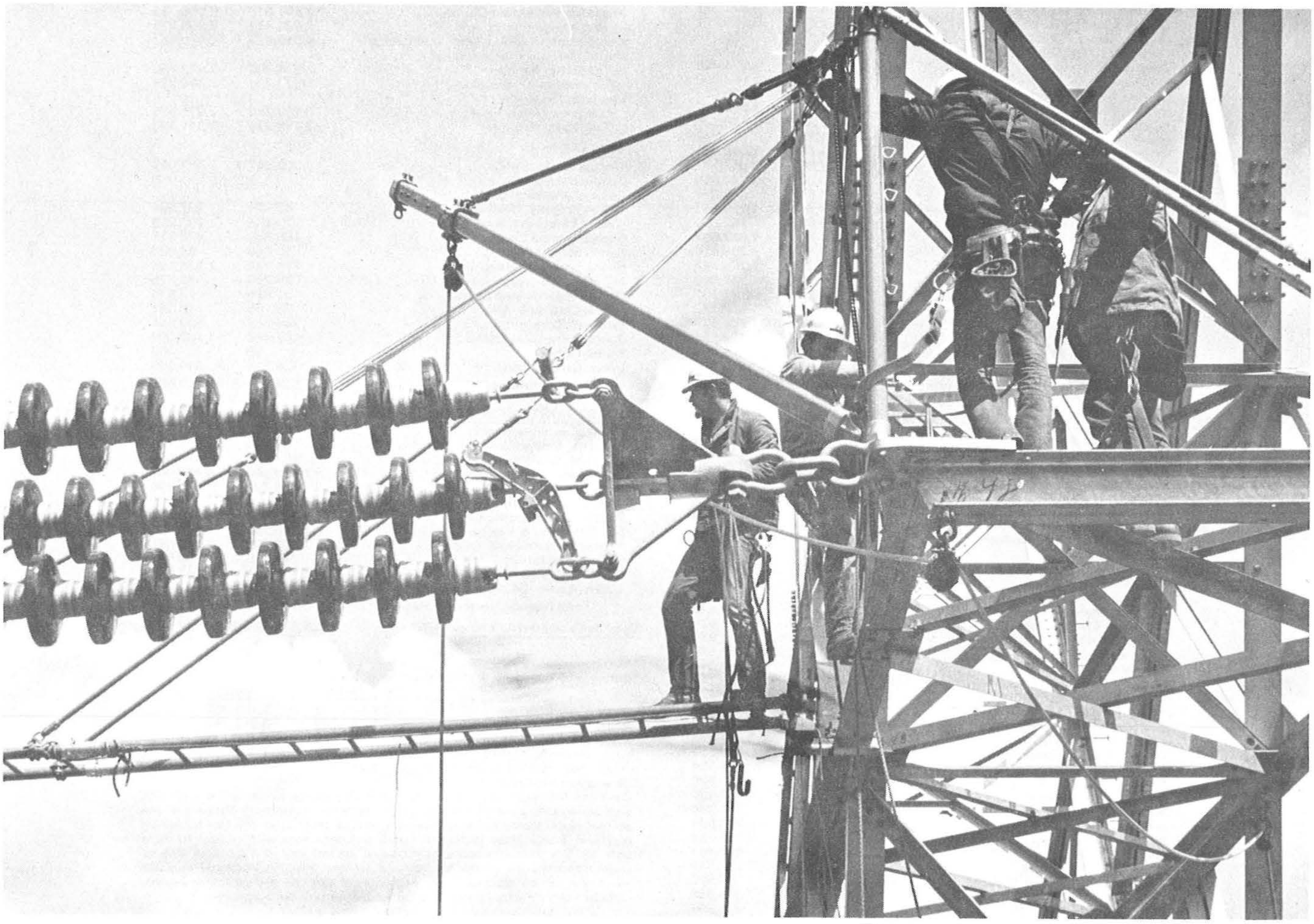
The General Services Administration (GSA) provides facilities to BPA, the Corps, and the Bureau. Beginning in fiscal year 1975, all three agencies are required by law to pay GSA approximate commercial rental rates. Prior to fiscal year 1975, BPA and the Bureau imputed the rental cost, but the Corps did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

Note 10. **Adjustments to Accumulated Net Revenues**

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

	Fiscal Year 1975	Fiscal Year 1974
	(In thousands)	
1. Property retirements	$517	$ -o-
2. Retroactive pay increase off-setting prior year's funds	-o-	223
3. Capitalization of plant previously expensed	-o-	(89)
4. Reduction of interest expense, net	-o-	(35)
Net Decrease	$517	$ 99

Hot-line maintenance training.



Federal Columbia River Power System

SALES OF ELECTRIC ENERGY FISCAL YEAR 1975

Table 1

Customer	Energy Delivered for Year (000) KWH	Revenue From Sales of Energy
NORTHWEST AREA		
Publicly Owned Utilities		
Municipalities		
Albion, Idaho	2,869	$ 11,014
Bandon, Oregon	47,082	185,807
Blaine, Washington	30,595	114,303
Bonners Ferry, Idaho	26,401	116,411
Burley, Idaho	84,540	297,000
Canby, Oregon	61,643	243,870
Cascade Locks, Oregon	27,806	102,674
Centralia, Washington	67,441	336,415
Cheney, Washington	88,496	331,544
Consolidated Irrigation District, Washington	1,257	5,131
Coulee Dam, Washington	25,475	98,545
Declo, Idaho	2,416	9,689
Drain, Oregon	21,927	89,877
Ellensburg, Washington	137,240	480,972
Eugene, Oregon	1,471,620	4,221,818[1]
Forest Grove, Oregon	124,657	469,410
Heyburn, Idaho	57,715	201,160
Idaho Falls, Idaho	280,055	1,001,042
McCleary, Washington	28,771	112,080
McMinnville, Oregon	225,394	865,015
Milton-Freewater, Oregon	94,819	347,607
Minidoka, Idaho	909	3,374
Monmouth, Oregon	52,838	210,464
Port Angeles, Washington	409,476	1,388,142
Richland, Washington	391,846	1,481,738
Rupert, Idaho	53,838	195,713
Seattle, Washington	1,643,106	4,301,607[1]
Springfield, Oregon	233,445	813,967
Steilacoom, Washington	25,956	96,490
Sumas, Washington	5,336	20,428
Tacoma, Washington	1,527,144	3,920,456[1]
Vera Irrigation District, Washington	106,477	400,800
Washington Public Power Supply System	9,885	36,503
Total Municipalities (33)	7,368,475	$ 22,511,066
Public Utility Districts		
Benton County PUD No. 1	835,599	$ 2,829,307
Central Lincoln PUD	922,520	3,255,707
Chelan County PUD No. 1	280,349	759,920
Clallam Co. PUD No. 1	319,481	1,164,799
Clark Co. PUD No. 1	1,985,621	7,221,425
Clatskanie PUD	656,928	1,957,896
Cowlitz Co. PUD No. 1	2,277,513	7,051,883[1]
Douglas Co. PUD. No. 1	404,059	1,333,532[1]
Ferry Co. PUD No. 1	42,326	149,535
Franklin Co. PUD No. 1	391,298	1,319,060
Grant Co. PUD No. 2	641,544	2,078,071[1]
Grays Harbor Co. PUD No. 1	972,054	3,364,191
Kittitas Co. PUD No. 1	36,037	134,055
Klickitat Co. PUD No. 1	190,512	638,847
Lewis Co. PUD No. 1	497,361	1,729,647
Mason Co. PUD No. 1	42,886	152,689
Mason Co. PUD No. 3	301,854	1,026,097
Northern Wasco Co. PUD	69,457	268,810
Okanogan Co. PUD No. 1	369,214	1,280,753
Pacific Co. PUD No. 2	219,789	852,493
Pend Oreille Co. PUD No. 1	2,852	7,132
Skamania Co. PUD No. 1	80,346	308,772
Snohomish Co. PUD No. 1	3,465,627	11,848,979
Tillamook PUD	282,188	1,127,555
Wahkiakum Co. PUD No. 1	40,966	151,459
Whatcom Co. PUD	122,674	340,315
Total Public Utility Districts (26)	15,451,055	$ 52,352,929
Cooperatives		
Alder Mutual Light Co.	1,824	$ 7,093
Benton Rural Electric Assn.	154,622	484,410
Big Bend Electric Coop.	259,883	710,727
Blachly-Lane Co. Coop.	84,882	329,440
Central Electric Coop.	151,628	494,516
Clearwater Power Co.	125,094	454,483
Columbia Basin Electric Coop.	105,553	328,413
Columbia Power Coop. Assn.	34,188	122,286
Columbia Rural Electric Assn.	129,518	390,397
Consumers Power	233,254	853,182
Coos-Curry Electric Coop.	234,659	885,531
Douglas Electric Coop.	113,529	427,856
East End Mutual Electric Co. Ltd.	8,213	28,956
Elmhurst Mutual Power & Light Co.	111,075	403,676
Fall River Electric Coop.	77,998	270,530
Farmers Electric Co.	5,937	22,939
Flathead Electric Coop.	77,634	265,179
Harney Electric Coop.	99,353	258,312
Hood River Electric Coop.	70,250	254,147
Idaho Co. Light & Power Coop. Assn.	34,078	125,124
Inland Power & Light Co.	321,827	1,206,674
Kootenai Electric Coop. Inc.	106,325	366,198
Lane Co. Electric Coop.	259,212	1,004,672
Lincoln Electric Coop.—Montana	46,128	170,352
Lincoln Electric Coop.—Washington	90,980	256,834
Lost River Electric Coop.	34,335	101,826
Lower Valley Power & Light Co.	160,466	582,496
Midstate Electric Coop.	102,543	331,290
Missoula Electric Coop.	70,314	243,694
Nespelem Valley Electric Coop.	30,653	109,253
Northern Lights	107,792	372,991
Ohop Mutual Light Co.	19,254	71,519
Okanogan Co. Electric Coop.	19,704	67,630
Orcas Power & Light Co.	79,899	305,989
Parkland Light & Power Co.	91,789	335,657
Prairie Power Coop.	4,048	14,491
Raft River Electric Coop.	142,729	374,867
Ravalli Co. Electric Coop.	57,207	208,768
Riverside Electric Co.	5,705	22,168
Rural Electric Co.	51,253	183,143
Salem Electric	184,413	681,388
Salmon River Electric Coop.	27,182	81,259
South Side Electric Lines	19,605	67,359
Surprise Valley Electric Corp.	57,506	186,653
Tanner Electric	12,129	46,086
Umatilla Electric Coop. Assn.	398,865	1,252,327
Unity Light & Power Co.	35,488	127,108
Vigilante Electric Coop.	61,257	195,648
Wasco Electric Coop.	72,041	264,253
West Oregon Electric Coop.	55,872	206,643
Total Cooperatives (50)	4,839,693	$ 16,556,433
Total Publicly Owned Utilities (109)	27,659,223	$ 91,420,428
Federal & State Agencies		
U.S. Energy Research Development Agency	303,195	$ 879,819
U.S. Bureau of Mines	7,141	28,011
U.S. Bureau of Reclamation—Roza Project	1,320	4,409
Fairchild Air Force Base	23,048	88,427
U.S. Bureau of Indian Affairs	73,854	303,563
U.S. Navy	189,977	628,763
Total Federal & State Agencies (6)	598,535	$ 1,932,992
Privately Owned Utilities		
California-Pacific Utilities Co.	10,080	$ 22,960
Idaho Power Co.	30,050	75,125
Montana Power Co.	876,512	2,406,972[1]
Pacific Power & Light Co.	762,908	4,995,569[1]
Portland General Electric Co.	838,221	3,397,454[1]
Puget Sound Power & Light Co.	269,030	1,519,733[1]
Utah Power Co.	20,120	67,258
Washington Water Power Co.	454,679	1,150,848
Total Privately Owned Utilities (8)	3,261,600	$ 13,635,919
Aluminum		
Aluminum Co. of America (combined)[2]	3,644,551	$ 9,102,107
Anaconda Aluminum Co.	2,841,570	6,506,753
Intalco Aluminum Co.	3,426,433	8,600,825
Kaiser Alum. & Chem. Corp. (combined)[2]	5,045,979	12,650,663
Martin Marietta Aluminum Inc.		
The Dalles, Oregon	1,374,302	2,922,863
Goldendale, Washington	1,627,735	3,486,996
Reynolds Metals Co.		
Longview, Washington	3,153,242	7,921,521
Troutdale, Oregon	2,118,975	5,341,393
Other Industries		
The Carborundum Co.	203,247	$ 537,059
Cominco American, Inc.	0	0
Crown Zellerbach Corp.		
Port Angeles, Washington	40,674	132,694
Port Townsend, Washington	79,146	237,258
Georgia Pacific Corp.	168,846	470,255
Hanna Mining Co.[3]	15,446	34,033
Hanna Nickel Smelting Co.	794,122	2,134,415
ITT Rayonier Incorporated	25,750	82,775
Oregon Metallurgical Corp.	21,025	77,576
Pacific Carbide & Alloys Co.	58,185	160,081
Pennwalt Corporation	356,262	939,564
Stauffer Chemical Works	407,648	1,103,000
Stewart Elsner	55	486
Union Carbide Corp.	125,514	340,268
Total Industries (18)	25,528,707	$ 62,782,585
OUTSIDE NORTHWEST REGION		
British Columbia Hydro	100,789	$ 302,367
Burbank, California	167,964	596,775
Glendale, California	131,459	414,976
Los Angeles, California	1,869,906	6,742,061
Pasadena, California	140,777	500,495
Sacramento, California	0	0
Pacific Gas & Electric Co.	2,137,433	6,910,471
San Diego Gas & Electric Co.	309,386	895,480
Southern California Edison Co.	2,308,902	7,743,995
State of California	45,439	90,878
USBR—Mid-Pacific Region	1,417,801	4,773,538
USBR—Lower Colorado Region	0	0
Total Outside Northwest Region (12)	8,629,856	$ 28,971,036
Total Sales of Electric Energy (155)	65,677,921	$198,742,960[4]

[1] Includes capacity sales.

[2] Billing is by company. Approximate break by plant:

	MWH	Revenue
Alcoa-Vancouver	2,076,615	5,185,365
Alcoa-Wenatchee	1,567,936	3,916,742
Kaiser-Spokane Reduction	3,403,608	8,496,171
Spokane Rolling	401,025	1,012,888
Tacoma Reduction	1,241,346	3,141,604

[3] Service terminated 9/74.

[4] Data on this table are based on statistical records which differ from the accounting data used in the financial statements. Accounting data are on the accrual basis. Statistical data, however, are adjusted after the fact for billing corrections and other factors. A significant difference with respect to fiscal year 1975 is that the accounts recorded the delivery of 1.5 billion kwh of surplus firm hydro energy to Portland General Electric Company as a sale when the Trojan Nuclear Plant was delayed whereas the statistical records recorded this delivery as an exchange subject to possible future return.

Federal Columbia River Power System

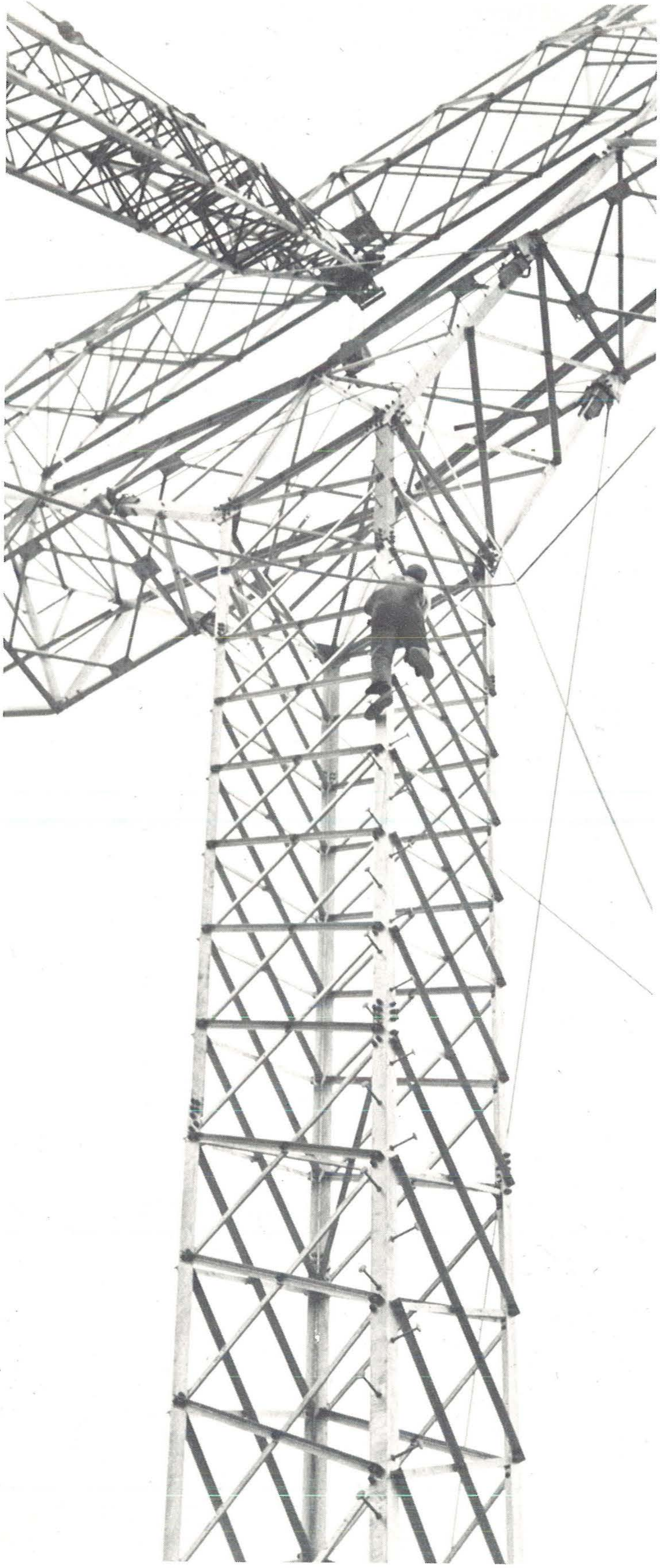
Table 2

GENERAL SPECIFICATIONS, PROJECTS EXISTING, UNDER CONSTRUCTION AND AUTHORIZED

NAMEPLATE RATING OF INSTALLATIONS AS OF JUNE 30, 1975

					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	8	544,000	–	–	–	–	18	1,062,400
Grand Coulee	BR	Washington	Columbia	Sept. 1941	18-3	2,229,000[2]	6	3,951,000[3]	–	–	6	3,600,000	30-3	9,780,000
Grand Coulee (Pump Generator)		Washington	Columbia–Banks Lake	Dec. 1974	2	100,000	–	–	4	200,000	–	–	6	300,000
Hungry Horse	BR	Monta a	S. Fk. Flathead	Oct. 1952	4	285,000	–	–	–	–	–	–	4	285,000
Detroit	CE	Oregon	North Santiam	July 1953	2	100,000	–	–	–	–	–	–	2	100,000
McNary	CE	Ore.-Wash.	Columbia	Nov. 1953	14	980,000	–	–	–	–	10	1,050,000	24	2,030,000
Big Cliff	CE	Oregon	North Santiam	June 1954	1	18,000	–	–	–	–	–	–	1	18,000
Lookout Point	CE	Oregon	M. Fk. Willamette	Dec. 1954	3	120,000	–	–	–	–	–	–	3	120,000
Albeni Falls	CE	Idaho	Pend Oreille	Mar. 1955	3	42,600	–	–	–	–	–	–	3	42,600
Dexter	CE	Oregon	M. Fk. Willamette	May 1955	1	15,000	–	–	–	–	–	–	1	15,000
Chief Joseph	CE	Washington	Columbia	Aug. 1955	16	1,024,000	11	1,045,000	–	–	13	1,573,000	40	3,642,000
Chandler	BR	Washington	Yakima	Feb. 1956	2	12,000	–	–	–	–	–	–	2	12,000
The Dalles	CE	Ore.-Wash.	Columbia	May 1957	22-2	1,807,000[4]	–	–	–	–	–	–	22-2	1,807,000
Roza	BR	Washington	Yakima	Aug. 1958	1	11,250	–	–	–	–	–	–	1	11,250
Ice Harbor	CE	Washington	Snake	Dec. 1961	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[5]	BR	Idaho	Snake	May 1909	7	13,400	–	–	–	–	–	–	7	13,400
Boise Diversion[5]	BR	Idaho	Boise	May 1912	3	1,500	–	–	–	–	–	–	3	1,500
Black Canyon[5]	BR	Idaho	Payette	Dec. 1925	2	8,000	–	–	–	–	–	–	2	8,000
Anderson Ranch[5]	BR	Idaho	S. Fk. Boise	Dec. 1950	2	27,000	–	–	–	–	1	13,500	3	40,500
Palisades[5]	BR	Idaho	Snake	Feb. 1957	4	118,750	–	–	–	–	2	135,000	6	253,750
Cougar	CE	Oregon	S. Fk. McKenzie	Feb. 1964	2	25,000	–	–	1	35,000	–	–	3	60,000
Green Peter	CE	Oregon	Middle Santiam	June 1967	2	80,000	–	–	–	–	–	–	2	80,000
Foster	CE	Oregon	South Santiam	Aug. 1968	2	20,000	–	–	–	–	–	–	2	20,000
John Day	CE	Ore.-Wash.	Columbia	July 1968	16	2,160,000			4	540,000	–	–	20	2,700,000
Lower Monumental	CE	Washington	Snake	May 1969	3	405,000	3	405,000	–	–	–	–	6	810,000
Little Goose	CE	Washington	Snake	May 1970	3	405,000	3	405,000	–	–	–	–	6	810,000
Lower Granite	CE	Washington	Snake		3	405,000	3	405,000	–	–	–	–	6	810,000
Teton	BR	Idaho	Teton		–	–	3	30,000	–	–	–	–	3	30,000
Lost Creek	CE	Oregon	Rogue		–	–	2	49,000	–	–	–	–	2	49,000
Dworshak	CE	Idaho	N. Fk. Clearwater	Sept. 1974	2	310,000	1	90,000[6]	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
Libby Reregulating	CE	Montana	Kootenai		–	–	–	–	4	43,800	–	–	4	43,800
Asotin[7]	CE	Wash.-Ida.	Snake		–	–	–	–	4	540,000	–	–	4	540,000
Total installed capacity						11,540,900		7,676,880		2,443,300		6,371,500		28,032,580
Total number of projects						28		3		3		0		34

[1] CE–Corps of Engineers; BR–Bureau of Reclamation.
[2] Includes three service units and increase of 17,000 kW each for 15 rewound main units.
[3] Includes an increase of 17,000 kW each for 3 units to be rewound, three 600,000 kW units and three 700,000 kW units being installed at the Third Powerplant.
[4] Includes two fishway units of 13,500 kW each, 14 units of 78,000 kW and 8 units of 86,000 kW at The Dalles Powerplant.
[5] U.S. Bureau of Reclamation project incorporated into the Federal Columbia River Power System, effective July 1, 1963.
[6] Three Dworshak units have been operating at reduced capability since March 1973. Unit #2 is not acceptable for commercial operation pending manufacturer's correction of overheating problems. Unit #3 started commercial operation September 18, 1974, and Unit #1 June 2, 1975.
[7] Authorized, but not under active consideration.



Crane boom erecting 500-kilovolt BPA tower.

Federal Columbia River Power System

Table 3

ELECTRIC ENERGY ACCOUNT FISCAL YEAR – 1975

Energy Received (millions of kilowatt-hours)	
Energy Generated for BPA	
Bureau of Reclamation	18,709
Corps of Engineers	54,312
Washington Public Power Supply System (Hanford)	3,803
Centralia Thermal Project	2,166
Power Interchanged in	52,013
Total Received	131,003
Energy Delivered (millions of kilowatt-hours)	
Sales	65,678
Power Interchanged Out	61,134
Used by the Administration	68
Total Delivered	126,880
Energy Losses in transmission and transformation	4,123
Total	131,003
Losses in percent of total received	3.1
Maximum demand on Federal plants (kilowatts) (Date and Time) February 21, 1975, 7 P.M.	12,082,000
Load factor in percent of total generated for BPA	74.6

Table 4

GENERATION BY THE PRINCIPAL ELECTRIC UTILITY SYSTEMS OF THE PACIFIC NORTHWEST[1] FISCAL YEAR 1975

Utility	Kilowatt-Hours (Billions)	Of Total Generation (Percent)
Publicly Owned:		
Federal Columbia River Power System[2]	80.7	54.9
Grant County PUD	11.6	7.9
Chelan County PUD	8.5	5.8
Seattle City Light	6.3	4.3
Douglas County PUD	4.4	3.0
Tacoma City Light	2.9	2.0
Eugene Water & Electric Board	0.5	0.3
Pend Oreille County PUD	0.4	0.3
Total Publicly Owned	115.3	78.5
Privately Owned:		
Idaho Power Company	11.2	7.6
Pacific Power & Light Co.	7.2	4.9
Montana Power Company	5.0	3.4
Washington Water Power Co.	3.6	2.5
Portland General Electric Co.	2.8	1.9
Puget Sound Power & Light Co.	1.8	1.2
Total Privately Owned	31.6	21.5
Total Generation	146.9	100.0

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

[2] Includes generation from the Washington Public Power Supply System's Hanford steamplant (NPR) and the Centralia Steamplant.

BONNEVILLE POWER ADMINISTRATION FUND

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

	Cash Receipts	Cash Disbursements	Increase in Balance	Cumulative Balance	Appropriations Included in Balance	Bonds and Notes Outstanding
June 30, 1975				98.7	86.4	
FY 1976						
July	13.0	19.1	(6.1)	92.6	73.3	
August	28.3	16.7	11.6	104.2	61.2	
September	23.5	18.4	5.1	109.3	50.2	
October	24.0	19.0	5.0	114.3	38.2	
November	27.8	20.1	7.7	122.0	26.9	
December	23.8	16.6	7.2	129.2	18.2	
January 1976	33.6	19.0	14.6	143.8	7.6	
February	33.3	17.5	15.8	159.6		
March	32.4	18.2	14.2	173.8		
April	26.2	18.4	7.8	181.6		
May	25.0	16.0	9.0	190.6		
June	24.5	186.2[1]	(161.7)	28.9		
Transition Quarter						
July	24.4	20.7	3.7	32.6		
August	24.4	22.9	1.5	34.1		
September	26.7	57.3[1]	(30.6)	3.5		
FY 1977						
October	24.2	21.7	2.5	6.0		
November	26.4	22.7	3.7	9.7		
December	22.6	18.6	4.0	13.7		
January 1977	32.1	21.5	10.6	24.3		
February	31.9	19.6	12.3	36.6		
March	31.0	20.4	10.6	47.2		
April	25.0	21.1	3.9	51.1		
May	23.8	18.2	5.6	56.7		
June	18.2	20.7	(2.5)	54.2		
July	22.2	20.7	1.5	55.7		
August	21.4	23.0	(1.6)	54.1		
September	25.7	165.9[1]	(140.2)	(86.1)		
FY 1978						
October	19.6	18.8	.8	(85.3)		85.3
November	21.8	19.8	2.0	(83.3)		83.3
December	18.3	15.7	2.6	(80.7)		80.7
January 1978	27.0	18.6	8.4	(72.3)		72.3
February	26.8	16.7	10.1	(62.2)		62.2
March	26.0	20.0	6.0	(56.2)		56.2
April	20.3	18.2	2.1	(54.1)		54.1
May	19.3	15.3	4.0	(50.1)		50.1
June	14.1	17.8	(3.7)	(53.8)		53.8
July	17.8	17.8	0	(53.8)		53.8
August	17.0	20.0	(3.0)	(56.8)		56.8
September	19.2	168.6[1]	(149.4)	(206.2)		206.2
FY 1979						
October	22.1	18.0	4.1	(202.1)		202.1
November	24.3	19.0	5.3	(196.8)		196.8
December	20.3	15.1	5.2	(191.6)		191.6
January 1979	30.2	17.8	12.4	(179.2)		179.2
February	29.9	16.0	13.9	(165.3)		165.3
March	29.1	23.4	5.7	(159.6)		159.6
April	22.9	17.4	5.5	(154.1)		154.1
May	21.7	14.7	7.0	(147.1)		147.1
June	15.9	17.0	(1.1)	(148.2)		148.2
July	20.0	17.0	3.0	(145.2)		145.2
August	19.2	19.1	.1	(145.1)		145.1
September	21.6	175.7[1]	(154.1)	(299.2)		299.2

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

Federal Columbia River Power System

REPAYMENT STUDY FOR F.Y. 1975

AUTHORIZED PROJECTS

(All Amounts in $1,000)

Table 6

1	2	3	4	5	6	7	8	9	10
Fiscal Year	Revenues	O & M and Purchased Power	Interest Expense (Net)	Investment Placed In Service	Cumulative Investment In Service	Amortization	Unamortized Investment	Allowable Unamortized Investment	Cumulative Surplus Revenues
Cumulative 1975	2,702,853	1,002,585	968,466	4,519,325	4,519,325	731,802[1]	3,787,523	4,517,666	
1976	299,000	108,827	98,266	666,436	5,185,761	91,907	4,362,052	5,184,102	
T/Q	72,400	23,299	24,567	166,609	5,352,370	24,534	4,504,127	5,350,711	
1977	319,600	144,017	124,426	448,776	5,801,146	51,157	4,901,746	5,799,213	
1978	331,892	191,623	150,467	667,919	6,469,065	10,198	5,579,863	6,467,132	
1979	353,649	195,667	170,296	178,419	6,647,484	12,314–	5,770,596	6,645,259	
1980	375,648	194,958	187,726	343,394	6,990,878	7,036–	6,121,026	6,985,163	
1981	382,972	198,712	206,757	255,207	7,246,085	22,497–	6,398,730	7,212,972	
1982	393,926	205,230	220,839	373,490	7,619,575	32,143–	6,804,363	7,569,715	
1983	420,563	207,917	241,641	364,834	7,984,409	28,995–	7,198,192	7,912,324	
1984	444,477	208,897	255,783	30,720	8,015,129	20,203–	7,249,115	7,933,583	
1985	453,388	209,386	259,112	43,249	8,058,378	15,110–	7,307,474	7,965,796	
1986	453,721	209,267	261,917	49,142	8,107,520	17,463–	7,374,079	8,003,758	
1987	442,125	208,930	265,854	73,214	8,180,734	32,659–	7,479,952	8,065,193	
1988	447,716	209,870	272,854	172,067	8,352,801	35,008–	7,687,027	8,214,669	
1989	448,572	210,305	286,092	284,593	8,637,394	47,825–	8,019,445	8,475,797	
1990	453,132	213,063	300,284	149,565	8,786,959	60,215–	8,229,225	8,591,501	
1991	451,716	213,631	309,417	61,424	8,848,383	71,332–	8,361,981	8,621,924	
1992	450,916	213,916	318,775	186,578	9,034,961	81,775–	8,630,334	8,734,746	
1993	450,001	208,082	328,442	69,381	9,104,342	86,523–	8,786,238	8,744,407	
1994	448,908	207,034	336,677	88,688	9,193,030	94,803–	8,969,729	8,742,505	
1995	448,278	207,114	346,188	105,697	9,298,727	105,024–	9,180,450	8,826,665	
1996	447,499	207,114	356,264	76,950	9,375,677	115,879–	9,373,279	8,858,078	
1997	448,592	207,114	366,519	75,298	9,450,975	125,041–	9,573,618	8,896,100	
1998	449,130	207,114	376,976	51,724	9,502,699	134,960–	9,760,302	8,886,061	
1999	450,728	207,114	387,512	83,757	9,586,456	143,898–	9,987,957	8,936,217	
2000	453,569	207,114	398,253	87,243	9,673,699	151,798–	10,226,998	8,979,798	
2001	453,800	207,114	409,516	77,863	9,751,562	162,830–	10,467,691	8,980,402	
2002	453,915	207,114	421,788	81,594	9,833,156	174,987–	10,724,272	9,011,890	
2003	454,921	207,114	433,995	68,009	9,901,165	186,188–	10,978,469	9,024,711	
2004	457,000	207,114	446,135	82,890	9,984,055	196,249–	11,257,608	8,931,175	
2005	457,000	207,114	458,923	83,064	10,067,119	209,037–	11,549,709	8,881,036	
2006	457,000	207,114	472,409	97,583	10,164,702	222,523–	11,869,815	8,816,667	
2007	456,609	207,114	487,116	108,301	10,273,003	237,621–	12,215,737	8,774,141	
2008	455,300	207,114	501,715	84,329	10,357,332	253,529–	12,553,595	8,629,754	
2009	455,300	207,114	516,623	95,215	10,452,547	268,437–	12,917,247	8,550,544	
2010	454,058	207,114	533,294	93,827	10,546,374	286,350–	13,297,424	8,427,620	
2011	449,647	207,114	551,450	111,385	10,657,759	308,917–	13,717,726	8,450,476	
2012	448,800	187,114	569,415	106,260	10,764,019	307,729–	14,131,715	8,339,772	
2013	448,800	187,114	587,259	96,678	10,860,697	325,573–	14,553,966	8,279,276	
2014	444,430	187,114	606,684	109,882	10,970,579	349,368–	15,013,216	8,277,174	
2015	429,340	114,614	626,142	92,899	11,063,478	311,416–	15,417,531	8,224,952	
2016	427,800	114,614	647,369	136,020	11,199,498	334,183–	15,887,734	8,157,136	
2017	427,800	114,614	668,326	105,915	11,305,413	355,140–	16,348,789	8,036,038	
2018	427,800	114,614	689,296	92,642	11,398,055	376,110–	16,817,541	7,908,810	
2019	427,800	114,614	709,651	113,578	11,511,633	396,465–	17,327,584	7,641,510	
2020	427,800	114,614	731,500	105,441	11,617,074	418,314–	17,851,339	7,211,616	
2021	427,800	114,614	753,818	90,656	11,707,730	440,632–	18,382,627	7,100,027	
2022	427,800	114,614	775,679	104,225	11,811,955	462,493–	18,949,345	7,068,699	
2023	427,800	114,614	798,015	104,366	11,916,321	484,829–	19,538,540	6,993,111	
2024	427,800	114,614	820,272	95,919	12,012,240	507,086–	20,141,545	7,019,234	
2025	427,800	114,614	843,712	94,790	12,107,030	530,526–	20,766,861	6,512,115	
2026	427,800	114,614	869,501	131,768	12,238,798	556,315–	21,454,944	5,909,368	
2027	427,800	114,614	897,184	114,619	12,353,417	583,998–	22,153,561	5,673,005	
2028	427,800	114,614	925,493	94,135	12,447,552	612,307–	22,860,003	5,231,323	
2029	427,800	114,614	955,298	106,981	12,554,533	642,112–	23,609,096	5,152,157	
2030	427,800	114,614	986,933	95,525	12,650,058	673,747–	24,378,368	5,132,839	
2031	427,800	114,614	1,019,955	98,156	12,748,214	706,769–	25,183,293	4,994,433	
2032	427,800	114,614	1,055,751	99,507	12,847,721	742,565–	26,025,365	4,738,666	
2033	427,800	114,614	1,093,260	73,836	12,921,557	780,074–	26,879,275	4,520,669	
2034	427,800	114,614	1,132,539	84,759	13,006,316	819,353–	27,783,387	4,561,645	
2035	427,800	114,614	1,174,626	74,182	13,080,498	861,440–	28,719,009	4,565,345	
2036	427,800	114,614	1,220,935	87,193	13,167,691	907,749–	29,713,951	4,570,483	
2037	427,800	114,614	1,271,822	63,160	13,230,851	958,636–	30,735,747	4,534,370	
2038	427,800	114,614	1,325,795	52,609	13,283,460	1,012,609–	31,800,965	4,472,118	
2039	427,800	114,614	1,382,117	60,338	13,343,798	1,068,931–	32,930,234	4,304,691	
2040	427,800	114,614	1,442,426	65,051	13,408,849	1,129,240–	34,124,525	4,224,285	
2041	427,800	114,614	1,507,639	66,419	13,475,268	1,194,453–	35,385,397	4,209,275	
2042	427,800	114,614	1,577,752	88,035	13,563,303	1,264,566–	36,737,998	4,140,682	
2043	427,800	114,614	1,652,527	53,616	13,616,919	1,339,341–	38,130,955	4,127,030	
2044	427,800	114,614	1,730,742	59,080	13,675,999	1,417,556–	39,607,591	4,110,255	
2045	427,800	114,614	1,814,124	69,012	13,745,011	1,500,938–	41,177,541	4,077,904	
2046	427,800	114,614	1,861,490	76,102	13,821,113	1,548,304–	42,801,947	4,078,260	
2047	427,800	114,614	1,872,159	63,997	13,885,110	1,558,973–	44,424,917	4,077,431	
2048	427,800	114,614	1,887,972	58,946	13,944,056	1,574,786–	46,058,649	4,047,468	
2049	427,800	114,614	1,911,682	79,032	14,023,088	1,598,496–	47,736,177	4,006,617	
2050	427,800	114,614	1,943,644	63,486	14,086,574	1,630,458–	49,430,121	3,979,714	
TOTALS	35,043,891	12,993,600	57,393,838	14,086,574		35,343,547–			

[1] The amount of cumulative amortization shown through fiscal year 1975 ($731,802,000) includes $720,650,000 actually returned to the U.S. Treasury for the repayment of the Government investment in power facilities and $11,152,000 of revenues invested in Government securities in lieu of amortization.

REPAYMENT POLICY

Revenues must be sufficient to satisfy the following repayment criteria:

1. Pay the cost of operating and maintaining the power system.
2. Pay the cost of obtaining power through purchase and exchange agreements.
3. Pay interest on and amortize outstanding revenue bonds sold to the Treasury to finance transmission system construction.
4. Pay interest on the unamortized investment in power facilities financed with appropriated funds (Federal hydroelectric projects and BPA transmission facilities constructed prior to BPA's authorization to finance its construction program with sales receipts and revenue bonds).
5. Repay:
   a. Each increment of the power investment at the Federal hydroelectric projects within 50 years after such increment becomes revenue producing.
   b. Each annual increment of the investment in the BPA transmission system previously financed with appropriated funds within the average service life of the transmission facilities (currently 40 years).
   c. The investment in each replacement of a facility at a Federal hydroelectric project within its service life.

   (In repaying the investment financed with appropriated funds, the investment bearing the highest interest rate will be amortized first to the extent possible while still completing repayment of each increment of investment within its prescribed repayment period.)
6. Repay the portion of construction costs at Federal reclamation projects which is beyond the ability of the irrigation water users, and which is assigned for repayment from commercial power revenues, within the same overall period available to the water users for making their repayments. These periods range from 40 to 66 years, with 60 years being applicable to most of the irrigation repayment assistance.

The FY 1975 Repayment Study (Table 6, page 42), prepared in accordance with the foregoing criteria, shows that cumulative revenues through June 30, 1975, totaled \$2.703 billion. These have been applied to pay purchase and exchange power costs of \$238 million, operation and maintenance costs of \$767 million, interest costs of \$968 million, with \$721 million having been applied to amortization of the investment in power facilities. The remaining \$11 million was invested in Treasury securities as of the end of the fiscal year. Cumulative investment to be repaid from power revenues totaled \$4.519 billion with the unamortized balance totaling \$3.788 billion.

Starting with these cumulative results, the repayment study forecasts future revenues and costs over the balance of the repayment period. Costs and revenues are included for all Federal hydroelectric projects which are (1) currently in service, (2) under construction, and (3) authorized by Congress and scheduled for construction by the constructing agency, plus the costs of the transmission facilities necessary to market the output of these projects as well as handle the other sources of power transmitted by BPA. The repayment study also includes BPA power purchase costs which will commence within the 5-year period from December 20, 1974, to December 20, 1979, for which the Federal Power Commission has approved BPA's present wholesale power rates.

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

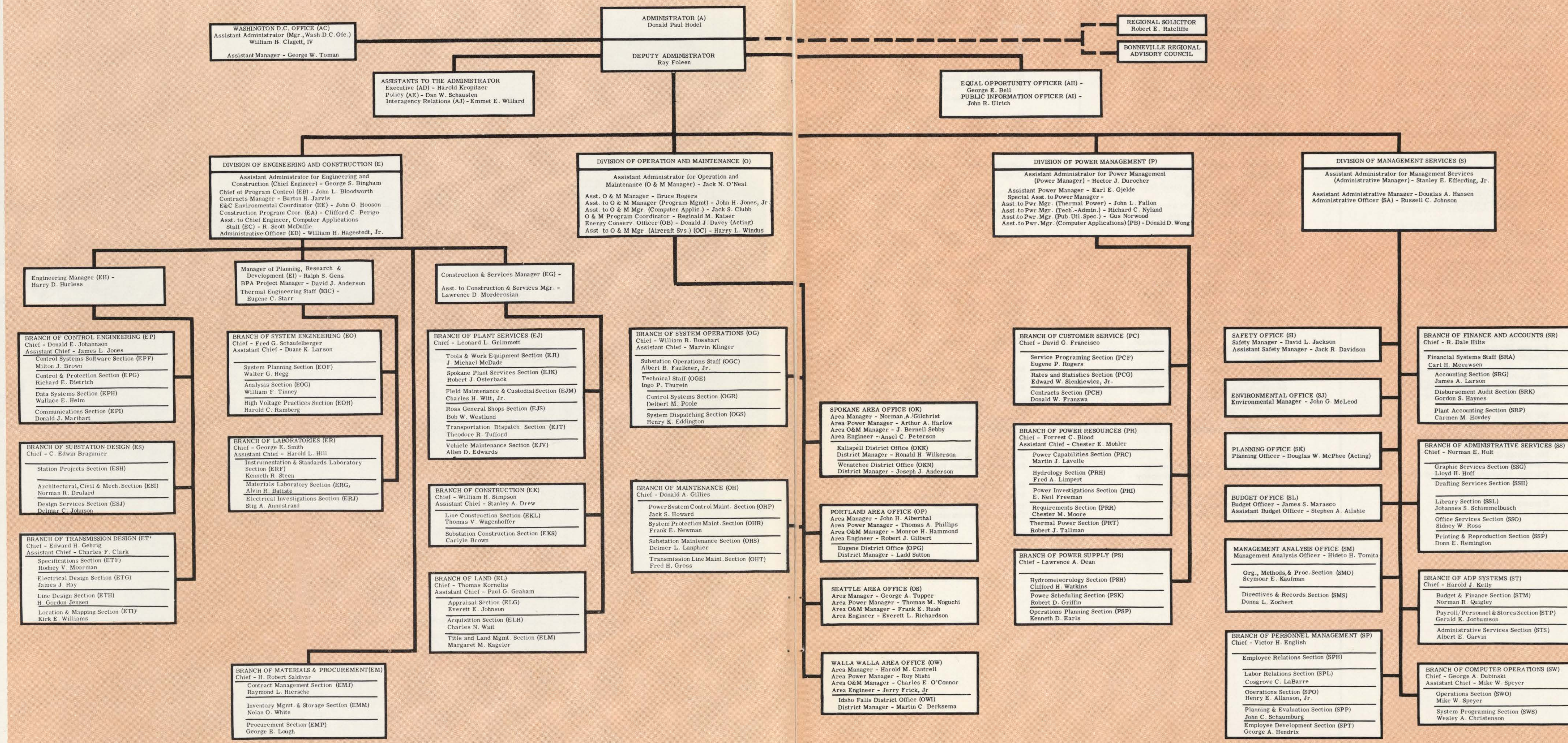
Agriculture flourishes under BPA transmission towers.

BPA
Structure and Administration

Assistant Secretary of the Interior, Jack W. Carlson, shown with BPA Administrator, Don Hodel, and Carl Blake of the BPA staff, on visit to BPA's Dittmer Control Center in Vancouver, Washington, in November, 1975.

BPA Organization Chart

MANAGEMENT ANALYSIS OFFICE
November 1, 1975



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2.5M March 1976 Interior—Portland, Oregon

As the Nation's principal conservation agency, the Department of the Interior has responsibility for most of our nationally owned public lands and natural resources. This includes fostering the wisest use of our land and water resources, protecting our fish and wildlife, preserving the environmental and cultural values of our national parks and historical places, and providing for the enjoyment of life through outdoor recreation. The Department assesses our energy and mineral resources and works to assure that their development is in the best interests of all our people. The Department also has a major responsibility for American Indian reservation communities and for people who live in Island Territories under U.S. Administration.