Our strategic direction is about preserving the core assets of the federal base system so they can provide benefits to ratepayers and taxpayers well into the future. We are guided by four fundamental goals: high reliability, low rates consistent with sound business principles, environmental stewardship and accountability to the region.

2004 Annual Report

Bonneville
Power
Administration

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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 40 percent of all the electric power used in the Northwest comes from BPA.

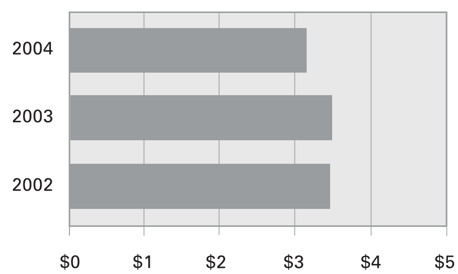
BPA is a self-funding agency that covers its costs by selling its services wholesale to the region's public utilities, municipalities, investor-owned utilities and some large industries. BPA also sells or exchanges power with marketers and utilities in Canada and the western United States. Its service 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.

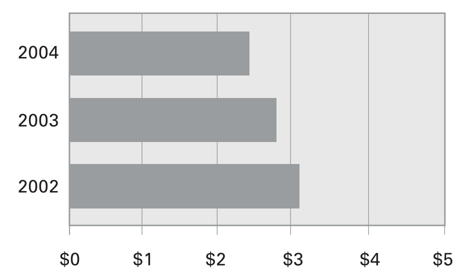
Financial Results

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 26. *Net Revenues With and Without Debt Management Actions and Statement of Financial Accounting Standards* 133 reflect the impact of nonfederal debt management actions and SFAS 133 (see Adoption of Statement 133 and Related Guidance in the first note to the Financial Statements). *Nonfederal Debt Service Coverage Ratio* 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. The *Status of Treasury Principal Repayment* shows the scheduled and early repayment of federal appropriations and U.S. Treasury bonds. *Financial Reserves* is the sum of BPA cash and deferred borrowing authority at year end.

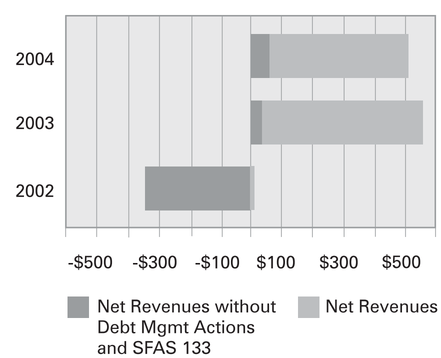
Operating Revenues
billions of dollars



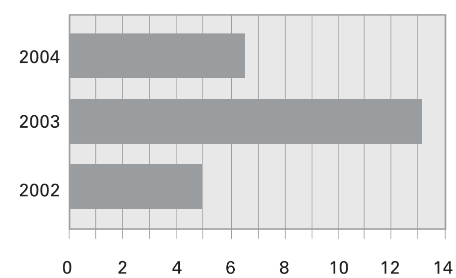
Operating Expenses
billions of dollars



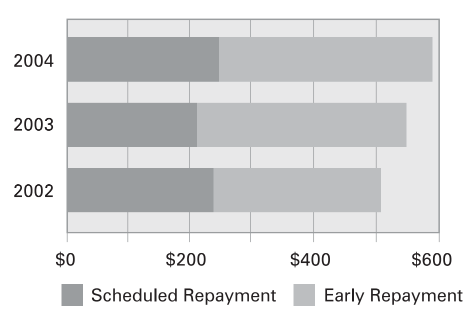
Net Revenues With and Without Debt Management Actions and SFAS 133
millions of dollars



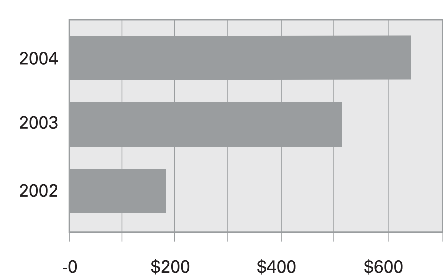
Nonfederal Debt Service Coverage Ratio
times covered



Status of Treasury Principal Repayment
millions of dollars



Financial Reserves
millions of dollars



Dear Mr. President:

The Bonneville Power Administration had two great year-end accomplishments in the past 12 months. On New Year's Eve 2003, we energized the first major high-voltage transmission line built in the Pacific Northwest since 1987, and we ended fiscal year 2004 by announcing a significant wholesale power rate decrease. Both were high points and underscored our two major thrusts for the year – infrastructure investment and cost management.

Financially and strategically, 2004 was the year BPA stopped looking primarily backward to recover from the West Coast energy crisis and began aggressively looking forward to the longer-term future. We released a new draft Strategic Direction that focuses on the years 2006 and beyond. Our direction adheres to four goals – high reliability, low rates, environmental stewardship and regional accountability. The Strategic Direction is fundamentally about protecting the core assets of the federal base system so they can provide benefits to ratepayers and taxpayers well into the future.

We ended the year in the black showing a clear upward trend as we continue to improve our financial situation. The financial information for the year is displayed on the previous page and is discussed on the following pages.

Moody's Investors Service acknowledged our improving situation by raising its rating for BPA-backed bonds from Aa1 to Aaa, its highest rating. Moody's cited "significant financial improvements" through reductions in expense, debt optimization and rate adjustments. Standard and Poor's also changed the outlook on BPA's credit from "negative" to "stable."

U.S. taxpayers should be pleased to know that BPA made its annual Treasury payment in full and on time. For the 21st year in a row we have not used provisions in the law that would allow us to defer payment if necessary.

Recovery from the lingering impacts of the turbulent years of 2000-2001 is accelerating. The clearest sign of that recovery is the fact that we were able

to set our fiscal year 2005 wholesale power rate 7.5 percent lower than the fiscal year 2004 rate. This was good news for the Northwest's economy. And, equally important to our fiscal health, we maintained our high level of Treasury Payment Probability at just over 86 percent even as we lowered rates.

Also, during fiscal year 2004, the Federal Energy Regulatory Commission voted unanimously to clear BPA of any allegations of market manipulation during the West Coast energy crisis. We were pleased, but not surprised. We believe people have a right to expect that a federal agency will serve the public interest broadly and ethically.

We take our public responsibilities seriously. These responsibilities are the law; they are part of our mission statement and they underlie how we go about our business. As for that business, the following pages of this Annual Report will detail highlights of fiscal year 2004.

Sincerely,

Stephen J. Wright
Administrator and CEO

Highlights of the Year

Financial

We earned net revenues of $504 million in fiscal year 2004. Excluding non-federal debt management actions and the application of SFAS 133, our results would have been $66 million. This compares to last year when we had net revenues of $555 million or, when debt management and SFAS 133 actions were excluded, $37 million.

Our liquidity also improved significantly as we ended fiscal year 2004 with $638 million in financial reserves, compared to $511 million at the end of 2003. Financial reserves are vital in our system, which is primarily hydropower. A weather-dependent system can bring wide fluctuations in revenues from year to year.

We paid the U.S. Treasury $1.053 billion during fiscal year 2004. This payment is a return, with interest, of the U.S. taxpayer investment in the Federal Columbia River Power System (FCRPS), which includes the federal hydropower dams and transmission system.

Our Treasury payment included $592 million in principal and $420 million in interest. The principal payment included $346 million in early retirement of Treasury debt as part of our debt-optimization program. Through this program we are both reducing the interest cost of BPA's debt portfolio and conserving BPA's capacity to borrow in the future from the U.S. Treasury. In the last three years, this debt-optimization program and other debt-management initiatives have resulted in a total saving of over $100 million a year to our power and transmission customers.

We also are working to increase the transparency of our finances to external stakeholders. In March, BPA adopted a new Financial Disclosure Policy designed to enhance consistent and clear communication with regard to the agency's financial information. The monthly financial briefings we initiated for the Public Power Council have gotten good reviews.

Cost Management

Cost management underscored every aspect of BPA in fiscal year 2004. While more than one factor played into our ability to decrease power rates, there is no question that a major factor was the intense and focused cost-cutting effort by our own employees as well as the efforts of our cost partners – the U.S. Army Corps of Engineers, Bureau of Reclamation, Energy Northwest and the Northwest Power and Conservation Council.

On the power side, we captured $70 million in program-related cost reductions in fiscal year 2004 over and above what we expected when we set rates in August 2003. For fiscal years 2005-2006, we are forecasting an additional $350 million in program-related cost savings relative to when we set rates in August 2003. Well over half of this amount was secured through agreements with the region's investor-owned utilities, and most of the remainder is associated with the interest expense savings mentioned above.

In fiscal year 2004, our Power Business Line (PBL) launched the Power Net Revenue Improvement Sounding Board made up of customers and interest group representatives. Its charge was to help us identify $100 million in potential cost

Our employees have responded to multiple budget trimmings with innovative ideas and pride. Over 80 percent reported they have instituted changes in their work that have served to cut costs or increase efficiency. Our greatest asset is a highly experienced and knowledgeable work force. This is essential to our long-term success.

reductions and revenue enhancements for fiscal years 2004-2005. The group exceeded expectations, identifying $165 million, with the largest contribution coming from lower net interest expense.

We also worked closely with customers on agencywide cost and efficiency issues through the Customer Collaborative. This group, which is self-selected, formed in August 2003 when a group of customers approached us seeking background on our costs and policy choices.

On the transmission side, unfortunately revenues continue to run well below rate case estimates. In fiscal year 2004, our Transmission Business Line (TBL) aggressively cut operating costs by more than $65 million, largely offsetting an $80 million drop in revenues and a $10 million increase in depreciation compared to the rate case estimate. This difficult action reduced actual transmission revenue losses to $12 million. TBL also cut or deferred $55 million in capital projects in fiscal year 2004 in addition to the $19 million in capital spending cut or deferred in 2003.

TBL has set a goal to achieve a 10 percent reduction in its in-house work force, which will provide a flat cost structure between fiscal years 2006 and 2007. In addition, the business line is reviewing a new asset performance management approach as a first step toward a full asset management model. Asset management offers an even more rigorous process to examine capital and expense commitments resulting in better business decisions and prioritization.

Efficiency Initiatives

Overall, the agency is seeking both additional efficiencies and greater effectiveness through better use of its resources. In fiscal year 2003, BPA completed a report to the administrator and a report to the region that collectively became known as the Lessons Learned reports. These reports pointed to a number of ways BPA could be made more efficient and effective, and BPA began pursuing and implementing the Lessons Learned recommendations throughout fiscal year 2004.

As part of this effort, BPA hired a consultant to take a high-level strategic look at our functions and provide a framework for our subsequent, more detailed examination of how to improve the efficiency and effectiveness of these functions. As a first step, the consultant recommended that BPA streamline and standardize its processes.

In the first phase of implementing this recommendation, BPA launched process improvement initiatives in seven of 23 functional areas targeted by the consultant for potential efficiencies. The seven are TBL project planning, design and construction; marketing and sales; energy efficiency project management; fish and wildlife project management; information technology; communications and liaison; and human resources and staff management. We expect that through standardizing and streamlining our processes we will capture efficiencies and ensure that, as experienced employees retire, new staff can replicate the processes.

The consultant also noted that our organizational structure is not best suited to today's business climate. Since the mid-90s, we have been divided into two distinct business lines because, at the time, there was a strong expectation that the agency itself might be legally divided into separate power marketing and transmission businesses. Today, that is not likely, and many of the redundancies created to support two separate businesses no longer make sense. Therefore, we are on a path toward a "One-BPA" construct that will fully comply with the Federal Energy Regulatory Commission's Standards of Conduct.

Power Rates

One of the most satisfying moments of fiscal year 2004 was the announcement that BPA would reduce its wholesale power rates 7.5 percent starting Oct. 1, 2004. By doing so, we were able to leave over $120 million in the Northwest economy. We implemented the rate decrease despite a number of challenging conditions in fiscal year 2004. These included the fifth below-average water year in a row and a drop of $150 million in net secondary power sales below initial projections. At the same time, we also maintained our high probability of repaying the U.S. Treasury at 86.2 percent over a two-year period.

A June agreement with the region's investor-owned utilities that reduced BPA's costs in fiscal years 2005-2006 by $200 million helped set the stage for a rate decrease. The IOUs agreed to forgo $100 million in payments and defer the remaining $100 million until fiscal years 2007-2011 with interest. In return, the IOUs received greater certainty about the benefits they'll receive for residential and small-farm customers in those years. This coupled with stringent cost management, contributed to the rate decrease.

Transmission Rates

The Transmission Business Line conducted Programs in Review in fiscal year 2004, a public involvement process to solicit customers' and constituents' feedback on our proposed budget levels and revenue requirements for the next rate period.

In July, TBL also began holding a series of rates workshops to discuss rate issues and methodology for fiscal years 2006 and 2007. In mid-July, faced with continuing flat sales and increases in depreciation and debt-service costs associated with new infrastructure, TBL told its customers that transmission rates were likely to rise for fiscal years 2006-2007 despite aggressive cost cutting.

We are projecting a continued shortfall in transmission revenues over the next few years, resulting in the need for a rate increase beginning in fiscal year 2006. Transmission costs typically account for roughly 10 percent of utilities' overall power bills.

Transmission Infrastructure

We believe BPA is engaged in the largest high-voltage transmission construction program in the nation. The physical distances between load centers in the West mandate a much larger grid than the relatively compact delivery systems in other parts of the country.

The Kangley-Echo Lake 500-kilovolt line was built to improve reliability for the populous Puget Sound area. Energized on Dec. 31, 2003, it was the first major high-voltage line built in the Northwest in 17 years. The timing was fortuitous and

The Kangley-Echo Lake 500-kilovolt line was built to improve reliability for the populous Puget Sound Area. It was energized on New Year's Eve, just days before a storm brought record-high loads to the area. We took unprecedented steps to mitigate environmental impacts, even using helicopters to lift tower sections into the site.

may have prevented outages at its onset as the line went into operation just days before a severe storm brought record-high loads to the area. On Jan. 5, power flowing over the transmission grid in our control area reached a record 20,000 megawatts. The average for the time of year is 16,000 megawatts. The addition of this line also will reduce transmission losses for an annual energy savings of 48,000 megawatt-hours.

The Kangley-Echo Lake line broke new ground in many ways. Because it traverses Seattle's Cedar River Watershed, which supplies the city's water, we took unprecedented steps to mitigate environmental impacts. Helicopters lifted tower sections into the site. Trucks and ground-based equipment were fitted with catch cloths to prevent contamination from oil leaks. We installed all 47 transmission towers in less than a week.

We also funded a $1.9 million land acquisition as part of the agreement to protect Seattle's watershed. The Trust for Public Land will protect 640 acres of sensitive forest previously slated for residential development. As a result of these efforts, BPA received unanimous approval from the Seattle City Council and praise from environmental groups who, just the year before, had opposed the construction.

Kangley-Echo Lake was one of 20 transmission projects scheduled to relieve a growing number of congested transmission paths and to provide delivery systems for new generation. However, an expected infusion of new development did not materialize as the region's economy recovered slowly from recession. As a result, TBL canceled or delayed some projects, converted others to upgrades and increased its focus on non-wires alternatives.

Construction did proceed on critical projects. The 500-kilovolt Grand Coulee-Bell line, now nearing completion, will replace about 84 miles of existing 115-kilovolt wood pole transmission line between the Bell Substation in Spokane, Wash., and Grand Coulee Dam. The 63-mile, 500-kilovolt Schultz-Wautoma line will strengthen BPA's grid in central Washington and help ease electricity flows in the Interstate-5 corridor.

The Schultz-Wautoma project is employing a third-party capital lease agreement with Northwest Infrastructure Financing Corp. Although BPA is leasing the line, we will manage construction and exclusively operate the line, with the right to purchase the line when the lease expires. This arrangement reduces pressure on BPA's Treasury borrowing limit.

In another unique approach, we held an "open season" to determine if a new transmission line will be needed between McNary and John Day dams. We asked power plant sponsors and others requesting transmission in this area to sign up for transmission service and commit to help finance transmission. Interest has been lively, and we expect to know by January if we have sufficient commitments to move forward with construction.

Another high point of the year was completing modernization of BPA's Celilo Converter Station near The Dalles Dam. We replaced 30-year-old mercury arc valves with state-of-the-art, solid-state converters. This station is the northern end of the Direct Current Intertie that runs to Los Angeles providing 3,100 megawatts of transfer capability. This work, as well as continuing work by the Los Angeles Department of Water and Power on the southern end of the line, is expected to extend the life of this transmission by 35 years.

Non-Wires Alternatives

Some of the most exciting work in the region revolves around efforts to find alternatives to constructing new transmission facilities. BPA is working with a regional group known as the Non-Wires Solutions Round Table made up of 20 representatives from Northwest states, utilities, developers, public interest groups and tribes. The goal is to ensure that we thoroughly review non-wires solutions before building a new line.

Alternatives to construction include demand-side management, pricing, distributed generation and other strategies. Major drivers for our efforts are the substantial construction and environmental costs associated with new lines. For example, the 9-mile Kangley-Echo Lake transmission line cost about $57 million due to extensive mitigation requirements.

In March, we conducted a successful pilot test on Washington's Olympic Peninsula. Mason County Public Utility District #3, paper plants in Port Townsend and Port Angeles, and the U.S. Navy participated. The test simulated severe weather conditions to determine if transmission needs could be met through non-wires alternatives, such as demand management. BPA asked participants to reduce their need for transmission services and posted an hourly price per megawatt, giving pilot participants the chance to accept, reject or counter the offer. The result was an average 22-megawatt reduction of real load.

Generation Infrastructure

The Columbia Basin's 31 federal dams are often called the crown jewels of the Federal Columbia River Power System. But some of these projects are more than 60 years old, and the average age of all the dams is 45 years. A 1999 report requested by Congress showed that power production from these dams was declining for lack of maintenance and refurbishments. Absent investments, hydro capability was expected to continue declining at an annual rate of about 1.5 percent.

Direct funding, authorized by Congress, has made it possible to operate, maintain and make capital investments on the system's hydropower facilities expeditiously. In fiscal year 2004, BPA provided $216 million in direct funding to the U.S. Army Corps of Engineers, Bureau of Reclamation and U.S. Fish and Wildlife Service for operation and maintenance expenses. This amount is in addition to what BPA pays to the U.S. Treasury.

In addition to funding the O&M expenses, BPA also direct-funds capital improvements to maintain the viability and integrity of the stations and to improve hydro generating efficiency, essentially getting more generation from the same amount of water passing through the system. In fiscal year 2004, BPA funded approximately $111 million in hydropower capital improvements. These investments provided for repairs and replacements of generators, turbines, exciters, governors and control systems, as well as powerhouse structures.

Examples of recent turbine efficiency investments are the turbine runner replacement at Grand Coulee Dam and the McNary Dam uprate project.

As a result of these investments, we have set a target to acquire a minimum of 20 megawatts of generation through the hydro efficiencies program in the next year.

Strategic Direction

For the last four years, much of the utility industry in the West has been absorbed in recovering from the West Coast energy crisis of 2000-2001. BPA was no exception, and our challenges were compounded by five consecutive years of below-average water. The result has been a short-term focus on recovering BPA's financial stability. Now, as those efforts are bearing fruit, BPA is determined to renew its focus on the long term. We want to ensure that the actions and decisions BPA makes today preserve the value of the Federal Columbia River Power System for tomorrow and beyond.

To that end, BPA developed and released a draft Strategic Direction in March that laid out a broad direction for the agency over the next few years. We took informal comments on the draft and received over 500 comments. We found strong support for the overall direction and endorsement of looking to the long term. While we made modifications based on the comments we heard, we do not consider the Strategic Direction final. It is a work in progress that is flexible enough to accommodate changing conditions but tight enough to provide solid and measurable guidance for moving forward.

We are guided by four fundamental goals: high reliability, low rates consistent with sound business principles, responsible environmental stewardship and accountability to the region. As we developed this Strategic Direction, we assumed that our goals would be accomplished without new legislation. We also remained committed to three fundamentals of our existing statutory mission – cost-based rates, public preference and regional preference in the marketing of power.

Regional Dialogue

In April, our Power Business Line resumed the Regional Dialogue. This public process addresses issues that will influence new rates scheduled to take effect in fiscal year 2007 and new long-term contracts for fiscal year 2009 and beyond. A key objective is to clarify how BPA will serve the region's future power needs. BPA provides about 40 percent of the region's power. The heart of the discussion centers on a proposal to limit future power sales at the lowest cost-based rate to the capacity of the existing federal system.

At issue are the structure of BPA's long-term obligations, how access to our lowest-cost power should be limited, whether BPA should tier its power rates, rules for serving new public loads, methods for controlling costs and consulting with our stakeholders and how the agency's conservation and renewables responsibilities should be fulfilled.

The Regional Dialogue is key to achieving many of the objectives in BPA's Strategic Direction, including assuring regional infrastructure development, holding rates down, defining future benefits to investor-owned utility residential and small-farm customers, defining future service to direct-service industries and controlling risk.

BPA issued a policy proposal addressing a dozen Regional Dialogue issues in July and conducted six public meetings. Because of sharp divisions on some of the issues, we conducted follow-up discussions into November. A final record of decision is scheduled for December.

Fish and Wildlife

The federal investment in protection of endangered fish appears to be paying dividends, as adult salmon and steelhead returns to the Columbia and Snake rivers continue to be at the higher end of historic levels. This year's overall chinook salmon returns appear to be the fourth highest counted since 1938. Although favorable ocean conditions underlie these numbers, actions by BPA and its federal partners to improve fish survival certainly contribute as well.

Under the Northwest Power Act, the Endangered Species Act, and our tribal treaty and trust responsibilities, we fund and – together with our federal partners – implement a wide range of actions across the Columbia Basin to mitigate the effects of federal dams on fish and wildlife. We continue to advance the use of performance measures to gauge our progress whenever feasible. For example, in 2004, we adopted standard habitat performance metrics, consistent with metrics developed by regional salmon managers under the Pacific Coast Salmon Recovery Act.

Our comprehensive strategy adheres to an "All H" approach" – improving H*ydro* operations and passage, restoring tributary and estuary H*abitat*, artificially assisting fish production with H*atcheries* and encouraging more selective H*arvest* techniques.

Hydro

We achieved the performance objective established in the 2000 Biological Opinion, close to natural survival for adult fish passing through the hydro system via fish ladders. We are seeing promising results in our efforts to improve both juvenile fish survival and cost effectiveness using surface passage, a more natural approach for the fish. Our first such efforts, the "corner collector" at Bonneville Dam on the Columbia River and the removable spillway weir at Lower Granite Dam on the Snake River, showed positive results in initial testing.

In other developments, we tried unsuccessfully to substitute lower-cost mitigation efforts, which we believe would have provided the same or better biological benefits, for higher-cost spill levels in the late summer when few endangered fish are in the river. Although we received support in this effort from NOAA[1] Fisheries, judicial action precluded implementation.

[1] National Oceanic and Atmospheric Administration

The federal investment in recovery of endangered fish appears to be paying dividends, as adult salmon and steelhead returns to the Columbia and Snake rivers continue to be at the higher end of historic levels. This year's overall chinook salmon returns appear to be the fourth highest counted since 1938.

Habitat

We acquired over 3,000 acres of mitigation lands for fish and wildlife. This includes working with the Columbia Land Trust to acquire 451-acre Crims Island in the Columbia River, habitat for both endangered white-tailed deer and salmon. We helped fund the Asotin Wildlife Area in southeast Washington, which added habitat to an existing state wildlife area. The property is a vital link in a watershed for threatened steelhead and bull trout and endangered salmon.

In the Willamette Basin, BPA acquired a 165-acre conservation easement that became part of the West Eugene Wetlands/Willow Creek Wildlife Mitigation Area managed by The Nature Conservancy. This site benefits populations of six at-risk species including four species listed under the Endangered Species Act. And hundreds of acres of land were protected in the Cedar River watershed under the terms of a settlement agreement for the Kangley-Echo Lake transmission line.

Hatcheries

We funded ongoing operation and maintenance for 25 hatcheries and implemented the "safety net" hatchery programs for endangered salmon most at risk of extinction. A biological review conducted in coordination with state and tribal fishery agencies revealed that no new safety net programs are needed at this time.

Harvest

We continued to provide additional selective and terminal fishing opportunities in the lower Columbia River for coho and chinook for non-treaty sport and commercial fishing. This included selective live capture gear and methods developed through funding of the lower Columbia River tooth-tangle net study. Additionally, we provided treaty fishers with selective gillnets that reduce steelhead interceptions during commercial fisheries in the fall.

Notwithstanding these accomplishments, our program does face some future challenges in federal court. A federal judge has questioned the draft 2004 Biological Opinion for the federal dams, prepared by NOAA Fisheries in response to a judicial remand under the Endangered Species Act. The final Biological Opinion was issued in November, and, given the divisiveness in the region over this subject, litigation appears likely. Nevertheless, we are implementing a suite of actions that will continue to make progress toward fulfilling our mitigation responsibilities.

Energy Efficiency

Since passage of the Northwest Power Act, BPA has invested over $2 billion in conservation, and it has paid off. Almost a third of the region's load growth since 1980 has been met with conservation. In fiscal year 2004, BPA secured energy savings of 42 average megawatts, bringing the adjusted total savings to about 850 average megawatts in just over two decades. By comparison, the average annual energy output from The Dalles Dam is 798 average megawatts.

Nearly 130 of our utility customers are participating in one or more conservation programs, and more than 60 customers submitted proposals for funding under the Conservation Augmentation program.

We continue to make conservation more cost effective and thus more attractive. By driving the cost of delivered conservation savings down, BPA has been able to reduce its original $500 million capital investment projection for conservation to $300 million over 10 years from fiscal years 2002 to 2011 to save about 225 average megawatts.

BPA also is leading the region in its commitments to the Northwest Energy Efficiency Alliance through fiscal year 2009. We currently fund about 50 percent of the Alliance at a cost of $10 million a year. This organization has been very successful in developing and delivering market transformation initiatives for the region.

Currently, we are working with a Conservation Work Group to develop and recommend a proposed conservation program approach for the future. We look to this effort to bring the best features of our current programs together with other ideas to establish a robust conservation acquisition portfolio for BPA to consider.

A highlight of the year for us was being honored by the Alliance to Save Energy as a "Star of Energy" for being the premier public power utility engaged in energy efficiency activities. The Natural Resources Defense Council nominated BPA for its innovative applications of energy efficiency as an alternative to building transmission lines, as well as BPA's overall conservation effort. As NRDC Resource Program director Ralph Cavanagh put it, "This is the gold standard for utilities involved in energy efficiency, and the Alliance is effectively (and indeed very explicitly) saying that, across the whole universe of North American public power institutions, BPA is the clear leader."

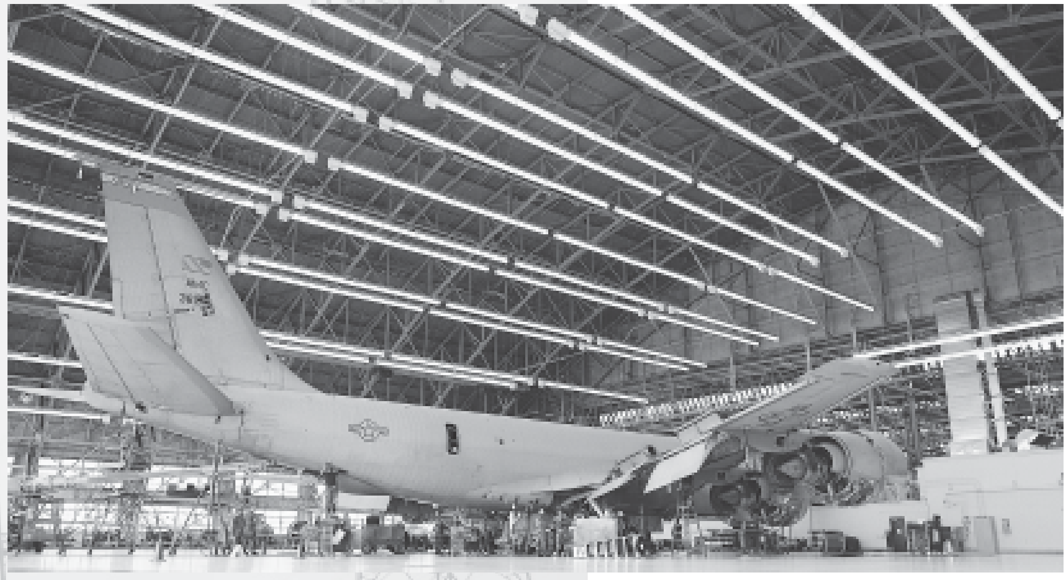
Renewable Energy

BPA is focused on fostering markets for renewable resources. This year, we created two new power integration products to help utilities bring wind energy to market. These products use the limited storage capacity of the federal hydro system to back and smooth intermittent energy from the wind. Cowlitz County Public Utility District was the first to buy these products.

In addition, more than 37 Northwest utilities now market renewable energy from BPA's environmentally preferred power product and purchase of Green Tags. Proceeds from these premium products leverage investment in new renewable resource development through the independent, nonprofit Bonneville Environmental Foundation. BPA directs about $1 million a year from Green Tags and environmentally preferred power sales to the foundation for new renewable resource and fish and wildlife projects.

On the transmission side, BPA is delivering 325 megawatts of installed wind power over its grid to buyers throughout the Northwest. Interest in wind resurged immediately after restoration of wind energy tax credits by Congress and President Bush this fall. Several developers are anxious to complete their projects before these credits expire. In all, BPA now has 5,213 megawatts of proposed wind projects in its queue for integration to the transmission grid. Five proposed wind projects are among those considering participating financially in BPA's proposed McNary-John Day transmission line.

We have invested over $2 billion in conservation. Almost a third of the region's load growth since 1980 has been met with conservation.



On the renewables side, we have created integration products to help utilities bring wind energy to market. A high note for the year was the decision by Fairchild Air Force Base to go all green.

Another high note for the year was the decision by Fairchild Air Force Base in Washington state to go all green, becoming the first federal facility in the Northwest to derive all of its power from renewable energy. Fort Lewis, a U.S. Army facility in Washington state, has also increased its green purchases. Both purchase power from BPA.

Industry Restructuring

We continue to work with other Northwest entities toward an approach to unified transmission operation and planning with the twin goals of enhancing regional system reliability and reducing costs to consumers.

In fiscal year 2004, a cross-section of regional parties produced a platform that described an independent grid operator with a planning function, to be developed in stages. Participation would be voluntary. Movement from one stage to the next would occur only if that step, by itself, is beneficial to the region. This potential organization has been named "Grid West." BPA is participating actively in Grid West development but is reserving its decision to join until we can determine the proposal meets certain principles that were laid out at the onset of the planning effort.

As part of our consideration of the Grid West bylaws, we commissioned the National Academy of Public Administration to review them. NAPA found the bylaws generally a "reasonable, workable approach" and said the Northwest's track record of "constructive mutual effort" bodes well for the ability of Grid West to function effectively. NAPA also recommended specific measures to tighten governance procedures and controls. In response to NAPA's recommendations and to public comments, BPA pursued bylaws refinements to create more regional accountability and assure cost control.

We also are working with a number of regional transmission providers on steps that could be taken within the next two years, even as Grid West development proceeds, to realize transmission improvements such as creation of a regional planning and expansion entity.

In addition to efforts focused on the transmission grid, we have also been working with the Northwest Power and Conservation Council and Western Electricity Coordination Council on measures to ensure that the Northwest and the larger Western interconnection have adequate generation supplies. The West Coast energy crisis of 2000-2001 highlighted the importance of both adequate transmission and generation facilities to ensure reliability as well as a stable and well functioning electricity market. Thus far, efforts have focused on development and adoption of planning standards for resource adequacy.

Risk Management

BPA established a Risk Office in 2003. In fiscal year 2004, we formalized risk management improvements through this new office. It is focused first on assuring governance and management of risks inherent to wholesale power transactions and counterparty credit, and second on assessing and mitigating the risks inherent to BPA's strategic direction by using the emerging discipline of Enterprise Risk Management. These efforts are aimed at managing the key risks to BPA's ability to deliver on its mission while at the same time maintaining the agency's long-term financial health.

During fiscal year 2004, we formed the Enterprise Risk Management Committee to provide the tools and discipline needed to understand and manage the major sources of risk that BPA faces. These include hydropower supplies, uncertainty around industry deregulation and restructuring, market price volatility, energy industry credit, capital asset performance and security of physical and cyber assets.

We are moving to employ coordinated, systematic and integrated risk management. This includes clarifying our tolerance for risk and working to minimize the costs of managing risks within that tolerance.

Also in fiscal year 2004, the agency implemented a key recommendation from the Lessons Learned reports by establishing new decision-making criteria that include disciplined assessment of risks.

Security

BPA has been widely recognized by the industry and the government for its leadership in Critical Infrastructure Protection initiatives. As a result, others frequently use our agency as a benchmark, and our security staff has been sought out for presentations to government and private organizations.

In fiscal year 2004, we received successful ratings in the Department of Energy's Safeguards and Security Survey. To ensure physical security, we have completed security enhancements at 18 facilities and completed risk assessments of critical facilities. Overall, we have trained our entire work force in security awareness and distributed employee guides for responding to emergencies.

We have designed and participated in regional security exercises and have developed agencywide continuity of operations plans that would go into effect following an emergency. These plans comply with the Federal Emergency Management Agency's guidelines.

Employees

Our employees have responded to multiple budget-trimmings with innovative ideas and pride. In a survey conducted in April, over 80 percent of our staff reported that they have instituted changes in their work that have served to cut costs or increase efficiency.

We believe as process improvements, now under way, are implemented, they will make for a more efficient and effective workplace that will enable us to carry out our mission with fewer people than we have today. The fact that 16 percent of our employees are currently eligible for retirement should help us manage to staffing levels that assure maximum efficiency.

However, our greatest asset is a highly experienced and knowledgeable work force, and the high number of potential retirements also exposes us to the risk of losing critical skills and knowledge. Having the right leaders and key staff in place will be essential to our long-term success. We recognize that succession planning must be a priority.

The Future

In our complex business, we expect to face a number of challenges and deal with a wide breadth of issues in the coming years. In the near term, the following are likely to be key areas of focus.

In transmission, we recently released a draft discussion paper for transmission adequacy, and we expect the pursuit of reliability and adequacy standards to move to center stage in our region, as well as in the nation.

The Regional Dialogue will figure large in the coming year as we seek to define our obligations to serve our power customers after fiscal year 2006, when the current rate period ends. As we move forward to clarify BPA's power supply role in the region, it is important that the region simultaneously develop a uniform and integrated approach to resource adequacy. This approach must ensure that all of the region's utilities with load serving obligations acquire their share of supplies in a manner that ensures overall resource adequacy.

We will need to focus on a plan for sustainable access to capital to ensure we can make our share of regional reliability and adequacy investments and are able to carry out our responsibilities to energy efficiency and fish and wildlife.

We will not let up on efforts to manage our costs and identify further efficiencies, both internally and in concert with our cost partners. Our new Strategic Direction calls for moving toward a "One-BPA" construct consistent with Standards of Conduct. At this time, we do not know exactly what that organization will look like, but we do know that any change must enhance our ability to deliver on our mission.

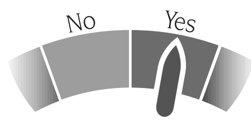
Finally, we face one particularly large challenge as we move into the future. There is currently little consensus among our customers, Northwest tribes, states, public interest groups and other constituents on many key electric power issues.

We may not be able to forge a consensus in all areas, but we will work hard to serve the interests of all Northwest citizens by providing clarity and transparency in our decision making and listening to and being accountable to all of our customers and constituencies.

Performance Measures

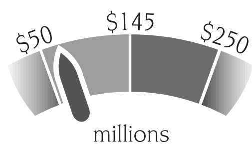
Each year since 1995, BPA has selected a set of measurable targets that the agency as a whole is responsible for achieving. These act as indicators of overall agency success and determine how agency management is evaluated. In fiscal year 2004, 10 of 15 targets were in the successful range.

Treasury payment – target met



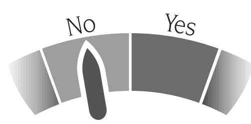
BPA made its payment to the U.S. Treasury in full and on time with a payment of $1.053 billion.

Modified net revenue – target not met



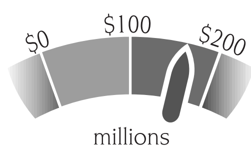
The agency's net revenues, when modified to exclude nonfederal debt management and Statement of Financial Accounting Standards 133 mark-to-market adjustments, were $66 million, which didn't satisfy the target of being between $145 and $250 million.

Sustainable access to capital – target not fully met



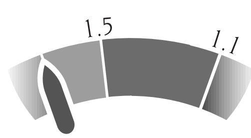
The agency did not complete its program to ensure that it has sustained access to capital funding without an increase in the agency's authority to borrow from the U.S. Treasury.

Additional cost reductions and revenue enhancements – target met



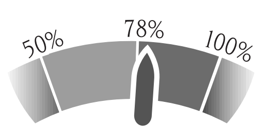
BPA and the Power Net Revenue Improvement Sounding Board were successful in identifying almost $165 million in cost reductions and revenue enhancements for fiscal years 2004-2005. The goal was $100 million.

Safety – target not met



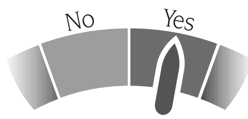
BPA did not attain this target. The lost-time accident frequency rate of 1.7 exceeded the target range of 1.1 to 1.5 accidents per 200,000 hours worked and, most significantly, a BPA employee was killed in a helicopter accident while working on a construction site.

Employee understanding of BPA business strategy – target met



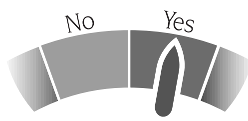
The employee survey confirmed that 79 percent of BPA employees understand the BPA business strategy, thereby exceeding the target of 78 percent.

Critical infrastructure milestones – target met



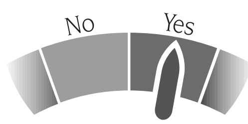
BPA focused during the year on nine key projects that are critical for the agency's transmission infrastructure. The agency met its goal of reaching project milestones on time and with expenditures of less than $167 million.

Conservation – target met



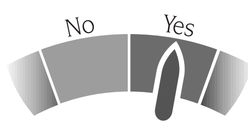
BPA met its target of obtaining 40 average megawatts from all conservation efforts and 25 aMW of new conservation augmentation under contract at a cost of between $1.2 million and $1.4 million per aMW.

Reliability – targets met



Transmission Reliability

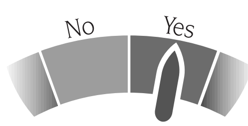
Transmission reliability is measured in terms of the frequency and duration of outages on key circuits and against a standard of no involuntary curtailment of firm load caused by a transmission security breach. Both portions of the target were met.



Generation Reliability

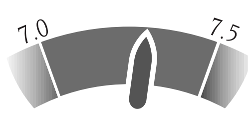
The generation reliability standard is no involuntary curtailment of firm load due to inadequate power supply or a generation system security breach. Both portions of the target were met.

Fish – target met

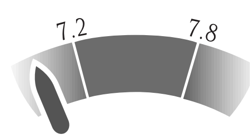


BPA met its target of supporting a Biological Opinion remand response that provides further definition of performance standards, provides support for least-cost implementation and is based on the best available science.

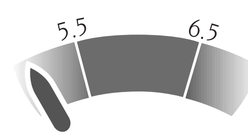
Customer, constituent & tribal satisfaction – targets: 1 met, 2 not met



Constituent Satisfaction



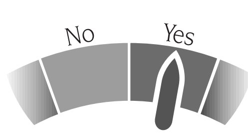
Customer Satisfaction



Tribal Satisfaction

BPA met its constituent satisfaction target scoring 7.3, but failed to meet the targets for customer and tribal satisfaction, scoring 7.0 and 5.1 respectively.

System and process improvement – target met



BPA brought in a contractor to identify agency systems and processes that need to be consistent with "best practices." BPA met its target of establishing plans for performance improvement with implementation schedules and benchmark efforts for high-priority areas.

Another high point was modernization of BPA's Celilo Converter Station near The Dalles Dam. We replaced 30-year-old mercury arc valves with state-of-the-art, solid-state converters. This and continuing work should extend by 35 years the life of the DC Intertie that runs to Los Angeles providing 3,100 megawatts of transfer capability.

Financial Section

Management's Discussion & Analysis

Results of Operations

2004 Compared to 2003

The Federal Columbia River Power System (FCRPS) includes the accounts of the Bonneville Power Administration (BPA), the accounts of generating facilities of the U.S. Army Corps of Engineers (Corps) and the Bureau of Reclamation (Reclamation) and the operation and maintenance costs of the U.S. Fish and Wildlife Service for the Lower Snake River Compensation Plan Facilities. BPA is the power marketing agency which purchases, transmits and markets power for the FCRPS. 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 fiscal year 2004 total operating revenues were $3,198 million, a decrease of $414 million, from the previous year due to declining sales of $355 million, SFAS 133 mark-to-market increasing $34 million, miscellaneous revenues increasing $4 million and U.S. Treasury credits for fish decreasing $98 million.

Sales and purchased power expenses reflect the Oct. 1, 2003, adoption of Emerging Issues Task Force Issue No. 03-11 (EITF 03-11), "Reporting Realized Gains and Losses on Derivative Instruments that are Subject to FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities, and Not Held for Trading Purposes." EITF 03-11 requires that realized gains and losses associated with non-trading derivative activities, that are not physically settled (i.e. bookouts), be reported on a net basis. As a result of the adoption of EITF 03-11, sales and purchased power expenses for the year both decreased by $212 million. Prior to Oct. 1, 2003, such settlements were recorded on a gross basis in both revenues and purchased power expense. Amounts for periods prior to Oct. 1, 2003, have not been reclassified. Although determination of the effect of the change on prior years' reported revenues and expenses is not practicable, the change has no impact on reported net revenues. The remaining $143 million decline in sales was the result of expiring purchase power commitments of nearly 400 average megawatts and a corresponding reduction in sales, reduced LB CRAC percentage for April through September, and lower non-firm transmission and other revenues as a result of changed customer-marketing practices.

U.S. Treasury credits for fish operations decreased from $175 million to $77 million in fiscal year 2004. The fiscal year 2003 credit includes $79 million from the Fish Cost Contingency Fund, which became fully depleted in fiscal year 2003. Conditions were drier prior to March 2003 resulting in higher credit estimates when compared to the same period of fiscal year 2004.

In fiscal year 2004, total operating expenses were $2,409 million, a decrease of $302 million compared to fiscal year 2003 due to operations and maintenance increasing $13 million, purchased power decreasing $461 million, nonfederal projects increasing $129 million and federal projects depreciation increasing $16 million.

Purchased power decreased after BPA negotiated the termination of several sales and purchase power commitments in 1993 for fiscal year 2004 and subsequent periods. Additionally, as previously discussed, purchased power expenses reflects the Oct. 1, 2003, adoption of EITF 03-11. Debt service on nonfederal projects increased as Energy Northwest net billing for debt service increased. Fiscal year 2003 Energy Northwest net billing for debt service included reductions from reserve funds freed-up. The cash flows from free-ups were entirely used in fiscal year 2003.

Interest on bonds issued to the U.S. Treasury decreased as the weighted average interest rate declined from 6.0 percent at the beginning of fiscal year 2003 to 5.3 percent at the beginning of fiscal year 2004. The decreased weighted average interest rate was due to two factors: the Debt Optimization program and the low interest rate environment. Through the Debt Optimization program BPA paid off relatively high coupon Treasury debt and issued new debt with very low interest rates.

To a lesser degree, interest on bonds issued to the U.S. Treasury decreased as the income earned on BPA's cash account at the U.S. Treasury increased with higher cash balances. BPA reports interest expense on bonds issued to the U.S. Treasury net of the interest income earned. Net interest expense for fiscal year 2004 decreased $61 million from fiscal year 2003.

Net revenues were $504 million in fiscal year 2004, a decrease of $51 million from fiscal year 2003.

2003 Compared to 2002

The fiscal year 2003 total operating revenues were $3,612 million, an increase of $78 million, from the previous year due to declining sales of $79 million, SFAS 133 mark-to-market increasing $17 million, miscellaneous revenues increasing $4 million and U.S. Treasury credits for fish increasing $136 million.

The sales decrease was the result of both reduced hydro generation due to drier-than-normal conditions and reduced power purchases offset by higher surplus sales prices. The average price for discretionary surplus power sales rose from $26 per megawatt-hour to $36 per megawatt-hour. Simultaneously, discretionary megawatt-hours sold declined, which led to an increase in discretionary sales revenues.

U.S. Treasury credits for fish operations increased from $38 million in fiscal year 2002 to $175 million in fiscal year 2003. The fiscal year 2003 credit includes $79 million from the Fish Cost Contingency Fund, which was not accessed in fiscal year 2002 and became fully depleted in fiscal year 2003. U.S. Treasury credits for fish mitigation increased due to below-average water conditions and increased power purchases that accompany reduced hydro supply.

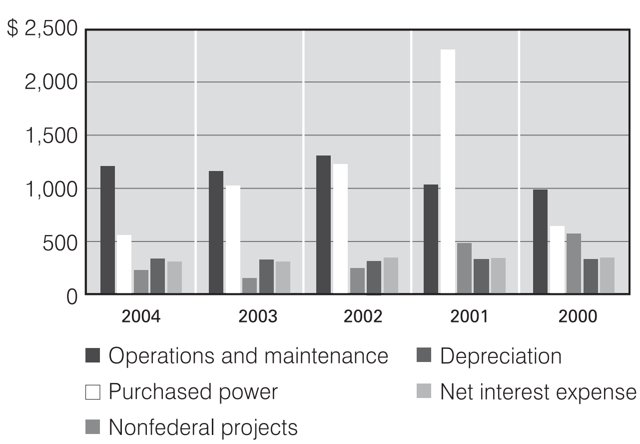
In fiscal year 2003, total operating expenses were $2,711 million, a decrease of $461 million compared to fiscal year 2002 due to operations and maintenance decreasing $121 million, purchased power decreasing $244 million, nonfederal projects decreasing $111 million and federal projects depreciation increasing $15 million.

Operations and maintenance costs decreased due to lower bad debt and general and administrative expenses. Purchased power decreased as several purchase power contracts were terminated or expired. Debt service on nonfederal projects declined when refinancing nonfederal projects bonds deferred some principal payments due in fiscal year 2003 into the future.

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

Expenses by Category

millions of dollars



$346 million in fiscal year 2003, a decrease of $7 million compared to fiscal year 2002.

Net revenues were $555 million in fiscal year 2003, an increase of $546 million from fiscal year 2002.

Modified Net Revenues

For a third year, BPA's Debt Optimization program and other debt management actions have contributed significantly to increased net revenues. Modified net revenues are net revenues after removing the effects of FASB Statement No. 133, "Accounting for Certain Derivative Instruments and Certain Hedging Activities," and nonfederal debt management actions that differ from rate case assumptions. Management has determined that modified net revenues are a better representation of the outcomes of normal operations during periods of debt management actions and fluctuations in derivative market prices. Calculations similar to modified net revenues were developed as part of the initial rates for the current period and are used to determine the thresholds for two of the Power Business Line Cost Recovery Adjustment Clauses (CRACs) – Financial-Based (FB CRAC) and Safety Net (SN CRAC). The table below demonstrates the calculation for modified net revenues. The primary change in modified net revenues from fiscal year 2002 through fiscal years 2003 and 2004 is due to the increase in net revenues as discussed above.

Customers

BPA sells power and related services to four main types of customers: Northwest publicly owned utilities, direct-service industries, Northwest investor-owned utilities 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 purchasers (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 current rate period Oct. 1, 2001, is reflected in revenues from sales to this group for the three fiscal years presented.

Modified Net Revenues

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

	2004	2003	2002
Net Revenues	**$ 504,415**	$ 555,424	$ 9,475
SFAS 133 mark-to-market gain	**(89,452)**	(55,265)	(38,354)
Nonfederal debt management actions	**(348,636)**	(463,285)	(319,447)
Modified net reveues (expenses)	**$ 66,327**	$ 36,874	$ (348,326)

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 $40 million or 68 percent from fiscal year 2002 to fiscal year 2003.

In fiscal year 2004, improved market outlook permitted one DSI customer to increase its power purchases from fiscal year 2003 levels by $74 million, resulting in total DSI revenue of $92 million.

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.

Revenues from Northwest IOUs increased $58 million or 15 percent in fiscal year 2003 compared to fiscal year 2002 and then decreased $74 million or 17 percent in fiscal year 2004. Revenues from Northwest IOUs fluctuate with streamflows in the Columbia River Basin. Streamflows directly impact the amount of surplus energy available for sale, the costs of generating power with alternative fuels, and ultimately the price BPA can obtain for these sales.

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. From fiscal year 2002, revenues from sales outside the Northwest region decreased $10 million or 2 percent in fiscal year 2003 and from those levels deceased another $139 million or 22 percent in fiscal year 2004. As is the case with revenues from Northwest IOUs, revenues from Sales Outside the Northwest Region fluctuate with streamflows in the Columbia River Basin. Streamflows directly impact the amount of surplus energy available for sale, the costs of generating power with alternative fuels, and ultimately the price BPA can obtain for these sales.

Transmission

BPA receives revenues by providing transmission and other related services. Higher transmission rates went into effect Oct. 1, 2001, and are reflected in transmission revenues for the three fiscal years presented. Compared to fiscal year 2002, transmission revenues decreased $14 million or 2 percent to $553 million in fiscal year 2003 and decreased another $17 million or 3 percent in fiscal year 2004. Lower transmission revenues are due largely to lower power sales. More efficient use of transmission contracts by customers also reduced revenues.

Fish credits and other revenues

This category increased $159 million or 169 percent in fiscal year 2003 over fiscal year 2002. This increase was mostly due to U.S. Treasury credits under section 4(h)(10)(C) of the Northwest Power Act for fish operations increasing from $38 million in fiscal year 2002 to $175 million in fiscal year 2003. The fiscal year 2003 credit includes $79 million from the Fish Cost Contingency Fund, which was fully depleted in fiscal year 2003. Fiscal year 2003 credits for fish mitigation increased due to below-average water conditions and increased power purchases that accompany reduced hydro supply.

In fiscal year 2004 fish credits decreased to $77 million from fiscal year 2003 when the credit was $96 million (net of $79 million from the Fish Cost Contingency Fund). The remaining $19 million decrease is the result of reduced purchased power. Fish credits are provided on the basis of estimates and forecasts and later are adjusted when actual data are available.

Mark-to-market accounting adjustments and other miscellaneous revenues are also included in this category.

Critical Accounting Policies

The accounting policies for the FCRPS are disclosed in the first note to the financial statements.

Financial Condition

At Sept. 30, 2004, BPA's year-end financial reserves were $638 million — consisting of $587 million cash and $51 million of 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, 2003, BPA's year-end financial reserves were $511 million. BPA's financial reserves at the end of fiscal year 2002 were $188 million.

BPA made payments of $1,053 million to the U.S. Treasury in fiscal year 2004, making it the 21st consecutive year in which BPA has made its payment on time and in full. The payment consisted of $592 million for principal and $420 million in interest for the federal investment in the FCRPS. BPA also paid $31 million in contributions to fully fund post retirement benefit programs for FCRPS employees and $10 million for other obligations. Payments made in fiscal year 2003 and fiscal year 2002 were $1,057 million and $1,056 million respectively.

This year's principal payment also included $346 million to repay federal appropriations and bonds issued to the U.S. Treasury in advance of due dates bringing cumulative advance payments to $1,146 million.

The "Rates" section, which follows Financing and Market Risk, discusses the Cost Recovery Adjustment Clauses that are used to mitigate risk and increase the probability of meeting the U.S. Treasury payments.

Financing

BPA refinanced or restructured approximately $600 million in its nonfederal debt portfolio in fiscal year 2004. BPA saved a net present value of $12.9 million in interest expenses by refinancing these Energy Northwest bonds. The results have helped bring down BPA's interest expenses in this rate period by $1.8 million. Among other things, this effort increased remaining Treasury borrowing authority by $346 million as a result of extending Energy Northwest debt into 2013-2018 and prepaying bonds issued to U.S. Treasury under the ongoing Debt Optimization program. The 2004 Energy Northwest refinancing effort under the program extended $291 million of bonds, and previous refinancings extended $55 million, totaling of $346 million for the fiscal year. BPA maintained its high credit ratings with the three bond rating agencies covering BPA. In fact, Moody's upgraded its credit rating on BPA-backed bonds to Aaa, and Standard & Poor's raised BPA-backed bonds from a "negative" outlook to a "stable" one.

Construction of the Schultz-Wautoma transmission line is being financed through Northwest Infrastructure Financing Corporation (NIFC), a Delaware "Special Purpose Corporation", formed on Dec. 17, 2003. In March 2004, NIFC issued $119.6 million in taxable bonds to finance the line under a lease-purchase agreement.

Market Risk

Commodity Price Risk and Volumetric Risk

Primarily due to the periodic variation in the available energy from its hydroelectric generation capacity, BPA enters into short-term and forward sales and purchase agreements for electricity in the wholesale markets to balance its energy supply and demand. Fluctuations in the electric market prices in the Pacific Northwest can affect the value of energy inventory being bought and sold as well as the value of prior purchase and sale contracts. This is referred to as commodity price risk. In fiscal year 2004, there was a net surplus and sale of energy, which was in excess of that needed to serve firm load obligations in the service region.

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,

Selected Quarterly Information *(unaudited)*

3 months ended — thousands of dollars

	December 31	March 31	June 30	September 30	Totals
2004					
Revenues	**$ 823,281**	**$ 755,437**	**$ 702,847**	**$ 826,894**	**$ 3,108,459**
SFAS 133 mark-to-market	**(1,210)**	**29,623**	**85,396**	**(24,357)**	**89,452**
Operating revenues	**822,071**	**785,060**	**788,243**	**802,537**	**3,197,911**
Operating expenses	**577,734**	**532,174**	**611,850**	**686,887**	**2,408,645**
Net interest expenses	**74,576**	**75,169**	**67,501**	**67,605**	**284,851**
Net revenues	**$ 169,761**	**$ 177,717**	**$ 108,892**	**$ 48,045**	**$ 504,415**
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	$ 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 (expenses) revenues	$ (75,698)	$ 12,223	$ 62,550	$ 10,400	$ 9,475

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 response to market price risk, futures, swaps and options may be used to alter BPA's exposure to price fluctuations.

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. A Transacting and Credit Risk Management Committee, chaired by the chief risk officer, determines the risk policy and control environment. The Office of the Chief Risk Officer was a new organization formed at the start of fiscal year 2004.

Due to both the operational risk posed by fluctuations in river flows affecting the hydroelectric generation supply capability and the commodity price risk, net revenues from any surplus energy sales are inherently uncertain.

Credit Risk

The Transacting Risk Management Committee is responsible for BPA's credit policy. Credit risk is mitigated at BPA by reviewing counterparties for creditworthiness, establishing credit limits, and monitoring credit exposure. In order to further reduce credit risk, BPA obtains credit support such as letters of credit and third party guarantees from some counterparties. Counterparties are monitored closely for changes in financial condition and credit reviews are updated regularly.

Rates

The fiscal year that ended Sept. 30, 2004, was the third 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. Rates for the FCRPS are disclosed in the first note to the financial statements.

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

Combined Statements of Revenues and Expenses

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

	2004	2003	2002
Operating revenues			
Sales	**$2,973,496**	$ 3,328,277	$ 3,407,404
SFAS 133 mark-to-market	**89,452**	55,265	38,354
Miscellaneous revenues	**57,963**	53,678	49,571
U.S. Treasury credits for fish	**77,000**	174,884	38,400
Total operating revenues	**3,197,911**	3,612,104	3,533,729
Operating expenses			
Operations and maintenance	**1,211,802**	1,198,521	1,319,707
Purchased power	**582,129**	1,043,009	1,286,867
Nonfederal projects	**248,475**	119,534	230,175
Federal projects depreciation	**366,239**	350,025	335,205
Total operating expenses	**2,408,645**	2,711,089	3,171,954
Net operating revenues	**789,266**	901,015	361,775
Interest expense			
Interest on federal investment:			
Appropriated funds	**213,041**	212,391	258,195
Bonds issued to U.S. Treasury	**110,251**	166,598	151,997
Allowance for funds used during construction	**(38,441)**	(33,398)	(57,892)
Net interest expense	**284,851**	345,591	352,300
Net revenues	**504,415**	555,424	9,475
Accumulated net revenues (expenses), Oct. 1	**343,748**	(211,676)	(221,151)
Irrigation assistance	**(739)**	—	—
Accumulated net revenues (expenses), Sept. 30	**$ 847,424**	$ 343,748	$ (211,676)

The accompanying notes are an integral part of these statements.

Combined Balance Sheets

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

Assets

	2004	2003
Utility plant		
Completed plant	**$ 12,243,684**	$ 11,873,798
Accumulated depreciation	**(4,357,496)**	(4,133,886)
	7,886,188	7,739,912
Construction work in progress	**1,401,793**	1,308,624
Net utility plant	**9,287,981**	9,048,536
Nonfederal projects		
Conservation	**43,566**	47,246
Hydro	**146,210**	146,210
Nuclear	**2,222,104**	2,181,182
Terminated hydro facilities	**28,090**	28,840
Terminated nuclear facilities	**3,894,273**	3,883,115
Total nonfederal projects	**6,334,243**	6,286,593
Decommissioning cost	**164,000**	126,000
IOU exchange benefits	**606,539**	—
Conservation, net of accumulated amortization of $946,322 in 2004 and $892,218 in 2003	**337,355**	374,443
Fish and wildlife, net of accumulated amortization of $142,465 in 2004 and $133,743 in 2003	**116,910**	128,337
Current assets		
Cash	**654,242**	503,026
Accounts receivable, net of allowance	**91,517**	146,768
Accrued unbilled revenues	**158,074**	190,416
Materials and supplies, at average cost	**81,246**	84,306
Prepaid expenses	**331,383**	288,068
IOU exchange benefits	**381,720**	—
Total current assets	**1,698,182**	1,212,584
Other assets	**387,569**	230,756
	$ 18,932,779	$ 17,407,249

The accompanying notes are an integral part of these statements.

Capitalization and Liabilities

	2004	2003
Capitalization and long-term liabilities		
Accumulated net revenues	**$ 847,424**	$ 343,748
Federal appropriations	**4,339,288**	4,607,476
Capitalization adjustment	**2,056,131**	2,124,697
Bonds issued to U.S. Treasury	**2,461,800**	2,521,554
Nonfederal projects debt	**6,218,932**	6,045,931
Decommissioning reserve	**164,000**	126,000
IOU exchange benefits	**626,576**	55,488
Accrued plant removal costs	**105,270**	147,174
Total capitalization and long-term liabilities	**16,819,421**	15,972,068
Commitments and contingencies (Notes 7 and 8)		
Current liabilities		
Current portion of federal appropriations	**104,673**	73,484
Current portion of bonds issued to U.S. Treasury	**438,500**	176,200
Current portion of nonfederal projects debt	**234,896**	240,662
Current portion of IOU exchange benefits	**381,720**	—
Accounts payable and other current liabilities	**338,867**	369,821
Total current liabilities	**1,498,656**	860,167
Deferred credits	**614,702**	575,014
	$18,932,779	$17,407,249

Combined 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	Bonds Issued to Treasury	Nonfederal Project Debt	Other	Total
Balance at Sept. 30, 2002	$(211,676)	$4,642,602	$2,770,441	$6,201,544	$2,407,238	$15,810,149
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 bonds issued to U.S. Treasury	—	—	470,000	—	—	470,000
Repayment of bonds issued to U.S. Treasury	—	—	(482,687)	—	—	(482,687)
Refinance of bonds issued to U.S. Treasury	—	—	(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
IOU exchange benefits	—	—	—	—	55,488	55,488
Accrued plant removal costs	—	—	—	—	6,197	6,197
Net revenues	555,424	—	—	—	—	555,424
Balance at Sept. 30, 2003	$ 343,748	$ 4,680,960	$ 2,697,754	$ 6,286,593	$ 2,453,359	$ 16,462,414
Increase in federal appropriations for construction	—	78,047	—	—	—	78,047
Repayment of federal appropriations for construction	—	(315,046)	—	—	—	(315,046)
Capitalization adjustment amortization	—	—	—	—	(68,566)	(68,566)
Increase in bonds issued to U.S. Treasury	—	—	480,000	—	—	480,000
Repayment of bonds issued to U.S. Treasury	—	—	(277,454)	—	—	(277,454)
Net increase in nonfederal projects debt	—	—	—	179,130	—	179,130
Repayment of nonfederal projects debt	—	—	—	(11,895)	—	(11,895)
Decommissioning reserve	—	—	—	—	38,000	38,000
IOU exchange benefits	—	—	—	—	952,808	952,808
Accrued plant removal costs	—	—	—	—	(41,904)	(41,904)
Net revenues	504,415	—	—	—	—	504,415
Irrigation assistance	(739)	—	—	—	—	(739)
Balance at Sept. 30, 2004	$ 847,424	$4,443,961	$2,900,300	$6,453,828	$3,333,697	$17,979,210

The accompanying notes are an integral part of these statements.

Combined Statements of Cash Flows

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

	2004	2003	2002
Cash from operating activities			
Net revenues	**$ 504,415**	$555,424	$ 9,475
Non-cash items:			
Depreciation	**294,975**	269,957	254,332
Amortization	**71,264**	77,610	78,047
Amortization of capitalization adjustment	**(68,566)**	(67,703)	(67,356)
Decrease (increase) in:			
Receivables and unbilled revenues	**87,594**	(38,144)	88,765
Materials and supplies	**3,061**	801	115
Prepaid expenses	**(43,316)**	(2,372)	(98,547)
Decrease (increase) in:			
Accounts payable and other current liabilities	**(30,954)**	26,396	(167,532)
Other	**(152,601)**	51,802	(6,399)
Cash provided by operating activities	**665,872**	873,771	90,900
Cash from investment activities			
Investment in:			
Utility plant (including AFUDC)	**(576,324)**	(535,211)	(544,922)
Nonfederal projects	**(47,650)**	(85,050)	(29,595)
Conservation	**(16,876)**	(25,458)	(25,344)
Fish and wildlife	**(5,849)**	(11,156)	(6,102)
Cash used for investment activities	**(646,699)**	(656,875)	(605,963)
Cash from borrowing and appropriations			
Increase in federal construction appropriations	**78,047**	99,418	168,583
Repayment of federal construction appropriations	**(315,046)**	(61,060)	(196,911)
Irrigation assistance	**(739)**	—	—
Increase in bonds issued to U.S. Treasury	**480,000**	470,000	390,000
Repayment of bonds issued to U.S. Treasury	**(277,454)**	(482,687)	(308,101)
Refinance of bonds issued to U.S. Treasury	**—**	(60,000)	—
Increase in nonfederal debt, net	**167,235**	85,050	29,595
Cash provided by borrowing and appropriations	**132,043**	50,721	83,166
Increase (decrease) in cash	**151,216**	267,617	(431,897)
Beginning cash balance	**503,026**	235,409	667,306
Ending cash balance	**$ 654,242**	$503,026	$235,409

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), the accounts of generating facilities of the U.S. Army Corps of Engineers (Corps) and the Bureau of Reclamation (Reclamation) and the operation and maintenance costs of the U.S. Fish and Wildlife Service for the Lower Snake River Compensation Plan Facilities. BPA is the power marketing agency which purchases, transmits and markets power for the FCRPS. 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 and U.S. Fish and Wildlife are 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.

In January 2003, the FASB issued FASB Interpretation No. 46 (FIN 46), "Consolidation of Variable Interest Entities – an interpretation of ARB No. 51," which 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. As a Variable Interest Entity, Northwest Infrastructure Financing Corporation (NIFC) has been consolidated into BPA for fiscal year 2004. (See Note 4 for a discussion of NIFC.)

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, the 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 fiscal years 2002 and 2003 combined financial statements from amounts previously reported to conform to the presentation used in fiscal year 2004. 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 Energy Policy Act of 1992. FERC reviews BPA's rates for all firm power and nonfirm energy 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 submitted to FERC a Power Rate Filing in fiscal year 2001 for fiscal years 2002 through 2006, and a Transmission and Ancillary Services Rate Filing in fiscal year 2003 for fiscal years 2004 through 2005. 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). FERC granted final approval of BPA's Transmission and Ancillary Services rates on Sept. 23, 2003, 104 FERC 62,207 (2003).

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 six 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 forecasts a 50 percent or greater probability of missing 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 subsequent adjustments result in an additional charge or rebate due to 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 46.0 percent for the first half of fiscal year 2002 compared to base rates, and 40.8 percent for the second half of fiscal year 2002. The LB CRAC percentage increase was revised to approximately 31.9 percent and 38.5 percent, respectively, for the six-month periods beginning Oct. 1, 2002, and April 1, 2003. The LB CRAC percentage increase was revised to approximately 21.3 percent and 24.6 percent, respectively, for the six-month periods beginning Oct. 1, 2003 and April 1, 2004.

The August 2002 forecast of the generation function's accumulated net revenues triggered the FB CRAC, and resulted in a rate increase of approximately 11 percent for fiscal year 2003 and approximately 12 percent for fiscal year 2004 for most of the requirements rates on top of the revised levels of the LB CRAC.

The SN CRAC did not trigger in fiscal year 2002 but did trigger in fiscal year 2003, requiring an expedited rate case and resulting in a rate increase that went into effect Oct. 1, 2003 through Sept. 30, 2004, of approximately 10 percent on top of the revised levels of the LB CRAC and FB CRAC. BPA submitted to FERC a separate power rate filing for SN CRAC in fiscal year 2003. FERC granted interim approval of the SN CRAC rate on Oct. 1, 2003, 105 FERC 61,006 (2003) and final approval on May 10, 2004, 107 FERC 61,138 (2004). The

SN CRAC rate filing augments the power rates already approved for fiscal years 2002 through 2006.

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 output. Settlement of any over or under collection occurs in the subsequent year. For the fiscal year 2003 settlement, BPA recognized a $30.4 million liability to be paid in fiscal year 2004. For the fiscal year 2004 settlement, BPA recognized a receivable of $10.1 million to be received in fiscal year 2005.

SFAS 71 Assets

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."

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.

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 $3.6 billion net extraordinary loss that would be reported in the Statement of Revenues and Expenses.

The SFAS 71 assets of $5.6 billion, shown in the following table, reflect an increase of

SFAS 71 Assets

As of Sept. 30 — thousands of dollars

	2004	2003
Nonfederal projects:		
Conservation	**$ 43,566**	$ 47,246
Terminated hydro facilities	**28,090**	28,840
Terminated nuclear facilities	**3,894,273**	3,883,115
Decommissioning cost*	**51,200**	18,200
IOU exchange benefits	**988,259**	—
Conservation	**337,355**	374,443
Fish and wildlife	**116,910**	128,337
Settlements	**70,142**	105,313
Capital bond premiums	**26,486**	30,802
Additional retirement contributions	**13,200**	23,400
	$ 5,569,481	$ 4,639,696

* The decommissioning amount to be collected in future rates is net of amounts paid into the decommissioning trusts of $112.8 million and $107.8 million at Sept. 30, 2004 and 2003 respectively.

$930 million from the prior year. Amortization of these costs aggregating $103 million, $84 million and $299 million in fiscal years 2004, 2003 and 2002 respectively, is reflected in the Statements of Revenues and Expenses. BPA does not earn a rate of return on its SFAS 71 assets.

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 and betterments are capitalized. Repairs and minor replacements are charged to operating expense. The cost of utility plant retired is charged to accumulated depreciation when it is removed from service. The removal costs less salvage is charged to the regulatory liability. Utility plant in the Statements of Cash Flows is reported net of the Regulatory Liability for Removal Costs and accumulated depreciation.

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 up 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 balance.

AFUDC capitalization rates are stipulated in the congressional acts authorizing construction for certain generating projects and were 1.3 percent to 5.3 percent in fisal year 2004, 1.8 percent to 6.3 percent in fiscal year 2003, and 3.3 percent to 6.5 percent in fiscal year 2002.

Capitalization rates for other construction were approximately 5.3 percent in fiscal year 2004, 6.3 percent in fiscal year 2003, and 6.5 percent in fiscal year 2002. 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. FCRPS has certain tangible long-lived assets for which AROs are not measurable. An ARO will be required to be recorded when circumstances change. Assets that may require removal when no longer in service include the hydro projects and transmission facilities.

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.

Asset Retirement Obligations Activity

As of Sept. 30, 2004, the AROs for Washington Nuclear Project No. 1 (WNP-1), Columbia Generating Station (CGS) and Trojan are $164 million. (See Decommissioning and Restoration Costs in Note 7, Commitments and Contingencies.) A corresponding amount representing a regulatory asset is included in Decommissioning Cost in the Balance Sheet.

The table below presents the effects to the balances and activities in AROs for the accounting periods reported herein. A revision was made in the current year adjusting the accretion rate from the original model and calculation. BPA has funded $112.8 million at Sept. 30, 2004, for these AROs, which is being held in trust. The remaining amount will be collected in future rates.

Cash

For purposes of reporting cash flows, cash includes cash in the BPA fund and unexpended appropriations of Reclamation and Corps. Cash paid for interest was $420 million, $466 million and $484 million in fiscal years 2004, 2003 and 2002 respectively.

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 $179 million, $99 million and $259 million in fiscal years 2004, 2003 and 2002 respectively.

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 securities of the U.S. government and agencies.

BPA's accounts receivable are spread across a diverse group of public utilities, investor-owned utilities, power marketers, and others that are geographically located throughout the Western United States and Canada. The accounts receivable

Asset Retirement Obligations Activity

For the years ended Sept. 30 — thousands of dollars

	2004	2003	Proforma 2002
Beginning Balance	**$ 126,000**	$129,900	$134,100
Activity:			
Expenditures	**(7,900)**	(7,000)	(9,100)
Accretion	**6,800**	3,100	3,100
Revisions	**39,100**	—	1,800
Ending Balance	**$ 164,000**	$126,000	$129,900

exposures result from BPA providing a wide variety of power products and transmission services. BPA's counterparties are generally large and stable and do not represent a significant concentration of credit risk. During fiscal year 2004, BPA experienced no significant losses as a result of any customer defaults or bankruptcy filings.

The Transacting Risk Management Committee is responsible for BPA's credit policy. Credit risk is mitigated at BPA by reviewing counterparties for creditworthiness, establishing credit limits, and monitoring credit exposure. In order to further reduce credit risk, BPA obtains credit support such as letters of credit and third-party guarantees from some counterparties. Counterparties are monitored closely for changes in financial condition and credit reviews are updated regularly.

Credit Risk from California

California power markets were in turmoil several years ago and 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 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. 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 amounts due in bankruptcy and other proceedings. Net exposure after the reserve is not significant.

Retirement Benefits

FCRPS employees are participants in either the Civil Service Retirement System (CSRS) or the Federal Employees Retirement System (FERS). Both FCRPS and its employees contribute a percentage of eligible employee compensation toward funding these defined post-retirement benefit plans. Based on the statutory contribution rates, agency retirement benefit expense under CSRS is equivalent to 7 percent of eligible employee compensation and under FERS is equivalent to 10.7 percent of eligible employee compensation. Retirement benefits are payable by the U.S. Treasury and not by the FCRPS. However, the legislatively mandated contribution levels do not fully cover the cost to the federal government to provide the plan benefits. Therefore, the programs are considered under funded. Employees also may be participants in the Federal Employees Health Benefits Program (FEHB) and/or the Federal Employees' Group Life Insurance Program (FEGLI); these plans are similarly under funded.

In order to ensure that all post-retirement benefit programs provided to its employees are fully funded and such costs are both recovered through rates and properly expensed, FCRPS makes additional annual contributions to the U.S. Treasury. Because these costs are included in rates, the amount has been recorded as an SFAS 71 asset. FCRPS has a $13.2 million remaining liability as of Sept. 30, 2004, which is included in other current liabilities and deferred credits in the accompanying Balance Sheet representing the balance of deferred additional contributions from fiscal years 1998 through 2001. The liability is reduced as prior year's additional contributions are made. FCRPS expects to satisfy its prior year commitments for under funded post-retirement benefits by fiscal year 2007.

Deferred Credits

Advances on customer reimbursable projects are either applied against the expenditure during the construction of the assets if the customer retains title to the assets, or are recorded to revenue over the related useful lives of the assets if BPA retains title.

Deferred revenues for Third AC intertie capacity agreements are recognized over the estimated 49-year life of the related assets.

Derivative/SFAS 133 mark-to-market represents unrealized losses on derivatives. It increased in fiscal year 2004 due to bookout transactions.

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

Up front leasing fees for fiber optic cable are recognized over the lease terms extending as far as 2020.

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

The table below summarizes deferred credits as of Sept. 30, 2004 and 2003.

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

Deferred Credits

As of Sept. 30 — thousands of dollars

	2004	2003
Customer reimbursable projects	**$ 183,933**	$ 153,190
Third AC intertie capacity agreements	**119,546**	122,612
Derivative/SFAS 133 mark-to-market	**106,513**	26,994
Load diversification fees	**81,163**	86,742
Fiber optic leasing fees	**59,335**	65,341
Enron settlement	**54,000**	94,000
Deferred CSRS	**6,600**	13,200
Unearned option premium revenue	**3,597**	12,822
Other miscellaneous long-term liabilities	**15**	113
Total	**$ 614,702**	$ 575,014

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, 2004 or 2003.

Purchased and Written Options

In fiscal year 2004, BPA purchased physical put options for the right to sell electricity at certain points in the future. With significant inventory risk due to currently unpredictable annual runoff, the put options allow BPA to hedge against falling prices without committing inventory and increasing the inventory risk.

In prior periods, BPA sold put options for the sale of electricity to BPA at certain points in the future. BPA intends to take delivery of power as a result of written put options that have been 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, which may require BPA to buy power at strike prices above market prices as a result of the exercised written put option obligations.

BPA records p urchased and written options on a mark-to-market basis and includes unrealized gains and losses in operating revenues in the Statement of Revenues and Expenses.

The following table reflects the purchased and written options outstanding as of Sept. 30, 2004 and 2003.

Purchased and Written Options

As of Sept. 30

	2004	2003
Purchased options		
Outstanding	**196,800 MWh**	—
Average strike price	**$ 56.45**	—
Written options		
Outstanding	—	1,972,800 MWh
Average strike price	—	$ 40.33

Financial Instruments

All significant financial instruments of the FCRPS were recognized in the Balance Sheets as of Sept. 30, 2004 and 2003. The carrying value reflected in the Balance Sheets 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 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 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 transactions do not qualify for special hedge accounting treatment under SFAS 133. The floating interest rates on the swaps are reset on a weekly basis. BPA recorded a $2.05 million fair value gain and a $7.9 million fair value loss in the Statements of Revenues and Expenses for fiscal years 2004 and 2003 respectively, 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, 2004, 2003 and 2002, 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 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, which 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 and related guidance. As of Sept. 30, 2004, BPA recorded a $51 million fair value unrealized gain related to power purchase and sale transactions impacted by SFAS 149.

BPA recorded a SFAS 133 fair value unrealized gain in the Statement of Revenues and Expenses related to its derivative portfolio (including physical power purchase and sale transactions and purchased options) of $89.4 million, $55.3 million and $38.4 million for fiscal years 2004, 2003 and 2002 respectively.

Revenues and Net Revenues

Operating revenues are recorded on the basis of service rendered, which includes estimated unbilled revenues of $158 million, $190 million and $93 million at Sept. 30, 2004, 2003 and 2002 respectively. For revenue purposes, BPA operates as two segments: the Power Business Line and the Transmission Business Line. The table in Note 9 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 7.

Fish Credits

The Northwest Power Act of 1980 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. The Act 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.

In the early 1990s, BPA, the U.S. Treasury and the Office of Management and Budget agreed to a crediting mechanism whereby BPA reduces its cash payments to the U.S. Treasury by an amount equal to the mitigation measures funded on behalf of the non-power purposes.

Prior to fiscal year 1995, over $325 million of credits had accrued since the Act passed in 1980. The Fish Cost Contingency Fund (FCCF) was established for credits earned by BPA but not applied prior to fiscal year 1995. The FCCF was only to be accessed under specified criteria. Since the establishment of the FCCF, BPA has applied for and taken an FCCF credit twice. The first time occurred in fiscal year 2001 when the Pacific Northwest experienced a severe drought. BPA accessed the fund again in fiscal year 2003 due to adverse hydro conditions and applied the remaining FCCF credits of $79 million, which depleted the fund.

BPA has taken 4(h)(10)(C) fish credits annually since fiscal year 1995.

Recent Accounting Pronouncements

In January 2003, the FASB issued FASB Interpretation No. 46 (FIN 46), "Consolidation of Variable Interest Entities – an interpretation of ARB No. 51." In December 2003, FIN 46 was reissued as FIN 46R, which contained revisions to address certain implementation issues. 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 these types of entities (variable interest entities) may need to be consolidated. For non-public entities there is no distinction in effective dates for Variable Interest Entities (VIEs) and non-VIEs. The application of FIN 46 is required for all entities created before Dec. 31, 2003, by no later than the beginning of the first interim or annual reporting period beginning after Dec. 15, 2003. For entities created after Dec. 31, 2003, application of FIN 46 is required as of the date they first become involved with the respective entities. Northwest Infrastructure Financing Corporation (NIFC) is the FCRPS's only VIE as of Sept. 30, 2004. NIFC has been consolidated into the BPA financial statements for fiscal year 2004. (See Note 4 for a discussion of NIFC.)

Emerging Issues Task Force Issue No. 03-11 (EITF 03-11), "Reporting Realized Gains and Losses on Derivative Instruments That are Subject to FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities, and Not Held for Trading Purposes," requires that revenues and expenses associated with non-trading energy activities that are "booked out" (not physically settled) be reported on a net basis. EITF 03-11 is effective for all derivative contracts that settle after Sept. 30, 2003, and does not require the reclassification of prior period amounts. Effective with the Oct. 1, 2003 adoption of EITF 03-11, the non-physical settlement of non-trading electricity derivative activities, formerly recorded on a "gross" basis in both operating revenues and purchased power expense, are now recorded on a "net" basis in operating revenues. This change which has no effect on margins, net revenue or cash flows, resulted in a $212 million decrease to both operating revenues and purchased power expense for fiscal year 2004. The determination of the sales and purchases of electricity that would have been reported on a net basis had EITF 03-11 been historically applied is not practicable. Prospective application of EITF 03-11 will continue to result in a significant decrease in reported non-trading wholesale energy sales and purchases and related amounts reported in comparative financial statements.

FASB has issued an Exposure Draft on a Proposed Interpretation of SFAS Statement No. 143, "Accounting for Conditional Asset Retirement Obligations." SFAS 143 requires the recognition of a liability for the fair value of an asset retirement obligation that is conditional on a future event if the liability's fair value can be reasonably estimated. The proposed interpretation is in response to diverse accounting practices that have developed with respect to the timing of liability recognition for conditional asset retirement obligations. If adopted, the interpretation may be applicable to BPA effective in fiscal year 2005.

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 the U.S. 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 $68.6 million, $67.7 million and $67.4 million for fiscal years 2004, 2003 and 2002 respectively.

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 Energy Policy Act of 1992 BPA directly funds 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, 2004.

Federal Appropriations

As of Sept. 30 — thousands of dollars

Term Repayments	
2005	$ 104,673
2006	68,939
2007	33,694
2008	10,913
2009	9,889
2010+	4,215,860
	$ 4,443,968

The weighted average interest rate was 7.0 percent on outstanding appropriations as of Sept. 30, 2004. Includes payments on historic replacements but excludes planned future replacements and irrigation assistance.

3. Bonds issued to U.S. Treasury

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. Of the $4.45 billion, $1.25 billion is reserved for conservation and renewable resource loans and grants. At Sept. 30, 2004, of the total $2.9 billion of outstanding bonds, $780 million were conservation and renewable resource loans and grants (including Corps, Reclamation and U.S. Fish & Wildlife capital investments). 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 BPA bonds issued to U.S. Treasury, based upon discounting future cash flows using rates offered by the U.S. Treasury as of Sept. 30, 2004, for similar maturities, exceeds carrying value by approximately $224 million, or 7.7 percent.

The table on the following page reflects the terms and amounts of bonds issued to U.S. Treasury.

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 Northern Wasco hydro projects. BPA has agreed to fund debt service on Emerald People's Utility District, 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.

Operating expense for the projects of $230 million, $223 million and $175 million in fiscal years 2004, 2003 and 2002 respectively, is included in operations and maintenance in the accompanying Statements of Revenues and Expenses. Debt service for the projects of $248 million, $120 million, and $230 million for fiscal years 2004, 2003 and 2002 respectively, is reflected as nonfederal projects expense in the accompanying Statements of

Bonds issued to U.S. Treasury

Long-Term Debt — thousands of dollars

	First Call Date	Maturity Date	Interest Rate	Amount	Cumulative Total
January 2000	none	2005	7.15%	$ 53,500	$ 53,500
January 2001	none	2005	5.65%	20,000	73,500
January 2001	none	2005	5.65%	25,000	98,500
March 2002	none	2005	4.60%	110,000	208,500
March 2002	none	2005	4.60%	30,000	238,500
May 1997	none	2005	6.90%	80,000	318,500
June 2002	none	2005	3.75%	60,000	378,500
June 2002	none	2005	3.75%	40,000	418,500
September 2000	none	2005	6.70%	20,000	438,500
October 2002	none	2005	3.00%	50,000	488,500
November 2002	none	2005	2.80%	40,000	528,500
April 2003	none	2006	2.40%	40,000	568,500
April 2003	none	2006	2.40%	25,000	593,500
July 2003	none	2006	2.30%	75,000	668,500
July 2003	none	2006	2.30%	30,000	698,500
August 1996	none	2006	7.05%	70,000	768,500
September 2000	none	2006	6.75%	40,000	808,500
September 2002	none	2006	3.05%	100,000	908,500
September 2002	none	2006	3.05%	30,000	938,500
September 2002	none	2006	3.05%	20,000	958,500
September 2003	none	2006	2.50%	20,000	978,500
September 2003	none	2006	2.50%	25,000	1,003,500
December 2002	none	2006	3.05%	40,000	1,043,500
January 2004	none	2007	2.50%	60,000	1,103,500
January 2004	none	2007	2.50%	25,000	1,128,500
April 2003	none	2007	2.90%	40,000	1,168,500
April 2004	none	2007	2.95%	65,000	1,233,500
April 2004	none	2007	2.95%	35,000	1,268,500
July 2003	none	2007	2.95%	25,000	1,293,500
July 2004	none	2007	3.45%	50,000	1,343,500
July 2004	none	2007	3.45%	25,000	1,368,500
August 1997	none	2007	6.65%	111,300	1,479,800
September 2003	none	2007	3.10%	20,000	1,499,800
September 2004	none	2007	3.10%	30,000	1,529,800
September 2004	none	2007	3.10%	30,000	1,559,800
January 2004	none	2008	2.95%	65,000	1,624,800
January 2004	none	2008	2.95%	30,000	1,654,800
April 1998	none	2008	6.00%	75,300	1,730,100
April 1998	none	2008	6.00%	25,000	1,755,100
July 2004	none	2008	3.80%	25,000	1,780,100
August 1998	none	2008	5.75%	40,000	1,820,100
September 1998	none	2008	5.30%	104,300	1,924,400
May 1998	none	2009	6.00%	72,700	1,997,100
May 1998	none	2009	6.00%	37,700	2,034,800
July 1989	none	2009	8.55%	40,000	2,074,800
January 2001	none	2010	6.05%	60,000	2,134,800
January 2001	none	2010	6.05%	30,000	2,164,800
May 1998	none	2011	6.20%	40,000	2,204,800
June 2001	none	2011	5.95%	25,000	2,229,800
August 2001	none	2011	5.75%	50,000	2,279,800
January 1998	none	2013	6.10%	60,000	2,339,800
September 1998	none	2013	5.60%	52,800	2,392,600
February 1999	none	2014	5.90%	60,000	2,452,600
April 1998	2008	2028	6.65%	50,000	2,502,600
August 1998	none	2028	5.85%	106,500	2,609,100
August 1998	none	2028	5.85%	112,300	2,721,400
May 1998	2008	2032	6.70%	98,900	2,820,300
April 2003	2008	2033	5.55%	40,000	2,860,300
September 2004	none	2034	5.60%	40,000	2,900,300
				$ 2,900,300	$ 2,900,300
Less current portion					(438,500)
					$ 2,461,800

The weighted average interest rate was 4.9 percent on outstanding bonds issued to U.S. Treasury as of Sept. 30, 2004. All construction, conservation, fish and wildlife, and Corps/Reclamation direct funding bonds are term bonds.

Revenues and Expenses. Refinancing activities reduced debt service by $333 million, $463 million and $319 million for fiscal years 2004, 2003 and 2002 respectively, from rate case estimates.

The fair value of all Energy Northwest debt exceeds recorded value by $454 million, or 7.5 percent based on discounting the future cash flows using interest rates for which similar debt could be issued at Sept. 30, 2004. All other nonfederal projects' debt approximates fair value as stated.

Construction of the Schultz-Wautoma transmission line was financed through Northwest Infrastructure Financing Corporation (NIFC), a Delaware "Special Purpose Corporation," formed on Dec. 17, 2003. In March 2004, NIFC issued $119.6 million in taxable bonds to finance the line under a lease-purchase agreement. NIFC owns the line and BPA leases the line for 30 years. Lease revenues from BPA back the bonds. BPA is managing construction and will operate the line. BPA has indemnified the equity owners of NIFC for all construction and operating risks associated with the line. BPA will have exclusive use and control of the asset during the lease period. At the end of the lease, BPA has the option to buy the line at a bargain purchase price. BPA has determined it is the primary beneficiary of NIFC. As such, NIFC financial statements are consolidated into BPA financial statements in accordance with FIN 46. Therefore the bonds are included as nonfederal debt on FCRPS's financial statements. NIFC's assets are included in FCRPS other assets at Sept. 30, 2004.

The following table summarizes future principal payments required for nonfederal projects as of Sept. 30, 2004.

Nonfederal Projects Debt

As of Sept. 30 — thousands of dollars

	Principal Repayments
2005	$ 234,896
2006	253,632
2007	296,435
2008	304,593
2009	310,789
2010+	5,053,483
	$ 6,453,828

The weighted average interest rate was 5.6 percent on the major portion of outstanding nonfederal projects debt as of Sept. 30, 2004.

5. Investor-owned Utility Exchange Benefits

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 resulted in payments to the utilities if a utility's average system cost exceeded BPA's priority firm power rate on the "exchanged" power. These payments were required to be passed through to their qualified residential and small-farm customers.

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, under which BPA was to provide monetary and power 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 and also allow the power to be converted to cash payments.

Amendments to the October 2000 contracts allowed payment of a portion of the fiscal year 2003 IOU Subscription settlement benefits to be deferred and paid in the fiscal year 2007 through 2011 period, except when they were reduced through credits to offset the SN CRAC.

IOU Exchange Benefit amounts for fiscal years 2005 and 2006 could range from $382 million to $750 million for the two years combined depending on the level of SN CRAC in fiscal year 2006. These estimates include $20 million assumed annual benefits to Portland General Electric from its 258-aMW power purchase. As the SN CRAC percentage has been set at zero percent for fiscal year 2005, an estimate for fiscal year 2005 IOU Exchange Benefits has been recorded as a current liability on the Balance Sheet.

In May 2004, BPA signed new contracts and amendments with all six IOU customers entitled "Agreements Regarding Payment of Residential Exchange Program Settlement Benefits During Fiscal Years 2007-2011." These latest agreements established a method for calculating the IOUs' Monetary Benefits for the fiscal years 2007 through 2011 period including an annual floor of $100 million and an annual cap of $300 million for the six IOUs in total, and all parties agreed that BPA would have no obligation to provide power to the IOUs during that period. The new agreements also eliminated $100 million of a $200 million risk contingency payment owed to two IOUs that have load reduction payments, and deferred the remaining $100 million payment and related interest to the fiscal years 2007 through 2011 period.

IOU Exchange Benefit amounts for the fiscal year 2007 through 2011 period cannot yet be calculated, however the annual floor of $100 million has been recorded as a liability on the Balance Sheets (for total floor of $500 million for this time period). In addition, the IOU Risk Contingency Payment amounts that were deferred in fiscal year 2004 will be repaid $20 million per year (plus interest) during the fiscal year 2007 through 2011 period and have been recorded as a liability on the Balance Sheets.

Financial benefits beyond fiscal year 2011 cannot currently be quantified.

6. Accrued Plant Removal Costs

Pursuant to regulation, BPA collects in rates removal costs for certain assets that do not have associated legal asset retirement obligations. At Sept. 30, 2004 and 2003, BPA has estimated $105 million and $147 million regulatory liabilities respectively, for removal costs and has reclassified these amounts from accumulated depreciation to a regulatory liability.

7. Commitments and Contingencies

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 years and as long as 10 years from Oct. 1, 2001. Current rates recover the additional costs of the Subscription obligations through fiscal year 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 delivered.

The table below summarizes future purchase power and sales commitments as of Sept. 30, 2004.

Purchase Power and Sales Commitments

As of Sept. 30 — thousands of dollars

	Purchase	Sales
2005	$ 629,994	$ 2,279,339
2006	571,990	2,117,166
2007	92,202	1,553,848
2008	48,561	1,563,224
2009	48,878	1,562,069
2010+	98,815	3,139,667
	$1,490,440	**$12,215,313**

Augmentation commitments run through 2006. Purchases and sales have not been reduced for bookouts.

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 $739 thousand, $17 million, and $25 million for fiscal years 2004, 2001 and 1997 respectively. Future irrigation assistance payments ultimately could total $667 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, 2004.

Irrigation Assistance

As of Sept. 30 — thousands of dollars

	Distributions
2005	$ —
2006	—
2007	—
2008	2,950
2009	6,590
2010+	657,693
	$ 667,233

On Aug. 2, 2004, BPA received an updated schedule of Irrigation Assistance (through Sept. 30, 2003) 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.

Additional Pension and Other Post-Retirement Plan Contributions Retirement Benefits

FCRPS makes additional annual contributions to the U.S. Treasury in order to ensure that all federal post-retirement benefit programs provided to its employees are fully funded and such costs are both recovered through rates and properly expensed. The additional contributions are based on employee plan participation and the extent to which the particular plans are under funded. BPA paid $30.9 million, $35.1 million and $55.2 million to the U.S. Treasury during fiscal years 2004, 2003 and 2002, respectively. These amounts were recorded as expense when paid. At Sept. 30, 2004, FCRPS has scheduled additional payments totaling $119.6 million as shown in the following table.

Additional Pension and Other Post-Retirement Plan Contributions

As of Sept. 30 — thousands of dollars

Scheduled Contributions	
2005	$ 26,500
2006	23,200
2007	21,100
2008	18,000
2009*	30,750
	$ 119,550

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

* 2009 is an estimate not currently scheduled.

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.

Decommissioning and Restoration Costs

In 1999 Energy Northwest transferred remaining WNP-3 and WNP-5 assets, including the real property, and site restoration liability to a consortium of local governments named the Satsop Redevelopment Project. BPA's site restoration obligations related to WNP-3 and WNP-5 were satisfied/liquidated as part of that transfer.

In December 2003, the state of Washington's Energy Facility Site Evaluation Council (EFSEC) approved Resolution No. 302, approving Energy Northwest's revised Dec. 5, 2002 Site Restoration Plan for WNP-1 and WNP-4. This approval was part of a contemporaneous comprehensive agreement between Energy Northwest, EFSEC, BPA and the U.S. Department of Energy – Richland Operations Office (lessor of the real property upon which the partially completed WNP-1 and WNP-4 are located). Under the terms of the comprehensive agreement, the level of site restoration agreed to involves partial demolition and sealing of project structures (Level 3D – without removal of the turbine pedestals). BPA committed to fund that level of site restoration for both projects in two phases. The estimated total site restoration costs for both sites is $31 million (2003 dollars).

Phase 1 will involve completion of near term restoration (within 18 to 24 months of Dec. 15, 2003) involving essential "Health, Safety and Environmental" protection designed to place the sites in a safe state for potential reuse and/or long-term storage. Absent long-term reuse, Phase 2 will commence in 23 years and will complete all remaining activities to implement Level 3D restoration.

In order to fund the Phase 2 site restoration obligations, BPA has placed $18 million in an external Trust Fund. BPA believes those funds plus projected earnings over the 23-year horizon will be adequate to cover most if not all costs for Phase 2 activities. Phase 2 site restoration will take place absent long-term reuse of the site and structures. BPA's obligation is not, however, conditioned upon the posited earnings growth of the initial amounts deposited in the Trust Fund or upon the posited total cost estimate. A reasonable extension of time could be provided if such additional funds for completion of Phase 2 site restoration are ultimately required due to higher than estimated costs to complete the work.

Decommissioning costs for Columbia Generating Station (CGS) are charged to operations over the operating life of the project. An external decommissioning sinking fund for costs is being funded monthly for CGS. The sinking fund is expected to provide for decommissioning at the end of the project's safe storage period in accordance with Nuclear Regulatory Commission (NRC) requirements. The NRC requires that this deferred decontamination period be no longer than 60 years. Sinking fund requirements for CGS are based on a NRC decommissioning cost estimate and assume a 40-year operating life.

The estimated decommissioning and site restoration expenditures for CGS are $673 million (2003 dollars). BPA has recorded an estimated liability of $91.9 million (fair value basis, see Note 1, Asset Retirement Obligations, SFAS 143) for CGS decommissioning costs. Payments to the sinking funds for fiscal years 2004, 2003 and 2002 were approximately $5 million, $4.8 million and $4.5 million respectively. The sinking fund balances at Sept. 30, 2004, are $85 million and $9.7 million for decommissioning and site restoration respectively.

In January 1993, the Portland General Electric (PGE) 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, 2004, Eugene Water and Electric Board's (EWEB) 30-percent share, which BPA backs, of this estimated remaining liability is $46 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 have been greater in the early years of decommissioning and will decrease significantly. These greater early funding requirements have altered the decommissioning trust fund contributions for fiscal years 2001, 2002 and 2003. For fiscal years 1995 through 2001, funding for the Trojan decommissioning trust fund was being applied directly to the decommissioning expenses. In fiscal years 2002 and 2003, the decommissioning trust fund was used to fund a portion of the fiscal years 2002 and 2003 Trojan decommissioning expenses. In fiscal year 2004, BPA again directly funded 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 EWEB's 30 percent share of Trojan's costs through rates. 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.

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 $6.8 million. For the Decontamination Liability, Decommissioning Liability and Excess Property Insurance policy, the maximum assessment is $14.1 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. Assessments would be included in BPA's costs and recovered through current rates.

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.

8. 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.

Judgments and settlements are included in BPA's costs and recovered through current rates.

9. Segments

In fiscal year 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 BPA has one fund with the U.S. Treasury, all cash and cash transactions are also centrally managed. Unaffiliated revenues represent sales to external customers for each segment. Intersegment revenues are eliminated.

Major Customers

During fiscal years 2004, 2003 and 2002, no single customer represented 10 percent or more of the FCRPS' revenues.

SFAS 131 Segment Reporting

For the years ended Sept. 30 — thousands of dollars

	Power	Transmission	Corporate	Consolidating	FCRPS
2004					
Unaffiliated revenues	**$ 2,661,975**	**$ 535,936**	**$ —**	**$ —**	**$ 3,197,911**
Intersegment revenues	**76,923**	**108,123**	**—**	**(185,046)**	**—**
Total operating revenues	**2,738,898**	**644,059**	**—**	**(185,046)**	**3,197,911**
Unaffiliated expenses	**1,971,620**	**252,738**	**(181,952)**	**—**	**2,042,406**
Depreciation	**177,297**	**188,942**	**—**	**—**	**366,239**
Intersegment expenses	**108,194**	**76,758**	**94**	**(185,046)**	**—**
Total operating expenses	**2,257,111**	**518,438**	**(181,858)**	**(185,046)**	**2,408,645**
Net operating revenues	**481,787**	**125,621**	**181,858**	**—**	**789,266**
Interest expense	**162,531**	**137,823**	**(15,503)**	**—**	**284,851**
Net revenues (expenses)	**$ 319,256**	**$ (12,202)**	**$ 197,361**	**$ —**	**$ 504,415**
2003					
Unaffiliated revenues	$ 3,059,386	$ 552,718	$ —	$ —	$ 3,612,104
Intersegment revenues	85,425	110,884	—	(196,309)	—
Total operating revenues	3,144,811	663,602	—	(196,309)	3,612,104
Unaffiliated expenses	2,435,923	240,460	(315,320)	—	2,361,063
Depreciation	178,896	171,130	—	—	350,026
Intersegment expenses	110,401	85,788	120	(196,309)	—
Total operating expenses	2,725,220	497,378	(315,200)	(196,309)	2,711,089
Net operating revenues	419,591	166,224	315,200	—	901,015
Interest expense	176,595	168,996	—	—	345,591
Net revenues (expenses)	$ 242,996	$ (2,772)	$ 315,200	$ —	$ 555,424
2002					
Unaffiliated revenues	$ 2,967,074	$ 566,655	$ —	$ —	$ 3,533,729
Intersegment revenues	80,729	153,727	—	(234,456)	—
Total operating revenues	3,047,803	720,382	—	(234,456)	3,533,729
Unaffiliated expenses	2,605,847	283,809	(52,907)	—	2,836,749
Depreciation	174,164	161,041	—	—	335,205
Intersegment expenses	153,630	80,729	97	(234,456)	—
Total operating expenses	2,933,641	525,579	(52,810)	(234,456)	3,171,954
Net operating revenues	114,162	194,803	52,810	—	361,775
Interest expense	201,582	150,718	—	—	352,300
Net revenues (expenses)	$ (87,420)	$ 44,085	$ 52,810	$ —	$ 9,475

Schedule of Amount and Allocation of Plant Investment

Federal Columbia River Power System
As of Sept. 30, 2004 — 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	$ 6,030,980	$ 5,539,134	$ 491,846	$ 6,030,980	$ —	$ —	$ —
Bureau of Reclamation							
Boise	144,493	27,577	404	27,981	(2,731)	67,539	64,808
Columbia Basin	1,964,353	1,238,515	60,682	1,299,197	495,526	142,008	637,534
Green Springs	35,726	11,175	212	11,387	9,934	8,070	18,004
Hungry Horse	149,212	121,985	285	122,270	—	—	—
Minidoka-Palisades	383,665	112,088	(37)	112,051	386	72,472	72,858
Yakima	264,243	6,127	725	6,852	13,762	127,826	141,588
Total Bureau Projects	2,941,692	1,517,467	62,271	1,579,738	516,877	417,915	934,792
Corps of Engineers							
Albeni Falls	50,605	43,126	2,809	45,935	—	—	—
Bonneville	1,401,586	927,603	69,656	997,259	—	—	—
Chief Joseph	629,987	571,149	18,368	589,517	—	163	163
Cougar	118,861	36,314	40,354	76,668	—	3,288	3,288
Detroit-Big Cliff	74,095	41,220	6,748	47,968	—	5,050	5,050
Dworshak	376,722	316,782	2,464	319,246	—	—	—
Green Peter-Foster	95,965	50,955	4,680	55,635	—	6,222	6,222
Hills Creek	51,457	18,463	1,265	19,728	—	4,623	4,623
Ice Harbor	223,909	159,247	3,937	163,184	—	—	—
John Day	657,206	494,244	14,816	509,060	—	—	—
Libby	577,223	433,212	1,240	434,452	—	—	—
Little Goose	255,468	212,068	1,738	213,806	—	—	—
Lookout Point-Dexter	113,180	50,192	10,787	60,979	—	1,496	1,496
William Jess (Lost Creek)	149,836	26,972	174	27,146	—	2,184	2,184
Lower Granite	414,613	332,599	8,459	341,058	—	—	—
Lower Monumental	276,546	230,564	3,071	233,635	—	—	—
McNary	397,747	300,736	21,626	322,362	—	—	—
The Dalles	424,917	308,486	66,985	375,471	—	—	—
Lower Snake	262,143	256,193	3,380	259,573	—	—	—
Columbia River Fish Bypass	920,589	376,958	529,058	906,016	—	—	—
Total Corps Projects	7,472,655	5,187,083	811,615	5,998,698	—	23,026	23,026
AFUDC on Direct Funded Projects	36,062	—	36,062	36,062	—	—	—
Irrigation Assistance at 12 Projects having no power generation	193,925	—	—	—	148,553	45,372	193,925
Total Plant Investment	16,675,314	12,243,684	1,401,794	13,645,478	665,430	486,313	1,151,743
Repayment obligation retained by Columbia Basin project	4,639	2,836 (1)	—	2,836	1,803	—	1,803
Investment in Teton project (2)	79,107	—	7,269 (2)	7,269	56,573	3,681	60,254
	$16,759,060	$12,246,520	$1,409,063	$13,655,583	$723,806	$489,994	$1,213,800

(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	Control	Flood Wildlife	Fish and Recreation	Other	Percent Returnable from Commercial Power Revenues
Bonneville Power Administration						
Transmission Facilities	$ —	$ —	$ —	$ —	$ —	100.00%
Bureau of Reclamation						
Boise	—	—	—	—	51,704	17.47%
Columbia Basin	—	17,489	6,054	3,071	1,008	91.36%
Green Springs	—	—	—	—	6,335	59.68%
Hungry Horse	—	26,942	—	—	—	81.94%
Minidoka-Palisades	—	64,404	2,718	10,651	120,983	29.31%
Yakima	—	2,547	50,397	296	62,563	7.80%
Total Bureau Projects	—	111,382	59,169	14,018	242,593	71.27%
Corps of Engineers						
Albeni Falls	183	274	—	4,213	—	90.77%
Bonneville	400,999	—	—	1,266	2,062	71.15%
Chief Joseph	—	—	4,977	6,330	29,000	93.58%
Cougar	548	38,357	—	—	—	64.50%
Detroit-Big Cliff	220	20,857	—	—	—	64.74%
Dworshak	9,733	31,934	—	15,809	—	84.74%
Green Peter-Foster	366	30,379	—	1,693	1,670	57.97%
Hills Creek	630	26,476	—	—	—	38.34%
Ice Harbor	57,184	—	—	3,541	—	72.88%
John Day	91,535	18,240	—	11,962	26,409	77.46%
Libby	—	95,308	876	15,950	30,637	75.27%
Little Goose	34,917	—	—	4,141	2,604	83.69%
Lookout Point-Dexter	748	49,355	—	602	—	53.88%
Lost Creek	—	52,967	24,483	29,435	13,621	18.12%
Lower Granite	52,605	—	—	13,108	7,842	82.26%
Lower Monumental	39,596	—	—	2,898	417	84.48%
McNary	70,413	—	—	4,972	—	81.05%
The Dalles	47,346	—	—	2,078	22	88.36%
Lower Snake	2,570	—	—	—	—	99.02%
Columbia River Fish Bypass	11,792	2,781	—	—	—	98.42%
Total Corps Projects	821,385	366,928	30,336	117,998	114,284	80.28%
AFUDC on Direct Funded Projects	—	—	—	—	—	100.00%
Irrigation Assistance at 12 Projects having no power generation	—	—	—	—	—	76.60%
Total Plant Investment	821,385	478,310	89,505	132,016	356,877	85.82%
Repayment obligation retained by Columbia Basin project	—	—	—	—	—	100.00%
Investment in Teton project	—	9,151	—	2,433	—	80.70%
	$ 821,385	$ 487,461	$ 89,505	$134,449	$356,877	85.80%

Schedule of Revenues and Expenses

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

Schedule B

	2004	2003	2002
Operating Revenues			
Sales of electric power:			
Sales within the Northwest Region			
Northwest Publicly Owned Utility Customers [1]	$ 1,737,895	$ 1,723,341	$ 1,798,477
Direct Service Industrial Customers	92,424	18,494	58,466
Northwest Investor-Owned Utilities	363,201	436,702	378,083
Sales Outside the Northwest Region [2]	489,063	628,243	638,267
Bookouts [3]	(212,155)	—	—
Total Sales of Electric Power	2,470,428	2,806,780	2,873,293
Transmission	535,936	552,718	566,654
Fish Credits and Other Revenues [4]	191,547	252,606	93,782
Total Operating Revenues	3,197,911	3,612,104	3,533,729
Operating Expenses			
BPA O&M [5]	613,121	607,616	775,077
Purchased Power [3]	582,129	1,043,009	1,286,867
Corps, Bureau and Fish & Wildlife O&M [6]	214,035	198,539	198,055
Nonfederal entities O&M – net billed [7]	221,210	208,535	167,026
Nonfederal entities O&M – non-net billed [8]	37,521	39,864	35,566
Total Operation and Maintenance	1,668,016	2,097,563	2,462,591
Net billed debt service	222,779	104,329	213,919
Non-net billed debt service	25,696	15,205	16,256
Nonfederal Projects Debt Service [9]	248,475	119,534	230,175
Federal Projects Depreciation	366,239	350,025	335,205
Residential Exchange	125,915	143,967	143,983
Total Operating Expenses	2,408,645	2,711,089	3,171,954
Net Operating Revenues	789,266	901,015	361,775
Interest Expense			
Appropriated Funds	281,607	280,094	325,551
Bonds issued to U.S. Treasury	110,251	166,598	151,997
Capitalization Adjustment [10]	(68,566)	(67,703)	(67,356)
Allowance for funds used during construction	(38,441)	(33,398)	(57,892)
Net Interest Expense	284,851	345,591	352,300
Net Revenues	$ 504,415	$ 555,424	$ 9,475

(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 streamflows in the Columbia River Basin. Streamflows directly impact the amount of nonfirm energy available for sale, the costs of generating power with alternative fuels, and ultimately the price BPA can obtain for its exported nonfirm energy and surplus firm power.

(3) Total operating expenses and revenue from electricity sales reflect recent accounting guidance from the Emerging Issues Task Force (EITF) of the Financial Accounting Standards Board. Under this new guidance (EITF 03-11) both revenues and expenses associated with non-trading energy activities that are “booked out” (settled other than by the physical delivery of power) are to be reported on a “net” basis in both operating revenues and purchased power expense. Formerly, such bookouts were to be treated on a “gross” basis. Application of the new guidance thus decreased both operating revenues and purchase power expense by $212 million and has no effect on the net revenue, cash flows or margins.

(4) 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.

(5) 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.

(6) Corps, Reclamation and Fish & Wildlife operations and maintenance expenses include the costs of the Corps and Reclamation generating projects and expenses of the U.S. Fish & Wildlife Service, in connection with the federal system.

(7) 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.

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

(9) 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 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.

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

Report of Independent Auditors

PRICEWATERHOUSECOOPERS

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

In our opinion, the accompanying combined balance sheets and the related combined 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, 2004 and 2003, and the results of its operations and its cash flows for the three years in the period ended September 30, 2004, and the changes in its capitalization and long-term liabilities for each of the two years in the period ended September 30, 2004, 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. Those standards 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.

As discussed in Note 1 of the financial statements, FCRPS changed the manner in which it accounts for realized gains and losses on the settled derivative contracts not held for trading purposes, as of October 1, 2003.

Our audit was made 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, 2004 (Schedule A) and the Schedule of Revenues and Expenses for each of the three years in the period ended September 30, 2004 (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, is fairly stated in all material respects in relation to the basic financial statements taken as a whole.

PricewaterhouseCoopers LLP

Portland, Oregon
October 28, 2004

Federal Repayment

Revenue Requirement Study

The revenue requirement study demonstrates repayment of federal investment, and it reflects revenues and costs consistent with BPA's 2002 final power rate proposal in May 2000 for fiscal years 2002 through 2006 (*see* WP-02-FS-BPA-02) and the 2004 final transmission proposal in May 2003 for fiscal years 2004 through 2005 (*see* TR-04-FS-BPA-01). The final proposals filed with FERC, contain the official amortization schedule for the rate periods.

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.

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.

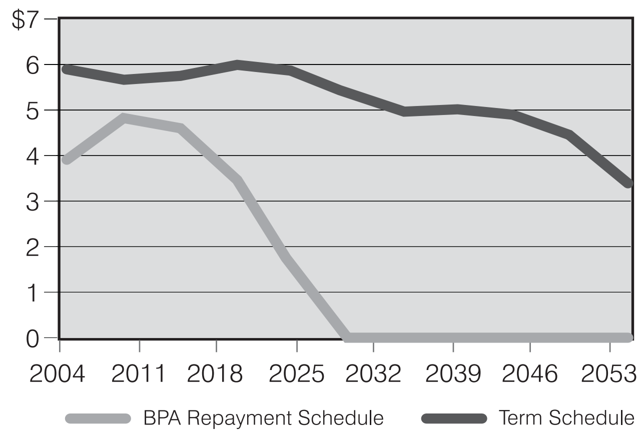
Repayment of FCRPS Investment

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

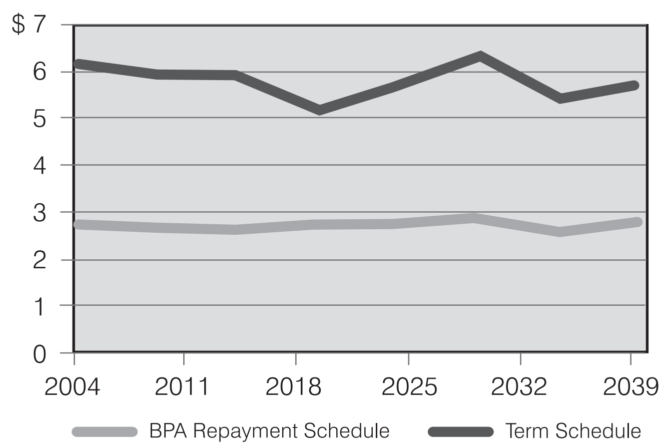
Unrepaid Federal Generation Investment

Includes future replacements — billions of dollars



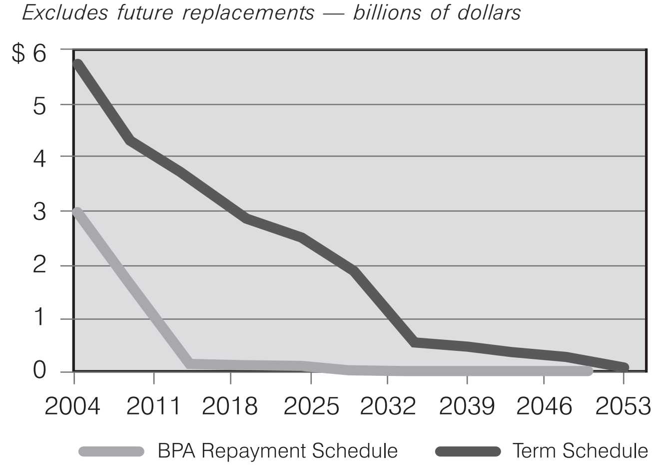
Unrepaid Federal Transmission Investment

Includes future replacements — billions of dollars



Unrepaid Federal Investment

Excludes future replacements — billions of dollars



repayment 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 2004 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.

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Deputy Administrator

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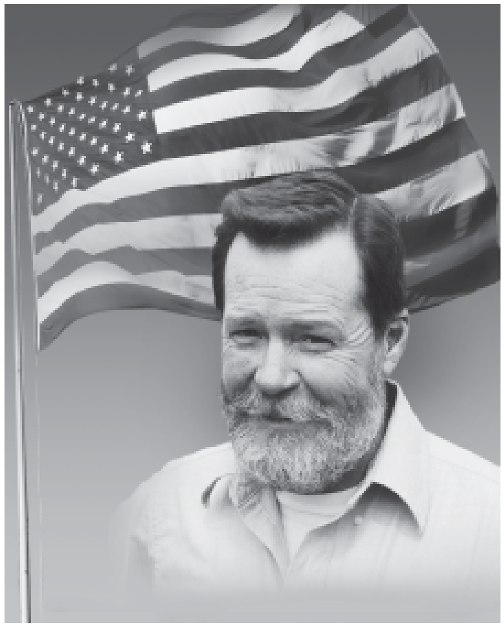
In Memory



All of us at BPA mourn the loss of pilot John Cooley who was killed when the helicopter he was piloting on Aug. 17, 2004, went down. The accident occurred while Mr. Cooley was performing a stringing operation on the last span into Bell Substation for the new Grand Coulee-Bell 500-kilovolt line scheduled for energization in December 2004.

Mr. Cooley was a true American hero. He died in the line of public service. He had served his country in war (Vietnam) and in peace. He died building a project that will bring benefits to Northwest citizens for years to come.

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