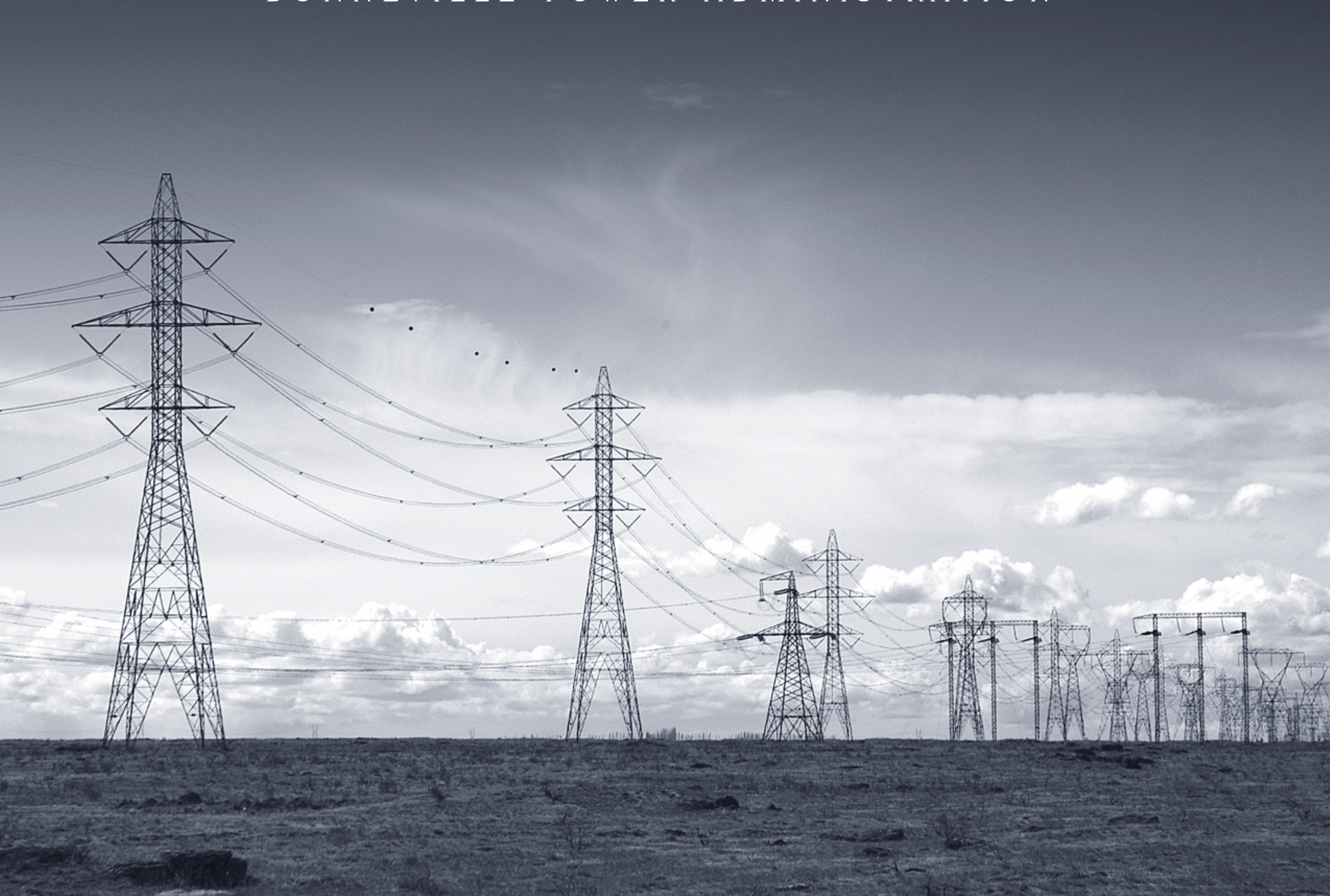
BPA

2003 ANNUAL REPORT

BONNEVILLE POWER ADMINISTRATION



2003 Annual Report

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BPA Profile

The Bonneville Power Administration is a federal agency under the Department of Energy. Based in the Pacific Northwest, the agency markets wholesale electrical power from 31 federal hydro projects, one nonfederal nuclear plant and several other small nonfederal power plants. BPA also operates and maintains about three-fourths of the region's high-voltage transmission. About 45 percent of all the electric power used in the Northwest comes from BPA.

BPA is a self-funding agency that covers its costs by selling its services wholesale to the region's public utilities, municipalities, investor-owned utilities and some large industries. BPA also sells or exchanges power with utilities in Canada and the western United States. Its service area includes Oregon, Washington, Idaho, western Montana and small parts of Wyoming, Nevada, Utah, California and eastern Montana.

BPA is committed to providing public service and seeks to make its decisions in a manner that provides opportunities for input from all stakeholders. In addition to keeping rates low by selling at cost, BPA is dedicated to providing high system reliability. BPA also promotes energy efficiency, renewable energy and new technologies. The agency funds the region's efforts to protect and rebuild fish and wildlife populations in the Columbia River Basin and works in partnership with others to ensure protection of the region's environment.

Financial Highlights

Federal Columbia River Power System
As of and for the periods ended Sept. 30

Operating Results
thousands of dollars

	2003	2002	2001
Revenues	**$ 3,556,839**	$ 3,495,375	$ 4,230,792
SFAS 133* mark-to-market	**55,265**	38,354	47,877
Total operating revenues	**3,612,104**	3,533,729	4,278,669
Total operating expenses	**2,711,089**	3,171,954	4,115,670
Net operating revenues	**901,015**	361,775	162,999
Net interest expense	**345,591**	352,300	331,909
Net revenues (expenses) before the cumulative effect of SFAS 133	**555,424**	9,475	(168,910)
Cumulative effect of SFAS 133	—	—	(168,491)
Net revenues (expenses)	**$ 555,424**	$ 9,475	$ (337,401)

End of Fiscal Year
thousands of dollars

	2003	2002	2001
Total assets (net of accumulated depreciation)	**$ 17,260,075**	$ 16,511,999	$ 16,770,530
Total capitalization and liabilities			
Accumulated net revenues (expenses)	**$ 343,748**	$ (211,676)	$ (221,151)
Federal appropriations	**4,680,960**	4,642,602	4,670,930
Capitalization adjustment	**2,124,697**	2,192,400	2,259,756
Long-term debt	**2,697,754**	2,770,441	2,688,542
Nonfederal projects debt	**6,286,593**	6,201,544	6,171,949
Other	**1,126,323**	916,688	1,200,504
	$ 17,260,075	$ 16,511,999	$ 16,770,530

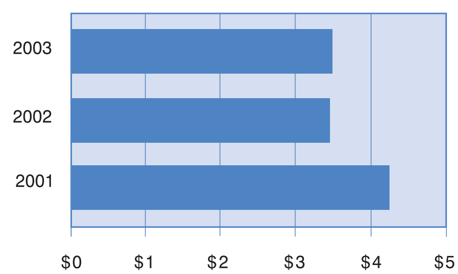
**Statement of Financial Accounting Standards 133. See Adoption of Statement 133 and Related Guidance in the Notes to Financial Statements.*

Financial Results

The charts below depict important BPA and Federal Columbia River Power System financial measures. Both *Operating Revenues* and *Operating Expenses* are reviewed in the Management's Discussion & Analysis at page 20. *Net Revenues With and Without Debt Management Actions and* SFAS 133 reflect the impact of BPA's debt optimization program, other debt management actions and SFAS 133 on net revenues (see *The year in review* narrative at page 6). *Nonfederal Debt Service Coverage* demonstrates how many times total nonfederal project debt service is covered by net funds available. A ratio of 1.0 is the minimum required to show adequate funds to meet debt service payments to nonfederal bondholders (see the *Nonfederal Projects* note on page 41 for a discussion of these projects). The *Status of Treasury Principal Repayment* shows the scheduled and early repayment of federal appropriations and U.S. Treasury bonds (see *Treasury payment probability* narrative at page 8). *Financial Reserves* is the sum of BPA cash and deferred borrowing authority at year end (see *The year in review* narrative at page 6).

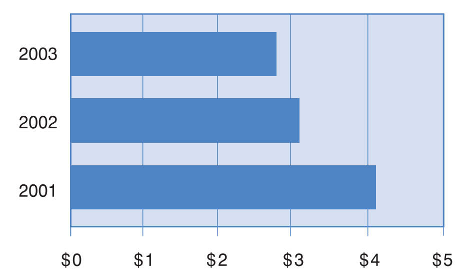
Operating Revenues

billions of dollars



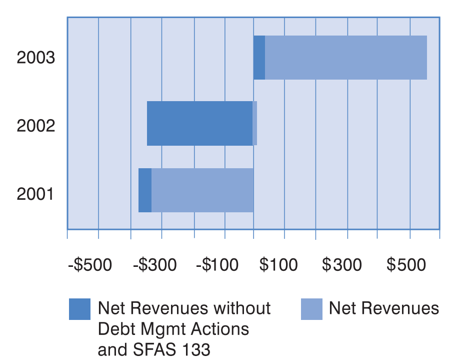
Operating Expenses

billions of dollars

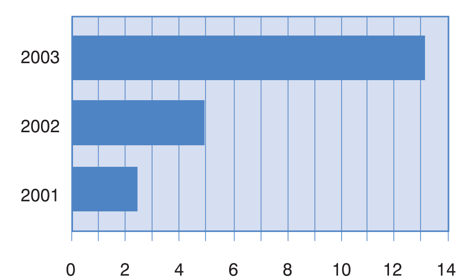


Net Revenues With and Without Debt Management Actions and SFAS 133

millions of dollars

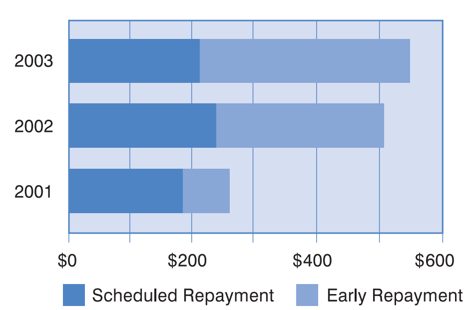


Nonfederal Debt Service Coverage



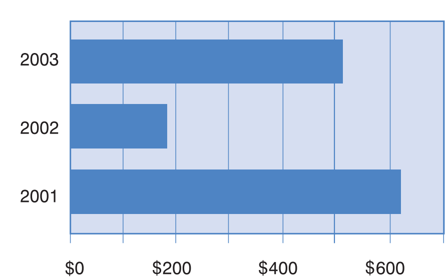
Status of Treasury Principal Repayment

millions of dollars



Financial Reserves

millions of dollars



Dear Mr. President:

The turn of the century brought some challenging years to the Bonneville Power Administration, as it did to the utility industry in general and the West Coast in particular. I am pleased to say we are meeting these challenges and looking to a bottom line that is much improved.

Our highest priority has been to restore our financial health after the devastating impacts of the 2000/2001 West Coast energy crisis and the Northwest drought. The financial results displayed on the opposite page make it clear that BPA is fulfilling this goal.

We improved our financial condition despite a water year that was 80 percent of normal primarily through cost management, debt optimization and use of a contingency fund available in severe drought conditions. As part of our cost management effort, we have committed to limit power-related internal operations expenses to 2001 actual levels with no allowance for inflation. We beat this target by nearly 10 percent in 2003. Overall, BPA's forecast power expenses have been reduced for the 2003-2006 period by approximately $350 million from where they were expected to be a year ago.

This past year we took advantage of historically low interest rates to refinance $1.4 billion of nonfederal debt, which gave us present value savings of $121 million. During this past year, we also triggered a safety net rate adjustment that went into effect on Oct. 1, 2003, the beginning of fiscal 2004. This raised rates 2.2 percent over fiscal 2003 levels. The result of all these efforts is that we now have an 80 percent probability of making our U.S. Treasury payments for the remainder of the rate period.

Even as we worked hard to improve financial stability, we also took significant steps in meeting our responsibilities to the Pacific Northwest.

We believe investment in electricity infrastructure – transmission, generation and energy efficiency – is critical to reduce price volatility and to ensure system reliability, both of which are important to our region's economy. This year, we began construction on a critical transmission infrastructure program designed to ensure reliable electricity delivery. In February 2003, with White House encouragement, Congress approved a $700 million increase in our borrowing authority to fund our capital program, which includes transmission as well as other infrastructure projects. While that increase will not finance our entire infrastructure program, we were able to begin work on our six most important transmission projects. Together, the six projects will serve growth in Portland and Seattle until at least 2010 and will assure continued use of the direct-current intertie to California for decades to come.

We also looked at infrastructure beyond transmission. We worked with the U.S. Army Corps of Engineers and the Bureau of Reclamation, our partners in the Federal Columbia River Power System, to create 35 average megawatts of increased hydro production through system improvements.

In the conservation arena, we are well ahead of our goal of acquiring 220 average megawatts of cost-effective conservation during the current five-year rate period. We acquired over 40 average megawatts of conservation in the last year. We also are working hard to meet our responsibilities in natural resources. Responding to a progress report, the National Oceanic and Atmospheric Administration Fisheries (formerly the National Marine Fisheries Service) found our implementation of the 2000 NMFS biological opinion to be essentially on track. We expect the same finding when the program is evaluated under a major three-year progress check-in that we completed on Sept. 30.

Working to bring about financial stability required making a number of major decisions, some of which were challenged. So I am particularly pleased to report that our decisions were given a vote of confidence from two important sources during fiscal 2003. The Ninth Circuit Court of Appeals found in the agency's favor in our decision to buy back power from aluminum companies during the 2001 West Coast energy crisis as a way of supporting the industry and reducing electricity demand in the Northwest. Calling BPA's decision to curtail load "eminently businesslike," the court said, "We will not second-guess the wisdom of BPA's winning business decisions, especially when it was responding to unprecedented market changes."

In another ruling in August, the Ninth Circuit Court of Appeals found that, during the 2001 power emergency and drought, BPA did provide equitable treatment to anadromous fish as required by the Northwest Power Act.

Most recently, staff from the Federal Energy Regulatory Commission investigating the practices of all sellers in the California market during the West Coast energy crisis found no evidence that BPA participated in any attempt to manipulate the power market. FERC staff has subsequently asked that the Commission remove BPA from the investigation. We believe that federal agencies should be expected to perform to high ethical standards, and we believe BPA is meeting that test.

Despite many positive accomplishments, however, the region's economy continues to struggle with some of the highest unemployment in the country. As we look to the future, we know we need to do all we can to lower our power rates while we continue to work on our financial health. As the 2003 fiscal year came to a close, BPA was engaged in developing a settlement of litigation that public power utilities filed against the agency related to the level of benefits that are currently going to residential and small-farm customers of the region's investor-owned utilities.

If the settlement, which is out for consideration, is reached, BPA will be able to reduce its fiscal 2004 wholesale power rates for public utilities and direct-service industries by 7.4 percent below our fiscal 2003 average rate. We would also eliminate the 2.2 percent safety net rate increase that took effect Oct. 1. The net effect would be a nearly 10 percent reduction in wholesale power rates from current levels.

This was also a good year for safety and reliability at BPA. We achieved our targets both for low accident frequency and for minimal frequency and duration of power outages.

As we look out to the longer term, we know that about 75 percent of our cost increases from the previous rate period came from the more than 3,000 megawatts of load we are serving beyond the Federal Columbia River Power System's capability. We will hold a regional dialogue that will begin in early calendar 2004 to examine whether and to what extent BPA should continue to augment our base hydro system. That decision will have a substantial impact on our future cost structure.

As you read this report, you will note other directions for the future. These include the need for measurable objectives that assure we have a cost-effective program to achieve our fish and wildlife mitigation responsibilities. We also will continue our efforts to further our support for infrastructure development including transmission, generation and energy efficiency.

Our goal is to respond to the region's desire for low-cost reliable power and positive environmental stewardship, while operating a successful business that covers all its costs.

Sincerely,

Stephen J. Wright
Administrator and CEO

The year in review

The Bonneville Power Administration ended fiscal 2003 in the black with financial results that provided a positive contrast to the agency's performance in the prior two years. The improvement provides clear evidence that BPA is recovering from the economic impact of the West Coast energy crisis and the drought of 2000/2001.

After taking into account debt management actions and SFAS 133 (Statement of Financial Accounting Standards 133), fiscal 2003 net revenues came in at a positive $555 million. Without these actions, net revenues would have been $37 million. This compares to 2002 when BPA's net revenues were $9 million including debt management actions and SFAS 133. Excluding these actions, the agency would have seen a loss of more than $300 million in fiscal 2002. In fiscal 2001, the year of the California energy crisis, BPA did lose $337 million.

BPA's liquidity also has improved dramatically. In 2002, BPA was still feeling the effects of the West Coast energy crisis and drew down its financial reserves to

$188 million. By contrast, in fiscal 2003, reserves increased to $511 million, in part through actions specifically designed to increase available cash.

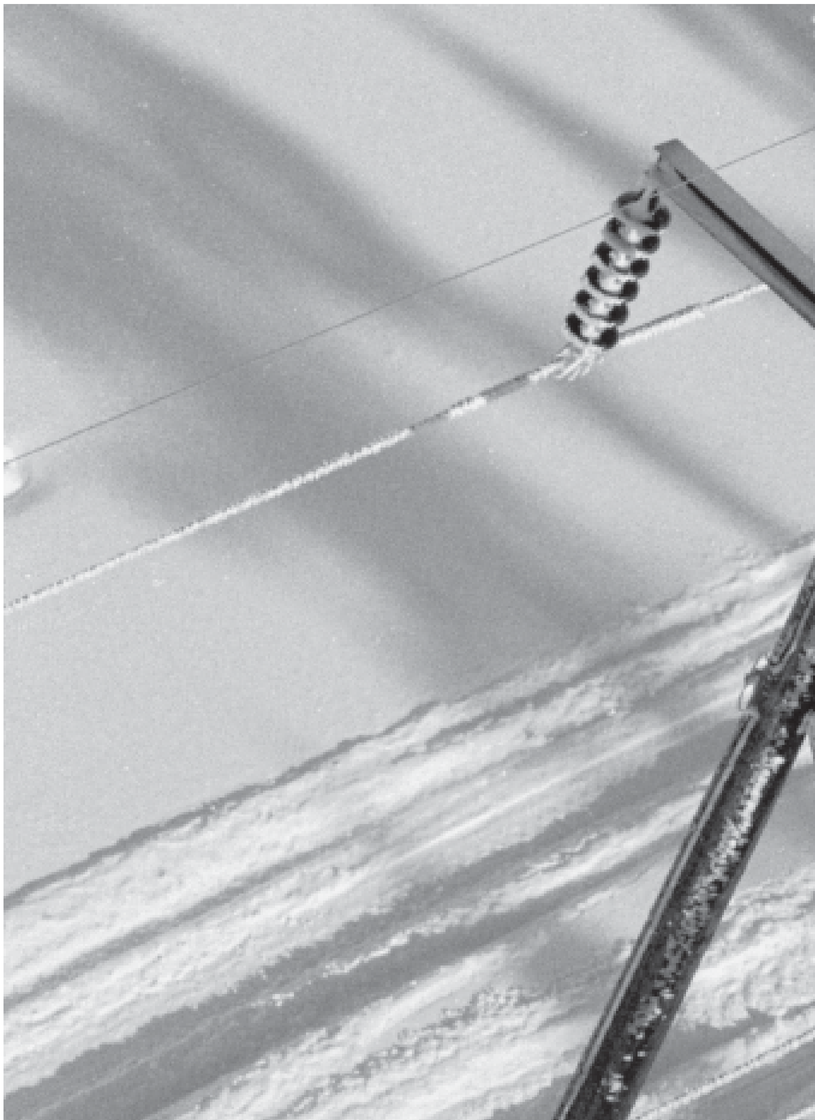
BPA did more than improve its net revenue and financial reserve positions in fiscal 2003. The agency also made deep cost cuts, kept rate increases to a minimum in both business lines and maintained a high probability of making payments to the U.S. Treasury. BPA also began construction of critical transmission infrastructure, saw progress in its fish and wildlife program, maintained an excellent safety record, met its energy efficiency and renewables program goals, and took steps to manage increased risks associated with a restructured electricity industry. These efforts are described in greater detail in the following sections.

Cost cutting

Since the agency implemented its fiscal 2002-2006 power rate case, it has reduced forecast costs through the remainder of the rate period by taking a number of actions. In April 2003, we announced in a letter to the region that we had identified approximately $350 million in forecast expense reductions, deferrals and other actions through the Financial Choices public process involving customers and constituents held in late 2002.

This was not a one-time effort. BPA is committed to instilling stringent cost management throughout the agency and intends cost cutting to be ongoing. The immediate target is to limit internal operations expenses that affect power rates to fiscal 2001 actual levels on average for the rest of the rate period, with no allowance for inflation. BPA beat this target by nearly 10 percent in 2003.

BPA also worked with its partners in the Federal Columbia River Power System – the U.S. Army Corps of Engineers and the Bureau of Reclamation – to reduce their power-related operations and maintenance costs, which BPA directly funds, and to make hydro system modifications to produce efficiencies. Similarly, the agency worked with Energy Northwest to reduce costs. Energy Northwest operates the region's only nuclear facility, and BPA markets the power from that plant.



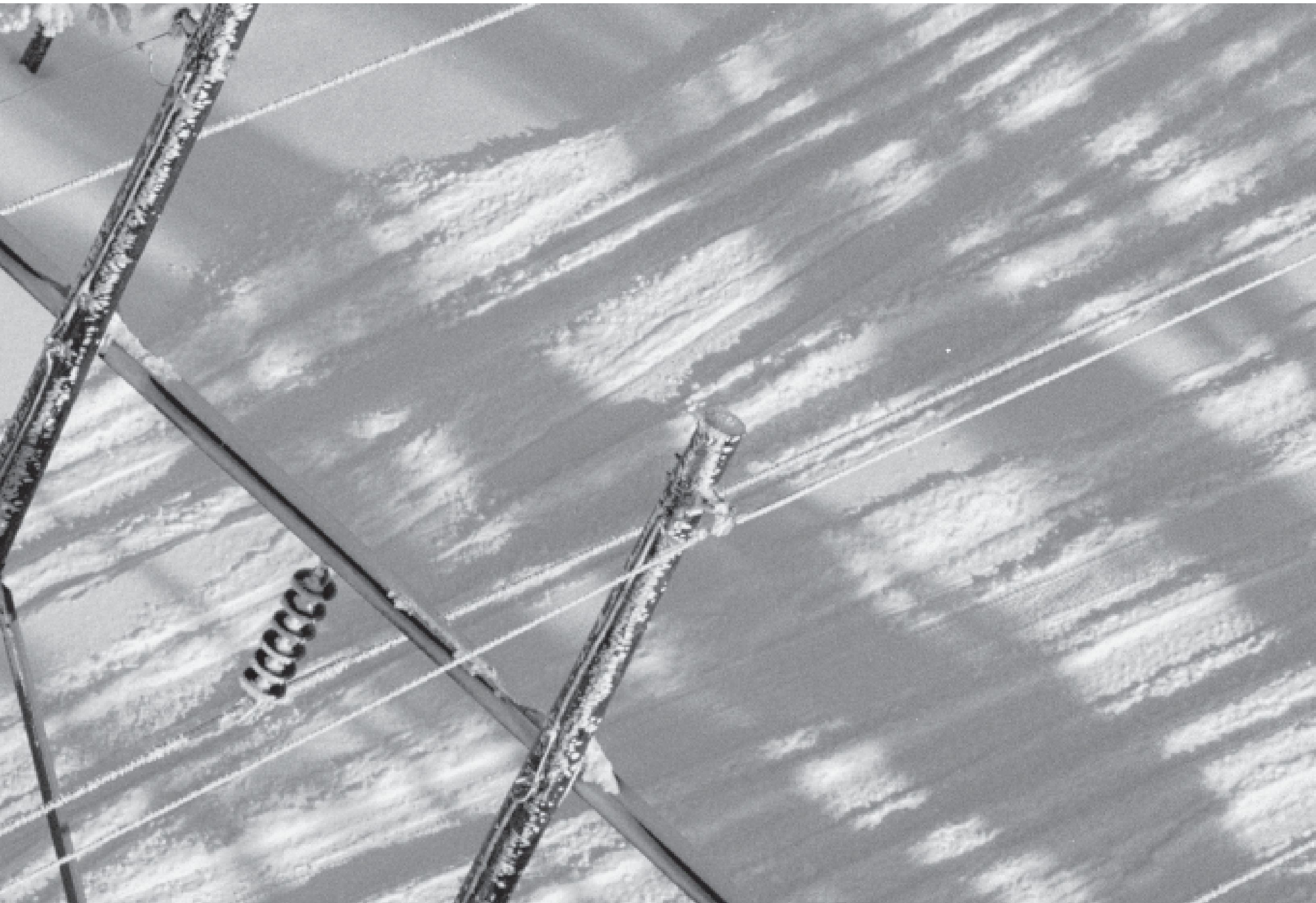
Cost recovery adjustments

About 80 percent of the cost increases in the current power rate period over the previous period were driven by the additional 3,300 average megawatts of load served by BPA beyond what the base Federal Columbia River Power System can provide. BPA purchased the additional power at the request of its customers, who were seeking shelter from the volatile market brought on by the West Coast energy crisis.

When BPA set its rates for the fiscal 2002-2006 period, its customers wanted base rates to be as low as possible. To meet this need, BPA incorporated a series of cost recovery adjustment clauses (CRACs) into its rates structure that could be implemented to respond to changing conditions. The alternative would have been to adopt higher base rates to cover contingencies. The first adjustment, the Load-Based CRAC, was implemented immediately on top of the agency's base rates. It captured the costs of providing the additional 3,300 average megawatts of load over and above what the federal system is able to provide.

To compensate for less-than-expected revenues from secondary power sales due largely to a downturn in market prices, BPA triggered a second CRAC in fiscal 2002, the Financial-Based CRAC. This CRAC went into effect starting in fiscal 2003. However, total power rates for the current year turned out to be only slightly higher than average 2002 rates because of a subsequent adjustment downward in the Load-Based CRAC.

In the winter of fiscal 2003, BPA proposed implementing the Safety Net CRAC process when losses from previous years, combined with a drought, placed projections of the agency's probability of making its 2003 Treasury payment well below an acceptable level. Fortunately, precipitation was remarkably heavy in March and April, and secondary sales prices remained higher than expected even though the water year ended at about



80 percent of normal. This improvement, combined with substantial cost reductions and debt refinancing, allowed BPA to reduce the Safety Net CRAC adjustment, which took effect in fiscal 2004. When it went into effect, the adjustment was about 2.2 percent over average fiscal 2003 rates, compared to the initial proposal that had suggested a 15 percent increase. Together, the improving conditions and the implementation of the Safety Net CRAC brought BPA's probability of making its Treasury payments through the rate period up to acceptable levels.

While BPA is committed to minimizing use of the Safety Net CRAC by seeking further cost reductions, the Safety Net CRAC has given the agency an important tool to respond to financial downturns that cannot be offset through cost controls alone. The Safety Net CRAC provides for additional increases or rebates in rates depending on financial outcomes through fiscal 2006.

Pending litigation settlement

While examining its cost structure, the agency determined that the most significant single action it could take to lower wholesale power rates would be to remove costs associated with lawsuits that a number of public power utilities had filed against BPA. These suits challenged the level of benefits flowing to the residential and small-farm customers of the region's investor-owned utilities. BPA initiated a dialogue with public and private utilities to reach a settlement that could lower fiscal 2004 average power rates about 7.4 percent below average fiscal 2003 rates.

The Northwest Power Act requires BPA to provide what has been termed "residential exchange" benefits to the residential and small-farm customers of the region's investor-owned utilities (IOUs). The level of the benefits has grown significantly over the past few years as a result of decisions made before and during the energy crisis.

Settlement of the litigation would reduce the cost of power in the current rate period for public power customers and the region's direct-service industries. The latter are large industrial customers, primarily aluminum, that purchase power directly from BPA. The agency's cost structure would also be significantly changed. The total impact during the current rate period would be in the range of $469 million. Of that, $200 million in litigation risk mitigation payments to the IOUs would be eliminated, and $269 million in IOU benefits would be deferred into the next rate period. In addition, the IOUs would gain assurance on the level and nature of benefits they would receive in the next rate period.

A final settlement will allow BPA to reduce its costs and lower its wholesale power rates, which should benefit the regional economy. Elimination of the lawsuits should also help stabilize relationships between BPA and its customers and allow the region to move forward on other important electricity infrastructure issues.

Transmission Business Line rates

The Transmission Business Line also addressed rates in fiscal 2003. Transmission rates have remained on a two-year cycle. To prepare for its fiscal 2003 rate case, the TBL conducted a series of meetings in fiscal 2002 called Programs in Review. In those meetings, the business line and its customers reviewed transmission program and spending levels in light of BPA's ability to maintain an adequate and reliable transmission system. As a result of the review, the TBL pared back its forecast program spending by about $35 million.

In rate settlement meetings, the parties reached an agreement that includes a 1.5 percent increase for most transmission and ancillary services rates and a 2.6 percent increase for the network integration rate.

The agreement was formalized by a brief rate case early in calendar 2003.

Treasury payment probability

Cost reductions and potential rate reductions were all reviewed within the context of their impact on BPA's U.S. Treasury payment probability (TPP). The agency has assured that it has the tools to retain an 80 percent or greater TPP for the rate period.

Not only did BPA make its fiscal 2002 and fiscal 2003 Treasury payments in full and on time, but payments in both years included additional principal payments to provide more room within the agency's Treasury borrowing authority limit. To date, BPA has prepaid $800 million of federal appropriations and bonds issued to the Treasury. Extending the room within the borrowing authority level is important because it provides BPA with fiscal flexibility and provides access to funds for future capital investments in transmission, hydropower, conservation and fish and wildlife. It also lowers BPA's interest costs.

Other activities

As BPA worked to restore its financial health, it also sought to accomplish its recovery while making investments for the future. The following sections address how BPA fulfilled its public responsibilities in fiscal 2003.

Fish and Wildlife

BPA has responsibilities for both fish and wildlife under the Northwest Power Act and under the Endangered Species Act. The Northwest Power and Conservation Council's program, mandated by the Northwest Power Act, addresses the impacts of hydroelectric dams on the Columbia Basin's fish and wildlife. The 2000 National Marine Fisheries Service (now National Oceanic and Atmospheric Administration Fisheries) and U.S. Fish and Wildlife Service biological opinions define how the agency, and its partners in the Federal Columbia River Power System, must meet responsibilities to anadromous and resident fish listed under the Endangered Species Act.

BPA has continued the comprehensive approach begun in the late 1990s to integrate the two sets of responsibilities and remains committed to a unified and collaborative plan for fish and wildlife mitigation that

defines biological objectives to be achieved at the least cost based on the best available science.

Each year, BPA, the U.S. Army Corps of Engineers and the Bureau of Reclamation submit a progress report to NOAA Fisheries that details actions taken to meet their ESA responsibilities to listed anadromous fish. These reports have shown consistent progress toward achieving these responsibilities. In October 2003, the agencies filed a comprehensive three-year check-in report to NOAA Fisheries on their progress toward implementing the biological opinion. This is the first of three check-ins over 10 years to evaluate the agencies' success.

As the three-year check-in displays, the action agencies' recovery efforts appear on track, and there has been significant improvement in the number of returning adult salmon to the Columbia Basin from 2001 to 2003. While ocean conditions are a significant contributing factor to improved fish runs, the investments in improved fish passage through the Federal Columbia River Power System also are paying dividends.

In May 2003, U.S. District Judge James Redden issued an opinion in a suit brought by the National Wildlife Federation against NOAA Fisheries. His ruling invalidated NOAA Fisheries' 2000 biological opinion because it did not meet certain legal requirements documenting the efficacy and timeliness of proposed salmon-saving actions. The court did not question what the agencies planned to do, only whether it could be done in as timely a manner and with the certainty that BPA and the other agencies proposed. The agencies believe the flaws Judge Redden found are correctable and are reviewing their actions. This review also provides an opportunity to up-date the biological opinion with more recent data regarding returning salmon. In the meantime, the judge has left the biological opinion in place while NOAA Fisheries corrects deficiencies. The federal action agencies continue to carry out actions to meet their obligations.

In early 2003, due to its financial situation, BPA asked the Northwest Power and Conservation Council to set project targets in a way that would ensure spending stayed within a fiscal-year ceiling. This goal was accomplished thanks to significant efforts made by many parties in the region to change their approach to project management. The result included some disruption to program planning and execution. In an effort to improve clarity and predictability, BPA has worked with the Council and other regional parties to develop protocols to guide fish and wildlife budgeting and spending for the remainder of the rate period. In addition, BPA began a review of contracting procedures and contract management practices applied to the more than 500 fish and wildlife program contracts it administers annually. The resulting changes in contracting, budgeting and financial management practices should promote greater accountability and measurable, performance-based outcomes.

Transmission infrastructure development

Reliability has been on everyone's mind since a major outage affected the Northeast in August 2003.

An outage the size of the one in the Northeast is not considered as likely in the West because of grid improvements made over the past few years. Still, no system is 100 percent reliable. BPA, which is the largest transmission owner in the Northwest, learned this and a number of lessons from the Aug. 10, 1996, power outage that affected millions of people on the West Coast.

Since 1996, BPA has taken many steps to improve system reliability. For example, the agency has:

- Created more conservative system operation requirements;
- Added remedial action schemes (RAS) – high-speed electronic detection devices that work to improve real-time monitoring and responsive control of the transmission grid;
- Added a RAS dispatcher desk that is staffed around the clock to monitor the system;
- Increased voltage support by adding 143 shunt capacitors (at the cost of about $86 million);
- Ramped up vegetation management under power lines from $2.6 million in 1996 to an average of $4.6 million annually. The number of times that BPA high-voltage lines came into contact with trees dropped from 42 in 1996 to two in 2003; and
- Enhanced the fiber optic communications system to improve BPA's ability to observe, measure and respond to situations.

In fiscal 2001, BPA's Transmission Business Line identified 20 infrastructure projects needed to shore up the regional system. Thanks to a $700 million increase in the agency's Treasury borrowing authority Congress granted in 2003, work began on six critical infrastructure projects that will improve the reliability of the Pacific Northwest grid. Two major 500-kilovolt lines are currently under construction – the first new 500-kilovolt lines in the BPA system since 1987.

Construction on the Grand Coulee-Bell 500-kilovolt transmission project began just after the record of decision was signed in January 2003. The project will remove a critical bottleneck that limits transmission from existing generation sources east of Spokane, Wash., to load centers farther west. The project expands BPA's Bell Substation near Spokane and replaces about 84 miles of old 115-kV line with new 500-kV line. It should be energized in December 2004.

Construction began on the Kangley-Echo Lake 500-kV line project in July 2003 shortly after the Seattle City Council unanimously approved a right-of-way the project required. The project is essential to assure reliable transmission to Seattle and the entire Puget Sound area. It also will support continued reliable delivery of power to Canada under a United States/Canadian treaty.

The new line crosses five miles of the Cedar River watershed, which supplies Seattle with its drinking water.

BPA worked with the city as well as with environmental groups to ensure that construction will not harm the watershed. The agency is protecting the watershed by flying transmission towers and other equipment in and out of the area by helicopter and will plant native vegetation in the area after construction is finished. The project is expected to be energized in December 2003.

BPA carried out intensive public involvement processes prior to beginning construction on the projects. As a result of these efforts, BPA has earned praise from public interest groups for adopting many construction techniques – such as using helicopters to fly in towers and putting "diapers" on equipment to prevent oil leaks – that will significantly reduce impacts on the environment.

The three other critical reliability projects involve substation modernization. One project replaces the last of the original vacuum-tube mercury-arc converters at the Celilo Converter Substation with solid-state silicon-based thyristors. Celilo is the northern end of the direct-current intertie that connects BPA's system to that of Los Angeles. The work will maintain the DC intertie's huge transfer capacity of 3,100 megawatts. The Los Angeles Department of Water and Power is rebuilding its Sylmar Converter Station on the southern end of the line and is working on a parallel schedule with BPA. BPA construction at Celilo began in 2001 and is scheduled to be complete by April 2004.

The Schultz series capacitors project will help prevent voltage collapse in the Puget Sound area. Series capacitors boost voltage when it sags during periods of high demand. The environmental review was completed and construction started in May 2003. The project is expected to be completed in November 2003.

The Pearl Substation transformer project adds a second 500/230-kV transformer at the existing substation south of Portland that will shore up reliability in the Portland area. The project is scheduled to be complete in December 2003.

These efforts will help assure that BPA continues to meet its transmission reliability performance standards. The standards measure performance against an index of how often outages occur and how long they last (frequency and duration). BPA met those standards again in fiscal 2003. The agency also met the standard that requires the transmission system experience no involuntary curtailment of firm load because of a transmission security breach.

Safety

Safety is always a major concern for a high-voltage utility. The goal is to keep recordable lost-time injuries within the range of 1.1 to 1.5 per 200,000 hours worked and to have no fatal injuries to BPA or contract employees working on BPA facilities. The agency met both standards, although the incidence of lost-time injuries was at the high end of the range, 1.5 per 200,000 hours worked.

Nonconstruction alternatives

In 2003, BPA began work with 18 representatives of Northwest states, utilities, public interest groups and tribes to study cost-effective alternatives to constructing new transmission lines. The parties are looking at energy-efficiency programs, demand reduction initiatives, pricing strategies and distributed generation, among other approaches. They first met in January, and by June had identified six institutional issues that may hamper development of nonconstruction alternatives. BPA has identified two pilot projects to test alternatives.

Hydro system improvements

During 2003, the Federal Columbia River Power System achieved an overall gain of 35 average megawatts in hydropower generation through new hydro unit performance curves, flow meters and runner replacements at Grand Coulee and other major dams. The effort also included governor recalibrations and deployment of software to better optimize power generation levels across the system.

These improvements help assure that generation will continue to meet its performance standard of no involuntary curtailment of firm load as a result of inadequate power supply or a generation security breach.

Energy efficiency/conservation

Over the past year, BPA has implemented a number of actions to meet its conservation goals while limiting its capital investments. BPA acquired over 40 megawatts in 2003 and is on track to deliver its goal of 220 average megawatts of energy conservation over the 2002-2006 rate period.

The Conservation Augmentation (ConAug) program, which accounts for approximately 120 of the total commitment, offers incentives to utilities to encourage and fund local conservation activities. To stretch its resources, BPA deferred some new financial commitments for fiscal 2003 and saved a portion of unused funds through voluntary reductions (over $6.5 million to date). BPA also developed enhanced standard offers for commercial lighting and other commercial/industrial projects by extending contract terms in exchange for acceptance of lower BPA payments.

As a result of these efforts, the program is on track to meet its goal for about $152 million instead of the originally budgeted $290 million. That means that the cost of delivering an average megawatt-hour of conservation under the ConAug program has dropped from $2.9 million to $1.5 million.

Despite the tightened budget, BPA added a new turnkey solar-heating program to the Conservation and Renewables Discount option. This program, Bright Way™ encourages utilities to support local programs.

BPA also continues to contribute half the budget for the Northwest Energy Efficiency Alliance. At about $20 million per year, the Alliance is operating highly cost-effective programs and is dramatically affecting markets. In just four years, ENERGY STAR© has increased its window market share from less than 15 percent to more than 70 percent.

Low-income weatherization programs for states and tribes have been part of BPA's mission to spread the benefits of Northwest resources to all the region's citizens. In 2003, Energy Efficiency continued its housing retrofit partnerships with the four Northwest states and the region's tribes. At over $3 million a year, BPA's financial support helps local agencies and tribes assist their neediest constituents.

For the last eight years, BPA has provided reimbursable energy-efficiency project support to several federal agencies as they implemented the "greening of government" executive orders. Last year, three of 22 national Federal Energy Management Program greening awards went to programs designed and implemented by BPA's energy conservation group.

Renewable energy

The agency's approach to renewable investment also has been influenced by its recent financial condition.

The focus has shifted from being a direct purchaser of renewable energy. BPA is now aiming to help its customers either develop or purchase the output of renewable projects. To further support wind development, for example, BPA is developing a storage and shaping product for wind generators. This complex product uses the hydro and transmission systems to provide energy when wind projects cannot meet their schedules. The initial offer will be about 100 megawatts so the agency can test the product's impact on the hydro system.

BPA also is helping encourage wind development by exempting wind projects from the normal imbalance charges – a penalty assessed when generators do not provide the power they have scheduled. Wind developers are still required to pay the cost of the power BPA must provide when there is a difference between scheduled and actual generation, but they are exempt from the added penalty.

Despite limiting its purchasing, BPA has the second-largest wind program in the region with a capacity of 198 megawatts, or 37 percent of the region's total wind capacity. The agency also has purchased the output from two solar projects (in Ashland, Ore., and Richland, Wash.).

Risk organization

Prior to industry restructuring, the risks utilities such as BPA faced were limited in number and centered on natural processes such as precipitation and hydro runoff timing. Restructuring has introduced a host of new risks to the electricity industry, particularly exposure to volatile wholesale electricity prices. During fiscal 2003, BPA expanded and formalized a new approach to risk by creating a new risk management organization and hiring its first chief risk officer.

Risk management is now being more broadly defined to address uncertainty in executing business strategies, which can include market risks, operations, credit practices and regulatory matters. Sound risk management is necessary to prevent net revenue volatility and to align risk with long-term business strategy. The chief risk officer's group will facilitate risk analysis on an agency-wide level.

Employee survey results

As part of its cost saving effort, BPA conducted this year's employee survey internally. The agency used questions from the 2002 Organizational Assessment Survey conducted by the Department of Energy and from previous high-performing organization surveys to provide valid points of comparison.

Employees' overall satisfaction with BPA remained at approximately the same level as the previous year although there were decreases in areas affected by agency cost cutting – particularly in employee awards/recognition and in training.

Challenges ahead

The effort to restore BPA's financial health is far from over. As part of the proposed litigation settlement agreement that BPA developed with its customers, the agency has set a new target. The target is to realize a net revenue improvement of $100 million through additional cost cuts and revenue enhancements over the fiscal 2004-2005 period. It is part of the effort to keep power rates as low as possible. Achieving this will take a substantial commitment on the part of all BPA employees as well as on the part of the agency's partners in the Federal Columbia River Power System.

As rates issues come to be settled for the balance of the current rate period (through fiscal 2006), the governors of the four Northwest states have encouraged BPA and the region's utilities to re-engage in what has been termed the Regional Dialogue. This dialogue addresses the way in which the benefits of the Federal Columbia

River Power System will be distributed among public and private utilities and the direct-service industries beginning with the new power rate period in fiscal 2007. One of the first points of discussion will be augmentation – should BPA purchase power to meet load requests that are beyond the approximately 8,000 average megawatts that the federal base system can reliably supply?

While BPA has begun work on the six most important transmission reliability construction projects for the region, there are more projects that will need to be built in the next few years. The increased Treasury borrowing authority Congress granted the agency in fiscal 2003 is not expected to meet BPA's long-term capital needs. The agency will have to address alternative methods of funding capital projects.

BPA also will continue its work with the region to address the broader issue of a regional transmission organization (RTO). Currently, BPA and the region are taking a back-to-the-basics approach to an RTO. A forum made up of a cross-section of regional parties has identified weaknesses resulting from fragmented management of the region's transmission system and is working to fix these. Weaknesses include disincentives to infrastructure investment, pancaked rates, increased complexity and transmission costs, and multiple control areas with multiple transmission rules and practices. This back-to-basics approach calls for unified regional transmission management that will maintain reliability, improve efficient use of the system and give Northwest customers access to diverse, widespread wholesale energy alternatives.

BPA's approach to these challenges will be collaborative. As part of the proposed litigation settlement agreement, BPA has committed to participate with customers in reviewing agency costs. This includes sharing financial information. The agency expects to create a similar venue for noncustomer groups.

Finally, BPA will seek to operate with greater transparency so that customers and constituents will be sufficiently informed and so that the basis for BPA's decision making will be clear. The ultimate goal is to improve trust and satisfaction between the agency and its customers and constituents.

Performance Measures

Each year since 1995, BPA has selected a set of measurable targets that the agency as a whole is responsible for achieving. These act as indicators of overall agency success and determine how agency management is evaluated. In fiscal 2003, all six targets were in the "successful" range. Two targets have multiple parts so eight measurements are displayed.

Additional cost reductions – The agency met its target of reducing fiscal 2003 expenses by between $35 million and $70 million over reductions already incorporated in the start-of-year budget. It captured $67 million.

Treasury payment and modified net revenues – For the twentieth year in a row, BPA made its Treasury payment in full and on time when it sent $1,057 million to D.C. In addition to making its Treasury payment, the agency's net revenues, when modified to exclude non-federal debt management savings and SFAS 133 mark-to-market adjustments, were $37 million, which satisfied the target of between $1 million and $100 million.

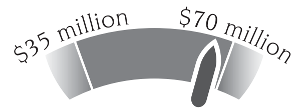
Reliability – Transmission reliability is measured in terms of the frequency and duration of outages on key circuits and against a standard of no involuntary curtailment of firm load caused by a transmission security breach. Both portions of the target were met. For generation reliability, the standard is no involuntary curtailments of firm load as a result of inadequate power supply or a generation security breach. The standard was met.

Transmission infrastructure – The target was for the agency to reach predetermined milestones on at least seven of nine identified transmission projects under construction while remaining within total budgeted costs. The target was met with seven projects on schedule and within budget.

Fish – The target was to have between 75 and 100 percent of the actions called for in the three-year check-in with NOAA Fisheries successfully under way. The target was met with 96 percent.

Safety – The safety target is to keep recordable lost-time injuries in the range of 1.5 to 1.1 per 200,000 hours worked and to have no fatal injuries to BPA or contract employees working on BPA facilities. The target was met with 1.5 per 200,000 and no fatal injuries.

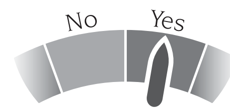
Agency Targets



Additional Cost Reductions

Range: $35 million to $70 million.

Target met ($67 million)



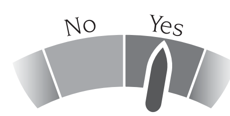
Treasury Repayment

Target met ($1,057 million)

Modified Net Revenues

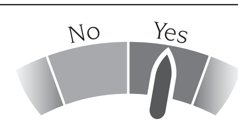
Range: $1 million to $100 million.

Target met ($37 million)



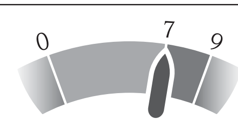
Transmission Reliability

Target met



Generation Reliability

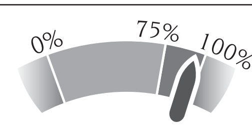
Target met



Transmission Infrastructure

Range: 7 to 9 key projects.

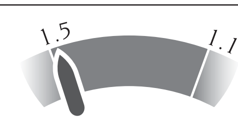
Target met (7)



Fish

Range: 75 percent to 100 percent of projects.

Target met (96 percent)



Safety

Range: 1.5 to 1.1 lost-time injuries per 200,000 hours.

Target met (1.5)

Financial Section

Results of Operations

2003 *Compared to* 2002

The Federal Columbia River Power System (FCRPS) includes the accounts of the Bonneville Power Administration (BPA), which purchases, transmits and markets power, and the accounts of generating facilities of the U.S. Army Corps of Engineers (Corps) and the Bureau of Reclamation (Reclamation) for which BPA is the power marketing agency. Each entity is separately managed and financed, but the facilities are operated as an integrated power system with the financial results combined as the FCRPS. The costs of multipurpose Corps and Reclamation projects are assigned to specific purposes through a cost allocation process. Only the portion of total project costs allocated to power is included in these statements.

The 2003 sales were $3,328 million, a decrease of $79 million, or 2 percent, from the previous year's level of $3,407 million. This was the result of both reduced hydro generation due to dryer than normal conditions and reduced power purchases offset by higher surplus sales prices. Federal generation declined from almost 83,000 gigawatt-hours to about 79,000 gigawatt-hours. Power purchases declined from about 21,000 gigawatt-hours to about 17,000 gigawatt-hours. This represents a total resource reduction of about 7 percent. The average price for discretionary surplus power sales, however, rose from $26 per megawatt-hour to $36 per megawatt-hour, an increase of 38 percent. Simultaneously, discretionary megawatt-hours sold declined 20 percent, which led to a 12 percent increase in discretionary sales revenues. U.S. Treasury credits for fish operations increased from $38 million to $175 million in 2003. The 2003 credit includes $79 million from the Fish Cost Contingency Fund , which was not accessed in fiscal 2002 and is now depleted. U.S. Treasury credits for fish mitigation increased due to below-average water conditions and increased power purchases that accompany reduced hydro supply. The 2003 operating revenues were $3,612 million, an increase of $78 million, or 2 percent, from the previous year.

In 2003, operating and net interest expenses were $3,057 million, a decrease of 13 percent compared to 2002. In 2003, operations and maintenance costs decreased by $121 million from the previous year, or 9 percent. Lower bad debt expense and general and administrative expense were the primary factors driving the decrease. Purchased power decreased by $244 million, or 19 percent to $1,043 million in 2003. In 2003, debt service on nonfederal projects decreased by $111 million, or 48 percent, from $230 million in 2002. Refinancing nonfederal projects bonds deferred some principal payments due in fiscal 2003 into the future and lower interest rates resulted in reduced total future payments. Federal projects depreciation was $350 million in 2003. Interest on appropriated funds and allowance for funds used during construction decreased primarily due to lower U.S. Treasury interest rates for construction work in progress at the Corps of Engineers federal generating projects. Net interest expense was $346 million in 2003, a decrease of $7 million compared to 2002.

Net revenues were $555 million in 2003, an increase of $546 million from 2002. BPA's Debt Optimization program and other debt management actions contributed significantly to the increased net revenues. With those events, nonfederal projects debt service decreased over the last two years from $473 million in 2001 to $230 million in 2002, and then to $120 million in 2003. Without the program and the effects of SFAS 133 net revenues would be $37 million for the current year.

2002 *Compared to* 2001

The 2002 operating revenues were $3,534 million, a decrease of $745 million, or 17 percent, from the previous year. Sales decreased $156 million, or 4 percent. This was the result of lower market prices for discretionary sales of surplus power. Average prices decreased to $26 per megawatt-hour from $101 per megawatt-hour the prior year. U.S. Treasury Credits for Fish decreased 94 percent from 2001 to 2002. Due to the improved water conditions and more normal market prices for purchased power the 4(h)(10)(C) revenue credit decreased to $38 million compared to $354 million in 2001. Criteria did not permit use of the Fish Cost Contingency Fund whereas $247 million was drawn from the fund during 2001.

In 2002, operating and net interest expenses were $3,524 million, a decrease of 21 percent compared to 2001. In 2002, operations and maintenance costs increased by $297 million from the previous year, or 29 percent. Investor-owned utility subscription settlement agreements and increased budgets for fish and wildlife and resource conservation management were the primary factors driving the increase. Purchased power decreased by $1,009 million, or 44 percent, to $1,287 million in 2002. Megawatt-hours purchased decreased 15 percent in 2002 from 2001 levels. The average cost of purchased power decreased from $90 per megawatt-hour in 2001 to $61 per megawatt-hour in 2002. In 2002 debt service on nonfederal projects decreased by $243 million, or 51 percent, from $473 million in 2001. Federal projects depreciation was $335 million in 2002. Net interest expense was $352 million in 2002, an increase of $20 million compared to 2001. The increase was a result of interest paid on redemption of bonds and less allowance for funds used during construction.

Net revenues were $9 million in 2002, an increase of $347 million from 2001 net expenses.

2001 *Compared to* 2000

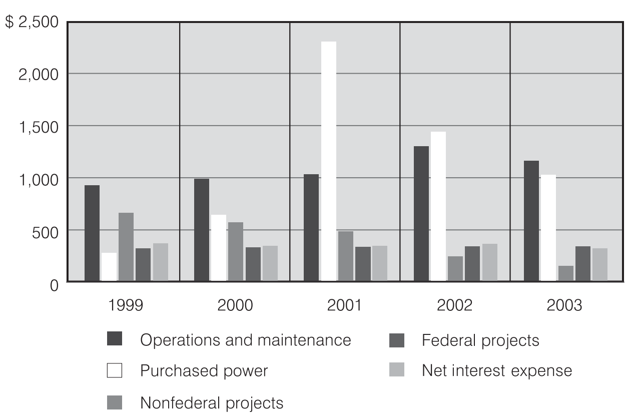
The 2001 operating revenues were $4,279 million, an increase of $1,212 million, or 40 percent, from the previous year. Despite a very low water year, sales were up primarily because market prices for discretionary power sales increased to $101 per megawatt-hour from the previous year's average of $29 per megawatt-hour. U.S. Treasury Credits for Fish increased over 10 times from 2000 to 2001. Due to the drought conditions and high market prices for purchased power the 4(h)(10)(C) revenue credit increased to $354 million. The credit computation is subject to an annual true up. Furthermore, as a result of the market conditions BPA accessed the Fish Cost Contingency Fund for the first time in history. The $325 million fund is for excess payments electric ratepayers have made for salmon recovery in prior years. BPA accessed the fund for an additional $247 million in credits, leaving the fund balance at $79 million.

Total operating and net interest expenses increased by $1,622 million in 2001 to $4,448 million, an increase of 57 percent over the previous year. Operation and maintenance costs rose by $46 million in 2001, an increase of 5 percent. Higher operations and maintenance expenses for BPA and the Columbia Generating Station nuclear project were the primary cause for the increase. Purchased power costs increased by $1,663 million, or 263 percent, to $2,296 million in 2001. Megawatt-hours purchased increased 137 percent in 2001 from 2000 levels. The average cost of purchased power increased from $57 per megawatt-hour in 2000 to $90 per megawatt-hour in 2001. In 2001, debt service on nonfederal projects was $473 million, a decrease of $87 million, or 16 percent, compared to 2000. Selective redemption of bonds at Energy Northwest allowed the free up of bond reserves that were used to reduce current debt service. Federal projects depreciation was $323 million in 2001. Net interest expense was $332 million in 2001, down $3 million from the prior year.

Net expenses were $337 million in 2001, a decrease of $578 million from 2000 net revenues. Approximately one-third of the loss was the result of adoption of a new industry accounting standard during the year, "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133). The changes as a result of SFAS 133 reflect an accounting only adjustment with no corresponding cash impact. Excluding the SFAS 133 adjustments, net expenses for 2001 were $217 million.

Expenses by Category

millions of dollars



Customers

BPA sells power and related services to four main types of customers: Northwest publicly owned utilities, direct-service industries (DSIs), Northwest investor-owned utilities (IOUs) and other regional and extra regional customers. BPA also sells relatively small amounts of power to several federal agencies within the region. The revenue derived from these customers provides BPA with a large portion of the funds needed to pay its costs. BPA sells transmission and related services under open access tariffs to a broad variety of power generators, marketers and purchaser (see the Schedule of Revenues and Expenses, Schedule B).

Northwest Publicly Owned Utilities

Qualifying public utility districts, municipalities and consumer-owned electric cooperatives within the region are entitled to a statutory preference and priority in the purchase of available federal system power. These customers have what is referred to as "public preference." They are eligible to purchase power at BPA's Priority Firm Rate or, PF Rate, for most of their loads. As a group, publicly owned utilities constitute BPA's largest customer base in terms of number, megawatt sales and revenues. A substantial rate increase at the beginning of the new rate period Oct. 1, 2001, and an increase in the amount of power BPA sold to these customers resulted in revenues increasing $858 million or 91 percent in 2002 compared to 2001. These revenues remained at a high, although somewhat lower level, decreasing $74 million or 4 percent in 2003.

Direct-Service Industrial Customers

BPA is not required to do so, but may offer to sell power for direct consumption to a limited number of existing DSIs within the region. For several years prior to 1995, BPA's annual DSI firm loads averaged approximately 2,800 average megawatts. Largely due to the repurchase by BPA of some of its power sales to DSIs and curtailments of purchases by some DSIs due to adverse business conditions in that sector, revenues decreased $362 million or 86 percent from 2001 to 2002. Revenues from the DSIs have decreased another $40 million or 68 percent in 2003.

Northwest Investor-Owned Utilities

BPA provides some firm power to Northwest IOUs. This is power not sold under the public preference priority rate. BPA also sells substantial amounts of peaking capacity to Northwest IOUs during cold periods. As part of BPA's Subscription Strategy, the agency entered into certain agreements, as amended, with the regional IOUs in settlement of BPA's statutory obligation to provide benefits under the Residential Exchange Program for specified periods beginning Oct. 1, 2001. The $323 million or 46 percent decline in revenues from Northwest IOUs in 2002 stemmed largely from payments arising under agreements between BPA and the Northwest IOUs to settle BPA's Residential Exchange obligations and the purchase back by BPA of some of its power sales to Northwest IOUs. Revenues from Northwest IOUs increased $58 million or 15 percent in 2003.

Sales Outside the Northwest Region

BPA sells non-firm and surplus firm power to various buyers that is in excess of what is needed to serve firm load obligations in the region. Revenue from sales outside the Northwest are highly dependent upon stream flows in the Columbia River Basin which affect the amount of non-firm energy available for sale, and upon the costs of generating power with alternative fuels, which affect the price BPA can obtain for its exported non-firm energy and surplus firm power. Sales outside the Northwest region decreased $446 million or 41 percent in 2002 compared to 2001 due to lower market prices. These sales decreased $10 million or 2 percent in 2003.

Transmission

BPA obtains revenues from the provision of transmission and other related services. Higher transmission rates went into effect Oct. 1 2001, and are reflected in transmission revenues which increased $113 million or 25 percent to $567 million in 2002 from $454 million in 2001. Transmission revenues decreased $14 million or 2 percent to $553 million in 2003.

Fish credits and other revenues

Fish credits are provided on the basis of estimates and forecasts and later are adjusted when actual data are available. The $585 million or 86 percent decline from 2001 to 2002 was the result of lower estimated U.S. Treasury revenue credits under section 4(h)(10)(C) of the Northwest Power Act. These revenues increased $159 million or 169 percent in 2003. This increase was mostly due to U.S. Treasury credits for fish operations increasing from $38 million to $175 million, in 2003. The 2003 credit includes $79 million from the Fish Cost Contingency Fund, which was not accessed in fiscal 2002 and is now depleted. U.S. Treasury credits for fish mitigation increased due to below-average water conditions and increased power purchases that accompany reduced hydro supply. Mark-to-market adjustments and other miscellaneous revenues are also included.

Critical Accounting Policies

The accounting policies for the Federal Columbia River Power System are disclosed in the first note to the financial statements beginning on page 32.

Financial Condition

The net effect of the year's financial effort was positive net revenues of $555 million. These results were a significant improvement over BPA's performance in fiscal 2001 and 2002. In 2001, BPA had a loss of $337 million, the largest annual loss in the agency's history. Net revenues were $9 million in 2002.

At Sept. 30, 2003, BPA's year-end financial reserves were $511 million — consisting of $408 million cash and $103 million for deferred borrowing authority. Deferred borrowing represents amounts that BPA is authorized to borrow from the U.S. Treasury for expenditures that BPA has incurred to date but the borrowing for which BPA has elected to delay. At Sept. 30, 2002, BPA's year-end financial reserves were $188 million. BPA's financial reserves at the end of fiscal 2001 were $625 million. BPA's debt optimization program and other financing actions had a significant effect on both its 2002 and 2003 net revenues. Without these actions, financial reserves would have been reduced at the end of the 2003 by at least $200 million.

BPA made payments of $1,057 million to the U.S. Treasury in 2003, making it the twentieth consecutive year in which BPA has made its payment on time and in full. The payment consisted of $544 million for principal and $466 million in interest for the federal investment in the Federal Columbia River Power System. BPA also paid $35 million in contributions to the Civil Service Retirement System and $12 million for other obligations. Payments made in 2002 and 2001 were $1,056 million and $729 million respectively. This year's principal payment also included $328 million to repay federal

Selected Quarterly Information *(unaudited)*

3 months ended — thousands of dollars

	December 31	March 31	June 30	September 30	Totals
2003					
Revenues	**$ 898,748**	**$ 901,112**	**$ 760,233**	**$ 996,746**	**$ 3,556,839**
SFAS 133 mark-to-market	**47,134**	**(25,904)**	**24,712**	**9,323**	**55,265**
Operating revenues	**945,882**	**875,208**	**784,945**	**1,006,069**	**3,612,104**
Operating expenses	**698,279**	**740,185**	**490,416**	**782,209**	**2,711,089**
Net interest expenses	**87,712**	**85,144**	**81,546**	**91,189**	**345,591**
Net revenues (expenses)	**$ 159,891**	**$ 49,879**	**$ 212,983**	**$ 132,671**	**$ 555,424**
2002					
Revenues	$ 916,329	$ 853,649	$ 795,947	$ 929,450	$ 3,495,375
SFAS 133 mark-to-market	(48,066)	49,385	13,477	23,558	38,354
Operating revenues	868,263	903,034	809,424	953,008	3,533,729
Operating expenses	856,924	790,533	661,041	863,456	3,171,954
Net interest expenses	87,037	100,278	85,833	79,152	352,300
Net revenues (expenses)	$ (75,698)	$ 12,223	$ 62,550	$ 10,400	$ 9,475
2001					
Revenues	$ 788,313	$1,322,994	$ 851,539	$1,267,946	$ 4,230,792
SFAS 133 mark-to-market	(292,720)	345,035	216,270	(220,708)	47,877
Operating revenues	495,593	1,668,029	1,067,809	1,047,238	4,278,669
Operating expenses	887,606	1,177,963	845,332	1,204,769	4,115,670
Net interest expenses	81,459	82,841	82,345	85,264	331,909
Net (expenses) revenues before cumulative effect of SFAS 133	(473,472)	407,225	140,132	(242,795)	(168,910)
Cumulative effect of SFAS 133	(168,491)	—	—	—	(168,491)
Net (expenses) revenues	$ (641,963)	$ 407,225	$ 140,132	$ (242,795)	$ (337,401)

appropriations and bonds issued to the U.S. Treasury in advance of due dates bringing cumulative advance payments to $800 million.

The "Rates" section on page 25 discusses the Cost Recovery Adjustment Clauses (CRACs) that are used to mitigate risk and increase the probability of meeting the U.S. Treasury payments.

Financing

BPA, along with third parties, refinanced or restructured about $1.4 billion in debt, almost one-fourth of its nonfederal debt portfolio. BPA saved a net present value of $121 million in interest expenses by refinancing Energy Northwest, Conservation and Renewable Energy System, City of Tacoma and Lewis County PUD bonds and putting in place BPA's first interest rate swap. The results have helped bring down BPA's expenses in general and particularly through 2006. Among other things, this work increased remaining Treasury borrowing authority by $315 million as a result of extending Energy Northwest debt into 2013-2018 and prepaying Treasury bonds under the ongoing debt optimization program. By arranging release of reserves held for Energy Northwest and other third-party debt, BPA expenses for 2002-2004 were reduced by about $239 million. For some of these reserve releases, Energy Northwest purchased surety insurance instruments in lieu of holding funds in reserve. In addition, in a year in which many utilities saw their credit ratings slashed, BPA was able to maintain high ratings with all three bond rating agencies.

Market Risk

As a result of short-term sales commitments and short-term purchase commitments, BPA is exposed to market and credit risks as a result of potential adverse changes in commodity prices and market conditions. Commodity market risk is a consequence of entering into fixed price sales and purchase commitments and owning and operating generation facilities. Credit risk stems from potential nonperformance of contracts by counterparties.

Management of market risk is critical to the success of BPA. Historically risk management processes, policies and procedures have been established to monitor and control these market risks. BPA manages its risk on a portfolio basis subject to parameters established by executive management and a risk management committee. To ensure compliance with the policies, individuals, who are independent of the group that creates and manages these risk exposures, monitor market risk measures. In 2003, BPA established the Office of the Chief Risk Officer and centralized certain risk analysis, enterprise risk management, credit and insurance functions and restructured its risk review process.

BPA measures the market price risk in its portfolio on a daily, weekly and monthly basis using net revenue at risk (NRaR), mark to market (MTM), value at risk (VAR), Monte Carlo simulation and other methodologies depending on the portfolio segment in question. The quantification of market risk using these methods provides a consistent measure of risk across the energy market in which BPA buys and sells. The use of these methods requires a number of key assumptions including hydro/price correlations, the selection of a confidence level for expected losses, the holding period for liquidation and the treatment of risks outside the methodology, including credit risk and event risk. These methods provide an estimate of reasonably possible net revenue outcomes that could be recognized on its portfolios assuming hypothetical movements in future market prices.

In addition to using market price risk measures, BPA measures the effects of volumetric risk using both scenario analysis and Monte Carlo simulation to estimate the economic impact of a sudden change in supply or price. Unlike many of its industry counterparts, BPA's principal market activity is the sale of surplus inventory rather than the purchase and sale of electricity to earn trading revenues. Therefore, the tests critical to trading organizations (i.e. amount of risk to carry over very short time frames) are considered less important than regular and rigorous analysis of the consequences of a range of hydro supply conditions. Experienced business and risk managers use the results of the hydro supply scenario and simulation analyses and the market price risk measures in conjunction with their professional judgment to capture additional market-related risks, including credit and event risk. In response to market price risk, futures, swaps and options may be used to alter BPA's exposure to price fluctuations.

BPA mitigates credit risk by insisting that counterparties and marketers are significant industry companies that are considered financially strong. BPA performs an initial financial review of new counterparties and establishes credit limits based on the results of that review. Reviews and credit limits are updated regularly to reflect the current financial conditions of each counterparty.

BPA faces several other uncertainties over the next few years, which may affect market risk. The deregulated electricity industry market has brought significant volatility to market prices and may continue to do so. National and state regulatory changes have been leading to further restructuring in the industry through ongoing discussions of a regional transmission organization. Price caps have been modified during the past fiscal year. Resource development has been in a state of flux. All of these factors contribute to the environment of market risk in which BPA continues to operate.

Rates

The fiscal year that ended Sept. 30, 2003, was the second year of operation under new power and transmission contracts and associated rates. FERC granted final approval for BPA's proposed power rates on July 21, 2003, for fiscal years 2002 through 2006. Those rates include several risk mitigation tools. The primary tools are three Cost Recovery Adjustment Clauses (CRACs). The CRACs are temporary upward adjustments to posted power prices if certain conditions occur. There are three sets of conditions in which rate increases under the CRACs may trigger. The first is the Load-Based CRAC (LB CRAC), which triggers if BPA incurs costs for meeting or reducing loads that were not included in the rate case. The LB CRAC percentage changes every six months. The second is the Financial-Based CRAC (FB CRAC), which triggers if the generation function's forecasted level of accumulated net revenues (not accounting for SFAS 133 and debt optimization transactions) is below a predetermined threshold. The third is the Safety Net CRAC (SN CRAC), which triggers when, after implementation of the LB and FB CRACs, BPA has missed or reasonably expects to miss a payment to the Treasury or another creditor. In addition to the CRACs, BPA established contracts and rates for a "Slice of the System Product." The basic premise of the product is that a purchaser pays a fixed percent of BPA's power costs in exchange for a fixed percent of generation and capabilities.

On Oct. 1, 2001, implementation of the LB CRAC caused BPA's rates to increase approximately 46 percent for the first half of fiscal 2002 compared to base rates, and 41 percent for the second half of fiscal 2002. The LB CRAC percentage increase was approximately 32 percent and 39 percent, respectively, for the 6-month periods beginning Oct. 1, 2002, and April 1, 2003. The August 2002 forecast of the generation function's accumulated net revenues triggered the FB CRAC, and resulted in a 1-year rate increase beginning Oct. 1, 2002, of approximately 11 percent for most of the requirement rates on top of the revised levels of the LB CRAC. SN CRAC did not trigger in fiscal 2002, so it did not affect rates in fiscal 2002 or 2003.

Early in fiscal 2003 BPA was projecting a low probability of repaying the U.S. Treasury at the end of the year. Losses were projected for the remainder of the rate period. The administrator initiated the SN CRAC process because BPA was projecting that the probability of making its fiscal 2003 payment to the U.S. Treasury to be 26 percent, well below acceptable levels.

BPA projected that it would need an SN CRAC that, combined with the two other CRACs, would produce a fiscal 2004 priority firm power rate that would average 15 percent higher than the average rate for fiscal 2003. At the end of the process, improvements in the PBL's financial condition resulted in a reduction in the total rate increase to 2.2 percent. The difference resulted primarily from improved secondary revenues and reduced operation and maintenance costs. BPA received interim approval of its recent SN CRAC rate proposal on Oct. 1, 2003, which will increase rates in fiscal 2004.

At the time that BPA filed its SN CRAC proposal with FERC, it was negotiating with its power customers to settle a lawsuit that had been filed by some of BPA's Northwest public utility customers, concerning Residential Exchange benefits BPA had agreed to provide Northwest IOUs. During October 2003, a proposed litigation settlement was reached and offered to BPA customers that, if approved, would reduce BPA's costs in the current rate period running through fiscal 2006. This would permit rates in fiscal 2004 to be reduced from 2003 levels by approximately 7.4 percent, rather than increased by 2.2 percent. The reduction in SN CRAC rates under the proposed litigation settlement are revenues subject to refund.

Standards of Ethical Conduct

As part of the United States federal government, employees of the FCRPS are bound by Standards of Ethical Conduct for Employees of the Executive Branch. The Standards contain general principles that address topics such as placing ethical principles above private gain, not engaging in conflicts of interest, not using public office for private gain, and complying with all applicable governmental rules and regulations and seeking to avoid the appearance of impropriety. The Standards document spells out these principles in detail and includes examples of how to respond in situations where ethical dilemmas arise. All employees of the FCRPS, including executives, are required to receive federal ethics training and sign a document stating they understand the Standards of Ethical Conduct on an annual basis.

Financial Statements

Statements of Revenues and Expenses

Federal Columbia River Power System
For the years ended Sept. 30 — thousands of dollars

	2003	2002	2001
Operating Revenues			
Sales	**$3,328,277**	$3,407,404	$3,563,182
SFAS 133 mark-to-market	**55,265**	38,354	47,877
Miscellaneous Revenues	**53,678**	49,571	66,902
U.S. Treasury Credits for Fish	**174,884**	38,400	600,708
Total operating revenues	**3,612,104**	3,533,729	4,278,669
Operating Expenses			
Operations and maintenance	**1,198,521**	1,319,707	1,023,180
Purchased power	**1,043,009**	1,286,867	2,296,076
Nonfederal projects	**119,534**	230,175	473,100
Federal projects depreciation	**350,025**	335,205	323,314
Total operating expenses	**2,711,089**	3,171,954	4,115,670
Net operating revenues	**901,015**	361,775	162,999
Interest Expense			
Interest on federal investment:			
Appropriated funds	**212,391**	258,195	248,429
Long-term debt	**166,598**	151,997	129,159
Allowance for funds used during construction	**(33,398)**	(57,892)	(45,679)
Net interest expense	**345,591**	352,300	331,909
Net revenues (expenses) before cumulative effect of SFAS 133	**555,424**	9,475	(168,910)
Cumulative effect of SFAS 133	**—**	—	(168,491)
Net Revenues (Expenses)	**555,424**	9,475	(337,401)
Accumulated net (expenses) revenues, Oct. 1	**(211,676)**	(221,151)	132,810
Irrigation Assistance	**—**	—	(16,560)
Accumulated net revenues (expenses), Sept. 30	**$ 343,748**	$(211,676)	$(221,151)

The accompanying notes are an integral part of these statements.

Balance Sheets

Federal Columbia River Power System
As of Sept. 30 — thousands of dollars

Assets

	2003	2002
Utility Plant		
Completed plant	$11,873,798	$ 11,488,047
Accumulated depreciation	(4,281,060)	(4,052,117)
	7,592,738	7,435,930
Construction work in progress	1,308,624	1,200,179
Net utility plant	8,901,362	8,636,109
Nonfederal Projects		
Conservation	47,246	47,733
Hydro	146,210	167,080
Nuclear	2,181,182	2,127,907
Terminated hydro facilities	28,840	29,555
Terminated nuclear facilities	3,883,115	3,829,269
Total nonfederal projects	6,286,593	6,201,544
Decommissioning Cost	126,000	73,861
Conservation, net of accumulated amortization of $892,218 in 2003 and $831,631 in 2002	374,443	409,571
Fish and Wildlife, net of accumulated amortization of $133,743 in 2003 and $129,207 in 2002	128,337	134,204
Current Assets		
Cash	503,026	235,409
Accounts receivable, net of allowance	146,768	206,036
Accrued unbilled revenues	190,416	93,004
Materials and supplies, at average cost	84,306	85,107
Prepaid expenses	288,068	285,696
Total current assets	1,212,584	905,252
Other Assets	230,756	151,458
	$17,260,075	$ 16,511,999

The accompanying notes are an integral part of these statements.

Capitalization and Liabilities

	2003	2002
Capitalization and Long-Term Liabilities		
Accumulated net revenues (expenses)	$ 343,748	$ (211,676)
Federal appropriations	4,607,476	4,595,915
Capitalization adjustment	2,124,697	2,192,400
Long-term debt	2,521,554	2,563,141
Nonfederal projects debt	6,045,931	5,958,538
Decommissioning reserve	126,000	73,861
Total capitalization and long-term liabilities	15,769,406	15,172,179
Commitments and Contingencies (Notes 5 and 6)		
Current Liabilities		
Current portion of federal appropriations	73,484	46,687
Current portion of long-term debt	176,200	207,300
Current portion of nonfederal projects debt	240,662	243,006
Accounts payable and other current liabilities	369,821	343,425
Total current liabilities	860,167	840,418
Deferred Credits	630,502	499,402
	$17,260,075	$16,511,999

Statements of Changes in Capitalization and Long-Term Liabilities

Federal Columbia River Power System

Including current portions — thousands of dollars

	Accumulated Net (Expenses) Revenues	Federal Appropriations	Long-Term Debt	Nonfederal Project Debt	Other	Total
Balance at Sept. 30, 2001	$ (221,151)	$ 4,670,930	$ 2,688,542	$ 6,171,949	$ 2,328,977	$15,639,247
Increase in federal appropriations for construction	—	168,583	—	—	—	168,583
Repayment of federal appropriations for construction	—	(196,911)	—	—	—	(196,911)
Capitalization adjustment amortization	—	—	—	—	(67,356)	(67,356)
Increase in long-term debt	—	—	390,000	—	—	390,000
Repayment of long-term debt	—	—	(308,101)	—	—	(308,101)
Net increase in nonfederal projects debt	—	—	—	258,775	—	258,775
Repayment of nonfederal projects debt	—	—	—	(229,180)	—	(229,180)
Decommissioning reserve	—	—	—	—	4,640	4,640
Net revenues	9,475	—	—	—	—	9,475
Balance at Sept. 30, 2002	$ (211,676)	$ 4,642,602	$ 2,770,441	$ 6,201,544	$ 2,266,261	$15,669,172
Increase in federal appropriations for construction	**—**	**99,418**	**—**	**—**	**—**	**99,418**
Repayment of federal appropriations for construction	**—**	**(61,060)**	**—**	**—**	**—**	**(61,060)**
Capitalization adjustment amortization	**—**	**—**	**—**	**—**	**(67,703)**	**(67,703)**
Increase in long-term debt	**—**	**—**	**470,000**	**—**	**—**	**470,000**
Repayment of long-term debt	**—**	**—**	**(482,687)**	**—**	**—**	**(482,687)**
Refinance of long-term debt	**—**	**—**	**(60,000)**	**—**	**—**	**(60,000)**
Net increase in nonfederal projects debt	**—**	**—**	**—**	**99,288**	**—**	**99,288**
Repayment of nonfederal projects debt	**—**	**—**	**—**	**(14,239)**	**—**	**(14,239)**
Decommissioning reserve	**—**	**—**	**—**	**—**	**52,139**	**52,139**
Net revenues	**555,424**	**—**	**—**	**—**	**—**	**555,424**
Balance at Sept. 30, 2003	**$ 343,748**	**$ 4,680,960**	**$ 2,697,754**	**$ 6,286,593**	**$ 2,250,697**	**$16,259,752**

The accompanying notes are an integral part of these statements.

Statements of Cash Flows

Federal Columbia River Power System
For the years ended Sept. 30 — thousands of dollars

	2003	2002	2001
Cash from Operating Activities			
Net revenues (expenses)	**$ 555,424**	$ 9,475	$ (337,401)
Expenses (income) not requiring cash:			
Depreciation	**269,957**	254,332	247,247
Amortization of conservation and fish and wildlife	**80,068**	78,047	76,067
Amortization of capitalization adjustment	**(67,703)**	(67,356)	(68,784)
AFUDC	**(33,398)**	(57,892)	(45,679)
(Increase) decrease in:			
Receivables and unbilled revenues	**(38,144)**	88,765	(31,283)
Materials and supplies	**801**	115	(20,930)
Prepaid expenses	**(2,372)**	(98,547)	(101,254)
Increase (decrease) in:			
Accounts payable and other current liabilities	**26,396**	(167,532)	138,687
IOU Settlement	**55,488**	—	—
Other	**(3,686)**	(6,399)	114,060
Cash provided by (used for) operating activities	**842,831**	33,008	(29,270)
Cash from Investment Activities			
Investment in:			
Utility plant	**(501,813)**	(487,030)	(399,220)
Conservation	**(25,458)**	(25,344)	141
Fish and wildlife	**(11,156)**	(6,102)	(16,493)
Other	**(2,458)**	—	—
Cash used for investment activities	**(540,885)**	(518,476)	(415,572)
Cash from Borrowing and Appropriations			
Increase in federal constructions appropriations	**99,418**	168,583	230,388
Repayment of federal construction appropriations	**(61,060)**	(196,911)	(125,469)
Irrigation assistance	**—**	—	(16,560)
Increase in long-term debt	**470,000**	390,000	260,000
Repayment of long-term debt	**(482,687)**	(308,101)	(84,658)
Refinance of long-term debt	**(60,000)**	—	—
Cash (used for) provided by borrowing and appropriations	**(34,329)**	53,571	263,701
Increase (Decrease) in cash	**267,617**	(431,897)	(181,141)
Beginning cash balance	**235,409**	667,306	848,447
Ending cash balance	**$ 503,026**	$ 235,409	$ 667,306

The accompanying notes are an integral part of these statements.

Notes to Financial Statements

1. Summary of General Accounting Policies

Principles of Combination

The Federal Columbia River Power System (FCRPS) includes the accounts of the Bonneville Power Administration (BPA), which purchases, transmits and markets power, and the accounts of generating facilities of the U.S. Army Corps of Engineers (Corps) and the Bureau of Reclamation (Reclamation) for which BPA is the power marketing agency. Each entity is separately managed and financed, but the facilities are operated as an integrated power system with the financial results combined as the FCRPS. The costs of multipurpose Corps and Reclamation projects are assigned to specific purposes through a cost allocation process. Only the portion of total project costs allocated to power is included in these statements.

FCRPS accounts are maintained in accordance with generally accepted accounting principles and the uniform system of accounts prescribed for electric utilities by the Federal Energy Regulatory Commission (FERC). FCRPS accounting policies also reflect specific legislation and executive directives issued by U.S. government departments. (BPA is a unit of the Department of Energy; Reclamation is part of the Department of the Interior; and the Corps is part of the Department of Defense.) FCRPS properties and income are tax-exempt. All material intercompany accounts and transactions have been eliminated from the combined financial statements.

Management Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Reclassifications

Certain reclassifications were made to the 2001 and 2002 combined financial statements from amounts previously reported to conform to the presentation used in fiscal year 2003. Such reclassifications had no effect on previously reported results of operations and cash flows.

Regulatory Authority

BPA's power and transmission rates are established in accordance with several statutory directives. Rates proposed by BPA are subjected to an extensive formal review process, after which they are proposed by BPA and reviewed by FERC. FERC's review is limited to three standards set out in the Pacific Northwest Electric Power Planning and Conservation Act (Act), 16 U.S.C. 839, and a standard set by the National Energy Policy Act of 1992. FERC reviews BPA's rates for all firm power, for nonfirm energy sold within the region, and for transmission service. Statutory standards include a requirement that these rates be sufficient to assure repayment of the federal investment in the FCRPS over a reasonable number of years after first meeting BPA's other costs.

After final FERC approval, BPA's rates may be reviewed by the United States Court of Appeals for the Ninth Circuit. Action seeking such review must be filed within 90 days of the final FERC decision. The court of appeals may either confirm or reject a rate proposed by BPA. It is the opinion of BPA's general counsel that, if a rate were rejected, it would be remanded to BPA for reformulation.

BPA has agreed that rates for the sale of power pursuant to its present contracts may not be revised until the current rate period expires on Sept. 30, 2006, except for certain rate cost recovery adjustment clauses (CRACs). The CRACs are temporary upward adjustments to posted power prices if certain conditions occur. There are three CRACs, each triggered by a different set of conditions. The first is the Load-Based CRAC (LB CRAC), which triggers if BPA incurs costs for meeting or reducing loads that were not included in the rate case. The LB CRAC percentage changes every 6 months. The second is the Financial-Based CRAC (FB CRAC), which triggers if the generation function's forecasted level of modified accumulated net revenues is below a predetermined threshold. The third is the Safety Net CRAC (SN CRAC), which triggers when, after implementation of the LB and FB CRACs, BPA has missed or reasonably expects to miss a payment to the Treasury or another creditor. Some of these rate adjustment clauses are calculated initially on forward-looking estimates of market conditions, and adjustments are made after the fact when actual conditions are known. These adjustments result in an additional charge or rebate due customers for any excess or shortfall of amounts initially charged to them.

On Oct. 1, 2001, implementation of the LB CRAC caused BPA's rates to increase approximately 46 percent for the first half of fiscal 2002 compared to base rates, and 41 percent for the second half of fiscal 2002. The LB CRAC percentage increase was again revised to approximately 32 percent and 39 percent, respectively, for the 6-month periods beginning Oct. 1, 2002 and April 1, 2003.

On Sept. 30, 2003, BPA recognized a receivable of $4.6 million for the LB CRAC period ended March 31, 2003, and BPA estimated a receivable of zero for the LB CRAC period ended Sept. 30, 2003. On Sept. 30, 2002, BPA recognized a liability of $5.8 million for the LB CRAC period ended March 31, 2002, and a receivable of $2.3 million for the LB CRAC period ended Sept. 30, 2002. The August 2002 forecast of the generation function's accumulated net revenues triggered the FB CRAC, and resulted in a one-year rate increase beginning Oct. 1, 2002, of approximately 11 percent for most of the requirements rates on top of the revised levels of the LB CRAC. The SN CRAC did not trigger in fiscal 2002 but did trigger in fiscal 2003, requiring an expedited rate case and resulting in rates that went into effect Oct. 1, 2003. BPA received interim approval of its recent SN CRAC rate proposal on Oct. 1, 2003, 105 FERC 61,006 (2003).

In addition to the CRACs, BPA established contracts and rates for a "Slice of the System Product." The basic premise of the product is that a purchaser pays a fixed percentage of BPA's power costs in exchange for a fixed percentage of generation and capabilities. Settlement of any over or under collection occurs in the subsequent year. For the fiscal 2003 settlement, BPA recognized a $30.4 million liability to be paid in fiscal 2004. For the fiscal 2002 settlement, BPA recognized a receivable of $49 million which was received in fiscal 2003.

FERC granted final approval for BPA's Power and Transmission rates on April 4, 1997, for fiscal years 1997 through 2001 (75 FERC 62,010 (1997)).

BPA separately submitted a Transmission and Ancillary Services Rate Filing in 2000 for fiscal years 2002 through 2003, and a Power Rate Filing in 2001 for fiscal years 2002 through 2006. FERC granted final approval of BPA's Transmission and Ancillary Services rates on May 7, 2001, for fiscal years 2002 through 2003, 62 FERC 62,094 (2001). On June 29, 2001, FERC granted final approval for the acceleration of the Ancillary Services and Control Area Services Rate (ACS-02) for Generation Imbalance Service (GIS), 95 FERC 62,286 (2001); and on Oct. 11, 2001, FERC granted final approval for corrections to the ACS-02 rate, 97 FERC 62,020 (2001). FERC granted interim approval for proposed Power rates on Sept. 28, 2001, for fiscal years 2002 through 2006, 96 FERC 61,360 (2001) and granted final approval on July 21, 2003, 104, FERC 61,093 (2003).

Because of the regulatory environment in which BPA establishes rates, certain costs may be deferred and expensed in future periods under Statement of Financial Accounting Standards (SFAS 71), Accounting for the Effects of Certain Types of Regulation.

SFAS 71 *Assets*

In order to defer incurred costs under SFAS 71, a regulated entity must have the statutory authority to establish rates that recover all costs and rates so established must be charged to and collected from customers. Due to increasing competitive pressures, BPA may be required to seek alternative solutions in the future to avoid raising rates to a level that is no longer competitive. If BPA's rates should become market-based, SFAS 71 would no longer be applicable, and any costs deferred under that standard would be expensed in the Statement of Revenues and Expenses.

The SFAS 71 assets of $4.7 billion, shown in the table on page 34, reflect an increase of $138 million from the prior year. Amortization of these costs aggregating $84 million in 2003, $299 million in 2002 and $259 million in 2001 is reflected in the Statements of Revenues and Expenses. If BPA were to discontinue using SFAS 71 it would simultaneously write down the SFAS 71 assets and amortize the remaining Appropriations Capitalization Adjustment resulting in a $2.6 billion net extraordinary loss being reported in the Statement of Revenues and Expenses.

Utility Plant

Utility plant is stated at original cost. Cost includes direct labor and materials; payments to contractors; indirect charges for engineering, supervision and similar overhead items; and an allowance for funds used during construction. The costs of additions, major replacements

SFAS 71 Assets

As of Sept. 30 — thousands of dollars

	2003	2002
Nonfederal projects:		
Conservation	**$ 47,246**	$ 47,733
Terminated hydro facilities	**28,840**	29,555
Terminated nuclear facilities	**3,883,115**	3,829,269
Decommissioning cost	**126,000**	73,861
Conservation	**374,443**	409,571
Fish and wildlife	**128,337**	134,204
Settlements	**105,313**	17,594
Additional retirement contributions	**23,400**	36,800
	$ 4,716,694	$ 4,578,587

and betterments are capitalized. Repairs and minor replacements are charged to operating expense. In accordance with FERC requirements the cost of utility plant retired, together with removal costs less salvage, is charged to accumulated depreciation when it is removed from service.

Depreciation and Amortization

Depreciation of original cost and estimated cost to retire utility plant is computed on the straight-line method based on estimated service lives of the various classes of property, which average 40 years for transmission plant and 75 years for generation plant. Amortization of capitalized conservation and fish and wildlife costs is computed on the straight-line method based on estimated service lives, which are 10 to 20 years for conservation and 15 years for fish and wildlife.

Allowance for Funds Used During Construction

The allowance for funds used during construction (AFUDC) constitutes interest on the funds used for utility plant under construction. AFUDC is capitalized as part of the cost of utility plant and results in a non-cash reduction of interest expense. While cash is not realized currently from this allowance, it is realized under the ratemaking process over the service life of the related property through increased revenues resulting from higher plant in-service and higher depreciation expenses. AFUDC is based on the monthly construction work in progress (CWIP) balance. A portion of CWIP as stated on the balance sheets represents study and investigation costs to which AFUDC is not attributed.

AFUDC capitalization rates are stipulated in the congressional acts authorizing construction for certain generating projects (1.8 percent to 6.3 percent in 2003, 3.3 percent to 6.5 percent in 2002 and 2.5 percent to 6.6 percent in 2001). Capitalization rates for other construction were approximately 6.3 percent in 2003, 6.5 percent in 2002 and 6.6 percent in 2001. These rates approximate the cost of borrowing from the U.S. Treasury.

Asset Retirement Obligations

BPA adopted SFAS 143, Accounting for Asset Retirement Obligations, on Oct. 1, 2002. SFAS 143 requires the recognition of Asset Retirement Obligations (AROs), measured at estimated fair value, for legal obligations related to the dismantlement and restoration costs associated with the retirement of tangible long-lived assets in the period in which the liability is incurred. Upon initial recognition of AROs that are measurable, the probability weighted future cash flows for the associated retirement costs, discounted using a credit-adjusted risk-free rate, are recognized as a liability. Due to the long lead time involved, a market-risk premium cannot be determined for inclusion in future cash flows.

Regulation

Pursuant to regulation, AROs of rate-regulated long-lived assets are included in depreciation expense allowed in rates. Any differences in the timing of recognition of costs for financial reporting and ratemaking purposes are deferred as a regulatory asset under SFAS 71. BPA expects any changes in estimated AROs to be incorporated in future rates. Substantially all significant AROs are included in rate regulation.

Also through regulation, BPA collects in rates removal costs for certain assets that do not have associated legal asset retirement obligations. At Sept. 30, 2003, BPA has an estimated $146 million regulatory liability for these removal costs recorded in Accumulated Depreciation.

Asset Retirement Obligations Activity

Upon adoption of SFAS 143, BPA recorded an ARO for WNP-1 and Columbia Generating Station (See Decommissioning and Restoration Costs in Note 5, Commitments and Contingencies) for $72.1 million and adjusted the ARO for the Trojan plant to $57.8 million. Prior to the adoption of SFAS 143, the ARO associated with the Trojan plant was recorded on a nominal dollar basis at the time of its abandonment in 1993, with costs to be recovered through regulation recorded as a regulatory asset. With the adoption of SFAS 143, the regulatory asset (Decommissioning Cost) and the related ARO (Decommissioning Reserve) for the Trojan plant were reduced by $16.1 million to adjust the balances to an estimated fair value as required by SFAS 143. As of Sept. 30, 2003, the ARO for WNP-1, Columbia Generating Station and Trojan are $126 million. A corresponding amount representing a regulatory asset is included within Decommissioning Costs in the Balance Sheet.

The adoption of SFAS 143 did not result in a cumulative effect adjustment on the Statement of Revenue and Expenses as the effect was offset by a regulatory asset. $89.9 million has already been funded by BPA and held in trust relating to these AROs. The remaining amount will be collected in future rates.

The following presents the proforma effects to the balances and activities in AROs for the accounting periods reported herein had SFAS 143 been in effect for all periods:

Asset Retirement Obligations Activity

As of Sept. 30 — thousands of dollars

	Proforma 2003	Proforma 2002
Beginning Balance	**$129,900**	$134,100
Activity:		
Expenditures	**(7,000)**	(9,100)
Accretion	**3,100**	3,100
Revisions	**—**	1,800
Ending Balance	**$126,000**	$129,900

Cash

For purposes of reporting cash flows, cash includes cash in the BPA fund and unexpended appropriations of Reclamation and the Corps. Cash paid for interest was $466 million in 2003, $484 million in 2002 and $464 million in 2001.

Non-cash transactions include changes in nonfederal projects and nonfederal projects' debt (other than amortization of nonfederal projects and payment of nonfederal projects' debt) of $99 million in 2003, $259 million in 2002 and $61 million in 2001.

Concentrations of Credit Risks

General Credit Risk

Financial instruments, which potentially subject the FCRPS to concentrations of credit risk, consist of available-for-sale investments held by Energy Northwest and BPA accounts receivable. Energy Northwest invests exclusively in U.S. government securities and agencies. BPA's accounts receivable are concentrated with a diverse group of customers and counterparties who have purchased capacity, energy, or other products and services. These customers are generally large and stable and do not represent a significant concentration of credit risk.

BPA mitigates credit risk by insisting that counterparties and marketers are significant industry companies that are considered financially strong. BPA performs an initial financial review of new counterparties and establishes credit limits based on the results of that review. Reviews and credit limits are updated regularly to reflect the current financial conditions of the company.

In conjunction with the financial reviews, BPA often obtains credit support in the form of parental guarantees and letters of credit to support established credit limits.

BPA also utilizes netting agreements and prepayment agreements to mitigate the credit risk of financial instruments.

Credit Risk from California

California power markets had been in turmoil several years ago, having experienced historically high power prices and volatility along with the continued uncertainty related to deregulation. Defaults by Pacific Gas & Electric (which filed for bankruptcy protection in April 2001) and Southern California Edison (which has established a creditor payment plan) in payments for energy and transmission to the California Independent System Operator (Cal-ISO) resulted in the Cal-ISO not paying its suppliers. In addition, the California Power Exchange (Cal-PX) has substantial outstanding payment obligations due from the California investor-owned utilities for day-ahead power exchanges. The Cal-PX filed for bankruptcy protection in March 2001.

BPA entered into certain power sales during the fiscal year 2001 through the Cal-PX for which BPA has not yet been paid. In addition BPA sold power and related services to the Cal-ISO during fiscal year 2001 for which BPA has not yet been paid in full. Based on management's current evaluation, the amount of ultimate or potential losses is not determinable at this time. However, BPA has recorded provisions for uncollectible receivables and potential refund amounts, which in management's best estimate are sufficient to cover potential exposure. Nonetheless, BPA is continuing to pursue collection of all amounts due in bankruptcy and other proceedings.

Retirement Benefits

FCRPS employees belong to either the Civil Service Retirement System (CSRS) or the Federal Employees' Retirement System (FERS). FCRPS and its employees contribute to the systems. Based on the statutory contribution rates, retirement benefit expense under CSRS is equivalent to 7 percent of eligible employee compensation and under FERS is variable based upon options chosen by the participant but does not exceed 24.2 percent of eligible employee compensation. Retirement benefits are payable by the U.S. Treasury and not by the FCRPS.

Beginning in fiscal 1998, and for the remainder of the rate period ended in 2001, FCRPS agreed to contribute additional amounts as a result of an underfunded status of the CSRS. These amounts have been calculated based on an estimate of FCRPS employees who participate in the plan as well as an estimate of FCRPS' share of the underfunded status. These contributions are projected over a period of years as shown in the table. The payments, when made, will be directly to the U.S. Treasury.

BPA paid $35.1 million, $55.2 million and $8.0 million to the U.S. Treasury during 2003, 2002 and 2001, respectively. These amounts were recorded as expense when paid. BPA has accrued $23.4 million as of Sept. 30, 2003, which represents the additional deferred contribution for 1998 through 2003. This amount has been recorded as an SFAS 71 asset on the Balance Sheet for recovery of the costs through rates in the period beginning Oct. 1, 2001. The related liability is included in other current liabilities and deferred credits in the accompanying Balance Sheet. At Sept. 30, 2003, BPA has scheduled additional payments totaling $119.7 million as follows.

Scheduled Additional CSRS Contributions
thousands of dollars

Scheduled Contributions	
2004	$ 30,900
2005	26,500
2006	23,200
2007	21,100
2008	18,000
	$119,700

BPA expects to recognize these amounts as expense in the years in which they are specifically recovered through rates.

Deferred Credits

Deferred credits consist of $153.2 million in advances from customers for projects which BPA is constructing on their behalf, $122.6 million paid to BPA from participants under the Third AC intertie capacity agreement, $94.0 million for the Enron settlement, $86.8 million in load diversification fees and other settlement payments for long-term agreements paid to BPA from various customers, $65.4 million leasing fees for fiber optic cable, $55.5 million for the IOU deferral, $27.0 million current fair market value of certain trading physical forward sales and purchases, written options and Libor interest rate swap transactions, $13.2 million in deferred CSRS, $12.8 million in unearned option premium revenue, and $.1 million in other miscellaneous long-term liabilities.

Advances on projects BPA constructs for customers are either applied against the expenditure during the construction of the assets if the customer retains title to the assets, or if BPA retains title, are recorded to revenue over the related useful lives of the assets. Deferred Third AC intertie capacity payments are recognized as revenue over the estimated 37-year life of the related assets.

BPA terminated all remaining contracts with Enron for $99 million effective April 1, 2003. BPA is reimbursing the U.S. Treasury judgment fund for their payment of the settlement through 2006.

Diversification fees are payments by customers to BPA in consideration for a reduction in their contractually obligated power purchases from BPA. Deferred diversification fees and other settlement payments for long-term agreements are recognized as revenue over the original contract terms (diversification fee contracts generally correspond to the rate period ended Sept. 30, 2001, while other settlement agreements extend over varying periods through 2019). Leasing fees for fiber optic cable are recognized over the lease terms extending as far as 2020.

Payment of a portion of the 2003 IOU subscription settlement benefits were deferred to be paid in 2007 through 2011 unless they are reduced through billing credits offsetting the SN CRAC. The current portion of deferred credits to be recorded as revenue in 2004 is included in accounts payable and other current liabilities in the Balance Sheet.

Hedging and Derivative Instrument Activities

BPA's hedging policy (Policy) allows the use of financial instruments such as commodity futures, options and swaps to hedge the price and revenue risk associated with electricity sales and purchases and to hedge risks associated with new product development. The Policy does not authorize the use of financial instruments for non-hedging purposes, unless such use is expressly authorized under specific provisions included in the Policy.

Historically, BPA has used financial instruments in the form of Over-the-Counter (OTC) electricity swap agreements and options and Exchange traded futures contracts to hedge anticipated production and marketing of hydroelectric energy. Under swap agreements, BPA makes or receives payments based on the differential between a specified fixed price and an index reference price of power. Under futures contracts, BPA either sells or buys Exchange traded futures contracts to hedge anticipated future electricity sales and purchases. There were no open or outstanding OTC electricity swap agreements or Exchange traded electricity futures and options at Sept. 30, 2003 or 2002.

As of and for the years ended Sept. 30, 2003, 2002 and 2001, both the deferred and the realized gains and losses resulting from these transactions were not material to the consolidated FCRPS financial statements.

Written Options

In prior periods, BPA sold put options for the sale of electricity at certain points in the future. BPA's intention is to take delivery of power as a result of written put options if exercised. The megawatt-hour quantities that BPA sold and the premiums that BPA collected for the sales of these options were priced on market-based information and a mathematical model developed by BPA. This model makes certain assumptions based on historical and other statistical data. Actual future results could vary from estimates resulting in the requirement that BPA may be required to buy power at strike prices above market prices as a result of its written put option obligations.

The following table reflects the written options outstanding.

Written Put Options
As of Sept. 30

	2003	2002
Put Options		
Outstanding	**1,972,800 MWh**	3,507,600 MWh
Average Strike Price	**$40.33**	$42.25

These options expire at various times through December 2003. BPA records written options on a mark-to-market basis and includes unrealized gains and losses in operating revenues in the Statement of Revenues and Expenses.

Financial Instruments

All significant financial instruments of the FCRPS were recognized in the Balance Sheet as of Sept. 30, 2003 and 2002. The carrying value reflected in the Balance Sheet approximates fair value for the FCRPS's financial assets and current liabilities. The fair values of long-term liabilities are discussed in the respective footnotes.

Interest Rate Swap Transactions

In fiscal year 2003, BPA entered into two floating-to-fixed Libor interest rate swaps to help manage interest rate risk related to its long-term debt portfolio.

In the first swap transaction, BPA pays a fixed 3.1 percent on $300 million notional amount for the next 10 years and receives a variable rate that changes weekly tied to LIBOR. In the second swap transaction, BPA pays a fixed 3.5 percent on $200 million notional amount for the next 15 years and receives a variable rate that changes weekly tied to LIBOR. The net effect of the two swap transactions is essentially replacing variable rate debt with 3.3 percent fixed rate debt. The swap transaction does not qualify for special hedge accounting treatment under SFAS 133. The floating interest rates on the swaps are reset on a weekly basis. As of Sept. 30, 2003, BPA recorded a $7.9 million fair value loss in the Statement of Revenues and Expenses related to the interest rate swap transactions.

Adoption of Statement 133 and Related Guidance

BPA adopted SFAS 133, "Accounting for Derivative Instrument and Hedging Activities," as amended, on Oct. 1, 2000. SFAS 133 requires that every derivative instrument be recorded on the Balance Sheet as an asset or liability measured at its fair value and that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met.

It is BPA's policy to document and apply as appropriate the normal purchase and normal sales exception under SFAS 133, as amended by SFAS 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities," related Derivative Implementation Group (DIG) guidance, and SFAS 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities." Collectively, these statements are referred to as "SFAS 133." Purchases and sales of forward electricity and option contracts that require physical delivery and which are expected to be used or sold by the reporting entity in the normal course of business are generally considered "normal purchases and normal sales" under SFAS 133. These transactions are excluded under SFAS 133 and therefore are not required to be fair valued in the financial statements.

For all other non-hedging related derivative transactions BPA applies fair value accounting and records the amounts in the current period Statement of Revenues and Expenses. BPA may also elect to use special hedge accounting provisions allowed under SFAS 133 for transactions that meet certain documentation requirements. As of Sept. 30, 2003, BPA had no outstanding transactions accounted for under the special hedge accounting provisions.

On the date of adoption (Oct. 1, 2000), in accordance with the transition provisions of SFAS 133, BPA recorded a cumulative-effect adjustment of $(168) million in net revenue (expense) to recognize the difference between the carrying values and fair values of derivatives not designated as hedging instruments. The adjustment consisted mainly of transactions known as bookouts that the FASB initially determined should be fair valued in net revenue (expense).

On June 29, 2001, the FASB issued guidance on Derivatives Implementation Group issue C15: "Scope Exceptions: Normal Purchases and Normal Sales Exception for Option-Type Contracts and Forward Contracts in Electricity." Issue C15 provided additional guidance on the classification and application of SFAS 133 relating to purchases and sales of electricity utilizing forward contracts and options including bookout transactions. This guidance became effective as of July 1, 2001. BPA elected this treatment of bookout transactions effective as of Sept. 30, 2001.

In April 2003, the FASB issued SFAS 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities." SFAS 149 amends financial accounting and reporting for derivative instruments, including the accounting treatment for certain forward power sales and purchase contracts. SFAS 149 is effective for new contracts transacted after July 1, 2003. The normal purchase and sales exception previously allowed for bookout transactions under DIG issue C-15 was effectively eliminated by SFAS 149. However, under SFAS 149, BPA expects to qualify bookout transactions for the normal purchase and normal sale exception unless certain applicable criteria is not met. As of Sept. 30, 2003, the impact of adoption of SFAS 149 is immaterial.

For fiscal years 2003, 2002 and 2001, BPA recorded the following SFAS 133 fair value unrealized gain or loss in the Statement of Revenues and Expenses related to its derivative portfolio.

Fair Value Gains (Losses)

As of Sept. 30 — thousands of dollars

	2003	2002	2001
Physical Power Derivatives	**$63,165**	$ 38,354	$ 47,877
Interest Rate Swap	**(7,900)**	—	—
	$55,265	$ 38,354	$ 47,877

Revenues and Net Revenues

Operating revenues are recorded on the basis of service rendered, which includes estimated unbilled revenues of $190 million, $93 million and $6 million at Sept. 30, 2003, 2002 and 2001 respectively. BPA operates as two segments: The Power Business Line and the Transmission Business Line. The table in Note 7 reflects the revenues and expenses attributable to each business line. Because BPA is a U.S. government power marketing agency, net revenues over time are committed to repayment of the U.S. government investment in the FCRPS and the payment of certain irrigation costs as discussed in Note 5.

Fish Credits

The NW Power Act obligated the BPA administrator to make expenditures for fish and wildlife protection, mitigation and enhancement for both power and non-power purposes, on a reimbursement basis. It also specified that consumers of electric power, through their rates for power services "shall bear the costs of measures designed to deal with adverse impacts caused by the development and operation of electric power facilities and programs only." Section 4(h)(10)(C) of the Act was designed to ensure that the costs of mitigating these impacts are properly accounted for among the various purposes of the hydroelectric projects.

BPA, the U.S. Treasury and the Office of Management and Budget agreed to a crediting mechanism against BPA's Treasury payments to reimburse BPA for expenditures made on behalf of mitigation for non-power purposes. Under the agreed-upon crediting mechanism, BPA reduces its cash payments to Treasury by an amount equal to the mitigation measures funded on behalf of the non-power purposes. The credits are used to recoup the amount owed to BPA by the other project purposes. BPA has taken this credit since 1995, in amounts that, with the exceptions of fiscal 2001 and 2003, ranged between $26 million and $60 million. Criteria was met permitting draws from the Fish Cost Contingency Fund of the $79 million and $247 million in 2003 and 2001 respectively. The fund is now depleted.

IOU *Subscription Settlement Agreements and Residential Exchange*

As provided for in the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. 839, Section 5(c), beginning in 1982 BPA entered into residential exchange contracts with most of its electric utility customers. These contracts were to result in payments to the utilities if a utility's average system cost exceeded BPA's priority firm power rate.

Subsequently, contract termination agreements were signed by all actively exchanging Pacific Northwest utilities except Northwestern Energy (formerly the Montana Power Co., which had not been receiving benefits). BPA made payments to settle the utilities' and BPA's rights and obligations under the residential exchange program through June 30, 2001, and in some cases, through June 30, 2011.

In October 2000, BPA's investor-owned utility (IOU) customers signed subscription settlement agreements, which provide financial benefits in place of residential exchange benefits for the period July 1, 2001, through Sept. 30, 2011. These agreements provide for both sales of power and monetary benefit payments to the IOUs. In fiscal 2003, BPA continued to negotiate a new settlement related to the IOUs benefits. See the Commitments and Contingencies section in Note 5 for additional information. The table below summarizes future IOU benefits as of Sept. 30, 2003, without the new settlement agreement discussed in Note 5.

IOU Exchange Benefits
thousands of dollars

	IOU Benefits
2004	$ 398,655
2005	473,865
2006	457,940
	$1,330,460

Includes approximately $20 million assumed annual benefits to Portland General Electric from its 258-aMW power purchase. Financial benefits beyond the current rate case period cannot currently be quantified.

Recent Accounting Pronouncements

In November 2002, FASB issued FASB Interpretation No. 45 (FIN 45), " Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of others – an interpretation of FASB Statements No. 5, 57, and 107, and recission of FASB Interpretation No. 34." FIN 45 clarifies that a guarantor is required to recognize, at the inception of the guarantee, a liability for the fair value of the obligation undertaken in issuing the guarantee. It also elaborates on the disclosures to be made by a guarantor on previously issued guarantees. Because of the guarantee associated with the nonfederal projects, BPA has historically recorded the associated debt, FIN 45 does not have a current effect on the FCRPS financial statements.

In January 2003, FASB issued FASB Interpretation No. 46 (FIN 46), "Consolidation of Variable Interest Entities – an interpretation of ARB No. 51." FIN 46 clarifies the application of Accounting Research Bulletin (ARB) No. 51, "Consolidated Financial Statements," to certain entities in which equity investors do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties. The Interpretation differentiates between an entity with a majority voting interest (the previous requirement under ARB No. 51) and entities that have controlling financial interest through other arrangements that may not involve any voting interests and how both of these types of entities (variable interest entities) may need to be consolidated. FIN 46 is effective for variable interest entities created after Feb. 1, 2003. BPA is currently evaluating the effect of FIN 46 for arrangements which existed before Feb. 1, 2003. FIN 46 will be effective for BPA for fiscal year ending Sept. 30, 2004.

2. Federal Appropriations

The BPA Appropriations Refinancing Act (Refinancing Act), 16 U.S.C. 8381, required that the outstanding balance of the FCRPS federal appropriations, which BPA is obligated to set rates to recover, be reset and assigned prevailing market rates of interest as of Sept. 30, 1996. The resulting principal amount of appropriations was determined to be equal to the present value of the principal and interest that would have been paid to Treasury in the absence of the Refinancing Act, plus $100 million. The $100 million was capitalized as part of the appropriations balance and was included pro rata in the new principal of the individual appropriated repayment obligations.

The amount of appropriations refinanced was $6.6 billion. After refinancing, the appropriations outstanding were $4.1 billion. The difference between the appropriated debt before and after the refinancing was recorded as a capitalization adjustment. This adjustment is being amortized over the remaining period of repayment so that total FCRPS net interest expense is equal to what it would have been in the absence of the Refinancing Act.

Amortization of the capitalization adjustment was $67.7 million for fiscal 2003, $67.4 million for 2002, and $68.8 million for 2001. The weighted-average interest rate was 7.0 percent in 2003 and 2002, and 6.9 percent in 2001.

Construction and replacement of Corps and Reclamation generating facilities historically have been financed through annual federal appropriations. Annual appropriations also were made for their operation and maintenance costs, although these are normally repaid by BPA to the U.S. Treasury by the end of each fiscal year. As a result of the National Energy Policy Act of 1992 BPA has begun directly funding operation and maintenance expenses and capital efficiency and reliability improvements for Corps and Reclamation generating facilities.

Federal Generation and Transmission appropriations are repaid to the U.S. Treasury within the weighted average service lives of the associated investments (maximum 50 years) from the time each facility is placed in service.

If, in any given year, revenues are not sufficient to cover all cash needs, including interest, any deficiency becomes an unpaid annual expense. Interest is accrued on the unpaid annual expense until paid. This interest must be paid from subsequent years' revenues before any repayment of federal appropriations can be made.

The table shows the term repayments on the remaining federal appropriations as of Sept. 30, 2003.

Federal Appropriations
thousands of dollars

Term Repayments	
2004	$ 73,484
2005	110,989
2006	68,939
2007	33,694
2008	10,913
2009+	4,382,941
	$4,680,960

Includes payments on historic replacements but excludes planned future replacements and irrigation assistance.

3. Long-Term Debt

To finance its capital programs, BPA is authorized by Congress to issue to the U.S. Treasury up to $4.45 billion of interest-bearing debt with terms and conditions comparable to debt issued by U.S. government corporations. A portion ($1.25 billion) of the $4.45 billion is reserved for conservation and renewable resource loans and grants. At Sept. 30, 2003, $305 million of conservation bonds and $2,393 million of other borrowings were outstanding. The average interest rate of BPA's borrowings from the U.S. Treasury exceeds the rate that could be obtained currently. As a result, the fair value of the BPA long-term debt, based upon discounting future cash flows using rates offered by the U.S. Treasury as of Sept. 30, 2003, for similar maturities exceeds carrying value by approximately $304 million, or 11 percent. The table at page 42 reflects the terms and amounts of long-term debt.

4. Nonfederal Projects

BPA has acquired all or part of the generating capability of five nuclear power plants. The contracts to acquire the generating capability of the projects, referred to as "net-billing agreements," require BPA to pay all or part of the annual projects' budgets, including operating expense and debt service, including projects that are not completed and/or not operating. BPA also has acquired all of the output of the Cowlitz Falls and Wasco hydro projects. BPA has agreed to fund debt service on Eugene Water and Electric Board, Emerald, City of Tacoma and Conservation and Renewable Energy System bonds issued to finance conservation programs sponsored by BPA.

BPA recognizes expenses for these projects based upon total project cash funding requirements reflected in project budgets that are adopted by BPA and the projects' owners.

Operating expense of $223 million in fiscal 2003, $175 million in fiscal 2002, and $217 million in fiscal 2001 for the projects is included in operations and maintenance in the accompanying Statements of Revenues and Expenses. Debt service for the projects of $120 million, $230 million, and $473 million for 2003, 2002 and 2001, respectively, is reflected as nonfederal projects expense in the accompanying Statements of Revenues and Expenses. Refinancing activities reduced debt service by $463 million, $319 million and $158 million for 2003, 2002, and 2001 respectively from rate case estimates.

The fair value of all Energy Northwest debt exceeds recorded value by $443 million or 7.3 percent based on discounting the future cash flows using interest rates for which similar debt could be issued at Sept. 30, 2003. All other nonfederal projects' debt approximates fair value as stated.

U.S. Treasury Bonds

Long-Term Debt (1) — thousands of dollars

	First Call Date	Maturity Date	Interest Rate	Construction and Fish & Wildlife	Conservation	Cumulative Total
January 1997	none	2004	6.80%	$ 30,000		$ 30,000
May 1999	none	2004	5.95%	26,200		56,200
June 2001 (2)	none	2004	4.75%	50,000		106,200
July 2000	none	2004	7.00%	50,000		156,200
September 1999 (2)	none	2004	6.40%	20,000		176,200
January 2000	none	2005	7.15%	53,500		229,700
January 2001	none	2005	5.65%	20,000		249,700
January 2001	none	2005	5.65%	25,000		274,700
March 2002	none	2005	4.60%	110,000		384,700
March 2002 (2)	none	2005	4.60%	30,000		414,700
May 1997	none	2005	6.90%	80,000		494,700
June 2002	none	2005	3.75%	60,000		554,700
June 2002	none	2005	3.75%		40,000	594,700
September 2000 (2)	none	2005	6.70%	20,000		614,700
October 2002	none	2005	3.00%	50,000		664,700
November 2002	none	2005	2.80%	40,000		704,700
April 2003 (2)	none	2006	2.40%	40,000		744,700
April 2003 (2)	none	2006	2.40%	25,000		769,700
July 2003	none	2006	2.30%	75,000		844,700
July 2003 (2)	none	2006	2.30%	30,000		874,700
August 1996	none	2006	7.05%	70,000		944,700
September 2000	none	2006	6.75%	40,000		984,700
September 2002	none	2006	3.05%	100,000		1,084,700
September 2002	none	2006	3.05%	30,000		1,114,700
September 2002 (2)	none	2006	3.05%	20,000		1,134,700
September 2003	none	2006	2.50%	20,000		1,154,700
September 2003 (2)	none	2006	2.50%	25,000		1,179,700
December 2002 (2)	none	2006	3.05%	40,000		1,219,700
April 2003	none	2007	2.90%	40,000		1,259,700
July 2003	none	2007	2.95%	25,000		1,284,700
August 1997	none	2007	6.65%	111,300		1,396,000
September 2003	none	2007	3.10%	20,000		1,416,000
April 1998	none	2008	6.00%	75,300		1,491,300
April 1998	none	2008	6.00%	25,000		1,516,300
August 1998	none	2008	5.75%	40,000		1,556,300
September 1998	none	2008	5.30%		104,300	1,660,600
May 1998	none	2009	6.00%	72,700		1,733,300
May 1998	none	2009	6.00%		37,700	1,771,000
July 1989	none	2009	8.55%		40,000	1,811,000
January 2001	none	2010	6.05%	60,000		1,871,000
January 2001	none	2010	6.05%	30,000		1,901,000
January 1996	2001	2011	6.70%		30,000	1,931,000
May 1998	none	2011	6.20%	40,000		1,971,000
June 2001	none	2011	5.95%	25,000		1,996,000
August 2001	none	2011	5.75%	50,000		2,046,000
November 1996	2001	2011	6.95%	40,000		2,086,000
January 1998	none	2013	6.10%	60,000		2,146,000
September 1998	none	2013	5.60%		52,800	2,198,800
February 1999	none	2014	5.90%	60,000		2,258,800
April 1998	2008	2028	6.65%	50,000		2,308,800
August 1998	none	2028	5.85%	106,500		2,415,300
August 1998	none	2028	5.85%	112,300		2,527,600
May 1998	2008	2032	6.70%	98,900		2,626,500
April 2003	2008	2033	5.55%	40,000		2,666,500
October 1993	1998	2033	6.85%	31,254		2,697,754
				$ 2,392,954	**$ 304,800**	**$ 2,697,754**
Less current portion						(176,200)
						$ 2,521,554

(1) The weighted average interest rate was 5.3 percent on outstanding long-term debt as of Sept. 30, 2003. All construction, conservation, fish and wildlife, and Corps/Reclamation direct funding bonds are term bonds.

(2) Corps/Reclamation direct funding

The following table summarizes future principal payments required for nonfederal projects as of Sept. 30, 2003.

Nonfederal Projects
thousands of dollars

	Debt Repayments
2004	$ 265,135
2005	234,897
2006	253,632
2007	294,745
2008	307,953
2009+	4,930,231
	$6,286,593

5. Commitments and Contingencies

Net-Billing Agreements

BPA has agreed with Energy Northwest that in the event any participant shall be unable for any reason, or shall refuse, to pay to Energy Northwest any amount due from such participant under its net-billing agreement for which a net-billing credit or cash payment to such participant has been provided by BPA, BPA will be obligated to pay the unpaid amount in cash directly to Energy Northwest, unless payment of such unpaid amount is made in a timely manner pursuant to the net-billing agreements.

Purchase and Sales Commitments

BPA has entered into Subscription power sales for 3,000 average megawatts more power than the federal system produces on a firm-planning basis. These contracts run for as short as three and as long as 10 years from Oct. 1, 2001. Current rates recover the additional costs of the Subscription obligations through 2006. BPA's trading floor enters into sales commitments to sell expected surplus generating capabilities at future dates and purchase commitments to purchase power at future dates when BPA forecasts a shortage of generating capability and prices are favorable. Further, BPA enters into these contracts throughout the year to maximize its revenues on estimated surplus volumes. BPA records these sales and purchases in the month the underlying power is sold or purchased.

The table below summarizes future purchase power and sales commitments as of Sept. 30, 2003.

Purchase Power and Sales Commitments
thousands of dollars

	Purchase	Sales
2004	$ 662,918	$ 1,795,554
2005	704,548	1,602,745
2006	650,867	1,689,882
2007	48,882	87,393
2008	49,525	71,114
2009+	152,475	264,726
	$2,269,215	**$5,511,414**

Augmentation commitments run through 2006.

Decommissioning and Restoration Costs

In 1999 Energy Northwest successfully transferred assets and site restoration liability for WNP-3 to a consortium of local governments named the Satsop Redevelopment Project. In June 1999, Energy Northwest submitted a site restoration plan to the state of Washington's Energy Facility Site Evaluation Council (EFSEC) that complied with EFSEC's requirement to restore the WNP-1 and WNP-4 sites with minimal hazard to the public. This plan updated Energy Northwest's June 1995 plan. EFSEC's approval recognized that uncertainty still exists as to the exact details of the proposed plan; accordingly, EFSEC's conditional approval provided for additional reviews once the details of the plan are finalized. As part of submitting the restoration plan to EFSEC, Energy Northwest obtained outside estimates for site restoration of WNP-1 and WNP-4. BPA is required to fund site restoration for WNP-1. Funding for WNP-4 is uncertain. The cost of complete site restoration for WNP-1 and WNP-4 is estimated to be up to

$60 million and $40 million respectively. BPA and Energy Northwest have been negotiating a reduced level of site restoration for WNP-1 as well as WNP-4 with EFSEC and the Department of Energy. A tentative conceptual solution involving a reduced level and delay in accomplishing restoration has been reached. EFSEC has approved a revised plan prepared by Energy Northwest (December 2002 Site Restoration Plan) and the agreement should be executed by the end of December 2003. The estimated cost for the recommended level of site restoration at WNP-1 and WNP-4 is about $25 million and $23 million (2003 dollars) respectively. BPA believes the existing funds plus earnings will be adequate to cover most if not all site restoration costs. BPA has recorded an estimated liability of $25.9 million (fair value basis, see Note 1, Asset Retirement Obligations, SFAS 143) for WNP-1 decommissioning costs.

Decommissioning costs for Columbia Generating Station are charged to operations over the operating life of the project. An external decommissioning sinking fund for costs is being funded monthly for Columbia Generating Station. The sinking fund is expected to provide for decommissioning at the end of the project's operating life in accordance with Nuclear Regulatory Commission requirements. Sinking fund requirements for Columbia Generating Station are based on a NRC decommissioning cost estimate and assume a 40-year operating life.

The estimated decommissioning and site restoration expenditures for Columbia Generating Station is $673 million (2003 dollars). BPA has recorded an estimated liability of $47.8 million (fair value basis, see Note 1, Asset Retirement Obligations, SFAS 143) for CGS decommissioning costs. Payments to the sinking fund for the years ended Sept. 30, 2003, 2002 and 2001 were approximately $4.6 million per year. The sinking fund balance at Sept. 30, 2003, is $84 million.

In January 1993, the Portland General Electric board of directors formally notified BPA of its intent to terminate the operation of the Trojan plant. PGE's rate filing in December 1997 with the Oregon Public Utility Commission included an estimated total decommissioning liability of $424 million (in 1997 dollars). The current remaining estimate of $265 million is based on site-specific studies less actual expenditures to date. As of Sept. 30, 2003, BPA's 30-percent share of this estimated remaining liability is $52.3 million (fair value basis, see Note 1, Asset Retirement Obligations, SFAS 143). The Trojan Decommissioning Plan calls for prompt decontamination with delayed demolition of non-radiological structures. Funding requirements will be greater in the early years of decommissioning and then will decrease significantly. These greater early funding requirements have altered the decommissioning trust fund contributions for 2001, 2002 and 2003. For the period 1995 through 2001, funding for the Trojan decommissioning trust fund was being applied directly to the decommissioning expenses. In 2002 and 2003, the decommissioning trust fund was used to fund a portion of the 2002 and 2003 Trojan decommissioning expenses. The decision to terminate the plant is not expected to result in the acceleration of debt-service payments. BPA will continue to recover its share of Trojan's costs through rates and decommissioning trust fund withdrawals. Decommissioning costs are included in operations and maintenance expense in the accompanying Statements of Revenues and Expenses. These costs incorporate the impacts of SFAS 143 as implemented by PGE.

Nuclear Insurance

BPA is a member of the Nuclear Electric Insurance Limited (NEIL), a mutual insurance company established to provide insurance coverage for nuclear power plants. The types of insurance coverage purchased from NEIL by BPA include: 1) Primary Property and Decontamination Liability Insurance; 2) Decommissioning Liability and Excess Property Insurance; and 3) Business Interruption and/or Extra Expense Insurance.

Under each insurance policy BPA could be subject to an assessment in the event that a member-insured loss exceeds reinsurance and reserves held by NEIL. The maximum assessment for the Primary Property and Decontamination Insurance policy is $6.6 million. For the Decontamination Liability, Decommissioning Liability and Excess Property Insurance policy, the maximum assessment is $13 million. For the Business Interruption and/or Extra Expense Insurance policy, the maximum assessment is $4.5 million.

As a separate requirement, BPA is liable under the Nuclear Regulatory Commission's indemnity for public liability coverage under the Price-Anderson Act. In the event of a nuclear accident resulting in public liability losses exceeding $300 million, BPA could be subject to a retrospective assessment of $95.8 million limited to an annual maximum of $10 million.

Endangered Species Act

Actions related to the Endangered Species Act are included in BPA's costs and recovered through current rates.

Environmental Cleanup

From time to time, there are sites where BPA, Corps or Reclamation have been or may be identified as a potential responsible party. Costs associated with cleanup of those sites are not expected to be material to the FCRPS financial statements and would be recoverable through future rates.

Retirement Benefits

See Note 1 for discussion of additional civil service retirement system contributions scheduled for payment through 2008.

Irrigation Assistance

As directed by legislation, BPA is required to make cash distributions to the U.S. Treasury for original construction costs of certain Pacific Northwest irrigation projects that have been determined to be beyond the irrigators' ability to pay. These irrigation distributions do not specifically relate to power generation and are required only if doing so does not result in an increase to power rates. Accordingly, these distributions are not considered to be regular operating costs of the power program and are treated as distributions from accumulated net revenues (expenses) when paid. BPA paid irrigation assistance payments of $25 million and $17 million for 1997 and 2001 respectively. Future irrigation assistance payments ultimately could total $673 million and are scheduled over a maximum of 66 years. The May 2000 Interim Cost Reallocation Report prepared by Reclamation resulted in approximately $77 million of Columbia Basin Project costs being moved from irrigation to commercial power. BPA is required by Public Law 89-448 to demonstrate that reimbursable costs of the FCRPS will be returned to the U.S. Treasury from BPA net revenues within the period prescribed by law. BPA is required to make a similar demonstration for the costs of irrigation projects, which are beyond the ability of the 22 irrigation water users to repay. These requirements are met by conducting power repayment studies including schedules of distributions at the proposed rates to demonstrate repayment of principal within the allowable repayment period.

The following table summarizes future irrigation assistance distributions as of Sept. 30, 2003.

Irrigation Assistance
thousands of dollars

	Distributions
2004	$ 739
2005	—
2006	—
2007	—
2008	2,950
2009+	669,787
	$673,476

On Dec. 11, 2002, BPA received an updated schedule of Irrigation Assistance (through Sept. 30, 2001) from the Bureau of Reclamation. The numbers above, reflect that new schedule. They exclude $56.6 million assistance for Lower Teton which was never completed therefore never produced electricity and the administrator has no obligation to recover these costs.

IOU Monetary Benefits

During fiscal 2003, BPA and various customer representatives negotiated a proposed litigation settlement that would, among other things, affect IOU Monetary Benefits if the settlement becomes effective. (The proposed settlement would also dismiss a number of existing lawsuits, preclude certain future lawsuits, result in lower 2004 rates through a reduction in the SN CRAC, and bind parties to a number of other commitments that do not have a current financial statement impact.) Subsequent to year-end, on Oct. 21, 2003, BPA signed and offered the proposed settlement to regional customers that are party to the litigation that the proposed settlement would dismiss. Three parties signed the proposed settlement by Oct. 23, 2003, making the settlement effective, but subject to the condition of subsequent actions by a number of parties over the following 120 day period for the settlement to remain in effect. During this 120-day period, in order for the proposed settlement to remain in effect, a number of other parties must sign the appropriate settlement agreements.

Under the proposed settlement, the method for establishing the IOUs' Monetary Benefits for the fiscal 2007 through 2011 period would be established, and BPA's option to provide power to the IOUs during that period would be relinquished. A portion of IOU Monetary Benefits currently scheduled to be paid out in fiscal 2004 through 2006 would be deferred to 2007 through 2011, and most of the deferral amounts could no longer be reduced through billing credits offsetting the IOUs' SN CRAC charges. The settlement would also eliminate the $200 million risk contingency payment owed to two IOUs that have load reduction contracts. However, if the settlement is terminated as the result of certain events during the 120-day period, BPA would expect to have to pay the $200 million in accordance with the terms of the contracts. The $200 million is considered augmentation costs and, if paid, would then be collected through the LB CRAC.

6. Litigation

The FCRPS is party to various legal claims, actions and complaints, certain of which involve material amounts. Although the FCRPS is unable to predict with certainty whether or not it will ultimately be successful in these legal proceedings or, if not, what the impact might be, management currently believes that disposition of these matters will not have a materially adverse effect on the FCRPS's financial position or results of operations.

7. Segments

In 1997 BPA opted to implement FERC's open-access rulemaking and standards of conduct. FERC requires that transmission activities are functionally separate from wholesale power merchant functions and that transmission is provided in a nondiscriminatory open-access manner.

The FCRPS's major operating segments are defined by the utility functions of generation and transmission. The Power Business Line represents the operations of the generation function, while the Transmission Business Line represents the operations of the transmission function. The business lines are not separate legal entities. Where applicable, "Corporate" represents items that are necessary to reconcile to the financial statements, which generally include shared activity and eliminations. Each FCRPS segment operates predominantly in one industry and geographic region: the generation and transmission of electric power in the Pacific Northwest.

The FCRPS centrally manages all interest expense activity. Since the Bonneville Power Administration has one fund with the U.S. Treasury, all cash and cash transactions are also centrally managed in the SFAS 131 Segment Reporting table. Unaffiliated revenues represent sales to external customers for each segment. Inter-segment revenues are eliminated.

FCRPS management evaluates the performance of the business lines based on Net Operating Margin (NOM) and does not track the separate balance sheets or net revenues on a business line level. NOM represents revenues generated from operations less operating and maintenance expenses of the segment's revenue-generating assets. On a consolidated basis, this amount represents $1,249 million for 2003 ($3,612 million Operating Revenues less $55 million SFAS 133 mark-to-market, $175 million U.S. Treasury Credits for Fish, $1,199 million Operations and Maintenance and $1,043 million Purchased Power Expenses) as shown in the accompanying Statement of Revenues and Expenses.

Major Customers

During 2003, 2002 and 2001, no single customer represented 10 percent or more of the FCRPS's revenues.

SFAS 131 Segment Reporting

For the years ended Sept. 30 — thousands of dollars

	Power	Transmission	Corporate	Total
2003				
Unaffiliated Revenues	**$ 3,059,386**	**$ 552,718**	**$ —**	**$ 3,612,104**
Intersegment Revenues	**85,425**	**110,884**	**(196,309)**	**—**
Operating Revenues	**$ 3,144,811**	**$ 663,602**	**$ (196,309)**	**$ 3,612,104**
Net Operating Margin	**$ 1,184,846**	**$ 337,353**	**$ (272,818)**	**$ 1,249,381**
2002				
Unaffiliated Revenues	$ 2,967,075	$ 566,654	$ —	$ 3,533,729
Intersegment Revenues	80,729	153,727	(234,456)	—
Operating Revenues	$ 3,047,804	$ 720,381	$ (234,456)	$ 3,533,729
Net Operating Margin	$ 927,061	$ 355,870	$ (288,547)	$ 994,384
2001				
Unaffiliated Revenues	$ 3,824,658	$ 454,011	$ —	$ 4,278,669
Intersegment Revenues	63,394	192,662	(256,056)	—
Operating Revenues	$ 3,888,052	$ 646,673	$ (256,056)	$ 4,278,669
Net Operating Margin	$ 180,790	$ 363,822	$ (161,587)	$ 383,025

Schedule of Amount and Allocation of Plant Investment

Federal Columbia River Power System

As of Sept. 30, 2003 — thousands of dollars

Schedule A

		Commercial Power			Irrigation *(unaudited)*		
	Total Plant	Completed Plant	Construction Work in Progress	Total Commercial Power	Returnable from Commercial Power Revenues	Returnable from Other Sources	Total Irrigation
Bonneville Power Administration							
Transmission Facilities	$ 5,787,429	$ 5,360,934	$ 426,495	$ 5,787,429	$ —	$ —	$ —
Bureau of Reclamation							
Boise	138,215	17,169	3,920	21,089	(363)	68,219	67,856
Columbia Basin	1,930,254	1,234,556	33,140	1,267,696	494,514	143,955	638,469
Green Springs	35,579	11,178	62	11,240	9,934	8,070	18,004
Hungry Horse	148,957	121,808	223	122,031	—	—	—
Minidoka-Palisades	382,454	109,789	787	110,576	386	72,966	73,352
Yakima	258,946	6,139	60	6,199	13,821	127,511	141,332
Total Bureau Projects	2,894,405	1,500,639	38,192	1,538,831	518,292	420,721	939,013
Corps of Engineers							
Albeni Falls	48,868	42,665	1,535	44,200	—	—	—
Bonneville	1,382,775	878,749	99,719	978,468	—	—	—
Chief Joseph	625,023	568,853	15,700	584,553	—	163	163
Cougar	104,922	20,332	42,396	62,728	—	3,288	3,288
Detroit-Big Cliff	70,272	41,220	2,926	44,146	—	5,050	5,050
Dworshak	375,281	316,522	2,095	318,617	—	—	—
Green Peter-Foster	95,966	49,787	5,851	55,638	—	6,222	6,222
Hills Creek	51,077	18,394	998	19,392	—	4,616	4,616
Ice Harbor	217,312	151,874	5,764	157,638	—	—	—
John Day	649,960	485,992	16,579	502,571	—	—	—
Libby	576,024	430,559	2,797	433,356	—	—	—
Little Goose	253,747	209,179	2,921	212,100	—	—	—
Lookout Point-Dexter	109,199	49,738	7,184	56,922	—	1,498	1,498
Lost Creek	149,983	26,988	35	27,023	—	2,190	2,190
Lower Granite	408,326	329,683	5,002	334,685	—	—	—
Lower Monumental	271,464	226,219	2,572	228,791	—	—	—
McNary	376,127	288,752	13,463	302,215	—	—	—
The Dalles	412,311	304,378	58,489	362,867	—	—	—
Lower Snake	261,019	255,964	2,502	258,466	—	—	—
Columbia River Fish Bypass	885,643	316,377	527,698	844,075	—	—	—
Total Corps Projects	7,325,299	5,012,225	816,226	5,828,451	—	23,027	23,027
AFUDC on Direct Funded Projects	27,711	—	27,711	27,711	—	—	—
Irrigation Assistance at 12 Projects having no power generation	196,150	—	—	—	153,381	42,769	196,150
Total Plant Investment	16,230,994	11,873,798	1,308,624	13,182,422	671,673	486,517	1,158,190
Repayment Obligation Retained by Columbia Basin Project	4,639	2,836 (1)	—	2,836	1,803	—	1,803
Investment in Teton Project	79,107	—	7,269 (2)	7,269	56,573	3,681	60,254
	$ 16,314,740	**$ 11,876,634**	**$ 1,315,893**	**$ 13,192,527**	**$ 730,049**	**$ 490,198**	**$ 1,220,247**

(1) Amount represents joint costs transferred to Bureau of Sports Fisheries and Wildlife. This is included in other assets in the accompanying balance sheets.

(2) The $7,269,000 commercial power portion of the Teton project is included in other assets in the accompanying balance sheets. Teton amounts exclude interest totaling approximately $2.2 million subsequent to June 1976, which was charged to expense.

Non-reimbursable *(unaudited)*

	Navigation	Flood Control	Fish and Wildlife	Recreation	Other	Percent Returnable from Commercial Power Revenues
Bonneville Power Administration						
Transmission Facilities	$ —	$ —	$ —	$ —	$ —	100.00%
Bureau of Reclamation						
Boise	—	—	—	—	49,270	15.00%
Columbia Basin	—	17,116	6,073	175	725	91.29%
Green Springs	—	—	—	—	6,335	59.51%
Hungry Horse	—	26,926	—	—	—	81.92%
Minidoka-Palisades	—	64,397	2,568	10,494	121,067	29.01%
Yakima	—	2,479	51,044	289	57,603	7.73%
Total Bureau Projects	—	110,918	59,685	10,958	235,000	71.07%
Corps of Engineers						
Albeni Falls	180	271	—	4,217	—	90.45%
Bonneville	400,979	—	—	1,266	2,062	70.76%
Chief Joseph	—	—	4,977	6,330	29,000	93.53%
Cougar	548	38,358	—	—	—	59.79%
Detroit-Big Cliff	219	20,857	—	—	—	62.82%
Dworshak	9,636	31,561	—	15,467	—	84.90%
Green Peter-Foster	366	30,377	—	1,693	1,670	57.98%
Hills Creek	630	26,439	—	—	—	37.97%
Ice Harbor	56,159	—	—	3,515	—	72.54%
John Day	90,980	18,038	—	11,962	26,409	77.32%
Libby	—	95,190	876	15,965	30,637	75.23%
Little Goose	34,913	—	—	4,130	2,604	83.59%
Lookout Point-Dexter	749	49,428	—	602	—	52.13%
Lost Creek	—	53,105	24,541	29,481	13,643	18.02%
Lower Granite	52,600	—	—	13,199	7,842	81.97%
Lower Monumental	39,382	—	—	2,874	417	84.28%
McNary	69,004	—	—	4,908	—	80.35%
The Dalles	47,344	—	—	2,078	22	88.01%
Lower Snake	2,553	—	—	—	—	99.02%
Columbia River Fish Bypass	38,798	2,770	—	—	—	95.31%
Total Corps Projects	845,040	366,394	30,394	117,687	114,306	79.57%
AFUDC on Direct Funded Projects	—	—	—	—	—	100.00%
Irrigation Assistance at 12 Projects having no power generation	—	—	—	—	—	78.20%
Total Plant Investment	845,040	477,312	90,079	128,645	349,306	85.36%
Repayment Obligation Retained by Columbia Basin Project	—	—	—	—	—	100.00%
Investment in Teton Project	—	9,151	—	2,433	—	80.70%
	$ 845,040	**$ 486,463**	**$ 90,079**	**$ 131,078**	**$ 349,306**	**85.34%**

Schedule of Revenues and Expenses

Federal Columbia River Power System
For the years ended Sept. 30 — thousands of dollars

Schedule B

	2003	2002	2001
Operating Revenues			
Sales of electric power:			
Sales within the Northwest Region			
Northwest Publicly Owned Utility Customers (1)	**$ 1,723,138**	$ 1,797,496	$ 939,362
Direct Service Industrial Customers	**18,480**	58,454	420,694
Northwest Investor-Owned Utilities	**435,709**	377,789	700,836
Other power sales	**1,211**	1,293	972
Sales Outside the Northwest Region (2)	**628,242**	638,261	1,084,076
Total Sales of Electric Power	**2,806,780**	2,873,293	3,145,940
Transmission	**552,718**	566,654	454,011
Fish Credits and Other Revenues (3)	**252,606**	93,782	678,718
Total Operating Revenues	**3,612,104**	3,533,729	4,278,669
Operating Expenses			
BPA O&M (4)	**607,616**	775,077	530,618
Purchased Power	**1,043,009**	1,286,867	2,296,076
Corps, Bureau and Fish & Wildlife O&M (5)	**198,539**	198,055	184,922
Nonfederal entities O&M – net billed (6)	**208,535**	167,026	208,839
Nonfederal entities O&M – non net billed (7)	**39,864**	35,566	30,719
Total Operation and Maintenance	**2,097,563**	2,462,591	3,251,174
Net billed debt service	**104,329**	213,919	451,282
Non net billed debt service	**15,205**	16,256	21,818
Nonfederal Projects Debt Service (8)	**119,534**	230,175	473,100
Federal Projects Depreciation	**350,025**	335,205	323,314
Residential Exchange	**143,967**	143,983	68,082
Total Operating Expenses	**2,711,089**	3,171,954	4,115,670
Net Operating Revenues	**901,015**	361,775	162,999
Interest Expense:			
Appropriated Funds	**280,094**	325,551	317,213
Long term debt	**166,598**	151,997	129,159
Capitalization Adjustment (9)	**(67,703)**	(67,356)	(68,784)
Allowance for funds used during construction	**(33,398)**	(57,892)	(45,679)
Net Interest Expense	**345,591**	352,300	331,909
Net Revenues (Expenses) before cumulative effect of SFAS 133	**555,424**	9,475	(168,910)
Cumulative Effect of SFAS 133 (10)	**—**	—	(168,491)
Net Revenues/(Expenses)	**$ 555,424**	$ 9,475	$ (337,401)

(1) This customer group includes municipalities, public utility districts and rural electric cooperatives in the region.

(2) In general, revenues from sales outside the Northwest are highly dependent upon stream flows in the Columbia River Basin, which affect the amount of nonfirm energy available for sale, and upon the costs of generating power with alternative fuels, which affect the price BPA can obtain for its exported nonfirm energy and surplus firm power.

(3) These revenues relate primarily to fish and wildlife credits BPA receives for its U.S. Treasury repayment obligation. Mark-to-market adjustments and other miscellaneous revenues are also included.

(4) BPA operations and maintenance expenses include the costs of BPA's transmission system, operation and maintenance program, energy resources, power marketing, and fish and wildlife programs.

(5) Corps, Reclamation and Fish & Wildlife operations and maintenance expenses include the costs for the Corps and Reclamation generating facilities included in the federal system as well as expenses incurred by the U.S. Fish & Wildlife Service in connection with the federal system.

(6) The nonfederal entities O&M — net billed expense includes the operation and maintenance costs for generating facilities, the generating capability or output of which BPA has agreed to purchase under certain capitalized contracts, the costs of which are net billed.

(7) The nonfederal entities O&M — non net billed expense includes the operation and maintenance costs for generating facilities, the generating capability or output of which BPA has agreed to purchase under certain capitalized contracts. The costs of which are not net billed.

(8) These amounts include payment by BPA for all or a part of the generating capability of, and debt service on, four nuclear power generating projects (three of which are terminated). They are Energy Northwest's Project 1, Project 3, and the Columbia Generating Station, and the City of Eugene Water and Electric Board's 30 percent ownership share of the Trojan nuclear project. These amounts also include payment by BPA with respect to several small generating and conservation projects.

(9) The capitalization adjustment represents the annual recognition of the reduction in principal realized from refinancing federal appropriations under legislation enacted in 1996.

(10) On Oct. 1, 2000, the date of adoption by BPA of Statement of Financial Accounting Standard No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133), BPA recorded a cumulative effect adjustment of $168 million loss to recognize the difference between the carrying values and fair values of derivatives not designated as hedging instruments. The adjustment consisted primarily of transactions known as bookouts that the FASB initially determined should be fair valued in net revenue (expense).

Report of Independent Auditors

PRICEWATERHOUSECOOPERS

To the Administrator of the
Bonneville Power Administration,
United States Department of Energy

In our opinion, the accompanying balance sheets and the related statements of changes in capitalization and long-term liabilities, of revenues and expenses, and of cash flows present fairly, in all material respects, the financial position of the Federal Columbia River Power System (FCRPS) at September 30, 2003 and 2002, the results of its operations, and its cash flows for each of the three years in the period ended September 30, 2003, and the changes in its capitalization and long-term liabilities for each of the two years in the period ended September 30, 2003, in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of FCRPS' management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

Our audit was conducted for the purpose of forming an opinion on the basic financial statements taken as a whole. The Schedule of Amount and Allocation of Plant Investment as of September 30, 2003 (Schedule A) and the Schedule of Revenues and Expenses for each of the three years in the period ended September 30, 2003 (Schedule B) are presented for purposes of additional analysis and are not a required part of the basic financial statements. Such information, except for that portion marked "unaudited," on which we express no opinion, has been subjected to the auditing procedures applied in the audit of the basic financial statements and, in our opinion, are fairly stated in all material respects in relation to the basic financial statements taken as a whole.

PricewaterhouseCoopers LLP

Portland, Oregon
November 7, 2003

Federal Repayment

Revenue Requirement Study

The revenue requirement study demonstrates repayment of federal investment, and it reflects revenues and costs consistent with BPA's 1996 Wholesale Power and Transmission Rate Filing. FERC granted final approval for proposed Power and Transmission rates on April 4, 1997, for fiscal years 1997 through 2001 (75 FERC 62,010 (1997)).

BPA separately submitted a Transmission and Ancillary Services Rate Filing in 2000 for fiscal years 2002 through 2003, and a Power Rate Filing in 2001 for fiscal years 2002 through 2006. In 2001, BPA submitted a Supplemental Power Rate Filing to amend the earlier power rate proposal. FERC granted final approval of BPA's Transmission and Ancillary Services rates on May 7, 2001, for fiscal years 2002 through 2003, 62 FERC 62,094 (2001). On June 29, 2001, FERC granted final approval for the acceleration of the Ancillary Services and Control Area Services Rate (ACS-02) for Generation Imbalance Service (GIS), 95 FERC 62,286 (2001); and on Oct. 11, 2001, FERC granted final approval for corrections of the ACS-02 rate, 97 FERC 62,020 (2001). FERC granted interim approval for proposed Power rates on Sept. 28, 2001, for fiscal years 2002 through 2006, 96 FERC 61,360 (2001) and granted final approval on July 21, 2003, 104 FERC 61,093 (2003). BPA received interim approval of its recent SN CRAC rate proposal on Oct. 1, 2003, 105 FERC 61,006 (2003).

Repayment Demonstration

BPA is required by Public Law 89-448 to demonstrate that reimbursable costs of the FCRPS will be returned to the U.S. Treasury from BPA net revenues within the period prescribed by law. BPA is required to make a similar demonstration for the costs of irrigation projects that are beyond the ability of irrigation water users to repay. These requirements are met by conducting power repayment studies including schedules of payments at the proposed rates to demonstrate repayment of principal within the allowable repayment period.

Since 1985, BPA has prepared separate repayment demonstrations for generation and transmission in accordance with an order issued by the Commission on Jan. 27, 1984 (26 FERC 61,096).

Repayment Policy

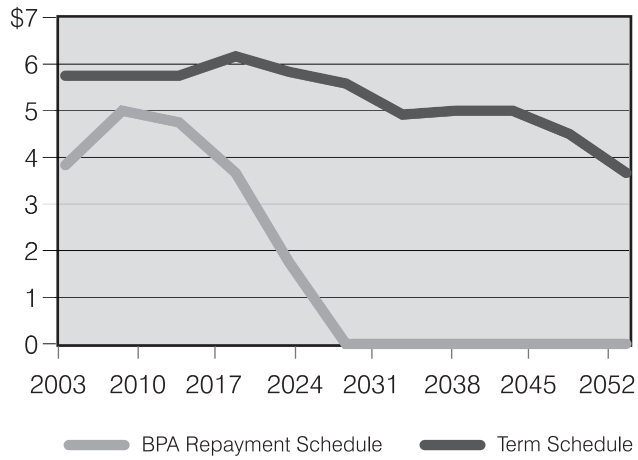
BPA's repayment policy is reflected in its generation and transmission revenue requirements and respective rate levels. This policy requires that FCRPS revenues by function be sufficient to:

1. Pay the cost of obtaining power through purchase and exchange agreements (nonfederal projects).
2. Pay the cost of operating and maintaining the power system including payments related to the underfunded status of the CSRS plan.
3. Pay interest on and repay outstanding bonds issued to the Treasury to finance transmission system construction, conservation, environmental, direct-funded Corps and Reclamation improvements, and fish and wildlife projects.
4. Pay interest on the unrepaid investment in power facilities financed with appropriated funds. (federal hydroelectric projects all were financed with appropriated funds, as were BPA transmission facilities constructed before 1978.)
5. Pay, with interest, any outstanding deferral of interest expense.
6. Repay the power investment in each federal hydroelectric project with interest within 50 years after the project is placed in service (except for the Chandler project, which has a legislated repayment period of 66 years).
7. Repay each increment of the investment in the BPA transmission system financed with appropriated funds with interest within the average service life of the associated transmission plant (40 years).
8. Repay the appropriated investment in each replacement at a federal hydroelectric project within its service life.
9. Repay construction costs at federal reclamation projects that are beyond the ability of the irrigators to pay and are assigned for payment from commercial power net revenues within the same period available to the water users for making payments. These periods range from 40 to 66 years, with 50 years being applicable to most of the irrigation payment assistance.

Investments bearing the highest interest rate will be repaid first, to the extent possible, while still completing repayment of each increment of investment within its prescribed repayment period.

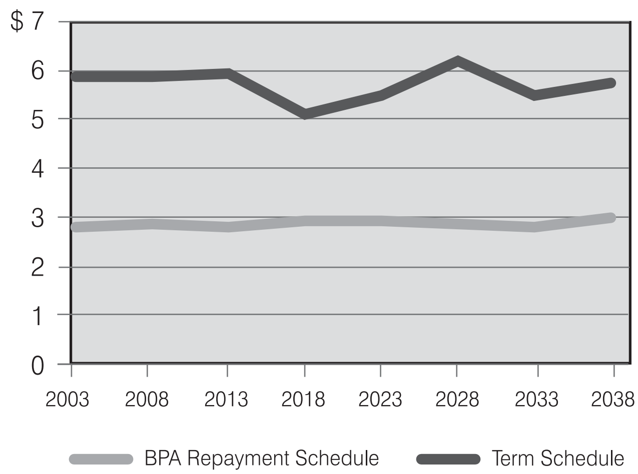
Unrepaid Federal Generation Investment

Includes future replacements — billions of dollars



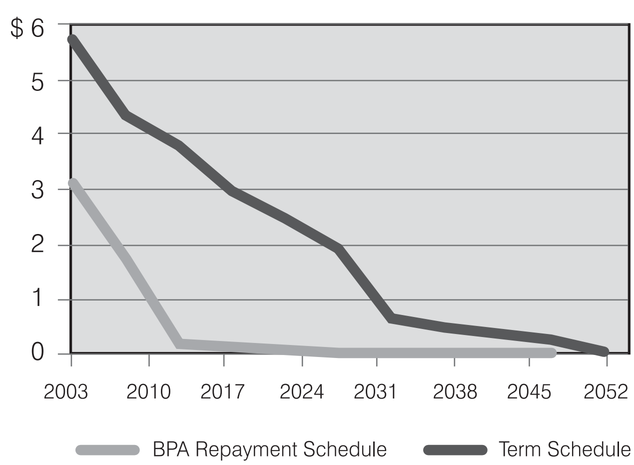
Unrepaid Federal Transmission Investment

Includes future replacements — billions of dollars



Unrepaid Federal Investment

Excludes future replacements — billions of dollars



Repayment Obligation

BPA's rates must be designed to collect sufficient revenues to return separately the power and transmission costs of each FCRPS investment and each irrigation assistance obligation within the time prescribed by law. If existing rates are not likely to meet this requirement, BPA must reduce costs, adjust its rates, or both. However, total irrigation assistance payments cannot require an increase in the BPA power rate level. Comparing BPA's repayment schedule for the unrepaid capital appropriations and bonds with a "term schedule" demonstrates that the federal investment will be repaid within the time allowed. A term schedule represents a repayment schedule whereby each capitalized appropriation or bond would be repaid in the year it is due.

Reporting requirements of Public Law 89-448 are met so long as the unrepaid FCRPS investment and irrigation assistance resulting from BPA's repayment schedule are less than or equal to the allowable unrepaid investment in each year. While the comparison is illustrated here by graphs representing total FCRPS generation and total FCRPS transmission investment, the actual comparison is performed on an investment-by-investment basis.

Repayment of FCRPS Investment

The graphs for Unrepaid Federal Generation and Transmission Investment illustrate that unrepaid investment resulting from BPA's generation and transmission repayment schedules is less than the allowable unrepaid investment. This demonstrates that BPA's rates are sufficient to recover all FCRPS investment costs on or before their due dates.

The term schedule lines in the graphs show how much of the obligation can remain unpaid in accordance with the repayment periods for the generation and transmission components of the FCRPS. The BPA repayment schedule lines show how much of the obligation remains to be repaid according to BPA's repayment schedules. In each year, BPA's repayment schedule is ahead of the term schedule. This occurs because BPA plans repayment both to comply with obligation due dates and to minimize costs over the entire repayment study horizon (40 years for transmission, 50 years for generation). Repaying highest interest-bearing investments first, to the extent possible minimizes costs. Consequently, some investments are repaid before their due dates while assuring that all other obligations are repaid by their due dates. These graphs include forecasts of system replacements during the repayment study horizon that are necessary to maintain the existing FCRPS generation and transmission facilities. The Unrepaid Federal Investment graph displays the total planned unrepaid FCRPS obligations compared to allowable total unrepaid FCRPS investment, omitting future system replacements. This demonstrates that each FCRPS investment through 2003 is scheduled to be returned to the U.S. Treasury within its repayment period and ahead of due dates.

If, in any given year, revenues are not sufficient to cover all cash needs including interest, any deficiency becomes an unpaid annual expense. Interest is accrued on the unpaid annual expense until paid. This must be paid from subsequent years' revenues before any repayment of federal appropriations can be made.

BPA Executives and Offices

Corporate Executives

Stephen J. Wright
Administrator & Chief Executive Officer

Steven G. Hickok
Deputy Administrator

Ruth B. Bennett
Chief Operating Officer

Allen L. Burns
Executive Vice President for
Industry Restructuring

Terence G. Esvelt
Senior Vice President,
Employee & Business Resources

Randy A. Roach
Senior Vice President, General Counsel

James H. Curtis
Vice President, Finance,
and Chief Financial Officer

Therese B. Lamb
Vice President, Environment, Fish & Wildlife

Pamela J. Marshall
Vice President, Strategic Planning

Jeffrey K. Stier
Vice President, National Relations

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Paul E. Norman
Senior Vice President, Power Business Line

Alexandra B. Smith
Vice President, Requirements Marketing

Gregory K. Delwiche
Vice President, Generation Supply

Stephen R. Oliver
Vice President, Bulk Marketing &
Transmission Services

Michael J. Weedall
Vice President, Energy Efficiency

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Burley Customer Service Center
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Burley, ID 83318
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Eastern Area Customer Service Center
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Richland Customer Service Center
Kootenai Bldg., Room 215
North Power Plant Loop
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Richland, WA 99352
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