2013 ANNUAL REPORT

Leading and Innovating

BONNEVILLE POWER ADMINISTRATION

TABLE OF CONTENTS

Financial Highlights 1

Letter to the President 2

Year in Review 4

Performance Target Results 22

Financial Section 25

Executives 78

Offices 79

FINANCIAL HIGHLIGHTS

FEDERAL COLUMBIA RIVER POWER SYSTEM

Thousands of dollars

Total operating revenues	$3,346,281
Total operating expenses	3,161,175
Net operating revenues	185,106
Net interest expense	289,871
Net expenses	$ 104,765

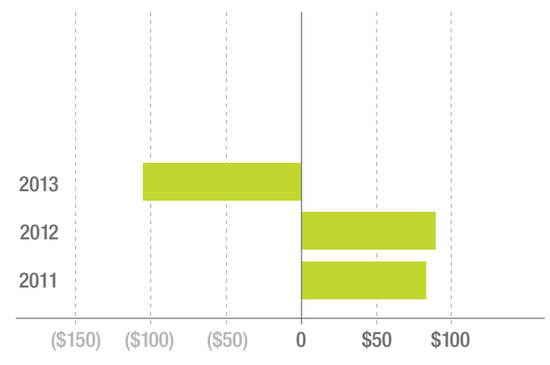
BPA Profile

The Bonneville Power Administration is a federal electric utility based in the Pacific Northwest within the Department of Energy. BPA markets wholesale electric power from 31 federal hydroelectric projects owned and operated by the U.S. Army Corps of Engineers and Bureau of Reclamation, one nonfederal nuclear plant and some small nonfederal resources. BPA supplies about one-third of the electric power used in the Pacific Northwest.

BPA also operates and maintains about three-fourths of the region's high-voltage transmission system and is a leader in integrating renewable resources, such as wind energy, into its grid. BPA's service area includes Oregon, Washington, Idaho, western Montana, and small parts of Wyoming, Nevada, Utah, California and eastern Montana.

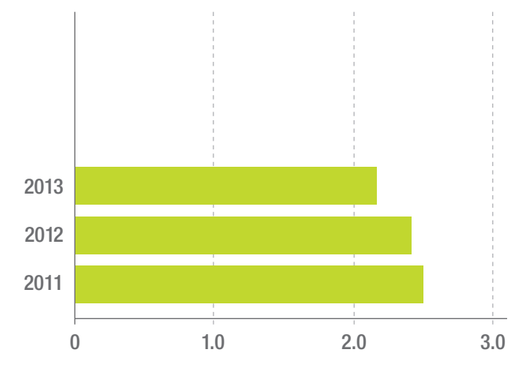
As a self-funded entity, BPA covers its costs by selling wholesale power, transmission and related services at cost. Under federal law, BPA must meet the power needs of its preference customers, consumer-owned utilities that include public utility districts, people's utility districts, cooperatives, tribal utilities, municipalities and federal agencies. BPA also sells power to investor-owned utilities, some direct-service industries in the region and — when there is a surplus of power in the Northwest — to marketers and utilities in Canada and the Western United States.

BPA promotes energy efficiency, renewable energy and new technologies. It also funds regional efforts to protect and enhance fish and wildlife populations affected by federal hydropower development in the Columbia River Basin. BPA is committed to public service and seeks to make its decisions in a manner that provides transparency and opportunities for input from all stakeholders.



NET REVENUES (EXPENSES)

Millions of dollars



NONFEDERAL DEBT SERVICE COVERAGE RATIO

Times covered

LETTER TO THE PRESIDENT

Dear Mr. President,

The Bonneville Power Administration is distinguished by its commitment to continuous improvement. In an organization whose energy experts, linemen, engineers, biologists and economists share a 76-year history of technical innovation, it may seem only natural to witness new best practices taking root. Even as the pace of change in the utility industry accelerates, our ability to identify fresh solutions and figure out how best to make them work magnifies our value to the Northwest.

However, continuous improvement can only occur with a commitment to two values: accountability and honesty. In 2013, we learned of serious shortcomings in our Human Capital Management practices in a period between 2010 and 2013. We are diligently working to address these failings and to take the proper corrective actions to remedy all cases where applicants, including veterans, may have been disadvantaged. We have strengthened our relationship with our colleagues at the Department of Energy and the Office of Personnel Management as we work together to restore our human resources functions to full compliance with all laws and regulations.

In fiscal year 2013, we not only continued to work hard to find new ways of approaching complex problems, we actively embraced opportunities to lead and innovate. Despite challenging economic conditions and low wholesale power prices, BPA is in sound financial condition and taking the lead on issues of consequence to the Northwest. Among them:

- Leading the development of a regional recommendation on the future of the Columbia River Treaty in partnership with the U.S. Army Corps of Engineers;
- Investing in the infrastructure of the region's unique hydroelectric system, including starting the 10-year overhaul of all six generating units of the Third Power Plant at the Bureau of Reclamation's Grand Coulee Dam. These generators provide 18 percent of the entire output of the 31-dam Federal Columbia River Power System;
- Working to restore the Columbia Basin's endangered and threatened fish runs. Results of rigorous scientific tests show all eight federal dams on the lower Columbia and Snake rivers are on track to achieve exacting standards of fish passage survival ranging from 93 to 96 percent. More than a million chinook salmon passed Bonneville Dam this year, the highest annual total since 1938;
- Advancing energy efficiency to meet public power's share of the Northwest Power and Conservation Council's five-year goal of saving an additional 504 average megawatts in the region by next year;
- Introducing new products to integrate intermittent renewable generators, including enabling customers to purchase nonfederal balancing reserves and committing to implement 15-minute transmission scheduling.

One of the challenges facing the region as more clean energy joins our resource base is the shift from an energy-constrained system to one that is more limited by capacity. This change presents a major opportunity for innovation to modernize the grid and explore methods of coordinating existing assets more efficiently to serve the region's future. To address this, we are engaged in a regional effort to evaluate the benefits and costs of a Northwest-footprint energy imbalance market and other approaches to gain reserve sharing and other operational efficiencies.

BPA and its partners are also making significant progress on projects to unlock the value of smart grid and energy storage technologies as part of the largest regional smart grid demonstration project in the nation. A key aspect of our role in the Pacific Northwest Smart Grid Demonstration Project is evaluating which infrastructure and technology investments will provide the greatest value to Northwest ratepayers in the long run.

The objective of these technologies is to empower the grid to operate more efficiently and reliably, and to stretch the region's supply of clean, affordable energy. In 2013, BPA and its partners earned national recognition from the Peak Load Management Alliance for recent work to explore one of the most promising such tools, demand response. Regional pilots at cold storage facilities and a paper mill demonstrated how industrial customers could react to relieve constraints on the transmission system, or support the reliability needs of the grid during periods of significant renewable resource variability without detracting from business operations.

BPA's most valuable asset is its workforce, and its diverse accomplishments helped move the region forward in 2013. One of the most meaningful opportunities came last fall, when BPA linemen and substation electricians served the nation in the devastating aftermath of Hurricane Sandy. More than 100 BPA employees boarded Air Force cargo planes with their trucks and equipment to fly to the East Coast, where they worked from before dawn until after dark to contribute BPA's proven skill set and teamwork to the administration's emergency effort to restore power in the Northeast.

These colleagues and many others epitomize BPA's exceptionally talented, innovative and dedicated workforce. I am proud to be a part of it as we work to continuously improve our service to the Northwest.

Elliot Mainzer, Acting Administrator and CEO

YEAR IN REVIEW

Finance

Wet or dry, Pacific Northwest weather shapes the revenues of the Bonneville Power Administration. With a generation base that's 80 percent hydroelectric, BPA is always prepared to manage through drought or high water. By that measure, the fiscal 2013 water year represented a welcome change.

Although precipitation was anything but ordinary in the first two quarters — a record wet fall reversed into an unusually dry winter — in the end, the Columbia Basin water year saw streamflows at 100 percent of average.

For fiscal year 2013, BPA had net expenses of $104.8 million based on total operating revenues of $3.35 billion. With adjusted net revenue of $56.3 million, we met a key financial target for the fiscal year. Transmission Services continued a pattern of healthy financial performance, netting $71.4 million, exceeding BPA's rate case forecast by $42.7 million. Power Services recorded net expenses of $15.1 million, $13.6 million below the rate case forecast of $1.5 million. Transmission net revenues exceeded expectations because of significantly lower interest expense, lower depreciation expense and higher revenues related to contracts. Power's performance was influenced by the continuation of low electricity market prices and lower-than-expected revenues from sales to our utility customers.

Our financial reserves were $1.27 billion. Of that total, $641 million was reserves available for risk.

Treasury payment

BPA is proud of its record of sound financial management. In 2013, we achieved a milestone, making our payment to the U.S. Treasury on time and in full for the 30th consecutive year. The payment of $691.8 million reaffirms BPA's commitment to fully repay U.S. taxpayers with interest for their investment in the Federal Columbia River Power System.

Rates

Keeping rates low while addressing the demands on the power and transmission system remains a challenging priority given diminished wholesale electricity prices. BPA's rate-setting begins with an invitation for customers and the public to participate in a review of our programs and costs, called the Integrated Program Review.

Through this collaborative process, which most recently began in January 2012 and concluded with a final report that November, Power Services and our partners identified an average of nearly $135 million in annual cost reductions to the initial IPR forecast for the 2014–2015 rate period. Cost management discussions resumed in April 2013 with a brief Integrated Program Review 2, which identified total capital and expense reductions of $192 million for fiscal years 2014 and 2015, compared to the 2012 IPR.

After reaching decisions on spending levels in the IPR, the formal, eight-month rate case began in November 2012 with the filing of an initial power and transmission rate proposal. The rate proceeding allows customers and constituents, as parties to the case, to test the policy and legal bases of the rate proposal. Our initial proposal for the upcoming 2014–2015 rate period reflected significant increases for both power and transmission rates, including the first transmission rate increase in six years. The specific drivers behind the power rates were higher costs to operate and maintain the federal hydro system, higher costs to fund existing long-term agreements for the fish and wildlife mitigation program, and lower revenues from surplus power sales due to low market prices.

The main drivers behind the transmission rate increase were a growing construction program necessary to repair and replace decades-old system assets, as well as increased spending on mandatory compliance and security requirements.

Parties to the rate case, primarily BPA customers, reached an early settlement on the cost of generation services required to operate the transmission system, which are recovered through rates for ancillary and control area services, including balancing services for variable energy generators.

After working to cut costs and hold increases to a minimum, BPA's power and transmission rates were established for fiscal years 2014–2015. BPA increased power rates by an average of 9 percent and the average transmission rate by 11 percent, compared to the rate period that just ended.

The final record of decision was released on July 24, 2013, in time for BPA to file for interim rate approval from the Federal Energy Regulatory Commission. BPA received interim approval of power and transmission rates from FERC effective Oct. 1, 2013. The rates are expected to be in effect through Sept. 30, 2015.

Access to capital

BPA has an obligation to make sound capital investments to support its multifaceted responsibilities to the region into the future. Securing additional sources of capital has become a top priority to optimize our power and transmission infrastructure, and fulfill commitments for energy efficiency and fish and wildlife restoration.

To finance major capital investments, BPA has traditionally relied on its ability to borrow from the U.S. Treasury. However, BPA's Treasury borrowing authority is capped by law and could be fully utilized as early as 2017, absent other actions BPA is undertaking.

To maintain and improve its transmission system, BPA has been using third-party (nonfederal) financing for some of its transmission facilities since 2004. As of Sept. 30, 2013, BPA's Lease Financing Program had replaced about $900 million of Treasury borrowing authority and is projected to offset an additional $2.5 billion over the next 10 years.

After a public process late in 2012, BPA's Finance organization released a comprehensive Access to Capital strategy that laid out various tools BPA will pursue to address the challenge. The strategy outlines actions BPA might undertake to provide cost-effective capital funding sources. It also describes means to ensure that funding costs are prudent and well-controlled, and that the sources will be reliable and sufficient to meet BPA's investment priorities. The steps we have taken since 2012, such as a new program that allows customers to prepay for power in the form of block purchases, have already put BPA in a better position to finance needed projects around the region.

Power Services

While the water year unfolded with relatively few unexpected challenges, the work year presented an array of problem-solving opportunities for the business line that guides the generation and marketing of the region's federal hydroelectricity. During 2013, Power Services played an integral leadership role in important regional and international issues. These included the Columbia River Treaty Review, reinvestment in the Federal Columbia River Power System, protection of endangered fish runs, and support of energy efficiency and renewables integration.

Preserving and enhancing the value of regional assets, including the federal dams in the Columbia River system, lies at the heart of BPA's mission. These legacy assets, constructed between 1909 and 1975, generate about 26 percent of the power produced in the Northwest. Our ratepayers fund maintenance and capital improvements, which BPA coordinates in partnership with the federal agencies that own and operate the dams, the U.S. Army Corps of Engineers and the Bureau of Reclamation. To reduce the risk of failure and ensure reliable operation, a disciplined program of capital investment prioritization guides our decisions and actions.

BPA is engaged in strengthening the hydroelectric system with a 10-year, estimated $275 million project to overhaul all six generating units in Grand Coulee's Third Power Plant in Washington. These massive units, some of which can generate nearly as much power as a nuclear plant, provide 18 percent of the entire output of the 31-dam system. The overhaul of the Third Power Plant is one of the most important activities in BPA's effort to preserve the long-term reliability of the FCRPS.

In 2013, we continued our work to update transformer banks in the Grand Coulee Dam left powerhouse. This project, scheduled for completion in 2014, replaces transformers that are more than six decades old.

South Idaho load

After receiving a 2011 termination letter from a partner utility, BPA engaged with the public and prioritized arrangements for service to six customer utilities in southeast Idaho currently served by an agreement called the South Idaho Exchange. We established a preferred option for future service to the area: participation in the proposed 500-kilovolt Boardman-to-Hemingway transmission line project between Boardman, Ore., and Melba, Idaho. In 2013, BPA advanced this option and focused on service to the loads in the interim period after termination of the agreement in 2016 and before completion of the new transmission line. We now await expenditure authority from Congress to prepare to deliver power to southeast Idaho when service by a partner utility is no longer available.

Building customer relationships

It is rare that a new public power utility is formed in the Northwest. In 2013, BPA began to serve only its eighth new public power customer in 65 years. After a five-year process, Jefferson County Public Utility District began to purchase 38 average megawatts to serve about 18,000 electricity customers on Washington's Olympic Peninsula.

Moving from our newest relationship to one of our most longstanding, BPA began service under a 10-year power sales agreement with aluminum manufacturer Alcoa in 2013. The contract, for 300 average megawatts through September 2022, provides long-term certainty to the Intalco Works plant in Ferndale, Wash., the last operating smelter that BPA directly serves, as well as the plant's 625 employees.

The agreement also provides financial and operational benefits to BPA and the region. They include increased long-term rate stability and operating flexibility to assist with intermittent resources such as wind.

SUPER FORECAST

The Super Forecast, a new software program built by a small team of BPA analysts, is one of BPA's latest steps to support the reliable integration of renewable resources.

"This is a great example of the type of innovation and creativity that has made BPA a world leader in renewable energy integration," says Elliot Mainzer, BPA acting administrator.

As wind generation has set record after record — most recently, on Feb. 22, 2013, wind produced an average of 4,464 megawatts for an hour, accounting for 34 percent of the generation in BPA's balancing area — BPA is seeking opportunities to use the finite resources of the Federal Columbia River Power System more efficiently.

"Improved forecasting would be incredibly valuable in helping us reduce the cost of wind integration," says Scott Winner, the project manager of BPA's Centralized Wind Power Forecasting Initiative who led development of the new tool.

To apply 21st century technology to the riddle of wind forecasting, BPA collaborated with wind customers for four years to arrange to collect the additional data that feeds the forecasting efforts. BPA is now able to monitor wind speed at the turbine level across 31 wind plants.

The Super Forecast methodology, launched in March 2013, supports wind integration in three ways. First, site-specific data is provided to BPA's two private wind forecasting vendors, strengthening their predictions. Second, the Super Forecast enables BPA to analyze and blend vendor forecasts into a hybrid that can perform better than either parent, especially for a particular site. Third, BPA makes project-specific forecasts available to generators at no charge to improve transmission scheduling.

"Lots of wind generators really wanted to be first on the list for getting the new forecast," Winner says. "They understand it, and they want to leverage its benefits."

Transmission Services

Operating the backbone of the Northwest electrical grid, BPA's Transmission Services organization continues to take the lead in creating new products and services in a rapidly evolving industry environment. In 2013, BPA advanced regional projects ranging from substation upgrades to new high-voltage lines.

Most prominently, BPA continued to move ahead on planning and review for several major 500-kilovolt transmission projects. On the I-5 Corridor Reinforcement, we announced the selection of a preferred route and released a draft environmental impact statement. This project would be the first north-south transmission line built in the I-5 corridor in southwestern Washington since the 1970s, a period in which the population of the area has more than doubled. We are engaged in collaborating with the public, stakeholders and elected officials on a final environmental impact statement expected in 2014.

BPA also ramped up pre-construction activities for another project identified in our 2008 Network Open Season process, the Central Ferry-Lower Monumental line in Washington. The 38-mile 500-kV line will connect a new BPA substation at Central Ferry in Garfield County with the existing Lower Monumental Substation in Walla Walla County. The project will add critical grid capacity and support new transmission requests from wind generators, delivering energy from the lower Snake River area to population centers west of the Cascades. Construction is expected to begin in spring 2014 and energization is scheduled in December 2015.

BPA continues to work to resolve cultural resource and land acquisition issues it has encountered on another 500-kV project, the 28-mile Big Eddy-Knight line. We have built the southern section, from our Big Eddy Substation in Wasco County, Ore., to the bank of the Columbia River, and are working through issues on the Washington side of the river. We anticipate energizing the line in late 2014.

BPA also decided to move forward this year with the rebuilding of the Celilo AC/DC converter station near The Dalles, Ore. The $428 million project will replace a station dating to 1970 that is the northern terminus of a 900-mile DC transmission line to Los Angeles. The line currently provides 3,100 megawatts of capacity between the Northwest and Southern California and will gain the potential to be upgraded to 3,800 megawatts.

Transmission Services' activities in 2013 demonstrate BPA's commitment to reliable electrical service by maintaining existing lines and facilities, and building the right lines in the right place at the right time, backed by strong commercial agreements.

Revised Network Open Season

After a two-year hiatus for review and redesign, BPA and customers began participating in a modified Network Open Season program in May 2013 to better manage requests for long-term firm transmission service and plan for expansion of BPA's transmission system.

With a majority of transmission requests serving wind generation, the NOS processes of 2008, 2009 and 2010 successfully supported and accelerated the large-scale integration of wind generation into the region over the past five years.

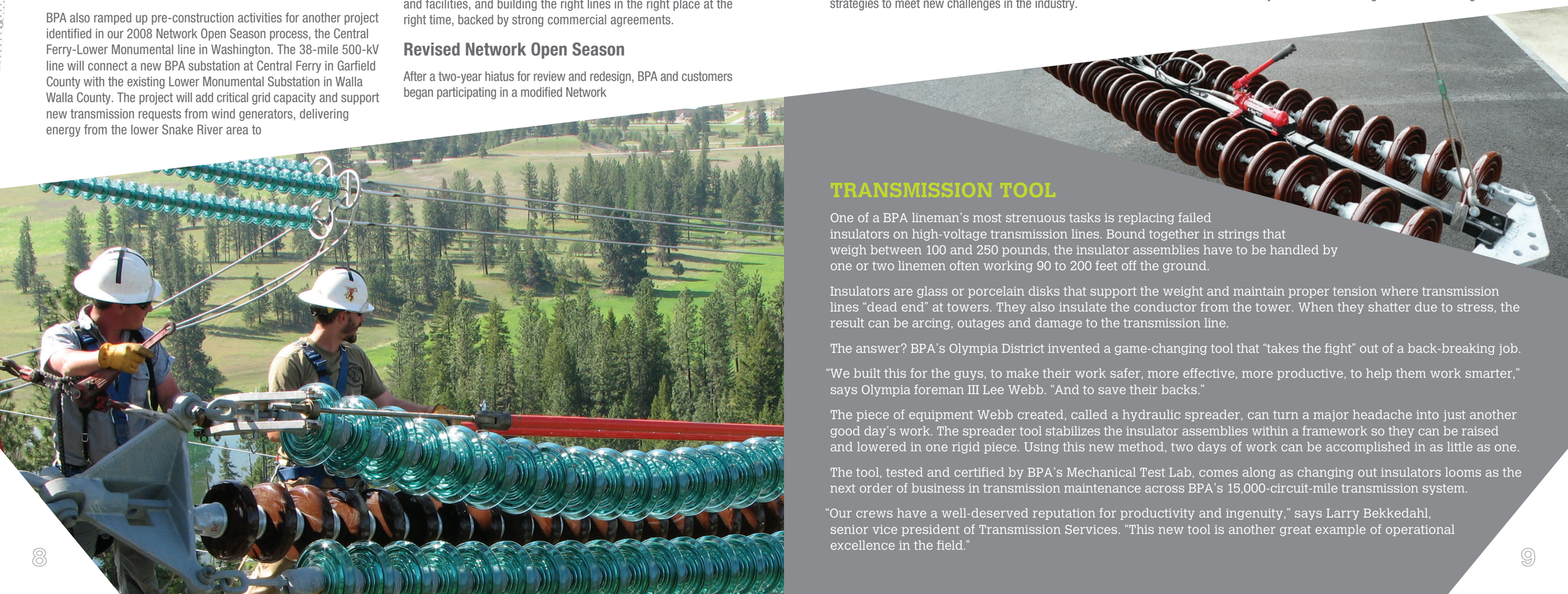
Three years of experience in employing the NOS model demonstrated that the innovative process provided many benefits to BPA and the region. However, it also yielded evidence of unintended financial and risk consequences, as well as system planning and study gaps. A pause in the program beginning in 2011 allowed BPA, in collaboration with regional partners and in coordination with FERC, to evaluate alternatives and refine the process to more effectively serve the region. The revised process resumed in May 2013 and moved forward with a series of cluster studies in fall 2013.

The reformed NOS process is an example of Transmission Services' emphasis on continually improving and developing effective strategies to meet new challenges in the industry.

LiDAR program

BPA's pioneering use of Light Detection and Ranging, or LiDAR, to manage vegetation achieved a milestone this year and was recognized as a national example of excellence by the North American Transmission Forum. In 2013, we completed a five-year effort to map the more than 15,000 circuit miles of our transmission system, which crosses four states and reaches into seven, using the laser-based optical remote-sensing units mounted on helicopters.

Mapping our transmission grid via LiDAR enables BPA to more accurately and efficiently identify risks to transmission reliability, such as trees growing into the lines. We expanded our use of LiDAR after a tree grew into a line in 2008, prompting BPA to re-inspect all its transmission rights-of-way and revamp its vegetation management program. Today's innovative deployment of laser technology allows us to better protect the reliability of the regional transmission system by pinpointing sites requiring vegetation removal, which often lie in remote and rugged terrain. This innovation and other improved practices have proven highly effective; in summer 2013, we marked five years without a tree-growth-related outage.



TRANSMISSION TOOL

One of a BPA lineman's most strenuous tasks is replacing failed insulators on high-voltage transmission lines. Bound together in strings that weigh between 100 and 250 pounds, the insulator assemblies have to be handled by one or two linemen often working 90 to 200 feet off the ground.

Insulators are glass or porcelain disks that support the weight and maintain proper tension where transmission lines "dead end" at towers. They also insulate the conductor from the tower. When they shatter due to stress, the result can be arcing, outages and damage to the transmission line.

The answer? BPA's Olympia District invented a game-changing tool that "takes the fight" out of a back-breaking job.

"We built this for the guys, to make their work safer, more effective, more productive, to help them work smarter," says Olympia foreman III Lee Webb. "And to save their backs."

The piece of equipment Webb created, called a hydraulic spreader, can turn a major headache into just another good day's work. The spreader tool stabilizes the insulator assemblies within a framework so they can be raised and lowered in one rigid piece. Using this new method, two days of work can be accomplished in as little as one.

The tool, tested and certified by BPA's Mechanical Test Lab, comes along as changing out insulators looms as the next order of business in transmission maintenance across BPA's 15,000-circuit-mile transmission system.

"Our crews have a well-deserved reputation for productivity and ingenuity," says Larry Bekkedahl, senior vice president of Transmission Services. "This new tool is another great example of operational excellence in the field."

GRAND COULEE LINE REPLACEMENT

Scorching 105-degree heat. Finger-numbing 20-degree cold. A grass fire that raged a stone's throw away, forcing the evacuation of part of the town. Workers rappelling like mountaineers down the face of the nation's largest dam.

BPA, the Bureau of Reclamation and their contractors together mastered a unique set of circumstances during fiscal year 2013 to complete the $37.5 million Grand Coulee Line Replacement Project. Among the unusual demands and conditions they encountered on the way to retire aging 500-kilovolt transmission cables inside the Washington dam and construct new overhead lines:

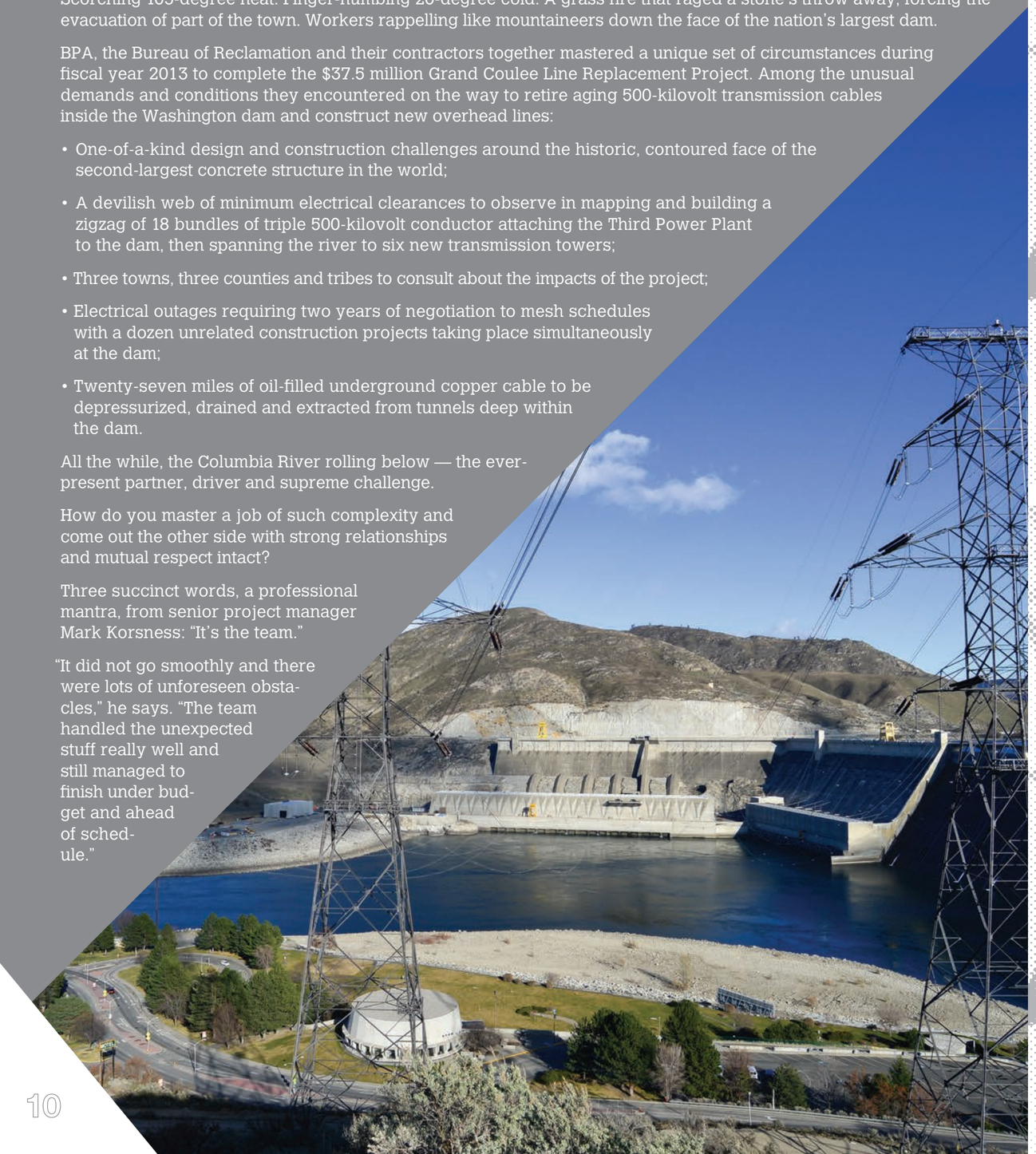
- One-of-a-kind design and construction challenges around the historic, contoured face of the second-largest concrete structure in the world;
- A devilish web of minimum electrical clearances to observe in mapping and building a zigzag of 18 bundles of triple 500-kilovolt conductor attaching the Third Power Plant to the dam, then spanning the river to six new transmission towers;
- Three towns, three counties and tribes to consult about the impacts of the project;
- Electrical outages requiring two years of negotiation to mesh schedules with a dozen unrelated construction projects taking place simultaneously at the dam;
- Twenty-seven miles of oil-filled underground copper cable to be depressurized, drained and extracted from tunnels deep within the dam.

All the while, the Columbia River rolling below — the ever-present partner, driver and supreme challenge.

How do you master a job of such complexity and come out the other side with strong relationships and mutual respect intact?

Three succinct words, a professional mantra, from senior project manager Mark Korsness: "It's the team."

"It did not go smoothly and there were lots of unforeseen obstacles," he says. "The team handled the unexpected stuff really well and still managed to finish under budget and ahead of schedule."



Energy Efficiency

Energy efficiency has held a prominent place in BPA's mission since passage of the Pacific Northwest Electric Power Planning and Conservation Act in 1980. Whether partnering with utilities to fund cost-effective initiatives, collaborating to develop cutting-edge programs and technologies, or helping pioneer smart grid strategies to strengthen the reliability of the transmission system, BPA continues to play a leadership role in the region as well as the nation.

Our energy efficiency program actively embodies BPA's three core values, most notably, the commitment to regional collaboration. The ambitious savings goals that have helped establish energy efficiency as the Northwest's resource of choice are established in five-year plans developed by the Northwest Power and Conservation Council.

In 2013, the Council released a midterm assessment of its Sixth Power Plan (2010–2014). The report concluded that the region's utilities, including BPA in cooperation with our public power partners, were on track to reach the Sixth Power Plan goal, having achieved 44 percent of the five-year target of 1,200 average megawatts in the plan's first two years. Heading into the fifth year of the current plan, BPA continues to work closely with its customers to meet or exceed the target, while collaborating to develop the Council's Seventh Power Plan, which will set the path to 2020 and beyond.

Since 1981, the energy efficiency efforts of BPA and the Northwest's publicly owned utilities have saved a total of more than 1,400 average megawatts, protecting the region's clean air quality by avoiding the need to build new power plants. However, recent economic challenges and other obstacles have made it more difficult for some utilities to make a case for investing in energy efficiency. To provide a better basis for decision making, BPA's Power Services Energy Efficiency staff developed a new suite of analytical tools in 2013 that offers greater clarity and detail on the economic case for conservation. This analysis compared BPA's energy efficiency achievements from 2001 through 2011 against the cost of purchasing power from the wholesale market and demonstrated that conservation led to significantly lower costs.

For customers' use, we also established a framework to allow utilities to analyze individual financial situations using their own costs and assumptions. The tool is especially valuable to utility customers who are examining the implications of BPA's Tiered Rate Methodology. Tiered rates, which went into effect in October 2012, encourage energy efficiency investments. Under the tiered rate structure, each customer can purchase a defined amount of power at Tier 1 rates; any purchases beyond that amount are priced at Tier 2 rates. On average, the cost of Tier 2 power is expected to be higher than Tier 1 because it will reflect the cost of new resources or market purchases.

Our longstanding dedication to increasing energy efficiency through innovative and cost-effective strategies allows the federal hydropower system to reliably provide the widest service at the lowest possible cost. BPA focuses its support and technical expertise across a broad spectrum including residential, commercial, industrial and agricultural sectors.

One of our fastest-growing programs, Energy Smart Industrial, earned national recognition in 2013 from the American Council for an Energy-Efficient Economy after a review of the country's leading programs. ACEEE called BPA a champion of energy efficiency "for the development and delivery of an exemplary industrial energy efficiency program on an aggressive schedule with impressive results."

Since being revamped in 2009, our Energy Smart Industrial program has saved 55 average megawatts, enough energy to power nearly 30,000 homes. Serving public power's industrial load in Idaho, Montana, Oregon and Washington, the program has helped more than 500 Northwest industrial customers in such market segments as pulp and paper, wood products, food processing, high tech, water/wastewater and mining to reduce costs and increase efficiency.

In 2013, the largest kraft pulp mill in the nation became an outstanding example of this work. Improving operations and purchasing more efficient equipment enabled KapStone Paper, formerly Longview Fibre, to reduce energy consumption by nearly 3 average megawatts a year. The Longview, Wash., company stands to save more than $835,000 in annual energy expenses, and our partner Cowlitz Public Utility District acquires a low-cost resource that counts toward state energy savings requirements.

BPA supported energy efficiency in the commercial sector in 2013 with an innovative behavioral pilot program at 10 Starbucks stores in Snohomish County, Wash. BPA, the Snohomish Public Utility District, Lucid and PECI partnered with Starbucks to provide baristas with the tools to operate stores more efficiently by identifying strategies for reducing energy and water use without diminishing customer service. Through this project, co-funded by BPA, Snohomish PUD assessed potential resource savings by providing 10 stores with utility data and best practices, coupled with friendly competition to encourage participation. The results were promising: Behavioral changes reduced energy use by 2 percent during the competition. In 2014, Starbucks and its partners expect to expand the pilot to 100 stores across the Northwest.

Smart grid and demand response

BPA is a leader in a regional effort to develop a business case for smart grid — technologies with two-way abilities to share information and power — to determine which major investments will provide the best value to Northwest ratepayers. In 2013, BPA moved ahead on projects to help unlock the value of smart grid and energy storage technologies as a major partner in the largest regional smart grid project in the country, comprising 60,000 metered customers and 11 Northwest-based utilities over five states.

The five-year, $178 million Pacific Northwest Smart Grid Demonstration Project is led by Battelle and funded by DOE and partners, including $10 million from BPA. It deploys and evaluates technologies such as a new micro-grid facility in Salem, Ore., which received original support as part of BPA's Technology Innovation portfolio. The 5-megawatt lithium-ion battery system in Portland General Electric's Smart Center anchors a reliable, localized power zone capable of providing reserve power to about 500 local customers in the event of an electrical disruption or power outage. The facility shows how smart assets can work together at the regional level to optimize the Northwest's abundance of renewable resources and provide balancing services that can enhance the reliability, resilience and flexibility of the regional grid.

In 2013, we continued to see great promise in demand response. This form of energy management has moved from simply reducing peak loads to working toward balancing supply and demand, contributing to a more sophisticated power grid. In April, BPA was among four demand response programs to earn top honors at the Peak Load Management Alliance Awards in Austin, Texas. The PLMA Award Program recognizes energy industry leaders that create innovative methods to meet peak load needs, mitigate price risks and manage variable generation.

The alliance honored BPA with the Innovative Application of Demand Response Award for its pilot projects to draw upon demand response capacity from commercial and industrial sites to balance both increases and decreases in energy supply from renewable resources, as well as traditional generation. One of the pilots tested the ability of a paper mill in Port Angeles, Wash., to provide up to 36 megawatts of bi-directional capability by controlling pulp refining. The program also tested other businesses, including a lumber yard, hospital, wastewater and government office, for a total of eight sites and another 900 kilowatts of load impact. These programs serve as models for how demand response can be used to help manage the intermittent nature of Northwest renewable energy resources.

TECHNOLOGY INNOVATION

Research and development holds a storied place in BPA history. In 2013, BPA continued to deliver value to the region through projects supported by our Technology Innovation program across such areas as energy efficiency, grid optimization, energy storage and seismic mitigation.

Working with the U.S. Department of Energy and partners such as the Electric Power Research Institute, BPA's Technology Innovation program has become a national model for collaboration that enables breakthroughs and solves business problems. A disciplined approach unique to the industry ensures BPA makes the right investments in technology research and that projects stay on track. BPA's approach is distinguished by a rigorous process of benchmarking, roadmapping, vetting and monitoring of projects in its research portfolio. The goal is to yield measurable results in the form of better technologies, safer practices and greater efficiency. Now seen as a leader in R&D program management, BPA has been sharing its best practices with other organizations, including EPRI.

Recent innovations such as the BPA-engineered helical connector shunt, a technology that can up-rate and extend the life of aging transmission lines; the advancement of heat-pump technologies; and the upgrade of our telecommunications network have covered the program's costs to date and more.

SYNCHROPHASORS

Twenty-five years after helping introduce synchrophasors to the electrical grid, BPA is part of a project to use the monitoring devices to give transmission operators from Canada to Mexico a much clearer view of operations — and potential problems — across the entire West. BPA and 18 partners are building a trouble-shooting network of more than 600 of the devices, the Western Interconnection Synchrophasor Program.

"Now we can see more precisely how all the interconnected power systems in the West are responding to changes and disturbances on the grid," says BPA engineer Nick Leitschuh.

In addition to early detection of equipment failures, the system monitoring and operations from the $108 million network will improve the integration of renewable energy and unlock capacity, which translates to more efficient power flow on the grid.

"What we've been able to achieve working together with BPA is a true industry game-changer," says Vickie VanZandt, a former BPA executive who manages the program for the Western Electricity Coordinating Council. "Not only have we developed new technology to make the Western Interconnection more reliable and secure, we have facilitated a whole new level of cooperation among the West's energy entities."

For decades, utilities relied on Supervisory Control and Data Acquisition systems, which produced readings of the grid every two to four seconds. But synchrophasors can produce precise power system info a hundred times faster — BPA's devices take 60 measurements per second. The massive boost in resolution is akin to making the technology leap from black-and-white to color television.

BPA's five-year, $32 million project is deploying 126 synchrophasors at key substations and wind sites. Synchrophasors take current, frequency and voltage measurements, which are time-stamped using GPS. The measurements are transmitted over a high-speed broadband network to BPA's control center. The result is a turbo-charged Twitter-like feed of power system data that provides grid operators real-time intelligence so they can react more quickly to system disturbances and take actions to avoid a blackout or prevent one from cascading.

"It's as if we were driving with our eyes closed, only opening them every few seconds," says Terry Oliver, BPA's chief technology innovation officer. "Now we have a high-res understanding of the power system."

Columbia River Treaty

A model of international cooperation since 1964, the Columbia River Treaty has provided nearly five decades of flood management and hydropower benefits to the United States and Canada.

Leading up to 2014, the Treaty — which was written to allow either Canada or the United States to end most power provisions in 2024 with at least 10 years' notice — approached a critical stage in its life cycle.

In 2013, the Columbia River Treaty Review, a multi-year regional effort led by BPA and the U.S. Army Corps of Engineers on behalf of the U.S. Entity, progressed toward a recommendation to the U.S. Department of State on the future of the Treaty.

For the past several years, the U.S. Entity — created by executive order and comprised of the BPA administrator and the Northwestern Division engineer of the U.S. Army Corps of Engineers — has led an intense analytical effort to evaluate potential changes to Treaty operations after 2024. The goal is to provide a regional recommendation by December 2013 on the elements that the Pacific Northwest would like the Department of State to pursue in any negotiations with Canada.

The hallmark of this effort, called the Columbia River Treaty 2014/2024 Review, has been direct, ongoing engagement with the Sovereign Review Team, representing four Northwestern states, 15 tribal governments and 11 federal agencies, as well as with regional stakeholders, interest groups and the public.

Culturally, economically and environmentally, much has changed since the Treaty was ratified in 1964. The current process seeks input from tribes, regional power producers, irrigators, commercial river navigators, recreational users of the Columbia River and its tributaries, as well as the public at large.

Over the course of 2013, the U.S. Entity made great strides toward a regional recommendation. The two original primary purposes of the Treaty were flood risk management and hydropower.

Technical analyses, conducted in collaboration with the Sovereign Review Team, widened the scope of study in support of the Treaty Review to consider effects on a wide range of Northwest river users. The array of needs and concerns reflected in these detailed studies included irrigation, water supply and quality, navigation, recreation, cultural resources, fish protection operations and other ecosystem function needs, in addition to flood risk management and hydropower.

In June 2013, the U.S. Entity released a seven-page working draft recommendation, identifying content for a potential regional recommendation at a high level. It contained a set of overarching principles for the future of the Treaty, followed by more specific recommendations related to a number of Treaty elements. To reflect the region's recognition of ecosystem concerns and climate change, the Treaty Review draft recommendation suggested that these be included as important concerns in the Treaty.

The purpose of the release of the working draft document was to prompt further regional discussions with both sovereigns and stakeholders. These discussions, and the additional refinement of the concepts they generated, shaped the draft regional recommendation released Sept. 20, 2013. Public comment on the document was accepted through Oct. 25, 2013. The regional recommendation will be finalized by December 2013 and sent to the Department of State.

The Columbia River meanders 1,243 miles through British Columbia, Washington and Oregon.

Renewable Energy

Nearly a decade of innovation has established BPA as a national leader in the integration of renewable energy resources. Over the past few years, we've tested new transmission system operations to help the Northwest integrate 4,500 new megawatts of carbon-free energy.

While the day-to-day work of managing variable energy has become business as usual, we continued to find opportunities in 2013 to explore and present new strategies to serve renewable power. In cooperation with our regional partners, we created a forum to develop new services, achieved an early settlement of our rate case for balancing services for integrating renewable resources, and committed to introduce 15-minute transmission scheduling to better reflect the intermittent nature of the resource.

As the pace of new wind development slowed this year, much of our work focused on developing services to help our customers make more efficient use of a finite federal system. The Federal Columbia River Power System and the region's fleet of new renewable generators make up a uniquely complementary partnership between two carbon-free energy sources. This compatibility is grounded in an operational reality of electrical transmission: To protect the reliability of the grid, electricity being generated must exactly match the amount being consumed at all times. As the output of wind generation fluctuates with wind patterns, generation at the 31 hydroelectric dams responds accordingly — ramping up or backing down to partner in preserving the stability of the grid.

The concentration of wind plants in a single geographic area around the Columbia River Gorge intensifies the challenge of this balancing act. When wind generation levels swell and subside under the force of a common weather pattern, it amplifies simultaneous demand for balancing services, increasing or decreasing hydroelectric generation.

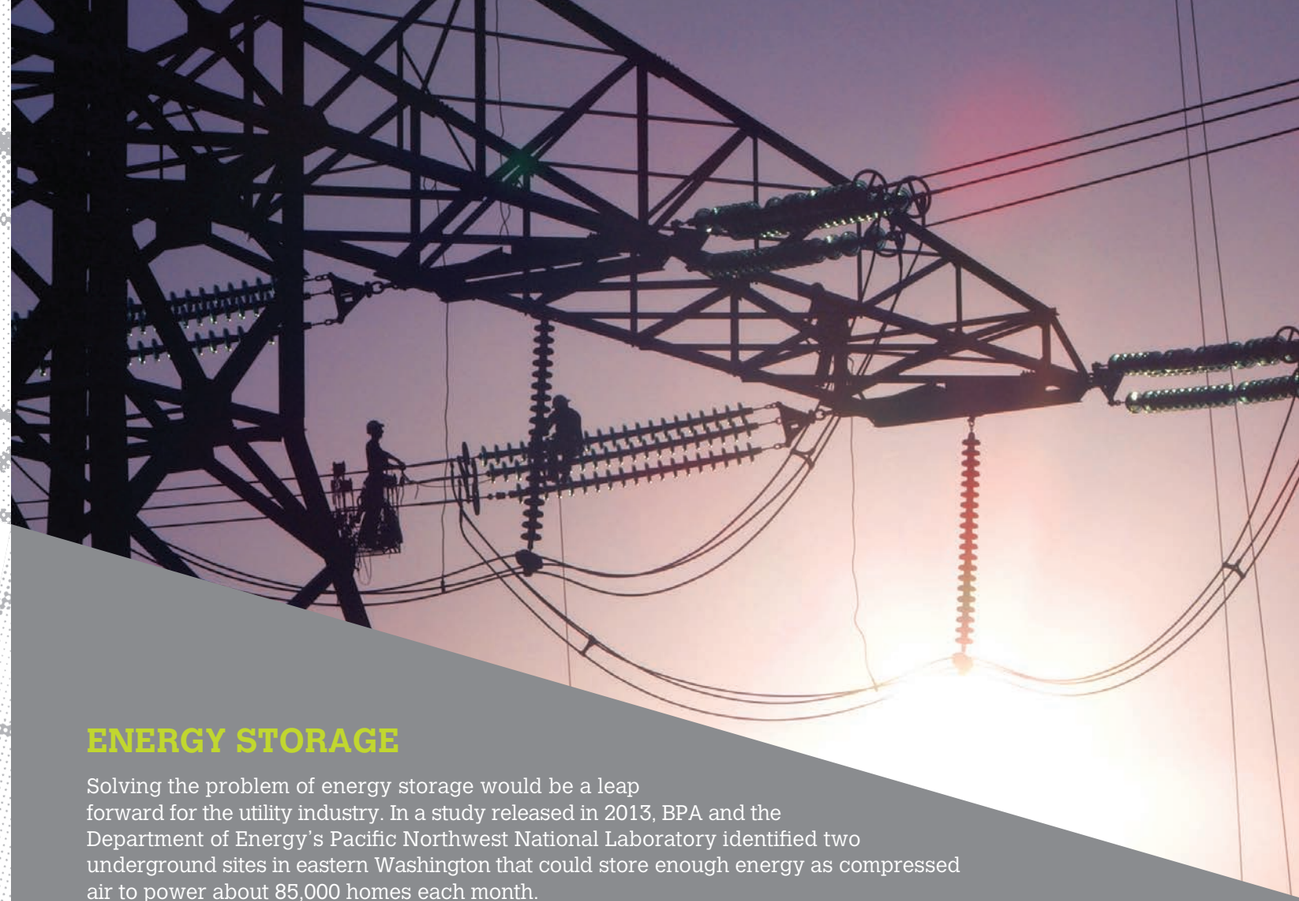
With the growth of variable renewable energy in the Northwest, the federal hydro system has reached the limits of its balancing capacity. That's why BPA has identified augmenting our balancing capacity and using it more efficiently as the key to reliable integration of renewable resources over the next decade.

Forecasting and scheduling errors account for the majority of the need for balancing reserves. BPA was one of the first transmission providers in the Northwest to offer intra-hour scheduling to allow customers to make more frequent adjustments to changing wind conditions. This year, we made the decision to take another major step in response to guidance from FERC and customer interests. Building on what we have learned in our pilot programs, we plan to offer a committed 15-minute transmission service in 2014. We will offer a significant rate discount to customers who commit to submitting transmission schedules every 15 minutes, allowing us to further stretch the resources of the federal system to serve the region.

In 2013, we offered several new services. For the first time, customers can opt to purchase balancing reserves beyond their share of the federal hydroelectric system's capacity. BPA purchases nonfederal balancing reserves on the market on behalf of customers who select this "full service" option, and these customers are exempt from the transmission schedule curtailments when federal balancing reserves are exhausted. To offer this product and other services, we developed a variety of technical and operational innovations to stretch the reserve capacity and extend the value of the FCRPS system.

In 2013, we also engaged in a regional effort through the Northwest Power Pool to evaluate the costs and benefits of potential changes to energy markets that could enable the region to balance power supply and demand in a more efficient, cost-effective way. Members of the NWPP initiative have funded a phased review of potential approaches.

Finally, the Northwest is finding renewable energy opportunities beyond wind. In the first quarter of 2013, we connected the largest solar array in the region to our transmission grid. The 5-megawatt Outback Solar Project near Christmas Valley, Ore., the first commercial-scale solar project in our territory, can serve 3,000 homes at peak capacity.



ENERGY STORAGE

Solving the problem of energy storage would be a leap forward for the utility industry. In a study released in 2013, BPA and the Department of Energy's Pacific Northwest National Laboratory identified two underground sites in eastern Washington that could store enough energy as compressed air to power about 85,000 homes each month.

The year-long research study looked at whether porous basalt rock beneath the Columbia Basin could serve as a kind of subsurface battery that could temporarily store excess renewable energy for later use. It evaluated both the technical and economic feasibility of developing a compressed-air energy storage facility.

Such plants could help hold some of the region's abundant wind power — often produced at night when winds are strong and energy demand is low — for later, when demand is higher and power supplies are stretched.

"With more power coming from variable sources such as wind and the sun, compressed-air energy storage plants can play a valuable role in helping manage and integrate renewable power onto the Northwest's electric grid," says Steve Knudsen, who managed the study for BPA.

All compressed-air energy storage plants work under the same premise. When energy is abundant, it's drawn from the grid and used to power a large air compressor to push pressurized air into an underground geologic storage structure. Later, when power demand is high, the air is released back to the surface, where it is heated and rushes through turbines to generate electricity.

Compressed-air energy storage plants can regenerate as much as 80 percent of the electricity they take in. The world's two existing plants — one in Alabama, the other in Germany — use man-made salt caverns to store excess electricity. The PNNL-BPA study examined a different approach: using natural, porous rock reservoirs deep underground to store renewable energy.

Working with the Northwest Power and Conservation Council, BPA is using the study data to perform an analysis of the technology's potential benefits to the Northwest. The results could be used by regional utilities to develop a commercial energy storage demonstration project.

The feasibility study was funded by BPA's Technology Innovation office, PNNL and other partners, including Seattle City Light, Snohomish County Public Utility District, Portland General Electric, Puget Sound Energy and Washington State University.

Fish and Wildlife

BPA's efforts to protect and enhance populations of fish and wildlife around the Columbia Basin reached important milestones in 2013. BPA worked with its federal partners to complete and release a comprehensive evaluation of their progress through the first five years of implementation of NOAA Fisheries' Biological Opinion. This report offered an expansive review of accomplishments in dam passage improvements, habitat restoration, hatchery reform and predator management, as well as a detailed update on the status of salmon and steelhead listed under the Endangered Species Act.

The evaluation showed the program is working: Salmon and steelhead are returning to reopened habitat and spawning in greater numbers in restored reaches. Meanwhile, ESA-listed fish that spawn in the interior Columbia River Basin have increased in numbers since their listing in the 1990s. And in 2013, Bonneville Dam recorded the largest run of fall chinook salmon — more than 950,000 fish — since the dam was built in 1938.

The Biological Opinion, describing federal agencies' actions to conserve fish stocks listed under the ESA, sets a high bar for survival of protected juvenile salmon and steelhead through the system. It calls for an average dam survival rate of 96 percent for spring-migrating juvenile fish and 93 percent for those migrating in summer. In 2013, the U.S. Army Corps of Engineers conducted scientifically rigorous tests at two of the eight federal dams on the lower Columbia and Snake rivers, part of an ongoing assessment of their ability to safely pass juvenile fish. For a dam to hit the mark, its fish survival must meet the performance standards in each of two years. The results currently show that all eight dams are on track to achieve these exacting standards.

Surface spill, which creates more natural conditions attractive to fish, is key to achieving these ambitious goals. Such spill uses less water and is often safer for fish than conventional spill. Improved passage routes for migrating fish are now in operation at all eight of the federal lower Columbia and Snake river dams.

This year marked the five-year anniversary and halfway point of the first Columbia Basin Fish Accords. Under these historic agreements, BPA, the U.S. Army Corps of Engineers, the Bureau of Reclamation, tribes and states are now working together as partners to provide tangible benefits for anadromous and resident fish. The focus is on tributary and estuary habitat restoration, as well as scientifically designed hatchery programs that are supplementing stocks and helping to avoid extinction of at-risk populations, while protecting wild fish through best management practices.

In 2013, the Colville Tribes completed the new Chief Joseph Hatchery, a $67 million project funded primarily under a Fish Accord. Its objective is to increase naturally spawning populations of spring, summer and fall chinook salmon in the Okanogan and Columbia rivers. At full capacity, the Washington hatchery will produce 2.9 million chinook salmon per year, helping to provide fish for tribal ceremonies, subsistence needs and recreation.

In early September, BPA helped dedicate the $13.8 million Snake River sockeye hatchery in Springfield, Idaho. Run by the Idaho Department of Fish and Game, the facility will produce up to 1 million sockeye smolts a year, the next step in re-establishing a natural population of the iconic species.

A record run of fall chinook salmon passed Bonneville Dam in 2013, more than 950,000 fish.

BPA also moved ahead in funding habitat acquisitions in Oregon's Willamette River Valley, based on a memorandum of agreement with the state of Oregon. With the majority of the state's population living in the I-5 corridor, land purchases for conservation have become more urgent and valuable. Over the course of 2013, BPA made significant progress under the Willamette Wildlife Agreement, funding the purchase of over 1,000 acres for fish and wildlife conservation in the Willamette River Basin. Parcels of land set aside under this program will provide habitat benefits for Oregon chub, bull trout and Fender's blue butterfly, in addition to salmon and steelhead.

These parcels join dozens of other notable habitat acquisitions and restoration projects in tributary rivers and the estuary this year. The progress was possible through BPA's partnership with tribes, states and local nonprofit organizations. For instance, BPA and its partners protected and restored about 1,110 acres in the estuary by breaching dikes, replacing culverts and taking other actions to reopen and reconnect tidal wetlands. In the tributaries, BPA and its partners have continued to fulfill extensive commitments under the Biological Opinion, improving access to nearly 680 miles of stream habitat through removing barriers such as diversion dams; improving nearly 48,000 acres by restoring wetlands, removing invasive species or other actions; and protecting about 150 miles of wetland channels through purchase or lease.

While salmon and steelhead on the endangered species list are the highest-profile beneficiaries of BPA's fish and wildlife funding, BPA supports projects intended to benefit other species as well. For example, Pacific lamprey, an ancient fish of cultural significance to many Northwest tribes, also migrate to the ocean and back. In recent years, their numbers have dwindled to historic lows. In 2013, the Army Corps of Engineers used BPA funding to install a unique passage device, called a lamprey flume, at Bonneville Dam. The new passage will better accommodate lamprey, which are less capable swimmers than salmon in high velocity flow, in surmounting Bonneville Dam on their way to ancestral tributaries.

HURRICANE SANDY

In the devastating aftermath of Hurricane Sandy, BPA linemen and substation electricians flew to the rescue. On Nov. 3, 2012, 106 of our employees and contractors boarded Air Force cargo planes, along with 72 pieces of heavy equipment, to support the administration's emergency mission to restore power after more than 8 million people were left without electricity along the Eastern Seaboard.

Working from before dawn to long after dark for 18 days, BPA's skilled crews used their expertise and teamwork to get the lights back on. BPA provided manpower and resources to Jersey Central Power and Light on behalf of parent company First Energy, under a mutual aid agreement that ensured no costs were shouldered by BPA ratepayers.

Here is an excerpt from a letter BPA received from a New Jersey family.

To the Bonneville Power Administration:

My name is Peter McNamara, and I live in Little Silver, N.J., with my wife and 4 children. We lost power on the night of the storm, Monday, Oct. 29, at 7:30 p.m. Like everyone else, we hunkered down and made the best of it, hoping it would not be too much longer without power.

On Sunday, Nov. 2, Jersey Central Power and Light began restoring power to my neighborhood, and by Monday, everyone around had power except for us and one other house. … While we always kept things in perspective (we still had our house and belongings and means to survive), I was extremely frustrated.

… As darkness settled in (on the 13th day) and we were resigning ourselves to the fact that we would be without power for another night, the crew from Washington state showed up … and asked if the power was on. We explained the situation and without hesitation they went to work. One crew climbed the trees to get to the cross wires over the pond and the other crew climbed to a utility pole to get to the wires at the other end. Over the next 2 hours, in the dark with their headlamps and chain-saws, they cut back the trees and freed the wires. We had the power restored at 7:30 p.m. on Saturday, Nov. 10 (Day 13).

I am writing this note to you to let you know how grateful I am for the work that Marty, Travis, Mike and all the other guys did to help us out. I know how hard you guys have been working — long 16-hour days — and I can't imagine how exhausted they must have been at the end of the day on Saturday — yet they stopped and helped us.

I am convinced that no one else could have done this job. Nobody had the tree-climbing gear to get up into those trees and do what they did.

While I can't remember all of the names of the guys, they referred to themselves as the "Barehand Crew" — so I think you know who they are. They should be commended for the work they did, and we will be forever grateful!!!!!!!!!!

Sincerely,

Peter McNamara

Editor's note: The barehand crew is a specially trained and equipped team of linemen who can work on power lines while they are energized.

PERFORMANCE TARGET RESULTS

For several years, BPA has set key agency targets that the organization as a whole is responsible for achieving in the specified year. These targets serve as indicators of BPA's annual performance.

Stakeholder Perspective

Energy efficiency

Target Met. BPA achieved over 59.4 average megawatts of new conservation savings against a target of 56 average megawatts and did so at an average cost of $1.7 million per average megawatt, well below the targeted cost of $1.9 million per average megawatt.

Transmission system performance

Target Not Met. BPA missed its transmission system performance target for availability due to higher than average construction outages resulting in availability of only 97.98 percent, just below the target of 98 percent. BPA did meet its reliability targets for outage duration and outage frequency and met milestones for flowgate intertie performance pilot development.

Federal hydro performance

Target Met. BPA met the equivalent availability factor target of 74.1 percent with a result of 78.3 percent. BPA met the forced outage factor target of 3.9 percent or less with a factor of 3.6 percent, and met targets in the following areas: generation reliability compliance, hydro generation safety, fleet cost performance and FCRPS Biological Opinion compliance.

Columbia Generating Station performance and cost

Target Met. The cost of power at Columbia Generating Station nuclear plant was $45.06 per megawatt-hour, within the targeted range of $45.51 and $50.30 or less per megawatt-hour. The Columbia Generating Station overall performance index indicator was 84.8 points, above the target of 82.6 or greater.

Renewable resource integration

Target Met. BPA successfully developed oversupply management protocols for spring 2013 to supply balancing reserves to integrate renewable resources. BPA is continuing to evaluate long-term solutions to oversupply conditions. BPA put in place business practices and necessary systems and tools to support market participant use of enhanced supplemental service for the acquisition of third-party supply of balancing capacity on a day-ahead basis for the FY 2014–2015 rate period. BPA actively supported and influenced the Northwest Power Pool (NWPP) Market Assessment Committee in the completion of an analysis of the benefits of an energy imbalance market in the NWPP footprint in spring 2013. BPA actively participated in the NWPP evaluations of variable energy resource tagging for parties scheduling wind generation in the BPA balancing area.

Commercial transmission policy

Target Met. BPA modified commercial transmission policies and processes to support efficient regional planning. BPA successfully worked with customers to complete the 2013 cluster study planning methodology and assumptions as part of Network Open Season. BPA's Generation Interconnection Queue Reform initiative resulted in a decision to modify several policies and is ready to conduct business reflecting the new changes. The Tariff Compliance Automation Program met its target by completing five projects consistent with BPA's tariff filing. BPA also met all planned implementation milestones for the Sustainable Transmission that is Available and Reliable (STAR) Program to close gaps in the transmission system model tools, policies and processes that affect NERC-regulated available transfer capability.

Columbia River Treaty

Target Met. BPA and the U.S. Army Corps of Engineers led the development of a balanced and informed recommendation to the U.S. Department of State on the future of the Treaty with Canada, by effectively engaging federal entities, regional entities and other parties.

Endangered Species Act compliance

Target Met. BPA is on track to meet its responsibilities by 2018 under the 2010 Supplemental Biological Opinion by meeting hydro, tributary habitat and estuary habitat projects. BPA collaborated with its partner agencies and the National Oceanic and Atmospheric Agency toward a goal of a new or supplemental Biological Opinion.

BPA rate case 2014–2015

Target Met. BPA successfully completed the rate case, establishing new wholesale power rates and transmission rates for the 2014–2015 rate period that reflect the lowest cost for service consistent with sound business principles.

Financial Perspective

Capital access strategy

Target Met. BPA implemented the capital access strategy for those items requiring action during fiscal year 2013 and demonstrated that BPA will have access to cost-effective capital over a rolling 10-year period.

Bond rating

Target Met. BPA-backed bonds maintained ratings as affirmed by Moody's (Aa1), Standard & Poors (AA-) and Fitch (AA).

Adjusted net revenue

Target Met. BPA achieved adjusted net revenue of $56 million, within the target range of $5 million to $107.5 million or greater.

Cost management

Target Met. BPA's departmental expenses were $846 million, which achieved the target of $886 million or less.

Treasury payment

Target Met. BPA's fiscal year 2013 payment to the U.S. Treasury, of $692 million, was made on time and in full for the 30th consecutive year. The payment consisted of $225 million for principal, $367 million for interest, $59 million in irrigation assistance payments and $41 million for other obligations.

Internal Operations Perspective

Transmission system infrastructure

Target Met. BPA achieved system direct capital expenditures of $345 million, which is 82 percent of the start-of-year budget and within the target range of 80 percent to 100 percent. BPA met 91 percent of the cumulative in-service date milestones in the capital work plan, which is above the minimum target of 90 percent. Of BPA's transmission projects, 90 of 111 major project milestones, or 80.2 percent, were on track to meet end-of-project completion targets for costs, schedule and scope, slightly exceeding the 80 percent target.

Hydro generation system infrastructure

Target Met. BPA's budget expenditure rate for the Federal Hydro Capital Program was 86 percent, within the target range of 85 percent to 100 percent and representing $196.9 million in investment. The fiscal year milestone completion rate for major projects was 82.9 percent, exceeding the target of 80 percent or greater. The end-of-project completion target for cost, schedule and scope was also met for 94 percent of projects against a target of 80 percent.

Grand Coulee mechanical overhaul

Target Met. BPA met milestones for a multi-year overhaul of a Third Power Plant generating unit to preserve the long-term value of the federal hydro system.

Reliability compliance

Target Met. BPA met North American Electric Reliability Corporation (NERC) reliability compliance standards and did not have any high-risk violations. All mitigation plans for technical and documentation compliance were submitted in a timely manner.

Cyber security

Target Met. BPA met cyber security targets aimed at monitoring and improving BPA's overall cyber security posture. Achievements included meeting targets pursuant to the IT Maturity Model and analyzing requirements for a Cyber Security Operations and Analysis Center.

Smart grid and demand response

Target Met. BPA met cost and project milestones in support of the Western Interconnection Synchrophasor Program Project. BPA met its target to complete over 80 percent of the milestones for the Pacific Northwest Smart Grid Demonstration Project and achieved greater than 95 percent of the milestones in the demand response business plan.

People and Culture Perspective

Talent management

Target Not Met. Ninety-three percent of employee performance plans and 95 percent of manager performance plans were in place by Nov. 30, 2012, which exceeded the 90 percent target. Ninety-seven percent of employees and 99 percent of managers had two documented progress reviews by June 30, 2013, against a target of 90 percent. However, BPA did not meet its target of 100 days time-to-hire with hiring actions initiated after Sept. 1, 2012, due to systemic issues in human capital management.

Safety

Target Met. BPA achieved a lost-time frequency rate of 0.9 per 200,000 hours worked, which is significantly below the industry lost-time frequency rate target of 1.5 as reported by the Bureau of Labor Statistics.

FINANCIAL SECTION

Forward-Looking Information 26

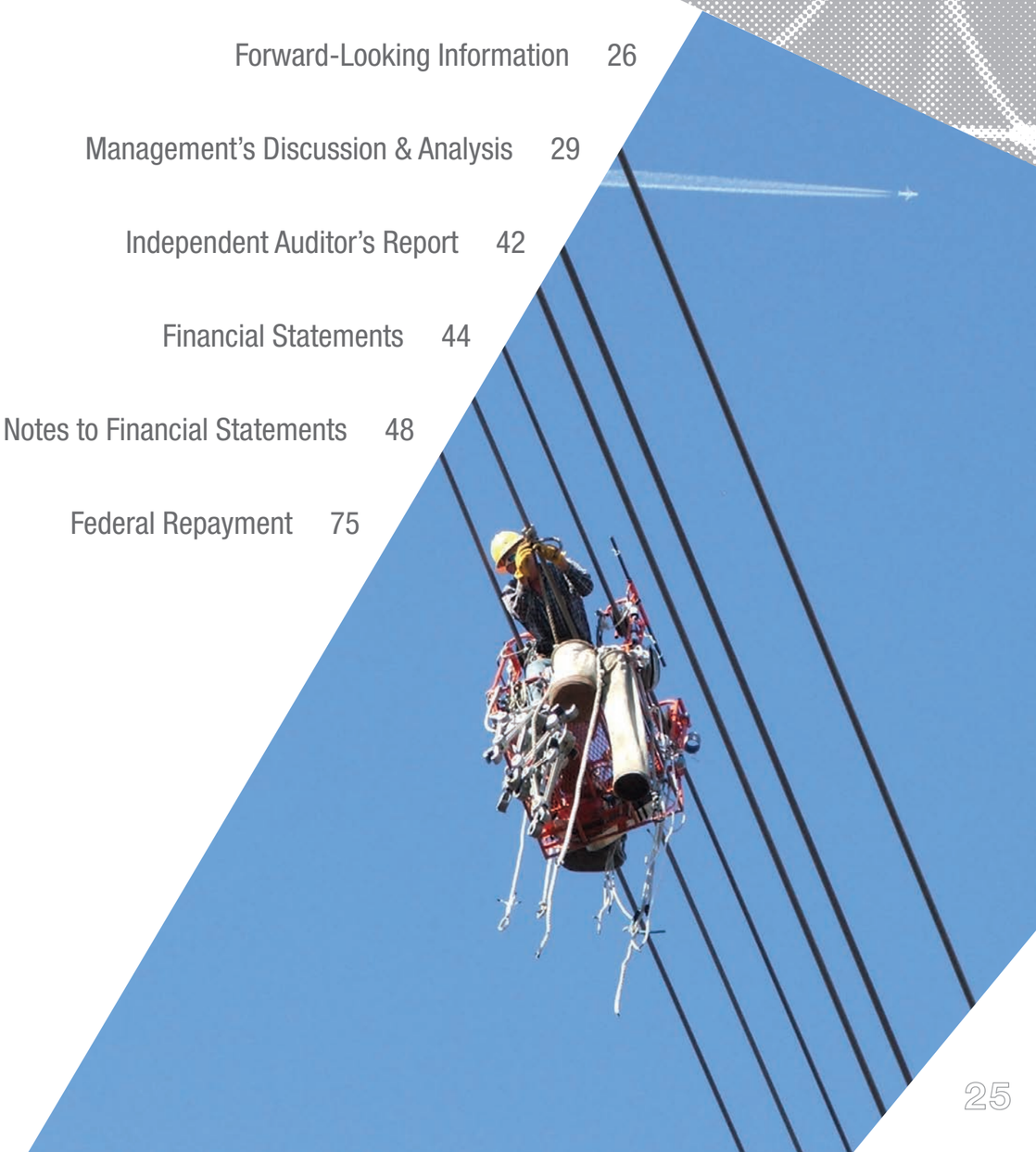
Management's Discussion & Analysis 29

Independent Auditor's Report 42

Financial Statements 44

Notes to Financial Statements 48

Federal Repayment 75



FORWARD-LOOKING INFORMATION

This forward-looking information contains statements which, to the extent they are not recitations of historical fact, constitute "forward-looking statements." In this respect, the words "forecast," "project," "anticipate," "expect," "intend," "believe" and similar expressions are intended to identify forward-looking statements. A number of important factors affecting Bonneville Power Administration's (BPA) business and financial results could cause actual results to differ materially from those stated in the forward-looking statements. BPA does not plan to issue updates or revisions to the forward-looking statements.

Rates

Cost recovery is challenging in an era of low wholesale electricity prices coupled with increasing costs and responsibilities. After efforts to cut costs and hold increases to a minimum, BPA's power and transmission rates were established for fiscal years 2014–2015. The power Tier 1 average net cost increased 9 percent, and the average transmission rate increased by 11 percent over the previous rate period. Most of BPA's power costs are recovered through Tier 1 rates to publicly owned utilities.

The specific drivers behind the 2014–2015 power rate increase were forecast increased costs to operate and maintain the federal hydro system, increased costs to fund existing long-term agreements for the fish and wildlife mitigation program, and reduced revenues for surplus power sales due to low market prices. The main drivers behind the transmission rate increase were a growing construction program necessary to repair and replace decades-old system assets, as well as forecast increased spending on mandatory compliance and security requirements.

The final record of decision was released on July 24, 2013, in time for BPA to file for interim rates approval from the Federal Energy Regulatory Commission (FERC). Interim approval from FERC was received Sept. 27, 2013, allowing BPA to charge customers at the new rates beginning Oct. 1, 2013. The rates are expected to be in effect until Sept. 30, 2015.

Infrastructure

One of BPA's most important responsibilities is to ensure the reliability of the Federal Columbia River Power System (FCRPS) for the Northwest. In recent years, BPA's capital requirements have grown to unprecedented levels with the need to replace and modernize aging infrastructure, add capacity for reliability and new transmission requests, and fulfill regional commitments for energy efficiency and fish and wildlife restoration.

BPA invests in preserving these regional assets to keep them performing as designed and to meet the power demands of the Northwest with continued low rates. With assets dating to the early and middle 20th century, many of the system's components are aging. As their condition declines over time, the risk of equipment not performing as expected increases. BPA and its federal partners seek to maintain the long-term operational health and economic value of the federal power and transmission systems, along with their related equipment, while taking into account long-term costs, benefits and the availability of low-cost sources of capital.

To accomplish this, BPA is implementing asset management strategies and a capital investment process to prioritize roughly $2.7 billion in capital investments that begin in fiscal years 2015–2017.

Access to capital

To fund the growing number of infrastructure improvements, BPA developed a comprehensive Access to Capital Strategy, released in 2013. This plan provides for reliable access to cost-effective sources of capital over a rolling 10-year period, ensuring that the costs of these sources are prudent and well controlled, and that the sources will be reliable and sufficient to meet BPA's capital investment priorities. Without other actions, BPA could have fully used its Treasury borrowing authority as early as 2017. The plan relies on tools such as lease financing, the new power prepaid program, conservation third-party financing, reserve and revenue financing, and prioritizing proposed capital investments to help make informed decisions on potential reductions or delays in capital investment to the extent needed.

Climate change

Potential climate change resulting from greenhouse gas emissions has emerged as a matter of intense and growing concern around the region and across the globe. In the Northwest, the Federal Columbia River Power System has a long history of cost-effective, climate-friendly generation. The Northwest, including the FCRPS, produces less carbon dioxide per megawatt-hour than any other region in the U.S. Even in low water years, the federal hydroelectric system produces about 7,000 average megawatts of electricity, allowing the region to sustain a relatively small carbon footprint.

While the direction of federal climate change and energy legislation remains uncertain, neighboring California has launched a cap and trade platform to put a price on greenhouse gas emissions. This is likely to affect electricity prices and the types of new generation that are developed in California and the West.

Also, recent studies suggest Northwest weather could continue to warm, resulting in increased river flows in winter and early spring, reduced flows in summer, and potentially significant new challenges for future river operations and planning. Regional population and economic growth will place increasing demands on an already stretched FCRPS for a variety of power and non-power needs, such as fish protection. While additions of renewable resources such as wind and solar power are important, it will be equally essential to preserve and enhance the value of the existing federal hydropower system.

Increasing risks of extreme weather events may pose unique threats to the reliability of the transmission grid. A 2013 report by the Department of Energy warned that the nation's energy infrastructure is vulnerable to more severe weather events connected to climate change, and suggested steps to harden transmission and develop emergency backup systems.

Biological Opinion

Under the Endangered Species Act, BPA, the U.S. Army Corps of Engineers (Corps) and the Bureau of Reclamation (Reclamation) must consult with the National Oceanic and Atmospheric Administration (NOAA) Fisheries to avoid jeopardizing 13 stocks of endangered and threatened salmon and steelhead in the Columbia Basin and mitigate for the effects on fish of 14 hydroelectric dams in the FCRPS.

A NOAA Fisheries plan in place since 2008 and supplemented in 2010, called the 2008/10 FCRPS Biological Opinion (BiOp), guides operation of the system to protect these fish. In recent years, BPA and its partners in federal, state and tribal governments have improved the dams to make them safer for fish, rehabilitated long-degraded habitat across three states, and managed predators to ensure that millions more young salmon and steelhead migrate safely to the ocean. Since the time of their listing, more wild fish have returned to their home streams to spawn and rebuild their numbers.

In 2011, the United States District Court for Oregon remanded the BiOp and ordered that a new plan be issued by Jan. 1, 2014, to provide more specific identification of habitat restoration projects for the 2014 through 2018 period. In response, the federal agencies in 2013 produced a comprehensive evaluation of the progress to date under the BiOp and submitted an implementation plan for 2014 through 2018 to NOAA Fisheries. NOAA will submit a revised BiOp to the court in December 2013.

Columbia River Treaty

A model of international cooperation since 1964, the Columbia River Treaty has provided nearly five decades of flood management and hydropower benefits to the United States and Canada.

While the agreement continues indefinitely, the year 2024 is a watershed date for its continued implementation, marking the end of 60 years of pre-paid flood-control storage from Canada. In addition, starting in 2014 and with at least 10 years' notice, the terms allow either Canada or the United States to end most power provisions of the Treaty after 2024.

For the past two years, the U.S. Entity — created by executive order and comprised of the BPA administrator and the Northwestern Division engineer of the U.S. Army Corps of Engineers — has led an intense analytical effort to evaluate potential changes to Treaty operations after 2024.

The goal of the Columbia River Treaty Review process is to provide a regional recommendation by December 2013 on the elements that the Pacific Northwest would like the Department of State to pursue in its negotiations with Canada.

MANAGEMENT'S DISCUSSION & ANALYSIS

Results of operations

OPERATING REVENUES

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

	2013	2012	2011
Gross sales:			
Power	**$ 2,438,468**	$ 2,450,595	$ 2,486,801
Transmission	**803,689**	790,969	739,606
Bookouts (Power)	**(66,587)**	(61,972)	(92,198)
Sales	**3,175,570**	3,179,592	3,134,209
U.S. Treasury credits for fish	**84,092**	76,983	85,102
Miscellaneous revenues:			
Power	**32,612**	31,012	29,299
Transmission	**54,007**	30,263	36,164
Total operating revenues	**$ 3,346,281**	$ 3,317,850	$ 3,284,774

Fiscal year 2013 revenues compared to fiscal year 2012

For the fiscal year ended Sept. 30, 2013, Power Services and Transmission Services consolidated gross sales, excluding the effects of bookouts, increased by approximately $600 thousand from the prior fiscal year.

Power Services gross sales decreased $12 million, or less than 1 percent. The change was primarily due to the following key factors:

- Firm sales decreased $17 million, or 1 percent in fiscal year 2013 compared to fiscal year 2012 due to lower demand and load shaping revenues.
- January through July 2013 runoff volume at The Dalles Dam was 98 million acre feet (maf), a decrease of 44 maf from the 142 maf for 2012. A typical metric to measure runoff is maf, an indicator of the amount of electricity the hydro system can produce. The full fiscal year 2013 volume finished at 130 maf, a decrease from the 159 maf in fiscal year 2012, and close to the historical average of 133 maf. The range of years used for the historical average is from 1928 to 2013.
- Power gross sales decreased to 85,965,165 megawatt-hours in fiscal year 2013 from 96,714,819 megawatt-hours in fiscal year 2012, or 11 percent. Hydro conditions and

Columbia Generating Station (CGS) scheduled refueling and maintenance resulted in decreased generation in fiscal year 2013.

- Secondary sales increased approximately $5 million, or 1 percent, primarily due to higher market prices that offset decreased streamflows year-over-year.

Transmission Services gross sales increased $13 million, or 2 percent, mainly due to increases in Variable Energy Resource Balancing Service (VERBS) and Point-to-Point Long-Term sales. VERBS, a control area service, is required to help maintain the power system frequency and to conform to reliability standards. Point-to-Point Long-Term is firm transmission services of one year or more delivering federal and nonfederal power across the Federal Columbia River Transmission System.

- VERBS sales increased by $7 million due to additional installed wind generation facilities.
- Point-to-Point Long-Term sales increased by $5 million due to increased Conditional Firm sales and the effect of Network Open Season sales that began in fiscal year 2012.

Bookouts are presented on a net basis in the Combined Statements of Revenues and Expenses. When sales and purchases are scheduled with the same counterparty on the same path for the same hour, the power is typically booked out and not scheduled for physical delivery. The megawatt-hours that offset each other net to zero. The dollar values of these offsetting transactions are recorded as bookouts. The result is that revenues and expenses are presented on a net basis in the Combined Statements of Revenues and Expenses. Therefore, the accounting treatment for bookouts has no effect on net revenues, cash flows or margins.

U.S. Treasury credits for fish increased from $77 million in fiscal year 2012 to $84 million in fiscal year 2013, or about 9 percent. The fiscal year 2013 increase was primarily driven by higher energy prices and an increased volume of power purchases made for fish and wildlife mitigation purposes.

Transmission miscellaneous revenues increased by $24 million, or 78 percent, mainly due to Hurricane Sandy reimbursable activity and terminations of Precedent Transmission Service Agreements.

Fiscal year 2012 revenues compared to fiscal year 2011

For the fiscal year ended Sept. 30, 2012, Power Services and Transmission Services consolidated gross sales, excluding the effects of bookouts, increased $15 million, or less than 1 percent, from the prior year.

Power Services implemented a new rates structure in fiscal year 2012. Under this rates structure, BPA's publicly owned utility customers may purchase only a limited amount of power at Tier 1 rates. Tier 1 rates recover the costs of the majority of the FCRPS resources, fish and wildlife costs and energy efficiency. Tier 2 rates recover costs of resources that BPA acquires specifically for publicly owned utility customers that request BPA meet their power requirements in excess of their purchases at Tier 1 rates.

Tiered rates provide BPA's customers with choices as to how they will serve their full power requirements. As designed, tiered rates also give BPA's customers even more reason to conserve energy. Energy conserved by a utility will contribute to reducing its need to add new resources or purchase power from BPA at higher Tier 2 rates. BPA's 2012–2013 rates also include incentives to reduce and control utilities' peak power use.

Power Services gross sales decreased $36 million, or slightly over 1 percent. The change was primarily due to the following key factors:

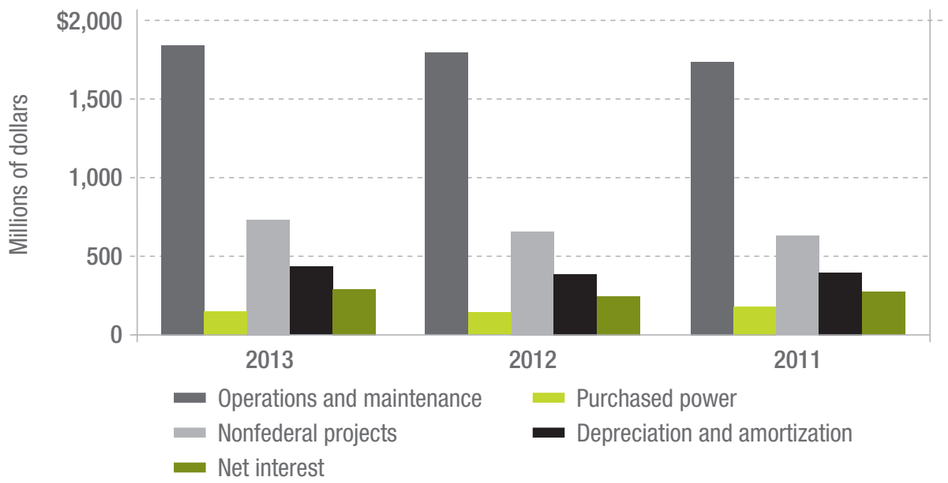
- Firm sales decreased $31 million, or slightly over 1 percent in fiscal year 2012 compared to fiscal year 2011 due to decreases in load shaping in the third and fourth quarters of fiscal year 2012.
- Load shaping revenues, under the new rate structure, were lower than expected because aggregate customer loads were lower than the capability of the Tier 1 federal system in fiscal year 2012.
- January through July runoff volume at The Dalles Dam was 129 maf, the ninth-highest runoff on record since 1938. The full fiscal year 2012 volume finished as the 13th-highest runoff on record at 159 maf, a decrease from the 175 maf in fiscal year 2011, but above the historical average of 133 maf.
- Power gross sales increased to 96,714,819 megawatt-hours in fiscal year 2012 from 93,557,046 megawatt-hours in fiscal year 2011 or 3 percent. The CGS condenser outage decreased generation in fiscal year 2011.
- Secondary sales decreased $10 million, or 2 percent, in fiscal year 2012 compared to fiscal year 2011 due to lower market prices. The effect of increased generation on secondary revenues was offset by lower market prices in fiscal year 2012 compared to fiscal year 2011.

Transmission Services gross sales increased $51 million, or 7 percent, mainly due to increases in Point-to-Point Long-Term sales and Operating Reserves. In addition, Southern Intertie Long-Term sales and Townsend-Garrison transmission revenues also increased. Point-to-Point Long-Term and Southern Intertie Long-Term are firm transmission services of one year or more delivering federal and nonfederal power across the Federal Columbia River Transmission System; Operating Reserves, an ancillary product, is a reserve obligation needed to serve load in the event of a system contingency; and Townsend-Garrison Transmission is transmission associated with the Montana Intertie on a separately identified portion of the Federal Columbia River Transmission System.

- Point-to-Point Long-Term sales increased by $20 million due to Conditional Firm sales, deferrals that started service, and the energization of the McNary-John Day transmission line, a Network Open Season Project.
- Operating Reserves revenue was higher by $20 million largely due to a rate increase for this product and a decrease in customer self-supplied Operating Reserves.
- Southern Intertie Long-Term sales increased by $8 million due to the California-Oregon Intertie improvement project, which enabled additional sales.
- Townsend-Garrison Transmission increased by $3 million due to the elimination of the exchange provision in the Montana Intertie Agreement, which provided a discount to customer charges.

U.S. Treasury credits for fish decreased from $85 million in fiscal year 2011 to $77 million in fiscal year 2012, or about 10 percent. The change was primarily due to lower direct capital program costs, lower prices of purchased power for fish mitigation, as well as lower volumes of power purchases.

OPERATING AND NET INTEREST EXPENSES



Fiscal year 2013 expenses compared to fiscal year 2012

For the fiscal year ended Sept. 30, 2013, operating expenses increased $172 million from fiscal year 2012.

Operations and maintenance expense increased $47 million, or 3 percent, from the prior fiscal year, as reported in the Combined Statements of Revenues and Expenses.

- Bureau of Reclamation costs increased by $38 million, primarily due to additional non-routine extraordinary maintenance work at Grand Coulee Dam associated with the Third Power Plant overhaul.
- CGS costs increased $38 million because of biennial refueling and maintenance work performed in fiscal year 2013.
- Transmission maintenance costs increased $11 million due to increased compliance activities and upgrades to BPA's communication systems.
- Transmission reimbursable cost increased $7 million primarily as a result of Hurricane Sandy East Coast emergency response activity, as described earlier.
- These increases were offset in part by $28 million from a settlement for costs incurred to store spent fuel at the terminated Trojan nuclear facility. BPA also reduced spending on long-term and renewable generation projects by $7 million, transmission marketing and business support by $7 million, and transmission acquisition and ancillary services by $5 million.

Purchased power expense increased $11 million, or 8 percent, from the prior fiscal year. The increase in purchased power was driven mainly by lower year-over-year hydro generation and reduced output of the CGS due to scheduled refueling and maintenance in fiscal year 2013, as previously discussed.

Nonfederal projects debt service expense increased $74 million, or 11 percent, for fiscal year 2013 compared to fiscal year 2012 due to increased scheduled debt payments for Energy Northwest's Columbia Generating Station and terminated nuclear Project Nos. 1 and 3. Since 1989, Energy Northwest debt service has been periodically restructured to achieve overall federal and nonfederal debt service objectives that reduced nonfederal projects expense. These debt management actions have created an uneven Energy Northwest debt service structure such that there can be significant variances from year to year.

Depreciation and amortization expense increased $40 million, or 10 percent from the prior fiscal year primarily due to higher transmission and generation completed plant.

Net interest expense increased $48 million, or 20 percent, for the year ended Sept. 30, 2013, from the comparable period a year ago.

- Interest expense increased $25 million, or 7 percent, due to increased borrowing necessary to finance power-related construction projects and lease financed transmission construction projects, and to a one-time reduction in fiscal year 2012 of interest and other costs allocated to power purposes at the Cougar Dam.
- Allowance for funds used during construction (AFUDC) decreased $8 million, or 18 percent, due to the completion of certain construction projects and a lower AFUDC rate.
- Interest income decreased $15 million, or 34 percent, as the result of interest income recognized in 2012 related to outstanding receivables and, to a lesser extent, a lower interest rate earned on a lower cash balance with U.S. Treasury.

Fiscal year 2012 expenses compared to fiscal year 2011

For the fiscal year ended Sept. 30, 2012, operating expenses increased $58 million from fiscal year 2011.

Operations and maintenance expense increased $63 million, or 4 percent, from the prior fiscal year, as reported in the Combined Statements of Revenues and Expenses, primarily due to:

- Transmission engineering, operations and maintenance costs increased by $29 million because of increased compliance activities and the write-off of a software project.
- Fish and Wildlife costs increased $28 million, primarily due to increased funding for the Northwest Power and Conservation Council's Columbia River Basin Fish and Wildlife Program, the ramp-up of work in support of the 2010 Supplemental Columbia River System Biological Opinion, and the Columbia River Basin Fish Accords.
- Corps of Engineers and Bureau of Reclamation costs increased by $20 million, primarily due to non-routine maintenance activities. The purpose of these activities was to minimize potential outages at other dams during work on Grand Coulee's Third Power Plant.
- Residential Exchange Program (REP) costs increased overall by $19 million as payments to investor-owned utilities were higher based on the 2012 REP Settlement Agreement, and payments to publicly owned utilities were also higher in the current rate case.
- Transmission acquisition and ancillary services costs increased by $11 million primarily driven by a probable settlement agreement.
- Other costs increased by $5 million primarily due to power scheduling and operations and business support costs.
- CGS costs decreased $30 million, mainly due to 2012 not being a refueling year, as well as the use of unrestricted funds from the Department of Energy spent fuel storage settlement in lieu of direct payments from BPA.
- The impairment of certain defective transmission line spacer dampers recorded in fiscal year 2011 did not recur in fiscal year 2012.

Purchased power expense decreased $35 million, or 20 percent, from the prior fiscal year primarily due to:

- Contracted power purchases declined by $58 million, largely due to higher total generation, which reduced the amount of power purchases to meet load. The drop in hydro generation was more than offset by the increase in generation at CGS. Slightly lower market prices for power purchases also contributed to the decline.
- The conservation and renewable rate credits were no longer part of the power rate structure, resulting in a decrease of $30 million.
- There was an increase of $48 million for BPA's current obligations under a new agreement for hydro storage with Canada.
- There was an $8 million increase in Tier 2 purchases, resulting from the implementation of the new Tiered Rate methodology in fiscal year 2012.

Nonfederal projects debt service expense increased $35 million, or 6 percent, due to increased payments for Energy Northwest's Project No. 1 and CGS, partially offset by reduced payments for Project No. 3.

Depreciation and amortization expense decreased $4 million, or 1 percent from the prior fiscal year. A BPA depreciation study was completed in March 2012 resulting in a decrease in depreciation expense.

Net interest expense decreased $30 million, or 11 percent, for the year ended Sept. 30, 2012, from the comparable period a year ago.

- Interest expense decreased $21 million, or 6 percent, due to a reduction of costs allocated to power purposes for intake assets at the Cougar Dam, partially offset by increases associated with borrowings for continued expansion of transmission construction, conservation, and fish and wildlife programs.
- Allowance for funds used during construction increased $3 million, or 7 percent, reflecting an increased construction work in progress balance related to capital investments for generation and transmission assets.
- Interest income increased $6 million, or 16 percent, as the result of a $16 million accrual for interest income related to outstanding receivables. This one time accrual was partially offset by the effect of lower cash balances and interest rates.

Liquidity and capital resources

CASH AND CASH EQUIVALENTS BALANCE AND BPA RESERVES

As of Sept. 30, 2013, the FCRPS ending Cash and cash equivalents balance on the Combined Balance Sheet was $1.01 billion. BPA's fiscal year-end cash and cash equivalents balance, excluding funds transferred from the Spectrum Relocation fund, was $690 million, and the Corps and Reclamation combined fiscal year-end cash balance was $320 million.

BPA's year-end reserves for fiscal years 2013, 2012 and 2011, were $1.27 billion, $1.02 billion and $1.01 billion, respectively. Financial reserves consist of BPA cash, investments in U.S. Treasury market-based special securities and deferred borrowing. The U.S. Treasury market-based special securities reflect the market value as if securities were liquidated as of Sept. 30, 2013. Deferred borrowing represents amounts that BPA is authorized to borrow from the U.S. Treasury for capital expenditures that BPA has incurred but has not borrowed for as of Sept. 30, 2013.

BPA BORROWING AUTHORITY FROM THE U.S. TREASURY

The aggregate principal amount of debt BPA is authorized to have outstanding with the U.S. Treasury at any one time is $7.70 billion. The U.S. Treasury borrowing authority may be used to finance BPA's capital programs, and in certain cases for Pacific Northwest Electric Power Planning and Conservation Act expenses. BPA and the U.S. Treasury have agreed to a liquidity facility included in the $7.70 billion borrowing authority, enabling BPA to borrow up to $750 million for qualifying Northwest Power Act expenses. For capital programs, the related U.S. Treasury debt is term limited depending on the facilities financed: 50 years for Corps and Reclamation capital investments, 35 years for transmission facilities, 15 years for fish and wildlife and environment projects, 12 years for conservation projects and six years for corporate capital assets.

As of Sept. 30, 2013, BPA had $3.89 billion of bonds outstanding with the U.S. Treasury. The original terms of the outstanding U.S. Treasury borrowings vary from five months to 30 years. All debt issued to the U.S. Treasury after April 30, 2008, is issued with call options exercisable by BPA. As of Sept. 30, 2013, BPA had 144 callable borrowings totaling $3.61 billion. The interest on BPA's outstanding borrowings from U.S. Treasury is set at fixed and variable rates comparable to the rates prevailing in the market for similar bonds issued by government corporations. As of Sept. 30, 2013, the interest rates on the outstanding U.S. Treasury borrowings ranged from 0.02 percent to 7.4 percent with a weighted-average interest rate of 3.8 percent. As of Sept. 30, 2013, BPA had $300 million in outstanding variable rate U.S. Treasury bonds at an average weighted interest rate of 0.1 percent.

LEASE FINANCING PROGRAM

The Lease Financing Program enables BPA to continue to invest in infrastructure to support a safe and reliable system for the transmission of power with an alternative to the use of limited statutory borrowing authority with the U.S. Treasury. Under this program, BPA has entered into lease arrangements with third parties to fund construction of specific transmission assets. These entities include the Port of Morrow and six special purpose entities. The special purpose entities are collectively referred to as the Northwest Infrastructure Financing Corporations (NIFCs) and are consolidated by BPA for financial statement reporting purposes.

As of Sept. 30, 2013, BPA had outstanding leases of $713 million with the NIFCs and $188 million with the Port of Morrow. BPA is responsible for constructing the leased assets. The construction costs of the assets are financed through bonds or bank lines of credit established by the third parties. The related debt service is paid from and secured solely by BPA's lease payments and amounts held in trust funds by the third parties. The related transmission assets are not pledged as security for repayment of the related loans or bonds. The lease agreements expire on various dates through 2042. Generally, the capital lease agreements contain provisions that allow BPA to purchase the leased assets at any time during each lease term for a bargain purchase price plus the value of the related outstanding debt instrument.

CUSTOMER PREPAID POWER PURCHASES

In fiscal year 2013, BPA implemented the Customer Prepayment Power Purchase Program, which allows customers to prepay power purchases in the form of block purchases, providing BPA with an additional source of funding. For each block purchased, BPA provides monthly fixed credits on the customers' power bills.

In March 2013, BPA received payments totaling $340 million from four regional publicly owned utilities for the express advance payment of future power purchases. Participating customers purchased 51 blocks representing $474 million of prepaid power credits that began in April 2013 and continue through fiscal year 2028, the remaining term of the power sales contracts. For each block purchased, the customers'

monthly power bills will reflect a credit of $50,000 through the remaining term of the power sales contracts. The difference between prepayment funds received and the total credits of prepaid power purchased represents the financing cost of the program. BPA accounts for the prepayment proceeds as a financing transaction and reports the value of the obligations associated with the fixed credits as a prepayment liability. BPA recognizes interest expense as electricity is provided to customers based on the established fixed prepayment credit schedules using a weighted-average effective interest rate of 4.5 percent. The prepaid liability is reduced as power is delivered and the credits are applied.

TREASURY PAYMENT

BPA paid the U.S. Treasury $692 million for fiscal year 2013, the 30th consecutive year in which BPA has made its payments on time and in full. The fiscal year 2013 payments included $225 million in principal and $367 million in interest for U.S. Treasury debt and for the appropriated federal investment in the FCRPS. This fiscal year's principal payment included $56 million to repay federal appropriations to the U.S. Treasury in excess of the base payment calculated for FERC filings. BPA also paid the U.S. Treasury $59 million for irrigation assistance and $41 million for other FCRPS costs. Payments made in fiscal years 2012 and 2011 were $886 million and $830 million, including $53 million and $70 million, respectively, to repay federal appropriations and bonds issued to the U.S. Treasury in excess of the base payments calculated for FERC filings.

CREDIT RATINGS

Credit ratings on nonfederal debt backed by BPA as of Sept. 30, 2013, were as follows:

- Moody's at Aa1 with a stable outlook
- Standard & Poor's at AA- with a stable outlook
- Fitch at AA with a stable outlook

SUMMARY CASH FLOWS

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

	2013	2012	2011
Cash and cash equivalents at beginning of year	**$ 948,859**	$ 892,125	$ 1,078,671
Cash flows from			
Operating activities	**568,645**	648,023	436,986
Investing activities	**(897,713)**	(837,491)	(983,466)
Financing activities	**390,337**	246,202	359,934
Net increase (decrease) in cash and cash equivalents	**61,269**	56,734	(186,546)
Cash and cash equivalents at end of year	**$1,010,128**	$ 948,859	$ 892,125

OPERATING ACTIVITIES

Cash flows from operating activities of the FCRPS decreased $79 million to $569 million for the fiscal year ended Sept. 30, 2013, when compared to fiscal year 2012. As a result of the factors previously discussed, such as stable revenues, increased operations and maintenance and nonfederal projects debt service expense, the FCRPS incurred net expenses of $105 million for the fiscal year ended Sept. 30, 2013. By comparison, net revenues were $87 million for the fiscal year ended Sept. 30, 2012. The year-over-year changes in operating cash flow activities reflect differences in the timing of collecting receivables and payments of accounts payable, and increases in depreciation and amortization. In fiscal year 2012 BPA received a cash payment of $74 million for outstanding accounts receivable related to the West Coast energy crisis of 2000 and 2001.

Cash flows from operating activities of the FCRPS increased $211 million to $648 million for the fiscal year ended Sept. 30, 2012, when compared to fiscal year 2011. The FCRPS earned net revenues of $87 million for the fiscal year ended Sept. 30, 2012. By comparison, net revenues were $82 million for the fiscal year ended Sept. 30, 2011. The change in operating cash flow activities primarily reflects increased amortization of nonfederal projects, differences in the timing of payments of accounts payable, and changes in regulatory assets and liabilities. Also, in fiscal year 2012, BPA received a cash payment of $74 million for an outstanding account receivable as mentioned previously.

INVESTING ACTIVITIES

Net cash used for investing activities of the FCRPS increased $60 million to $898 million for the fiscal year ended Sept. 30, 2013, when compared to the fiscal year ended Sept. 30, 2012. BPA continues to make significant investment in utility plant with $779 million invested in fiscal year 2013, which was down $83 million, or 10 percent, from fiscal year 2012. BPA's net incremental investment in U.S. Treasury market-based special securities across all categories including cash equivalents, purchases less maturities, was $161 million during the twelve months ended Sept. 30, 2013. The net incremental investment for those market-based specials classified as investments on the Combined Balance Sheets, purchases less maturities, for the fiscal year ended Sept. 30, 2013 was $131 million, which was an increase of $135 million over the comparative period in the prior year. The increase in fiscal year 2013 was the result of $60 million of market-based specials that matured in 2012 and were reinvested in fiscal year 2013, as well as an overall increase in net investment activity. Under a banking arrangement with the U.S. Treasury, BPA has agreed to invest at least $100 million annually for up to 10 years or until the BPA fund is fully invested.

BPA manages restricted trust funds in connection with its Lease Financing Program activities through consolidated special purpose corporations, the NIFCs, and an unconsolidated third party, the Port of Morrow. Receipts from, and deposits into these restricted funds are investing activities. Net cash inflows were $16 million in the twelve months ended Sept. 30, 2013, as compared with net cash inflows of $30 million in the comparative period in fiscal year 2012. This change was primarily the result of lower overall trust fund activity in fiscal year 2013 when smaller construction projects were financed through the Lease Financing Program.

Net cash used for investing activities of the FCRPS decreased $146 million to $837 million for the fiscal year ended Sept. 30, 2012, when compared to the fiscal year ended Sept. 30, 2011. Investment in utility plant increased $74 million, driven primarily by a ramp-up of transmission and generating capital projects. During the fiscal year ended Sept. 30, 2012, $639 million of investments and $115 million of cash equivalents matured and were re-invested in other market-based special securities. In the fiscal year ended Sept. 30, 2012, the consolidated special purpose corporations deposited $202 million into their restricted trust funds and transferred $232 million to the BPA fund to support construction activities on leased transmission projects. When compared to the same activities for the fiscal year ended Sept. 30, 2011, the $69 million net change reflects an increase in construction activity on leased projects as seen by increases in both deposits to the restricted trust funds and advances to the BPA fund.

FINANCING ACTIVITIES

Net cash provided by financing activities of the FCRPS was $390 million for the fiscal year ended Sept. 30, 2013, compared to $246 million for the fiscal year ended Sept. 30, 2012.

BPA borrowings from the U.S. Treasury for fiscal year 2013 were $632 million, or $174 million lower than fiscal year 2012 borrowings. The $632 million was borrowed at fixed interest rates and was used to fund investments of $302 million for transmission, $220 million for generation, $56 million for conservation and $54 million for fish and wildlife programs. Nonfederal debt proceeds increased from $202 million in fiscal year 2012 to $489 million in fiscal year 2013. Of the $489 million, $340 million was for customer prepayment power purchases received in March 2013 and $149 million was for new Lease Financing Program arrangements with consolidated special purpose corporations and an unconsolidated third party, the Port of Morrow. Nonfederal debt repayments increased from $364 million in fiscal year 2012 to $499 million for fiscal year 2013. The $135 million increase was primarily due to higher principal payments for Energy Northwest's Columbia Generating Station and terminated nuclear Projects Nos. 1 and 3.

Net cash provided by financing activities of the FCRPS was $246 million for the fiscal year ended Sept. 30, 2012, compared to $360 million for the fiscal year ended Sept. 30, 2011. Cash provided by federal appropriations decreased compared to fiscal year 2011 primarily due to $125 million higher repayment and $25 million lower funding for capital investments and operations and maintenance at federal generating facilities. BPA borrowings from the U.S. Treasury were $806 million, or $6 million higher than fiscal year 2011 borrowings. Of the $806 million, $506 million was at fixed rates and $300 million was at variable interest rates. The $806 million included $252 million for transmission investments, $259 million for generation investments, $115 million for conservation investments, $58 million for fish and wildlife investments, $22 million for internal business services and $100 million for current operations using the Treasury liquidity facility. Additional nonfederal debt of $202 million was issued under the Lease Financing Program. Increased nonfederal debt repayments were primarily due to an increase of $70 million for Energy Northwest Project No. 1 offset by a reduction in debt repayments of $34 million for Project No. 3.

Contractual obligations and federal payments

Amounts shown in the following table include interest expense or represent undiscounted cash flows and are therefore higher than amounts for these line items reflected in the Combined Balance Sheets and described in the Notes to Financial Statements — Note 4, Asset Retirement Obligations; Note 6, Federal Appropriations; Note 7, Borrowings from U.S. Treasury; Note 8, Nonfederal Financing; and Note 10, Residential Exchange Program. Irrigation assistance is treated as a distribution from accumulated net revenues when paid. Purchase power commitments are a period expense. Irrigation assistance and purchase power commitments are described in Note 14, Commitments and Contingencies.

CONTRACTUAL OBLIGATIONS AND FEDERAL PAYMENTS

As of Sept. 30 (thousands of dollars)

	2014	2015	2016	2017	2018	2019+	Total
Federal appropriations	$ 235,723	$ 235,723	$ 235,723	$ 235,723	$ 235,723	$ 9,768,363	$ 10,946,978
Borrowings - U.S. Treasury	294,457	354,324	172,005	209,814	149,859	5,331,920	6,512,379
Nonfederal financing	944,047	1,082,432	1,070,245	811,319	1,117,022	3,795,028	8,820,093
IOU exchange benefits	197,500	197,500	214,100	214,100	232,200	2,646,100	3,701,500
REP Refund Amounts	76,537	76,537	76,537	76,537	76,537	76,541	459,226
Asset retirement obligations	4,760	4,571	4,618	4,772	4,871	203,199	226,791
Irrigation assistance	52,547	52,108	60,954	51,391	27,564	362,322	606,886
Purchase power commitments	40,190	24,656	22,058	26,582	31,036	33,699	178,221
Total	$ 1,845,761	$ 2,027,851	$ 1,856,240	$ 1,630,238	$ 1,874,812	$ 22,217,172	$ 31,452,074

OFF-BALANCE SHEET ARRANGEMENTS

The FCRPS is not engaged in any off-balance sheet arrangements through unconsolidated limited purpose entities.

Critical accounting policies and estimates

Certain accounting policies require management to make estimates and judgments concerning transactions that will be settled in the future. Amounts recognized in the financial statements from such estimates are based upon numerous assumptions involving varying and potentially significant degrees of judgment and uncertainty. Accordingly, certain amounts currently reflected in the financial statements will likely increase or decrease in the future as additional information becomes available.

REGULATORY ACCOUNTING

BPA's rates are designed to recover its cost of service. In connection with the rate-setting process, certain current costs or credits may be included in rates for recovery or refund over future periods. Under those circumstances, regulatory assets or liabilities are recorded in accordance with authoritative guidance for Regulated Operations. Such costs or credits are amortized during the periods they are scheduled in rates.

In order to apply regulatory accounting, an 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. If BPA's rates should become market-based, any deferred costs and revenues would be expensed and recognized, respectively, in the Combined Statement of Revenues and Expenses in that period. Since BPA's rates are not structured to provide a rate of return on rate base assets, regulatory assets are recovered at cost without an additional rate of return. Amortization of these assets and liabilities is reflected in the Combined Statements of Revenues and Expenses.

REVENUES

Revenues on sales of power and transmission are recognized either when the service is provided or the product is delivered. Operating revenues include estimates for unbilled power and transmission services that were delivered but not billed by the end of the fiscal year. Accrued unbilled revenues are estimated from forecasts prepared by management. The amount of accrued unbilled revenues can vary significantly from period to period as a result of numerous factors, including streamflows, seasonality, weather, changes in electricity prices, and customer load and usage patterns.

At Sept. 30, 2013 and 2012, BPA had $261 million and $249 million, respectively, of accrued unbilled revenues.

Quantitative and qualitative disclosures about risk

RISK MANAGEMENT

Due to the operational risk posed by fluctuations in river flows and electricity market prices, net revenues that result from underlying surplus or deficit energy positions are inherently uncertain. BPA's Transacting Risk Management Committee (TRMC) has responsibility for the oversight of the market price, inventory and credit risks that arise from transacting in power markets. The TRMC establishes risk tolerances and limits that are represented in the transactional risk policy. This policy defines the control environment through which these risks are managed. Experienced business and risk analysts and managers conduct simulation and analysis of the hydro supply system and forward market prices to derive market price and credit risk positions. These results are measured against risk limits and reported to senior management.

Non-GAAP financial information

FISH AND WILDLIFE

The Northwest Power Act directs BPA to protect, mitigate and enhance fish and wildlife resources to the extent they are affected by federal hydroelectric projects on the Columbia River and its tributaries. BPA makes expenditures and incurs other costs for fish and wildlife consistent with the Northwest Power Act and the Northwest Power and Conservation Council's Columbia River Basin Fish and Wildlife Program. Additionally, certain Columbia River Basin fish species are listed under the Endangered Species Act (ESA) as threatened or endangered. BPA is financially responsible for expenditures and other costs arising from conformance with the ESA and certain biological opinions prepared by the National Oceanic and Atmospheric Administration Fisheries and the U.S. Fish and Wildlife Service in furtherance of the ESA.

BPA's fish and wildlife costs consist of direct costs and estimated operational impacts. Direct costs include integrated program costs. Estimated operational impacts include replacement power purchase costs and foregone power revenues. The following table includes these costs and estimates.

FISH AND WILDLIFE

Federal Columbia River Power System
For the years ended Sept. 30 (millions of dollars)

	2013	2012	2011
Direct costs	**$ 461**	$ 453	$ 422
Estimated operational impacts:			
Replacement power purchases	**86**	38	71
Foregone power revenues	**135**	152	157
Total fish and wildlife	**$ 682**	$ 643	$ 650

ADJUSTED NET REVENUE

In fiscal year 2013, BPA developed a new Key Agency Target called Adjusted Net Revenue. Adjusted Net Revenue is net revenue after removing the current year effects of certain debt management actions, in particular the Debt Service Reassignment, from prior years. These debt management actions were implemented to increase available U.S. Treasury borrowing authority by extending Energy Northwest's debt repayments and using the resultant available cash to repay U.S. Treasury debt. With the Energy Northwest debt maturing and due, nonfederal projects debt service expense is higher, resulting in lower FCRPS net revenues.

The effects of these past debt management actions are not considered to be related to ongoing FCRPS operations, and management has therefore determined that Adjusted Net Revenue is a better representation of FCRPS financial performance for the period. Adjusted Net Revenue for the fiscal year ended Sept. 30, 2013, was $56 million. The table below presents the calculation for Adjusted Net Revenue.

ADJUSTED NET REVENUE

Federal Columbia River Power System
For the fiscal year ended Sept. 30 (millions of dollars)

	2013
Net revenues (expenses)	$ (105)
Adjustment for Debt Service Reassignment	161
Adjusted Net Revenue	$ 56

Independent Auditor's Report

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

We have audited the accompanying combined financial statements of the Federal Columbia River Power System ("FCRPS"), which comprise the combined balance sheets as of September 30, 2013 and 2012, and the related combined statements of revenues and expenses and of cash flows for each of the three years in the period ended September 30, 2013.

Management's Responsibility for the Combined Financial Statements

Management is responsible for the preparation and fair presentation of the combined financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of combined financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on the combined financial statements based on our audits. We conducted our audits 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 combined financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the combined financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the combined financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the FCRPS' preparation and fair presentation of the combined financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the FCRPS' internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the combined financial statements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

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Opinion

In our opinion, the combined financial statements referred to above present fairly, in all material respects, the financial position of the Federal Columbia River Power System at September 30, 2013 and 2012, and the results of its operations and its cash flows for the three years in the period ended September 30, 2013 in accordance with accounting principles generally accepted in the United States of America.

PricewaterhouseCoopers LLP

October 30, 2013

Federal Columbia River Power System
Combined Balance Sheets
As of September 30

(Thousands of Dollars)

	2013	2012
Assets		
Utility plant		
Completed plant	**$ 16,153,536**	$ 15,401,287
Accumulated depreciation	**(5,700,821)**	(5,449,470)
	10,452,715	9,951,817
Construction work in progress	**1,344,033**	1,412,134
Net utility plant	**11,796,748**	11,363,951
Nonfederal generation	**3,243,713**	3,318,494
Current assets		
Cash and cash equivalents	**1,010,128**	948,859
Short-term investments in U.S. Treasury securities	**388,914**	242,495
Accounts receivable, net of allowance	**29,540**	86,632
Accrued unbilled revenues	**260,757**	248,769
Materials and supplies, at average cost	**112,019**	99,436
Prepaid expenses	**40,458**	26,060
Total current assets	**1,841,816**	1,652,251
Other assets		
Regulatory assets	**6,953,397**	7,464,988
Investments in U.S. Treasury securities	**34,961**	49,623
Nonfederal nuclear decommissioning trusts	**254,752**	235,598
Deferred charges and other	**146,682**	180,444
Total other assets	**7,389,792**	7,930,653
Total assets	**$ 24,272,069**	$ 24,265,349

The accompanying notes are an integral part of these statements.

Federal Columbia River Power System
Combined Balance Sheets
As of September 30

(Thousands of Dollars)

	2013	2012
Capitalization and Liabilities		
Capitalization and long-term liabilities		
Accumulated net revenues	**$ 2,432,217**	$ 2,595,940
Federal appropriations	**4,291,457**	4,249,022
Borrowings from U.S. Treasury	**3,738,040**	3,263,040
Nonfederal debt	**6,229,004**	6,370,733
Total capitalization and long-term liabilities	**16,690,718**	16,478,735
Commitments and contingencies (Note 14)		
Current liabilities		
Borrowings from U.S. Treasury	**147,000**	157,800
Nonfederal debt	**607,865**	493,650
Accounts payable and other	**503,112**	554,006
Total current liabilities	**1,257,977**	1,205,456
Other liabilities		
Regulatory liabilities	**2,434,065**	2,545,370
IOU exchange benefits	**2,992,740**	3,081,053
Asset retirement obligations	**171,554**	161,215
Deferred credits and other	**725,015**	793,520
Total other liabilities	**6,323,374**	6,581,158
Total capitalization and liabilities	**$ 24,272,069**	$ 24,265,349

The accompanying notes are an integral part of these statements.

Federal Columbia River Power System
Combined Statements of Revenues and Expenses

For the Years Ended September 30

(Thousands of Dollars)

	2013	2012	2011
Operating revenues			
Sales	**$ 3,175,570**	$ 3,179,592	$ 3,134,209
U.S. Treasury credits for fish	**84,092**	76,983	85,102
Miscellaneous revenues	**86,619**	61,275	65,463
Total operating revenues	**3,346,281**	3,317,850	3,284,774
Operating expenses			
Operations and maintenance	**1,843,972**	1,796,902	1,734,306
Purchased power	**154,173**	143,119	177,953
Nonfederal projects	**733,313**	659,680	624,972
Depreciation and amortization	**429,717**	389,097	393,502
Total operating expenses	**3,161,175**	2,988,798	2,930,733
Net operating revenues	**185,106**	329,052	354,041
Interest expense and (income)			
Interest expense	**356,337**	331,732	352,904
Allowance for funds used during construction	**(37,529)**	(45,845)	(42,983)
Interest income	**(28,937)**	(43,587)	(37,562)
Net interest expense	**289,871**	242,300	272,359
Net (expenses) revenues	**(104,765)**	86,752	81,682
Accumulated net revenues at October 1	**2,595,940**	2,510,373	2,428,691
Irrigation assistance	**(58,958)**	(1,185)	-
Accumulated net revenues at September 30	**$ 2,432,217**	$ 2,595,940	$ 2,510,373

The accompanying notes are an integral part of these statements.

Federal Columbia River Power System
Combined Statements of Cash Flows

For the Years Ended September 30

(Thousands of Dollars)

	2013	2012	2011
Cash flows from operating activities			
Net (expenses) revenues	**$ (104,765)**	$ 86,752	$ 81,682
Non-cash items:			
Depreciation and amortization	**429,717**	389,097	393,502
Amortization of nonfederal projects	**512,363**	390,266	306,175
Changes in:			
Receivables and unbilled revenues	**45,261**	(7,564)	(5,112)
Materials and supplies	**(12,583)**	(5,512)	(8,127)
Prepaid expenses	**(14,398)**	3,370	(3,598)
Accounts payable and other	**(53,511)**	35,084	(50,229)
Regulatory assets and liabilities	**(141,867)**	(162,772)	(209,173)
Other assets and liabilities	**(91,572)**	(80,698)	(68,134)
Net cash provided by operating activities	**568,645**	648,023	436,986
Cash flows from investing activities			
Investment in utility plant, including AFUDC	**(778,785)**	(861,754)	(787,384)
U.S. Treasury securities:			
Purchases	**(940,000)**	(635,000)	(310,000)
Maturities	**808,783**	638,767	163,193
Deposits to nonfederal nuclear decommissioning trusts	**(3,598)**	(9,211)	(9,616)
Lease financing trust funds:			
Deposits to	**(144,208)**	(202,287)	(106,260)
Receipts from	**160,095**	231,994	66,601
Net cash used for investing activities	**(897,713)**	(837,491)	(983,466)
Cash flows from financing activities			
Federal appropriations:			
Proceeds	**99,175**	104,696	129,632
Repayment	**(56,740)**	(164,594)	(39,528)
Borrowings from U.S. Treasury:			
Proceeds	**632,000**	806,000	800,000
Repayment	**(167,800)**	(328,600)	(370,000)
Nonfederal debt:			
Proceeds	**488,965**	202,289	201,963
Extinguished through refinancing	**-**	-	(90,000)
Repayment	**(498,748)**	(364,388)	(308,277)
Customers:			
Net advances (refunds) for construction	**(6,425)**	27,634	59,806
Repayment of funds used for construction	**(41,132)**	(35,650)	(23,662)
Irrigation assistance	**(58,958)**	(1,185)	-
Net cash provided by financing activities	**390,337**	246,202	359,934
Net increase (decrease) in cash and cash equivalents	**61,269**	56,734	(186,546)
Cash and cash equivalents at beginning of year	**948,859**	892,125	1,078,671
Cash and cash equivalents at end of year	**$ 1,010,128**	$ 948,859	$ 892,125
Supplemental disclosures:			
Cash paid for interest, net of amount capitalized	**$ 377,167**	$ 350,581	$ 375,755
Significant noncash investing and financing activities:			
Federal appropriations	**$ -**	$ (40,583)	$ -
Nonfederal debt increase for Energy Northwest	**$ 12,639**	$ 782,655	$ 147,145
Debt actions by Energy Northwest	**$ (20,235)**	$ (66,865)	$ -
Other nonfederal	**$ (10,135)**	$ 38,101	$ -

The accompanying notes are an integral part of these statements.

Notes to Financial Statements

1. Summary of Significant Accounting Policies

ACCOUNTING PRINCIPLES

Combination and consolidation of entities

The Federal Columbia River Power System (FCRPS) financial statements combine the accounts of the Bonneville Power Administration (BPA), the accounts of the Pacific Northwest generating facilities of the U.S. Army Corps of Engineers (Corps) and the Bureau of Reclamation (Reclamation) as well as the operations and maintenance costs of the U.S. Fish and Wildlife Service for the Lower Snake River Compensation Plan facilities. Consolidated with BPA are "Special Purpose Corporations" known as Northwest Infrastructure Financing Corporations (NIFCs), from which BPA leases certain transmission facilities. (See Note 8, Nonfederal Financing.)

BPA is the power marketing administration that purchases, transmits and markets power for the FCRPS. Each of the combined entities is separately managed and financed, but the facilities are operated as an integrated power system with the financial results combined as the FCRPS. While the costs of Corps and Reclamation projects serve multiple purposes, only the power portion of total project costs are assigned to the FCRPS through a cost allocation process. All intracompany and intercompany accounts and transactions have been eliminated from the combined financial statements.

FCRPS accounts are maintained in accordance with generally accepted accounting principles of the United States of America 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 directives issued by U.S. government agencies. BPA is a separate and distinct entity within the U.S. Department of Energy; Reclamation and U.S. Fish and Wildlife Service are part of the U.S. Department of the Interior; and the Corps is part of the U.S. Department of Defense. U.S. government properties and income are tax exempt.

Use of 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.

Rates and regulatory authority

BPA establishes separate power and transmission rates in accordance with several statutory directives. Rates proposed by BPA are subject to an extensive formal hearing 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 (Northwest Power Act), 16 U.S.C. 839e(a)(2), and a standard set out by the Energy Policy Act of 1992, 16 U.S.C. 824. Statutory standards include a requirement that rates must be sufficient to ensure repayment of the federal investment in the FCRPS over a reasonable number of years after first meeting BPA's other costs. After the final FERC approval, BPA's rates may be reviewed by the United States Court of Appeals for the Ninth Circuit (Ninth Circuit Court) if challenged by parties involved in the rate proceedings. Petitions seeking such review must be filed within 90 days of the final FERC approval. The Ninth Circuit Court may either confirm or reject a rate proposed by BPA.

In accordance with authoritative guidance for Regulated Operations, certain costs or credits may be included in rates for recovery or refund over a future period and are recorded as regulatory assets or liabilities. (See Note 3, Effects of Regulation.) Regulatory assets or liabilities are amortized over the periods they are included in rates. Amortization is computed using either the straight-line method or is based upon specific amounts included in rates each year. Since BPA's rates are not structured to provide a rate of return on rate base assets, regulatory assets are recovered at cost without an additional rate of return.

Utility plant

Utility plant is stated at original cost and includes generation and transmission assets. Generation assets were $8.43 billion and $8.17 billion at Sept. 30, 2013, and 2012, respectively. Transmission assets were $7.72 billion and $7.23 billion, including assets under capital lease agreements of $127.7 million and $127.6 million, at Sept. 30, 2013, and 2012, respectively. The costs of substantial additions, major replacements and substantial betterments are capitalized. Costs include direct labor and materials; payments to contractors; indirect charges for engineering, supervision and similar overhead items; and an allowance for funds used during construction. Maintenance, repairs and replacements of items determined to be less than major units of property are charged to maintenance and operating expense as incurred. When BPA retires utility plant, it charges the original cost and any net proceeds from the disposition to accumulated depreciation.

Depreciation

Depreciation of the original cost of generation plant is computed using straight-line methods based on estimated service lives of the various classes of property, which average 75 years. For transmission plant, depreciation of original cost and estimated net cost of removal is computed primarily on the straight-line group life method based on estimated service lives of the various classes of property, which average 48 years. The estimated net cost of removal is included in depreciation. In the event removal costs are expected to exceed salvage proceeds, a reclassification of this negative salvage is made from accumulated depreciation to a regulatory liability. As actual removal costs are incurred, the associated regulatory liability is reduced. (See Note 3, Effects of Regulation.)

Allowance for funds used during construction

Allowance for funds used during construction (AFUDC) represents the estimated cost of interest on financing the construction of new assets. AFUDC is based on the construction work in progress balance and is charged to the capitalized cost of the utility plant asset. AFUDC is a reduction of interest expense.

FCRPS capitalizes AFUDC at one rate for Corps and Reclamation construction funded by congressional appropriations and at another rate for construction funded substantially by BPA and the NIFCs. The rates for appropriated funds are provided each year to BPA by the U.S. Treasury, whereas the BPA rate is determined based on the weighted-average cost of borrowing for BPA and the NIFCs. The respective rates for appropriated and BPA funds were approximately 0.1 percent and 3.6 percent in fiscal year 2013, 0.1 percent and 4.1 percent in fiscal year 2012, and 0.3 percent and 4.4 percent in fiscal year 2011. The weighted-average AFUDC rates for fiscal years 2013, 2012 and 2011 approximated the BPA rates for these years.

Nonfederal generation

BPA contracted to acquire all of the generating capability of Energy Northwest's Columbia Generating Station (CGS) nuclear power plant and Lewis County PUD's Cowlitz Falls Hydroelectric Project. The contracts to acquire the generating capability of the facilities require BPA to pay all of the facilities' operating, maintenance and debt service costs. BPA recognizes expenses for these projects based upon total project cash funding requirements. The nonfederal generation assets in the Combined Balance Sheets are amortized over the term of the outstanding debt. (See Note 8, Nonfederal Financing.)

Cash and cash equivalents

Cash amounts include cash in the BPA fund with the U.S. Treasury and unexpended appropriations of the Corps and Reclamation. Cash equivalents consist of short-term U.S. Treasury market-based special securities

with maturities of 90 days or less at the date of investment. The carrying value of cash and cash equivalents approximates fair value.

Concentrations of credit risks

General credit risk

Financial instruments that potentially subject the FCRPS to concentrations of credit risk consist primarily of BPA accounts receivable. Credit risk represents the loss that would be recognized if counterparties fail to perform as contracted.

BPA's accounts receivable are spread across a diverse group of customers throughout the western United States and Canada, which include consumer-owned utilities (COUs), investor-owned utilities (IOUs), power marketers, wind generators and others. BPA's accounts receivable exposure is generally from large and stable counterparties and does not represent a significant concentration of credit risk. During fiscal years 2013, 2012 and 2011, BPA experienced no material losses as a result of any customer defaults or bankruptcy filings.

BPA mitigates credit risk by reviewing counterparties for creditworthiness, establishing credit limits and monitoring credit exposure on a daily basis. In order to further manage credit risk, BPA obtains credit support, such as letters of credit, parental guarantees, and cash in the form of prepayments, deposits or escrow funds from some counterparties. BPA closely monitors counterparties for changes in financial condition and regularly updates credit reviews.

Allowance for doubtful accounts

Management reviews accounts receivable on a monthly basis to determine if any receivable will potentially be uncollectible. The allowance for doubtful accounts includes amounts estimated through an evaluation of specific customer accounts, based upon the best available facts and circumstances of customers that may be unable to meet their financial obligations, and a reserve for all other customers based on historical experience. The balance is not material to the financial statements.

Derivative instruments

BPA measures its derivative instruments at fair value and recognizes them on the Combined Balance Sheets as either an asset or liability unless the contract is eligible for the normal purchases and normal sales exception under Derivatives and Hedging accounting guidance. Forward electricity contracts are generally considered normal purchases and normal sales if they require physical delivery, are expected to be used or sold by BPA in the normal course of business and meet the derivative accounting definition of capacity. Recognition of these contracts in Sales or Purchased power in the Combined Statements of Revenues and Expenses occurs when the contracts settle.

The fair value of derivative instruments that do not qualify for the normal purchases and normal sales exception are recognized on the Combined Balance Sheets as deferred credits or deferred charges. Changes in fair value are not recognized in the Combined Statements of Revenues and Expenses but are deferred as either regulatory assets or regulatory liabilities in accordance with Regulated Operations accounting guidance.

Fair value

BPA's carrying amounts of current assets and current liabilities approximate fair value based on the short-term nature of these instruments. In accordance with authoritative guidance for Fair Value Measurements, BPA uses fair value measurements to record adjustments to certain financial assets and liabilities and to determine fair value disclosures. When developing fair value measurements, it is BPA's policy to use quoted market prices whenever available or to maximize the use of observable inputs and minimize the use of unobservable inputs when quoted market prices are not available. Fair values are primarily developed using industry standard models that consider various inputs including: (a) quoted forward prices for commodities; (b) time value; (c) volatility factors; (d) current market and contractual prices for underlying instruments; (e) market interest rates and yield curves; and (f) credit spreads, as well as other relevant economic measures. (See Note 12, Risk Management and Derivative Instruments and Note 13, Fair Value Measurements.)

Revenues and net revenues

Operating revenues are recorded when power, transmission and related services are delivered and include estimated unbilled revenues. BPA's net revenues over time are committed to payment of operational obligations, including debt for both operating and nonoperating nonfederal projects, repayment of the U.S. government investment in the FCRPS, and the payment of certain irrigation costs.

Interest income

Interest income includes earnings on BPA's fund balance with the U.S. Treasury, on investments in market-based special securities and from other sources. BPA earns interest credits on cash balances in the fund not invested in market-based specials at the weighted-average interest rate of its outstanding U.S. Treasury borrowings and reduces some of its monthly debt interest payments by the interest earned. Interest earnings on U.S. Treasury market-based special investments are based on the stated rates of the individual securities.

U.S. Treasury credits for fish

Under the Northwest Power Act, BPA makes expenditures for fish and wildlife protection, mitigation and enhancement for both power and nonpower purposes on a reimbursement basis. Section 4(h)10(c) of the Northwest Power Act also specifies that consumers of electric power, through rates BPA establishes 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." This provision of law ensures that the costs of mitigating these impacts are properly accounted for among the power-related and other purposes of the hydroelectric projects of the FCRPS. Power-related costs are recovered in BPA's rates. Nonpower-related costs are recovered as a reduction to BPA's cash payments to the U.S. Treasury and are shown as a component of Operating revenues in the Combined Statements of Revenues and Expenses.

Residential Exchange Program

In order to provide qualifying regional utilities, primarily IOUs, access to benefits from the FCRPS, Congress established the Residential Exchange Program (REP) in Section 5(c) of the Northwest Power Act. Whenever a Pacific Northwest electric utility offers to sell power to BPA at the utility's average system cost of resources, BPA purchases such power and offers, in exchange, to sell an equivalent amount of power at BPA's priority firm exchange rate to the utility for resale to that utility's residential and small farm consumers. REP costs are forecast for each year of the rate period and included in the revenue requirement for establishing rates. The cost of this program is collected through rates. Program costs are recognized when incurred net of the purchase and sale of power under the REP.

In fiscal year 2008, BPA conducted the 2007 Supplemental Wholesale Power Rate Case (WP-07 Supplemental Rate Case) to resolve outstanding claims and address associated judicial rulings related to prior REP billings. In 2009, BPA conducted the 2010 Wholesale Power and Transmission Rate Adjustment Proceeding (WP-10 Rate Case), continuing the policies established in WP-07 Supplemental Rate Case. In connection with those filings, Lookback Amounts due to and due from BPA customers were identified and recorded as regulatory amounts. Such Lookback Amounts were collected from identified IOU customers and were being returned to the COUs over time.

In fiscal year 2011, the BPA administrator signed the 2012 Residential Exchange Program Settlement Agreement (Settlement Agreement), resolving disputes related to the REP. The Settlement Agreement provides for fixed "Scheduled Amounts" payable to the IOUs, as well as fixed "Refund Amounts" payable to the COUs. The Settlement Agreement eliminates the Lookback Amounts as of Sept. 30, 2011, and replaces them with the Refund Amounts for amounts overpaid by the COUs. These amounts do not reduce rates but are reflected as credits to qualifying COUs' bills as designated in the Settlement Agreement. BPA utilizes the rates process to reduce the IOUs' benefits and thus reduce the expense in the year it is applied. (See Note 10, Residential Exchange Program.)

Pension and Other Postretirement Benefits

Federal employees associated with the operation of the FCRPS participate in either the Civil Service Retirement System or the Federal Employees Retirement System. Employees may also participate in the Federal Employees Health and Benefit Program and the Federal Employee Group Life Insurance Program. All such postretirement systems and programs are sponsored by the Office of Personnel Management; therefore, BPA does not record any accumulated plan assets or liabilities related to the administration of such programs. Contribution amounts are included in rates and are recorded as expense during the year to which the payment relates.

RECENT ACCOUNTING PRONOUNCEMENTS

Balance Sheet Offsetting

In December 2011, the Financial Accounting Standards Board (FASB) issued authoritative guidance that requires an entity to provide quantitative disclosures about offsetting financial instruments and derivative instruments. Additionally, this guidance requires qualitative and quantitative disclosures about master netting agreements or similar agreements when the financial instruments and derivative instruments are not offset. This guidance will be effective for fiscal year 2014. BPA is evaluating the impact of adopting this guidance on its disclosures included within Notes to Financial Statements.

Fair value measurements and disclosures

In May 2011, the FASB issued authoritative guidance which made a number of incremental changes to current fair value measurement and disclosure guidance. Changes with relevance to BPA include certain additional required disclosures for Level 2 and 3 fair value measurements. BPA adopted this guidance on October 1, 2012. This guidance had no impact to BPA's financial condition, results of operations or cash flows.

SUBSEQUENT EVENTS

FCRPS has performed an evaluation of events and transactions for potential recognition or disclosure through Oct. 30, 2013, which is the date the financial statements were issued.

2. Investments in U.S. Treasury Securities

As of Sept. 30 — thousands of dollars	**2013**		2012	
	Amortized cost	**Fair value**	Amortized cost	Fair value
Short-term	**$ 388,914**	**$ 389,127**	$ 242,495	$ 242,911
Long-term	**34,961**	**34,972**	49,623	49,984
Total	**$ 423,875**	**$ 424,099**	$ 292,118	$ 292,895

BPA participates in the U.S. Treasury's Federal Investment Program which provides investment services to federal government entities that have funds on deposit with the U.S. Treasury and have statutory authority to invest those funds. Investments of the funds are generally restricted to special non-marketable securities, also called market-based specials. Under its banking arrangement with the U.S. Treasury, BPA has agreed to invest at least $100 million annually for up to 10 years or until the BPA fund is fully invested. Any remaining balance in the BPA fund at Sept. 30, 2018, will be invested through the Federal Investment Program.

Market-based specials held during fiscal years 2013 and 2012 had a weighted-average yield of 0.3 percent and 0.4 percent, respectively, and maturities of up to two years. The amounts shown in the preceding table exclude U.S. Treasury securities with maturities of 90 days or less at the date of investment, which are considered cash equivalents and are included in the Combined Balance Sheets as part of Cash and cash equivalents. For all other securities, BPA follows the authoritative guidance for Investments, Debt and Equity Securities. These investments are classified as held-to-maturity and reported at amortized cost. Investments with maturities that will be realized in cash within one year are classified as short-term investments. Long-term investments have stated maturities at October 2015.

3. Effects of Regulation

REGULATORY ASSETS

As of Sept. 30 — thousands of dollars	**2013**	2012
REP Scheduled Amounts	**$ 2,903,634**	$ 2,993,310
Terminated nuclear facilities	**2,154,900**	2,606,661
Columbia River Fish Mitigation	**600,413**	546,604
REP Refund Amounts	**432,850**	500,155
Conservation measures	**319,082**	297,838
Fish and wildlife measures	**302,245**	278,102
Legal claims and settlements	**76,601**	74,419
Spacer damper replacement program	**46,563**	37,775
Federal Employees' Compensation Act	**32,558**	31,352
Derivative instruments	**27,108**	39,049
Trojan decommissioning and site restoration	**24,431**	23,189
Terminated hydro facilities	**17,238**	18,602
Capital bond premiums	**9,067**	9,810
Other	**6,707**	8,122
Total	**$ 6,953,397**	$ 7,464,988

Regulatory assets include the following items:

"REP Scheduled Amounts" reflect the costs of REP Scheduled Amounts representing REP benefits payable under the 2012 REP Settlement Agreement that will be recovered through rates through 2028. (See Note 10, Residential Exchange Program.)

"Terminated nuclear facilities" consists of the nonfederal debt for Energy Northwest Nuclear Project Nos. 1 and 3. These assets are amortized over the term of the related outstanding debt. (See Note 8, Nonfederal Financing.)

"Columbia River Fish Mitigation" is the cost of research and development for fish bypass facilities funded through appropriations since 1989 in accordance with the Energy and Water Development Appropriations Act of 1989, Public Law 100-371. These costs are recovered through rates and amortized as scheduled over 75 years.

"REP Refund Amounts" is the amount recoverable in future rate periods that reduces the REP benefit payments through 2019 as set forth in the 2012 REP Settlement Agreement. (See Note 10, Residential Exchange Program.)

"Conservation measures" consist of the costs of capitalized conservation measures and are amortized over periods from five to 20 years.

"Fish and wildlife measures" consist of capitalized fish and wildlife projects and are amortized over a period of 15 years.

"Legal claims and settlements" reflect accrued liabilities related to outstanding legal claims and settlement agreements. These costs will be recovered and amortized through future rates over a period as established by the administrator.

"Spacer damper replacement program" consists of costs to replace deteriorated spacer dampers and are being recovered in rates under the Spacer Damper Replacement Program. These costs are being amortized over a

period of 25 or 30 years. In fiscal year 2011, BPA recognized an impairment charge of $20.6 million in deferred spacer damper replacement program costs.

"Federal Employees' Compensation Act" reflects the actuarial estimated amount of future payments for current recipients of BPA's worker compensation benefits.

"Derivative instruments" reflect the unrealized losses from BPA's derivative portfolio. (See Note 12, Risk Management and Derivative Instruments.) These amounts are deferred over the corresponding underlying contract delivery months.

"Trojan decommissioning and site restoration" costs reflect the amount to be recovered in future rates for funding the Trojan asset retirement obligation (ARO) liability. (See Note 4, Asset Retirement Obligations.)

"Terminated hydro facilities" consists of the nonfederal debt for the terminated Northern Wasco hydro project. These assets are amortized over the term of the related outstanding debt. (See Note 8, Nonfederal Financing.)

"Capital bond premiums" are losses related to refinanced U.S. Treasury debt and are amortized over the life of the new debt instruments.

REGULATORY LIABILITIES

As of Sept. 30 — thousands of dollars	**2013**	2012
Capitalization adjustment	**$ 1,471,986**	$ 1,536,891
REP Refund Amounts to COUs	**432,850**	500,155
Accumulated plant removal costs	**408,218**	390,622
CGS decommissioning and site restoration	**109,819**	99,182
Other	**11,192**	18,520
Total	**$ 2,434,065**	$ 2,545,370

Regulatory liabilities include the following items:

"Capitalization adjustment" is the difference between appropriated debt before and after refinancing per the BPA Refinancing Section of the Omnibus Consolidated Rescissions and Appropriations Act of 1996 (Refinancing Act), 16 U.S.C. 838(l). The 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 $64.9 million for fiscal years 2013, 2012 and 2011, respectively. (See Note 6, Federal Appropriations.)

"REP Refund Amounts to COUs" is the amount previously collected through rates that is owed to qualifying consumer-owned utilities and will be credits on their future bills. These costs will be repaid and amortized through future rates over the period as established in the 2012 REP Settlement Agreement, and are equal to regulatory assets for REP refund amounts. (See Note 10, Residential Exchange Program.)

"Accumulated plant removal costs" are the amounts previously collected through rates as part of depreciation. The liability will be relieved as actual removal costs are incurred. In fiscal year 2012, collections associated with estimated removal costs in prior years of $178.8 million were reclassified from accumulated depreciation to this regulatory liability. This adjustment was not considered material to previously issued financial statements.

"CGS decommissioning and site restoration" is the amount previously collected through rates and invested in the related nonfederal nuclear decommissioning trusts in excess of the ARO balances for CGS decommissioning and site restoration as well as Project Nos. 1 and 4 sites.

4. Asset Retirement Obligations

As of Sept. 30 — thousands of dollars	**2013**	2012
Beginning Balance	**$ 161,215**	$ 176,212
Activities:		
Accretion	**8,507**	8,305
Expenditures	**(596)**	(1,269)
Revisions	**2,428**	(22,033)
Ending Balance	**$ 171,554**	$ 161,215

BPA recognizes AROs based on the estimated fair value of the dismantlement and restoration costs associated with the retirement of certain tangible long lived assets. The liability is adjusted for any revisions, expenditures and the passage of time. During fiscal year 2012, the ARO for CGS decreased by $15.0 million primarily due to a revised cost estimate following Nuclear Regulatory Commission (NRC) relicensing of the facility for an additional 20 years. FCRPS also has tangible long-lived assets such as federal hydro projects and transmission assets without an associated ARO since no future obligation exists to remove these assets.

AROs include the following items as of Sept. 30, 2013:

- CGS decommissioning and site restoration of $126.5 million;
- Trojan decommissioning of $24.4 million;
- Energy Northwest Project Nos. 1 and 4 site restoration of $20.6 million.

Decommissioning costs for CGS are charged to operations over the operating life of the project.

NONFEDERAL NUCLEAR DECOMMISSIONING TRUSTS

As of Sept. 30 — thousands of dollars	**2013**		2012	
	Amortized cost	**Fair value**	Amortized cost	Fair value
Equity index funds	**$ 87,723**	**$ 117,212**	$ 84,377	$ 100,050
U.S. government obligation mutual funds	**77,022**	**76,801**	72,200	74,067
Corporate bond index funds	**59,402**	**60,726**	57,150	61,460
Cash and cash equivalents	**13**	**13**	21	21
Total	**$ 224,160**	**$ 254,752**	$ 213,748	$ 235,598

BPA recognizes an asset that represents trust fund balances for decommissioning and site restoration costs. External trust funds for decommissioning and site restoration costs are funded monthly for CGS. The trust funds are expected to provide for decommissioning at the end of the project's safe storage period in accordance with the NRC requirements. The NRC requires that this period be no longer than 60 years from the time the plant stops operating. In May 2012, the NRC renewed CGS's operating license for an additional 20 years and the license now expires in 2043. Trust fund requirements for CGS are based on an NRC decommissioning cost estimate and the license termination date. The trusts are funded and managed by BPA in accordance with the NRC requirements and site certification agreements.

The investment securities in the decommissioning and site restoration trust accounts are classified by BPA as available-for-sale in accordance with accounting guidance related to Investments, Debt and Equity Securities.

BPA recognizes the unrealized gains and losses on these investment securities as adjustments to the related regulatory liability, which represents the excess of the amount previously collected through rates over the current ARO balance. (See Note 3, Effects of Regulation.) Payments to the trusts for fiscal years 2013, 2012 and 2011 were approximately $3.6 million, $9.2 million and $9.6 million, respectively. In connection with the relicensing of CGS in 2012, funding of the trust was reassessed and resulted in a reduction in annual contributions beginning in fiscal year 2013.

Based on an agreement in place, BPA directly funds Eugene Water and Electric Board's 30 percent share of Trojan's decommissioning costs through current rates. Decommissioning costs are included in Operations and maintenance expense in the accompanying Combined Statements of Revenues and Expenses.

5. Deferred Charges and Other

As of Sept. 30 — thousands of dollars	**2013**	2012
Lease financing trust funds	**$ 99,623**	$ 121,032
Settlements receivable	**16,000**	16,000
Spectrum Relocation fund	**8,307**	9,608
Funding agreements	**7,174**	7,174
Derivative instruments	**4,814**	12,141
Energy receivable	**4,391**	4,768
Trust fund and other deposits	**3,103**	6,290
Other	**3,270**	3,431
Total	**$ 146,682**	$ 180,444

Deferred charges and other include the following items:

"Lease financing trust funds" are amounts held in separate trust accounts for the construction of transmission assets, debt service payments during the construction period and a fund mainly for future principal and interest debt service payments. (See Note 8, Nonfederal Financing.)

"Settlements receivable" represents interest earned by BPA on certain settlements, the principal of which has been collected. The timing of cash receipt of the interest is unknown.

"Spectrum Relocation fund" was created to reimburse the costs of replacing radio communication equipment displaced as a result of radio band frequencies no longer available to federal agencies. Amounts received from the U.S. Treasury in connection with the Commercial Spectrum Enhancement Act are held in the BPA fund and are restricted for use in constructing replacement assets.

"Funding agreements" represents deferred costs associated with BPA's contractual obligations to determine the feasibility of certain joint transmission projects.

"Derivative instruments" represent unrealized gains from the derivative portfolio which includes physical power purchase and sale transactions and power exchange transactions.

"Energy receivable" primarily consists of energy to be returned to BPA for prior transmission line losses.

"Trust fund and other deposits" primarily represent funds held in the Conservation and Renewable Energy System (CARES) defeasance trust fund.

6. Federal Appropriations

Appropriations consist primarily of the power portion of Corps and Reclamation capital investments funded through congressional appropriations and the remaining unpaid capital investments in the BPA transmission system made prior to implementation of the Federal Columbia River Transmission System Act of 1974, 16 U.S.C. 838(j).

The Refinancing Act required that the outstanding balance of the FCRPS federal appropriations be reset and assigned market rates of interest prevailing as of Oct. 1, 1996. This resulted in a determination that the principal amount of appropriations should 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. Appropriations in the amount of $6.69 billion were subsequently refinanced for $4.10 billion. This adjustment was recorded as a capitalization adjustment in regulatory liabilities and is being amortized over the remaining period of repayment. (See Note 3, Effects of Regulation.)

Federal generation and transmission appropriations are repaid to the U.S. Treasury within the weighted-average service lives of the associated investments from the time each facility was placed in service, with a maximum of 50 years. Federal appropriations may be paid early without penalty. All outstanding federal appropriations are due 2019 and thereafter.

The weighted-average interest rate was 6.1 percent and 6.2 percent on outstanding appropriations as of Sept. 30, 2013, and 2012, respectively.

7. Borrowings from U.S. Treasury

BPA is authorized by Congress to issue to the U.S. Treasury and have outstanding at any one time up to $7.70 billion of interest bearing bonds or related debt instruments with terms and conditions comparable to debt issued by U.S. government corporations. The debt may be issued to finance BPA's capital programs, which include Corps and Reclamation direct funded capital investments. Of the $7.70 billion, $750 million can be issued to finance Northwest Power Act related expenses and $1.25 billion is restricted for conservation and renewable resources.

As of Sept. 30, 2013, of the total $3.89 billion of outstanding bonds, none related to NW Power Act expenses and $361.0 million were for conservation and renewable resources investments. Outstanding bonds carrying a variable rate of interest were $300.0 million at both Sept. 30, 2013, and 2012. The weighted-average interest rate of BPA's borrowings from the U.S. Treasury exceeds current rates. As a result, the fair value of BPA's U.S. Treasury borrowings exceeded the carrying value by approximately $297.2 million and $484.8 million, based on discounted future cash flows using agency rates offered by the U.S. Treasury as of Sept. 30, 2013, and 2012, respectively, for similar maturities.

The weighted-average interest rate on outstanding U.S. Treasury borrowings was 3.8 percent and 3.6 percent as of Sept. 30, 2013, and 2012, respectively. As of Sept. 30, 2013, the outstanding bonds with a variable rate of interest carried an interest rate of 0.1 percent.

Of the outstanding U.S. Treasury borrowings, $278.8 million is not subject to redemption prior to their stated maturities. As of Sept. 30, 2013, $512.0 million are callable by BPA at par value and the remaining $3.10 billion are callable by BPA at a premium or discount, which is calculated based on the current government agency rates for the remaining term to maturity at the time the bond is called.

MATURING BORROWINGS FROM U.S. TREASURY

As of Sept. 30 — thousands of dollars	
2014	$ 147,000
2015	210,000
2016	30,000
2017	68,400
2018	9,000
2019 through 2043	3,420,640
Total	**$ 3,885,040**

8. Nonfederal Financing

PROJECTS FINANCED WITH NONFEDERAL DEBT

As of Sept. 30 — thousands of dollars	**2013**	2012
Nonfederal generation:		
Columbia Generating Station	**$ 3,175,659**	$ 3,224,040
Cowlitz Falls	**87,995**	104,650
Nonfederal generation	**3,263,654**	3,328,690
Terminated generation:		
Nuclear Project No. 1	**1,048,005**	1,321,060
Nuclear Project No. 3	**1,229,245**	1,395,405
Terminated nuclear facilities	**2,277,250**	2,716,465
Terminated Northern Wasco Hydro Project	**18,375**	19,735
Sponsored conservation:		
Tacoma	**3,495**	5,120
Conservation and Renewable Energy System	**3,004**	5,870
Sponsored conservation	**6,499**	10,990
Lease financing program	**713,762**	668,054
Customer prepaid power purchases	**334,909**	-
Capital leases	**222,420**	120,449
Total	**$ 6,836,869**	$ 6,864,383

Nonfederal generation, terminated generation and sponsored conservation

BPA contracted to acquire all of the generating capability of Energy Northwest's Columbia Generating Station and Lewis County PUD's Cowlitz Falls Hydroelectric Project. These contracts require that BPA pay all of the operating, maintenance and debt service costs for these projects. BPA also contracted to acquire all of the generating capacity of Energy Northwest's Nuclear Project No. 1 and 70 percent of Energy Northwest's Nuclear Project No. 3; however, these projects were terminated prior to completion. Although not in operation, BPA is required by these contracts to pay debt service costs for these projects.

BPA funds debt service on Conservation and Renewable Energy System (CARES) and City of Tacoma Conservation bonds issued to finance conservation programs sponsored by BPA. BPA is also required by The Settlement and Termination Agreement between BPA and the Northern Wasco PUD to pay annual debt service on the terminated Northern Wasco Hydro Project.

BPA recognizes expenses for these nonfederal projects based on total project cash funding requirements, which include debt service and operating and maintenance expenses. BPA recognized operating and maintenance expense for these projects of $307.3 million, $298.3 million and $328.1 million in fiscal years 2013, 2012 and 2011, respectively, which is included in Operations and maintenance in the accompanying Combined Statements of Revenues and Expenses. Debt service for the projects of $733.3 million, $659.7 million and $625.0 million for fiscal years 2013, 2012 and 2011, respectively, is reported as Nonfederal projects in the accompanying Combined Statements of Revenues and Expenses.

On the accompanying Combined Balance Sheets, related assets for operating projects are included in Nonfederal generation. Related assets for terminated generation and sponsored conservation are included in Regulatory assets. (See Note 3, Effects of Regulation.)

The underlying debt for the Energy Northwest obligations (including terminated nuclear facilities Projects Nos. 1 and 3 and CGS) currently matures through 2044 with interest rates that are fixed between 1.1 percent and 7.1 percent. Energy Northwest debt of $1.61 billion is callable, in whole or in part, at Energy Northwest's option, on call dates between July 2014 and July 2024 at 100 percent of the principal amount.

The fair value of Energy Northwest debt exceeded recorded value by $510.7 million and $824.2 million as of Sept. 30, 2013, and 2012, respectively. The valuations are based on a market input evaluation pricing methodology using a combination of market observable data such as current market trade data, reported bid/ask spreads and institutional bid information. The weighted-average interest rate was 4.6 percent for the Energy Northwest outstanding nonfederal debt at both Sept. 30, 2013, and 2012, respectively.

Lease financing program

Under the Lease Financing Program, BPA consolidates six special purpose corporations, collectively referred to as Northwest Infrastructure Financing Corporations (NIFCs), which issue debt to and receive advances from nonfederal sources. The combined NIFCs have issued $119.6 million in bonds and borrowed $593.4 million on lines of credit with various banks as of Sept. 30, 2013. The bonds bear interest at 5.4 percent and mature in 2034. All NIFC bonds outstanding are subject to redemption by the issuing NIFC, in whole or in part, at any date, at the higher of the principal amount of the bonds or the present value of the bonds discounted using the U.S. Treasury rate plus a premium of 12.5 basis points. The lines of credit become due in full at various dates ranging between Jan. 1, 2015, and Jan. 1, 2019.

On the accompanying Combined Balance Sheets, the bonds and bank line of credit facilities are included in Nonfederal debt. The leased assets are primarily included in Utility plant and also in Deferred charges and other for unspent funds held in trust.

In July 2012, NIFC II sold its lease receivable, rights to future lease revenue, and title to the leased assets to the Port of Morrow, a port district located in Morrow County, Oregon. As the Port of Morrow is not consolidated in the combined FCRPS financial statements, the lease is reported as a capital lease included in Nonfederal debt. The net effect of this transaction was a decrease in Nonfederal debt of $12.4 million and a gain of $1.9 million.

The fair value of the combined NIFC bonds and lines of credit exceeded the recorded value by $30.2 million and $45.5 million as of Sept. 30, 2013, and 2012, respectively. The valuations are based on the discounted future cash flows using interest rates for similar debt that could have been issued at Sept. 30, 2013, and 2012, respectively. The weighted-average interest rate on the NIFCs' outstanding debt was 3.5 percent and 3.6 percent as of Sept. 30, 2013, and 2012, respectively.

Customer prepaid power purchases

During fiscal year 2013 BPA entered into agreements with four regional COUs for the express advance payment of customer power purchases. Under this program, customers purchased prepaid power in blocks through fiscal year 2028. For each block purchased BPA provides monthly fixed credits on the customers' power bills.

In March 2013, BPA received $340.0 million representing $474.3 million in scheduled credits for blocks purchased by customers. BPA accounts for the prepayment proceeds as a financing transaction and reports the value of the obligations associated with the fixed credits as a prepayment liability. Interest expense is recognized using a weighted-average effective interest rate of 4.5 percent. The prepaid liability is reduced as power is delivered and the credits are applied.

MATURING NONFEDERAL DEBT

As of Sept. 30 — thousands of dollars

2014	$	606,644
2015		799,965
2016		817,999
2017		593,456
2018		931,617
2019 and thereafter		2,864,768
Total	**$**	**6,614,449**

Capital leases

Capital leases include BPA's lease agreements with the Port of Morrow and other counterparties for transmission facilities and equipment, including lines, substations and general plant assets. Completed plant assets under capital lease agreements were $127.7 million and $127.6 million, and the accumulated depreciation was $19.3 million and $16.1 million, at Sept. 30, 2013, and 2012, respectively. The capital leases expire on various dates through 2044. Generally, the capital lease agreements contain provisions that allow BPA to purchase the leased assets at anytime during each lease term for a bargain purchase price plus the value of the related outstanding debt instrument. Additionally, one lease agreement includes a minimum lease payment escalation clause based on transmission usage.

FUTURE MINIMUM LEASE PAYMENTS UNDER CAPITAL LEASES

As of Sept. 30 — thousands of dollars

2014	$	9,621
2015		9,613
2016		9,615
2017		9,617
2018		9,619
2019 and thereafter		315,072
Total undiscounted payments	$	363,157
Less: Executory costs		32,407
Less: Amount representing interest		108,330
Present value of minimum lease payments		**222,420**
Less: Current portion		1,221
Long-term capital lease liability	$	221,199

9. Variable Interest Entities

A VIE is an entity that does not have sufficient equity at risk to finance its activities without additional financial support or whose equity investors lack characteristics of a controlling financial interest. An enterprise that has a controlling interest is known as the VIE's primary beneficiary and is required to consolidate the VIE.

BPA reviews executed power purchase agreements with counterparties that may be considered VIEs. These VIEs are typically legal entities structured to own and operate specific generating facilities, primarily wind farms. Because of their pricing arrangements, these agreements may provide that BPA absorb commodity price risk of the counterparty entities. BPA does not provide, and does not plan to provide, any additional financial support to these entities beyond what BPA is contractually obligated to pay. BPA has concluded that it does not control the operating and maintenance activities that most significantly impact these entities. Therefore, BPA is not considered the primary beneficiary of these VIEs and does not consolidate any entities because of power purchase agreements.

BPA is the primary beneficiary of the NIFCs, which are considered VIEs, and BPA therefore consolidates these entities into the FCRPS financial statements. The key factor in this determination is BPA's ability to direct the commercial and operating activities of the transmission facilities underlying the lease agreements. Additionally, BPA's lease agreements with the NIFC entities obligate BPA to absorb the operational and commercial risks, and thus potentially significant benefits or losses, associated with the underlying transmission facilities. Under the lease purchase agreements, the NIFCs issue debt to finance the construction of the transmission facilities which are then leased to BPA. The collateral for the debt is the lease payment stream from BPA. The NIFC entities hold legal title to the transmission facilities during the lease term, and BPA is responsible for constructing the leased facilities. BPA also has exclusive use and control of the facilities during the lease periods and has indemnified the equity owners for all construction and operating risks associated with the transmission facilities. At any time during each lease term, BPA has the option to buy the transmission facilities at a bargain purchase price plus the value of the related outstanding debt instruments. BPA is obligated to indemnify certain expenses of the NIFCs related to their respective facilities.

Amounts related to the NIFC entities include Deferred charges and other assets of $27.0 million and $32.3 million and Nonfederal debt of $713.0 million and $668.1 million as of Sept. 30, 2013, and 2012, respectively. In July 2012, NIFC II recorded a gain of $1.9 million on the sale of a lease.

10. Residential Exchange Program

BACKGROUND

As provided in the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), beginning in 1981 BPA entered into 20-year Residential Purchase and Sale Agreements (RPSAs) with eligible regional utility customers. The RPSAs implemented the REP.

In 2000, BPA signed Residential Exchange Program Settlement Agreements ("REP settlements" or "settlement agreements") with the region's six IOUs under which BPA provided monetary and power benefits as a settlement of Residential Exchange disputes for the period July 1, 2001, through Sept. 30, 2011. BPA later signed additional agreements and amendments with IOU customers related to the settlement agreements. One such agreement provided for the elimination or deferral of certain IOU benefit payments, while later agreements and amendments provided for minimum and maximum amounts for the IOU monetary benefits for fiscal years 2007 through 2011, provided that BPA would have no obligation to provide power to the IOUs in this period. When future amounts were committed through these agreements, BPA recorded a REP settlement liability for the minimum committed amounts and a regulatory asset for amounts recoverable in future rates.

In May 2007, the Ninth Circuit Court ruled that the REP settlements were inconsistent with the Northwest Power Act and that BPA improperly allocated settlement costs to BPA's preference rates. In response to that ruling, in fiscal year 2008 BPA reduced the REP settlement agreement liability and regulatory asset to zero and conducted the 2007 Supplemental Wholesale Power Rate Case (WP-07 Supplemental Rate Case). This rate case established Lookback Amounts (representing amounts over-collected from COUs in prior years' rates, which also represented the amounts overpaid to the IOUs in the prior year's settlement agreements) that were also confirmed in the subsequent 2010 Wholesale Power and Transmission Rate Adjustment Proceeding. The Lookback Amount was recorded as both a regulatory asset, representing amounts to be collected from IOUs through future rate proceedings, and a regulatory liability, representing amounts to be credited to the COUs in future rates.

2008 IOU EXCHANGE BENEFITS

In fiscal year 2008, Interim Agreements were executed to provide certain IOUs with temporary REP benefits for their residential and small farm consumers. These agreements included a provision to true up the amounts advanced with the actual REP benefits for fiscal year 2008. The true up amount for the IOUs was $69.6 million; however, provisions in the agreement provided that true up payments could not be paid until any subsequent legal challenges to BPA's final Record of Decision (ROD), if any, are resolved. (See Note 14, Commitments and Contingencies.) As yet, all legal challenges related to this program have not been resolved.

In 2009, BPA reached a settlement with Avista over its disputed deemer balance, which resulted in the amount due to them for their 2008 benefits changing from zero to $12.0 million and an increase in the IOU exchange benefits balance to $81.6 million. After applying interest for fiscal year 2013, this balance has increased to $89.1 million and is reported as part of the IOU exchange benefits liability of $2.99 billion as of Sept. 30, 2013.

2012 RESIDENTIAL EXCHANGE PROGRAM SETTLEMENT AGREEMENT

Beginning in April 2010, over 50 litigants and other regional parties entered into mediation to resolve their numerous disputes over the REP. Participants reached an agreement in principle in early September 2010 and in February 2011 reached a final settlement agreement – the 2012 Residential Exchange Program Settlement Agreement (2012 Settlement Agreement). In March 2011, BPA distributed the 2012 Settlement Agreement for regional entities' consideration and signature. In conjunction with the customers' settlement agreement efforts, in December 2010 BPA initiated the Residential Exchange Program Settlement Agreement Proceeding (REP-12) to evaluate the 2012 Settlement Agreement and determine whether it was in the region's best interest for the BPA administrator to sign the Settlement Agreement on behalf of BPA. In July 2011, the BPA administrator signed the REP-12 Final ROD and the 2012 Settlement Agreement.

In 2011, BPA recorded a long-term IOU exchange benefits liability and corresponding regulatory asset of $3.07 billion associated with the Settlement Agreement. Beginning in fiscal year 2012, under the provisions of the 2012 Settlement Agreement the IOUs began to receive Scheduled Amounts annually starting at $182.1 million with increases over time to $286.1 million as the final payment in fiscal year 2028. The distribution of these payments is established in the 2012 Settlement Agreement that relies upon IOU's average system cost, BPA's Priority Firm Exchange rates and exchange load. The settled Scheduled Amounts to be paid to the IOUs total $4.07 billion over the 17-year period through 2028. Amounts recorded of $2.90 billion at Sept. 30, 2013, represent the present value of future cash outflows for these exchange benefits.

In addition to Scheduled Amounts, the 2012 Settlement Agreement calls for Refund Amounts to be paid to COUs in the amount of $76.5 million each year from fiscal year 2012 through fiscal year 2019. The Refund Amounts replace the Lookback Amounts and are accounted for similar to the Lookback Amounts in that a regulatory asset and liability have been established for the refunds that will be provided to BPA customers as credits on customer monthly bills. The 2012 Settlement Agreement replaces the Lookback Amounts that were reduced to zero as of Sept. 30, 2011, with the Refund Amounts totaling $612.3 million. Amounts recorded as a regulatory liability of $432.8 million at Sept. 30, 2013, represent the present value of future cash flows for the amounts to be refunded to COUs, as well as reduced exchange benefits. The distribution of the Refund Amounts will be split with 50 percent of the Refund Amounts ($38.3 million per year) returned to COUs based on the percentages BPA established in the WP-10 Rate Case and 50 percent returned to COUs based on each customer's expected share of Tier 1 load as defined in BPA's 2012 Wholesale Power and Transmission Rate Adjustment Proceeding (BP-12 Rate Case).

11. Deferred Credits and Other

As of Sept. 30 — thousands of dollars	**2013**	2012
Customer reimbursable projects	**$ 227,120**	$ 232,516
Generation interconnection agreements	**219,510**	271,714
Third AC Intertie capacity agreements	**104,406**	99,231
Legal claims and settlements	**82,580**	80,904
Federal Employees' Compensation Act	**32,558**	31,352
Derivative instruments	**27,108**	39,049
Fiber optic leasing fees	**27,004**	32,599
Other	**4,729**	6,155
Total	**$ 725,015**	$ 793,520

Deferred credits and other include the following items:

"Customer reimbursable projects" consist of advances received from customers where either the customer or BPA will own the resulting asset. If the customer will own the asset under construction, the revenue is recognized as the expenditures are incurred. If BPA will own the resulting asset, the revenue is recognized over the life of the asset once the corresponding asset is placed in service.

"Generation interconnection agreements" are generators' advances held as security for requested new network upgrades and interconnection. These advances accrue interest and will be returned as cash or credits against future transmission service on the new or upgraded lines.

"Third AC Intertie capacity agreements" reflect unearned revenue from customers related to the Third AC Intertie capacity project. Revenue is being recognized over an estimated 49-year life of the related assets.

"Legal claims and settlements" reflect amounts accrued for outstanding legal claims and settlements. (See Note 14, Commitments and Contingencies.)

"Federal Employees' Compensation Act" reflects the actuarial estimated amount of future payments for current recipients of BPA's worker compensation benefits.

"Derivative instruments" reflect the unrealized loss of the derivative portfolio which includes physical power purchase and sale transactions.

"Fiber optic leasing fees" reflect unearned revenue related to the leasing of the fiber optic cable. Revenue is being recognized over the lease terms extending through 2024.

12. Risk Management and Derivative Instruments

BPA is exposed to various forms of market risk including commodity price risk, commodity volumetric risk, interest rate risk, credit risk and event risk. Non-performance risk, which includes credit risk, is described in Note 13, Fair Value Measurements. BPA has formalized risk management processes in place to manage agency risks, including the use of derivative instruments. The following describes BPA's exposure to and management of risks.

RISK MANAGEMENT

Due to the operational risk posed by fluctuations in river flows and electricity market prices, net revenues that result from underlying surplus or deficit energy positions are inherently uncertain. BPA's Transacting Risk Management Committee has responsibility for the oversight of market risk and determines the transactional risk policy and control environment at BPA. Through simulation and analysis of the hydro supply system, experienced business and risk managers install market price risk measures to capture additional market related risks, including credit and event risk.

COMMODITY PRICE RISK AND VOLUMETRIC RISK

BPA has exposure to commodity price risk through fluctuations in electricity market prices that affect the value of energy bought and sold. Volumetric risk is the uncertainty of energy production from the hydro system. The combination of the two results in net revenue uncertainty. BPA routinely models commodity price risk and volumetric risk through parametric calculations, Monte Carlo simulations and general market observations to derive net revenues at risk, mark-to-market valuations, value at risk and other metrics as appropriate. These metrics capture the uncertainty around single point forecasts in order to monitor changes in the revenue risk profile from changes in market price, market price volatility and forecasted hydro generation. BPA measures and monitors the output of these methods on a regular basis. In order to mitigate revenue uncertainty that is beyond the agency's risk tolerance, BPA enters into short-term and long-term purchase and sale contracts by using instruments such as forwards, futures, swaps, and options.

CREDIT RISK

Credit risk relates to the loss that might occur as a result of counterparty non-performance. BPA mitigates credit risk by reviewing counterparties for creditworthiness, establishing credit limits and monitoring credit exposure on a daily basis. To further manage credit risk, BPA obtains credit support such as letters of credit, parental guarantees, cash in the form of prepayment and/or deposit of escrow from some counterparties. BPA monitors counterparties for changes in financial condition and regularly updates credit reviews. BPA uses scoring models, publicly available financial information and external ratings from major credit rating agencies to determine appropriate levels of credit for its counterparties.

During fiscal year 2013, BPA experienced no material losses as a result of any customer defaults or bankruptcy filings. As of Sept. 30, 2013, BPA had $25.9 million in credit exposure to purchase and sale contracts after taking into account netting rights. BPA's credit exposure, net of cash collateral, to sub-investment grade counterparties was less than one percent of total outstanding credit exposures. BPA's top five credit exposures were $21.0 million, or 81.0 percent, of the total credit exposure.

INTEREST RATE RISK

BPA has the ability to issue variable rate debt to the U.S. Treasury. BPA manages the interest rate risk presented by variable rate U.S. Treasury debt by holding an identical amount of variable rate U.S. Treasury security investments with a similar maturity profile. These U.S. Treasury investments earn interest at a variable rate that is correlated, but not identical, to the interest rate paid on U.S. Treasury variable rate debt. (See Note 2, Investments in U.S. Treasury Securities and Note 7, Borrowings from U.S. Treasury.)

DERIVATIVE INSTRUMENTS

Commodity Contracts

BPA's forward electricity contracts are eligible for the normal purchases and normal sales exception if they require physical delivery, are expected to be used or sold by BPA in the normal course of business and meet the derivative accounting definition of capacity described in the Derivatives and Hedging accounting guidance. These transactions are not recorded at fair value in the financial statements. Recognition of these contracts in Sales or Purchased power in the Combined Statements of Revenues and Expenses occurs when the contracts settle.

For derivative instruments not eligible for the normal purchases and normal sales exception, BPA recorded unrealized gains of $4.6 million and unrealized losses of $30.4 million in Regulatory assets and liabilities in the Combined Balance Sheets in fiscal years 2013 and 2012, respectively. Realized gains and losses are included in Sales and Purchased power in the Combined Statements of Revenues and Expenses as the contracts are delivered and settled.

When available, quoted market prices or prices obtained through external sources are used to measure a contract's fair value. For contracts without available quoted market prices, fair value is determined based on internally developed modeled prices. (See Note 13, Fair Value Measurements.)

As of Sept. 30, 2013, the derivative commodity contracts recorded at fair value totaled 4.8 million MWh (gross basis) with delivery months extending to September 2019. BPA does not apply hedge accounting.

DERIVATIVE ASSETS AND LIABILITIES MEASURED AT FAIR VALUE

As of Sept. 30 — thousands of dollars	**2013**	2012
Assets		
Derivative instruments [1]		
Commodity contracts, gross	**$ 5,377**	$ 14,263
Less: netting [2]	**(563)**	(2,122)
Total, net	**$ 4,814**	$ 12,141
Liabilities		
Derivative instruments [1]		
Commodity contracts, gross	**$ (27,671)**	$ (41,171)
Less: netting [2]	**563**	2,122
Total, net	**$ (27,108)**	$ (39,049)

[1] Derivative instruments assets and liabilities are included in Deferred charges and other and Deferred credits and other in the Combined Balance Sheets, respectively. (See Note 5, Deferred Charges and Other and Note 11, Deferred Credits and Other.)
[2] Netting represents a balance sheet adjustment for same counterparty master netting arrangements.

13. Fair Value Measurements

BPA applies Fair Value Measurements and Disclosures accounting guidance to certain assets and liabilities including commodity derivative instruments, nuclear decommissioning trusts and other investments. BPA maximizes the use of observable inputs and minimizes the use of unobservable inputs when measuring fair

value. Fair value is based on actively quoted market prices, if available. In the absence of actively quoted market prices, BPA seeks price information from external sources, including broker quotes and industry publications. If pricing information from external sources is not available, BPA uses forward price curves derived from internal models based on perceived pricing relationships to major trading hubs.

BPA also utilizes the following fair value hierarchy, which prioritizes the inputs to valuation techniques used to measure fair value, into three broad levels:

Level 1 – Quoted prices (unadjusted) in active markets for identical assets and liabilities that BPA has the ability to access at the measurement date. Instruments categorized in Level 1 primarily consist of financial instruments such as fixed income investments, equity mutual funds and money market funds.

Level 2 – Inputs other than quoted prices included within Level 1 that are either directly or indirectly observable for the asset or liability, including quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are observable for the asset or liability, and inputs that are derived from observable market data by correlation or other means. Instruments categorized in Level 2 include certain non-exchange traded commodity derivatives and certain agency securities as part of the lease financing trust funds investments. Fair value for certain non-exchange traded derivatives is based on forward exchange market prices and broker quotes adjusted and discounted. Lease financing trust funds investments are based on a market input evaluation pricing methodology using a combination of observable market data such as current market trade data, reported bid/ask spreads, and institutional bid information.

Level 3 – Unobservable inputs for the asset or liability, including situations where there is little, if any, market activity for the asset or liability. Instruments categorized in Level 3 include long dated and modeled commodity contracts where inputs into the valuation are indicative broker quotes for a significant tenor.

The fair value hierarchy gives the highest priority to quoted prices in active markets (Level 1) and the lowest priority to unobservable data (Level 3). In some cases, the inputs used to measure fair value might fall in different levels of the fair value hierarchy. The lowest level input that is significant to a fair value measurement in its entirety determines the applicable level in the fair value hierarchy. Assessing the significance of a particular input to the fair value measurement in its entirety requires judgment, considering factors specific to the asset or liability.

BPA includes non-performance risk in calculating fair value measurements. This includes a credit risk adjustment based on the credit spreads of BPA's counterparties when in an unrealized gain position, or on BPA's own credit spread when in an unrealized loss position. BPA's assessment of non-performance risk is generally derived from the credit default swap market and from bond market credit spreads. The impact of the credit risk adjustments for all outstanding derivatives was immaterial to the fair value calculation at Sept. 30, 2013, and 2012.

ASSETS AND LIABILITIES MEASURED AT FAIR VALUE ON A RECURRING BASIS

As of Sept. 30, 2013 — thousands of dollars

	Level 1	Level 2	Level 3	Netting[2]	Total
Assets					
Nonfederal nuclear decommissioning trusts					
Equity index funds	$117,212	$ —	$ —	$ —	**$ 117,212**
U.S. government obligation mutual funds	76,801	—	—	—	**76,801**
Corporate bond index funds	60,726	—	—	—	**60,726**
Cash and cash equivalents	13	—	—	—	**13**
Derivative instruments [1]					
Commodity contracts	—	630	4,747	(563)	**4,814**
Lease financing trust funds					
U.S. government sponsored enterprise obligations	—	50,265	—	—	**50,265**
U.S. government obligations	—	21,676	—	—	**21,676**
Total	$254,752	$ 72,571	$ 4,747	$ (563)	**$ 331,507**
Liabilities					
Derivative instruments [1]					
Commodity contracts	$ —	$(27,671)	$ —	$ 563	**$ (27,108)**
Total	$ —	$(27,671)	$ —	$ 563	**$ (27,108)**

As of Sept. 30, 2012 — thousands of dollars

Assets					
Nonfederal nuclear decommissioning trusts					
Equity index funds	$100,050	$ —	$ —	$ —	$ 100,050
U.S. government obligation mutual funds	74,067	—	—	—	74,067
Corporate bond index funds	61,460	—	—	—	61,460
Cash and cash equivalents	21	—	—	—	21
Derivative instruments [1]					
Commodity contracts	—	258	14,005	(2,122)	12,141
Lease financing trust funds					
U.S. government sponsored enterprise obligations	—	73,117	—	—	73,117
U.S. government obligations	—	17,979	—	—	17,979
Total	$235,598	$ 91,354	$ 14,005	$ (2,122)	$ 338,835
Liabilities					
Derivative instruments [1]					
Commodity contracts	$ —	$(41,132)	$ (39)	$ 2,122	$ (39,049)
Total	$ —	$(41,132)	$ (39)	$ 2,122	$ (39,049)

[1] Derivative instruments assets and liabilities are included in Deferred charges and other and Deferred credits and other in the Combined Balance Sheets, respectively. (See Note 5, Deferred Charges and Other and Note 11, Deferred Credits and Other.) See Note 12, Risk Management and Derivative Instruments for more information related to BPA's risk management strategy and use of derivative instruments.

[2] Netting represents a balance sheet adjustment for same counterparty master netting arrangements.

Level 3 derivative commodity contracts are power contracts measured at fair value on a recurring basis using the California-Oregon Border (COB) forward price curve. COB does not have a sufficient number of transactions to be considered a liquid trading point. Therefore, COB prices are considered unobservable. Prices are considered a key component to COB contract valuations. All valuation pricing data is generated internally by BPA's risk management organization.

The risk management organization constructs the COB forward price curve through the use of broker quotes and bid/offer spreads to a more liquid trading point. In periods where broker quotes are not available, the risk management organization derives monthly prices by applying seasonal shaping factors and/or models monthly prices based on historical broker quotes and spreads from a closely located major trading point. BPA management believes this approach maximizes the use of pricing information from external sources and is currently the best option for valuation.

The fair value of derivative commodity contracts transacted at COB was $4.7 million at Sept. 30, 2013. The volumes under these contracts will be physically delivered in various quantities through April 2016.

As of Sept. 30, 2013, forward prices for power to be delivered at COB through April 2016 varied as shown in the following table. All prices are presented in dollars per megawatt-hour.

COB	Low	High	Weighted Average
On-Peak	$32.30	$49.36	$42.37
Off-Peak	$21.77	$43.47	$34.28

Forward power prices are influenced by, among other factors, seasonality, hydro forecasts, expectations of demand growth, planned changes in the regional generating plants, and the emergence of new marginal fuels for generation.

COMMODITY CONTRACTS

The following table presents the changes in the assets and liabilities measured at fair value on a recurring basis and included in the Level 3 fair value category.

As of Sept. 30 — thousands of dollars	**2013**	2012
Beginning Balance	**$ 13,966**	$ 24,643
Changes in unrealized gains (losses)[1]	**(9,219)**	(10,677)
Ending Balance	**$ 4,747**	$ 13,966

[1] Unrealized gains and losses are included in Regulatory assets and liabilities in the Combined Balance Sheets. Realized gains and losses are included in Sales and Purchased power in the Combined Statements of Revenues and Expenses.

14. Commitments and Contingencies

INTEGRATED FISH AND WILDLIFE PROGRAM

The Northwest Power Act directs BPA to protect, mitigate and enhance fish and wildlife resources to the extent they are affected by federal hydroelectric projects on the Columbia River and its tributaries. BPA makes expenditures and incurs other costs for fish and wildlife projects that are consistent with the Northwest Power Act and that are consistent with the Pacific Northwest Power and Conservation Council's Columbia River Basin Fish and Wildlife Program. In addition, certain fish species are listed under the Endangered Species Act (ESA) as threatened or endangered. BPA is financially responsible for expenditures and other costs arising from conformance with the ESA and certain biological opinions (BiOp) prepared by the National Oceanic and Atmospheric Administration Fisheries Service and the U.S. Fish and Wildlife Service in furtherance of the ESA. BPA's total commitment including timing of payments under the Northwest Power Act, ESA and BiOp is not fixed or determinable. However, the current estimate of long-term fish and wildlife agreements with a contractual commitment which BPA has entered into is $799.7 million as of Sept. 30, 2013. These agreements will expire at various dates between fiscal years 2018 and 2025.

IRRIGATION ASSISTANCE

Scheduled distributions

As of Sept. 30 — thousands of dollars	
2014	$ 52,547
2015	52,108
2016	60,954
2017	51,391
2018	27,564
2019 through 2045	362,322
Total	**$ 606,886**

As directed by law, BPA is required to establish rates sufficient 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. In establishing power rates, particular statutory provisions guide the assumptions that BPA makes as to the amount and timing of such distributions. Accordingly, these distributions are not considered to be regular operating costs of the power program and are treated as distributions from accumulated net revenues when paid. Future irrigation assistance payments are scheduled to total $606.9 million over a maximum of 66 years since the time the irrigation facilities were completed and placed in service. BPA is required by the Grand Coulee Dam - Third Powerplant Act to demonstrate that reimbursable costs of the FCRPS will be returned to the U.S. Treasury from BPA within the period prescribed by law. BPA is required to make a similar demonstration for the costs of irrigation projects to the extent the costs have been determined to be beyond the irrigators' ability 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. Irrigation assistance excludes $40.3 million for Teton Dam which failed prior to completion and for which BPA has no obligation to repay these costs.

FIRM PURCHASE POWER COMMITMENTS

As of Sept. 30 — thousands of dollars	
2014	$ 40,190
2015	24,656
2016	22,058
2017	26,582
2018	31,036
2019	33,699
Total	**$ 178,221**

BPA periodically enters into long-term commitments to purchase power for future delivery. When BPA forecasts a resource shortage based on expected obligations and the historical water record for the Columbia River basin, BPA takes a variety of steps to cover the shortage including entering into power purchase commitments. Additionally, under BPA's current tiered rates structure, BPA's customers may request that BPA meet their power requirements in excess of their share of BPA's generation resources. BPA may meet these requests by entering into power purchase commitments. The above table includes firm purchase power agreements of known costs that are currently in place to assist in meeting expected future obligations under long-term power

sales contracts. Included are five contracts for winter purchases through fiscal year 2014 and 11 purchases made specifically to meet BPA's commitments to sell power at Tier 2 rates in fiscal years 2014-2019. The expenses associated with the winter purchases for 2013, 2012 and 2011 were $43.1 million, $43.4 million and $43.4 million, respectively. The expense associated with Tier 2 purchases were $23.4 million and $8.5 million for fiscal years 2013 and 2012, respectively. BPA has several power purchase agreements with wind-powered and other generating facilities that are not included in the table above as payments are based on the variable amount of future energy generated and there are no minimum payments required.

ENERGY EFFICIENCY PROGRAM

BPA is required by the Pacific Northwest Electric Power Planning and Conservation Act to meet the net firm power load requirements of its customers in the Pacific Northwest. BPA is authorized to help meet its net firm power load through the acquisition of electric conservation measures. BPA makes available a portfolio of initiatives and infrastructure support activities to its customers to ensure the conservation targets established in the Northwest Power and Conservation Council's Sixth Power Plan are achieved. These initiatives and activities are often executed via long-term conservation commitments made by BPA to its customers. These commitments are captured through $174.7 million of agreements with utility customers and contractors that provide support in the way of energy efficiency program research, development and implementation. The timing of the payments under these commitments is not fixed or determinable and these agreements will expire at various dates through fiscal year 2016.

1989 ENERGY NORTHWEST LETTER AGREEMENT

In 1989, BPA 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.

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 insurance policies purchased from NEIL by BPA include: 1) Primary Property and Decontamination Liability Insurance; 2) Decontamination Liability, Decommissioning Liability and Excess Property Insurance; and 3) NEIL I Accidental Outage Insurance.

Under each insurance policy, BPA could be subject to a retrospective premium 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 Liability Insurance policy is $10.9 million. For the Decontamination Liability, Decommissioning Liability and Excess Property Insurance policy, the maximum assessment is $15.9 million. For the NEIL I Accidental Outage Insurance policy, the maximum assessment is $4.4 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 $375.0 million, BPA could be subject to a retrospective assessment of up to $111.9 million limited to an annual maximum of $17.5 million. Assessments would be included in BPA's costs and recovered through rates. As of Sept. 30, 2013, there have been no assessments to BPA under either of these programs.

ENVIRONMENTAL MATTERS

From time to time there are sites for which BPA, Corps or Reclamation may be identified as potential responsible parties. Costs associated with cleanup of sites are not expected to be material to the FCRPS' financial statements. As such, no material liability has been recorded.

LITIGATION

Southern California Edison

Southern California Edison (SCE) filed two separate actions pending in the U.S. Court of Federal Claims against BPA related to a power sales and exchange agreement (Sale and Exchange Agreement) between BPA and SCE. The actions challenged: 1) BPA's decision to convert the contract from a sale of power to an exchange of power as provided for under the terms of the contract (Conversion Claim); and 2) BPA's termination of the Sales and Exchange Agreement due to SCE's nonperformance (Termination Claim).

In 2006, BPA and SCE executed an agreement to settle the claims wherein BPA would make a payment of $28.5 million plus applicable interest to SCE if certain identified conditions were met, including a final resolution of BPA's claims pending in the California refund proceedings and related litigation as discussed below. BPA has recorded a liability of $28.5 million on the basis that all conditions have been met except the final resolution in the California refund proceedings and related litigation which management considers probable. However, interest payable has not been recorded because the amount that will be paid cannot be reasonably estimated. BPA established an offsetting regulatory asset, as the costs will be collected in future rates.

California parties' refund claims

BPA was a party to proceedings at FERC that sought refunds for sales into markets operated by the California Independent System Operator (ISO) and the California Power Exchange (PX) during the California energy crisis of 2000-2001. BPA, along with a number of other governmental utilities, challenged FERC's refund authority over governmental utilities. In BPA v. FERC, 422 F.3d 908 (9th Cir. 2005) the Ninth Circuit Court found that governmental utilities, like BPA, were not subject to FERC's statutory refund authority. As a consequence of the Ninth Circuit Court's decision, three California investor-owned utilities along with the State of California filed breach of contract claims in the United States Court of Federal Claims against BPA. The complaints, filed in 2007, alleged that BPA was contractually obligated to pay refunds on transactions where BPA received amounts in excess of mitigated market clearing prices established by FERC.

In May 2012, the Court of Federal Claims issued an opinion in the trial on liability issues and held that BPA breached its contracts with the California parties by failing to pay refunds for amounts owed in excess of the mitigated market clearing prices during the refund period. BPA estimates that such refund amounts, including interest, through Sept. 30, 2013, could amount up to approximately $54.1 million. While this ruling does not establish a specific liability in this matter, BPA recorded a liability in this amount.

The plaintiffs' contractual breach claims were premised in part upon a November 2009 order where FERC found that as a consequence of establishing a new just and reasonable rate for the purpose of calculating refunds for jurisdictional utilities, it also retroactively reset the prices under the ISO and PX tariffs for all market participants. BPA separately appealed the November 2009 order to the Ninth Circuit Court. In August 2012, subsequent to the ruling of the Court of Federal Claims described above, the Ninth Circuit Court issued a decision on this appeal and held that establishing a new price for purposes of calculating refunds did not retroactively revise the rate for all market participants. The United States Department of Justice, representing BPA in this matter, filed a motion to reconsider the May 2012 decision of the Court of Federal Claims based upon this recent Ninth Circuit Court ruling. On April 2, 2013, the Court of Federal Claims denied the motion for reconsideration.

In a separate proceeding at FERC as part of the California refund docket, an administrative law judge appointed by the FERC Commissioners conducted a hearing in 2012 to make certain findings related to three additional classes of transactions ("summer 2000, exchange, and multi-day"). On Feb. 15, 2013, the FERC administrative law judge issued the initial decision on the summer 2000, exchange, and multi-day transactions to the FERC Commissioners. As part of his findings, the FERC administrative law judge determined that BPA violated the tariff with 84 summer 2000 transactions and that prices charged for the exchange and multi-day transactions were unjust and unreasonable and are subject to refund. The initial decision has been appealed to the commissioners and is advisory to them. The FERC administrative law judge recommended BPA pay $15.1 million for multi-day transactions and $44.5 million for exchange transactions, plus interest. However,

BPA liability for those amounts would not ripen unless the Commissioners adopt the initial decision and the related April 2, 2013 Court of Federal Claims order (mentioned below) stands. While the administrative judge made findings of summer period tariff violations by BPA, he did not make any recommendation regarding refund amounts related to them. When the Commissioners established the hearing, they stated that when they receive the administrative law judge's factual determinations regarding the summer period, they will decide the further steps to be taken. BPA does not believe the initial decision is defensible and filed a Brief on Exceptions on April 11, 2013, in an effort to overturn it. FERC will consider all the parties' arguments and issue a Final Decision.

The California parties filed separate motions with the Court of Federal Claims requesting a ruling on their declaratory relief claims for the summer 2000, exchange and multi-day transactions. On April 2, 2013, the Court of Federal Claims issued a Declaratory Judgment in favor of the California parties' relief claims.

A trial on the damages phase of the proceedings at the Court of Federal Claims was scheduled for June 2013, but has been delayed due to the retirement of the presiding judge. In April 2013, a new judge was appointed to preside over the cases. The new judge indicated that she will be reviewing all of the prior decisions in these proceedings before rescheduling the trial on the damages phase of the case. BPA has not adjusted its liability for the California parties' refund claims as a result of the events occurring at the FERC and the Court of Federal Claims during fiscal year 2013 on the basis that management has determined that it is not probable that such events will ultimately result in an increase in liabilities already recorded in connection with resolution of the California parties' refund claims.

Rates

BPA's rates are frequently the subject of litigation. Most of the litigation involves claims that BPA's rates are inconsistent with statutory directives, are not supported by substantial evidence in the record, or are arbitrary and capricious. It is the opinion of BPA's general counsel that if any rate were to be rejected, the remedy accorded would be a remand to BPA to establish a new rate. BPA's flexibility in establishing rates could be restricted by the rejection of a BPA rate, depending on the grounds for the rejection. BPA is unable to predict, however, what new rate it would establish if a rate were rejected. If BPA were to establish a rate that was lower than the rejected rate, a petitioner may be entitled to a refund in the amount overpaid; however, BPA is required by law to set rates to meet all of its costs. Thus, it is the opinion of BPA's general counsel that BPA may be required to increase its rates to seek to recover the amount of any such refunds, if needed.

Currently pending before the Ninth Circuit Court are numerous challenges to the decisions BPA reached in the WP-07 Supplemental Rate Case and the WP-10 Rate Case. The petitioners in these cases challenge, among other issues, BPA's calculation of certain refunds (referred to as "Lookback Amounts") associated with rates charged to BPA's preference customers from fiscal years 2002 through 2008. These refunds resulted from BPA's implementation of an REP settlement in fiscal years 2002 through 2008 that was later found unlawful and payment of REP benefits to BPA's investor-owned utility customers under that settlement. Following extensive negotiations, representatives from most of the region's consumer- and investor-owned utilities reached a proposed agreement on how BPA should establish REP benefits and recover the costs of those benefits through rates for the fiscal year period 2002 through 2028. BPA conducted a formal evidentiary hearing to review the proposed settlement agreement, which was signed by the administrator on July 2011. In October 2011, two petitions challenging the 2012 Settlement Agreement were filed. BPA settled with one petitioner and the remaining petitioner pursued its appeal. On October 28, 2013, the Ninth Circuit Court issued an opinion in which it upheld BPA's decision to adopt the 2012 Settlement Agreement. This decision is still subject to rehearing.

The 2012 Settlement Agreement completely replaced and superseded BPA's REP-related decisions in the WP-07 Supplemental Rate Case and WP-10 Rate Case. In 2011, BPA and many consumer-owned utilities filed respective motions in the Ninth Circuit Court to dismiss pending litigation challenging those decisions on the grounds that such challenges were moot due to the 2012 Settlement Agreement. Consideration of these motions has been stayed pending resolution of the challenge to the 2012 Settlement Agreement. As described above, the Court issued a decision on October 28, 2013, affirming BPA's decision to adopt the 2012 Settlement Agreement, but such decision is still subject to rehearing.

The cost of providing REP benefits will be recovered through future rates. BPA has recorded regulatory assets, a liability and a regulatory liability for the effects of the 2012 Settlement Agreement. (See Note 10, Residential Exchange Program.)

Other

The FCRPS may be affected by various other legal claims, actions and complaints, including litigation under the Endangered Species Act, which may include BPA as a named party. Certain of these cases may involve material amounts. BPA is unable to predict whether the FCRPS will avoid adverse outcomes in these legal proceedings; however, BPA believes that disposition of pending matters will not have a materially adverse effect on the FCRPS' financial position or results of operations for fiscal year 2013.

Judgments and settlements are included in BPA's costs and recovered through rates. Except with respect to the SCE, California parties' refund claims, and REP matters described above, BPA has not recorded a liability for the above legal matters. (See Note 11, Deferred Credits and Other, for discussion of amounts accrued for outstanding legal claims and settlements.)

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FEDERAL REPAYMENT

Revenue requirement study

The submission of BPA's annual report fulfills the reporting requirements of the Grand Coulee Dam — Third Powerplant Act, Public Law 89-448. The revenue requirement study demonstrates repayment of federal investment. It reflects revenues and costs consistent with BPA's 2012 Final Wholesale Power and Transmission Rate Proposals of Aug. 1, 2011, for fiscal years 2012 and 2013. (See BP-12-FS-BPA-02 for Power and BP-12-FS-BPA-07 for Transmission.) The final proposals filed with FERC contain the official amortization schedule for the rate periods. FERC approved the BP-12 filings on Dec. 31, 2012.

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 FERC 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 be sufficient to:

1. Pay the cost of operating and maintaining the power system.
2. Pay the cost of obtaining power through purchase and exchange agreements (nonfederal projects) and transmission services that BPA is obtaining under capitalized lease-purchase agreements.
3. Pay interest on and repay outstanding U.S. Treasury borrowings 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 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 (48 years).
8. Repay the appropriated investment in each replacement at a federal hydroelectric project within its service life.

9. Repay irrigation investment at federal reclamation projects assigned for payment from FCRPS revenues, after all other elements in the priority of payments are paid and within the same period established for irrigation water users to repay their share of construction costs. 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, irrigation assistance payments from projects authorized subsequent to Public Law 89-448 are to be scheduled to not 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.

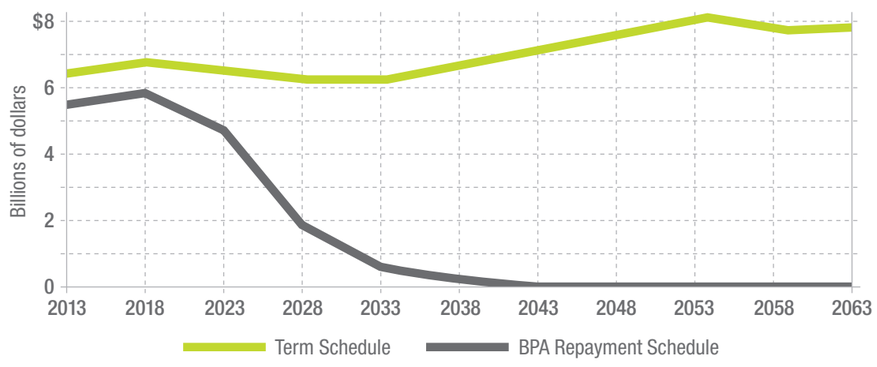
Reporting requirements of Public Law 89-448 are met so long as the unrepaid FCRPS investment and irrigation assistance resulting from BPA's repayment schedule are less than or equal to the allowable unrepaid investment in each year. While the comparison is illustrated by the following graphs representing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

Repayment of FCRPS investment

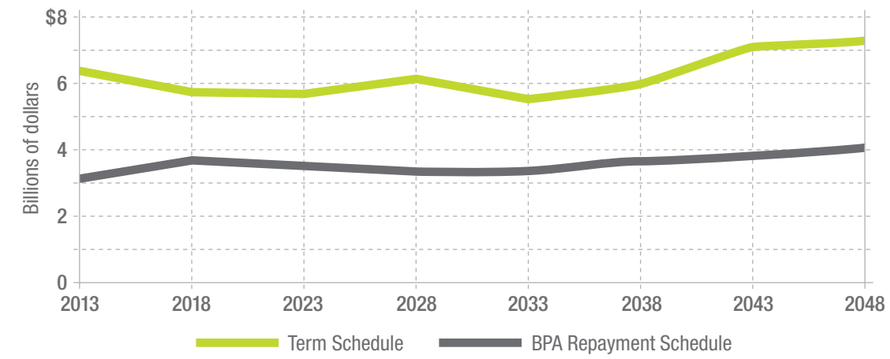
The graphs for Unrepaid Federal Generation and Transmission Investment illustrate that unrepaid investment resulting from BPA's generation and transmission repayment schedules is less than the allowable unrepaid investment. This demonstrates that BPA's rates are sufficient to recover all FCRPS investment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

The term schedule lines in the graphs show how much of the obligation can remain unpaid in accordance with the repayment periods for the generation and transmission components of the FCRPS. The BPA repayment schedule lines show how much of the obligation remains to be repaid according to BPA's repayment schedules. In each year, BPA's repayment schedule is ahead of the term schedule. This occurs because BPA plans repayment both to comply with obligation due dates and to minimize costs over the entire repayment study horizon (35 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.

UNREPAID FEDERAL GENERATION INVESTMENT — Includes Future Replacements

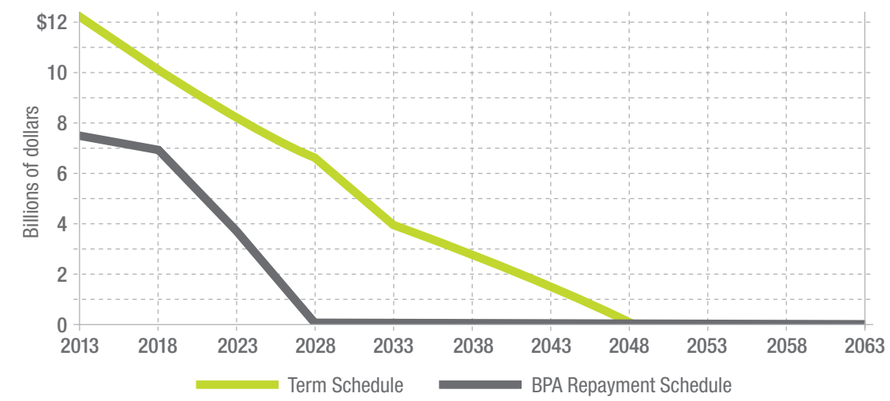


UNREPAID FEDERAL TRANSMISSION INVESTMENT — Includes Future Replacements



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 2013 is scheduled to be returned to the U.S. Treasury within its repayment period and ahead of due dates.

UNREPAID FEDERAL INVESTMENT — Excludes Future Replacements



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.

EXECUTIVES

Elliot E. Mainzer, Acting
Administrator and Chief Executive Officer

Gregory K. Delwiche, Acting
Deputy Administrator

Claudia R. Andrews, Acting
Chief Operating Officer

Nancy M. Mitman, Acting
Executive Vice President for Finance
and Chief Financial Officer

John L. Hairston, Acting
Executive Vice President for Internal Business Services

Cathy L. Ehli, Acting
Executive Vice President for Corporate Strategy

Randy A. Roach
Executive Vice President for General Counsel
and General Counsel

F. Lorraine Bodi
Vice President for Environment,
Fish and Wildlife

Larry D. Buttress
Vice President for Information Technology
and Chief Information Officer

Samuel D. Cannady
Chief Risk Officer

Peter T. Cogswell, Acting
Chief Public Affairs Officer

Terry V. Oliver
Chief Technology Innovation Officer

POWER SERVICES

Mark O. Gendron
Senior Vice President for Power Services (Acting)
and Vice President for Northwest Requirements Marketing

Suzanne B. Cooper
Vice President for Bulk Marketing

Richard B. Génecé
Vice President for Energy Efficiency

Stephen R. Oliver
Vice President for Generation Asset Management

TRANSMISSION SERVICES

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Senior Vice President for Transmission Services

Richard L. Shaheen
Vice President for Engineering and Technical Services

Kimberly A. Leathley, Acting
Vice President for Transmission Marketing and Sales

Robin R. Furrer
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Eastern Area Customer Service Center
707 W. Main Ave., Suite 500
Spokane, WA 99201
509-625-1300

Montana Customer Service Center
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Richland Customer Service Center
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EAST REGION

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Kalispell District
2520 U.S. Highway 2 East
Kalispell, MT 59901
406-751-7800

Spokane District
2410 E. Hawthorne Road
Mead, WA 99201
509-466-3833

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509-542-5459

SOUTH REGION

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86000 Hwy. 99 S.
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541-988-7401

Longview District
3750 Memorial Park Drive
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