Opening up new opportunities

ANNUAL REPORT 2004

Western Area Power Administration

Continue

“Opening up new opportunities”

When it comes to doing business, Western continually looks for opportunities to reach out to new customers, tailor services or enhance the reliability of the grid. In some cases, we have initiated these opportunities due to changes in technology or priorities; in others, changes in the utility industry beckoned us to look for new opportunities to reach out in innovative ways.

Projects highlighted in the FY 2004 report include:

- Western’s new contract-based sub-control area
- New allocations to tribal customers
- Wind studies in the Dakotas
- Transmission planning in the Rocky Mountain Region

This year’s Annual Report highlights these four areas to show that Western is opening up new opportunities to enhance not only how we do business, but also to help our customers and others move forward in an ever-changing utility environment.

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Western at a glance

Marketing profile

	FY 2004
Firm energy revenue	$663.8 million
Nonfirm energy revenue	$169.4 million
Firm energy sales	34.3 billion kWh
Nonfirm energy sales	5.4 billion kWh
Composite firm rate	17.68 mills KWh
Composite transmission rate	$1.53 kW/mo
Coincident peak load (est.)	6,067 MW
Ancillary service revenue	$9.3 million
Transmission service revenue	$170.7 million

Customer profile

	Number	Percent	Sales (billion kWh)	Revenue (million $)
Municipalities	299	44.1%	11.3	240.5
Cooperatives	60	8.8%	7.2	150.1
Public utility districts	17	2.5%	4.1	95.8
Federal agencies	35	5.2%	1.5	35.6
State agencies	47	6.9%	8.6	143.2
Irrigation districts	47	6.9%	0.7	15.3
Native American tribes	32	4.7%	0.7	10.0
Investor-owned utilities	25	3.7%	1.2	45.3
Power marketers	29	4.3%	2.2	71.0
Project use (Reclamation)	82	12.1%	1.7	14.9
Interproject	5	0.7%	0.4	11.4
Total	**678**	**100.0%**	**39.6**	**833.1**
Firm-only customers	532			
Nonfirm-only customers	74			
Firm and nonfirm customers	72			
Total	**678**			

IRP profile

Total Integrated Resource Plans submitted	299
Individual customer IRPs	111
Small customer plans submitted	83
IRPs from cooperatives	34
Minimum investment reports	71
Customers and members represented	715

Note: Some columns may not add due to rounding.

Repayment profile

Principal repaid in FY 2004	$82 million
Federal	$78 million
Non-Federal	$4 million
Federally-financed non-power	0 million
Total investment	$7.94 billion
Federal	$7.74 billion
Non-federal	$0.20 billion
Total repaid	$2.96 billion
Federal	$2.90 billion
Non-federal	$0.06 billion

Financial profile (in thousands)

Assets	$4,156,913
Liabilities	$509,285
Gross operating revenues	$992,350
Sales of electric power	$818,115
Other operating income	$174,235
Operating expenses	$876,072
Operation and maintenance expense	$297,641
Administration and general expense	$52,742
Purchased power expense	$373,083
Purchased transmission expense	$49,407
Depreciation	$103,199
Net interest expense	$167,556

Resource profile

Hydro powerplants	56
Thermal powerplants	1
Total powerplants	57
Actual operating capability-July 1, 2004	9,159 MW
Total units	182
Net generation	28,314 GWh
Purchased power	13,165 GWh

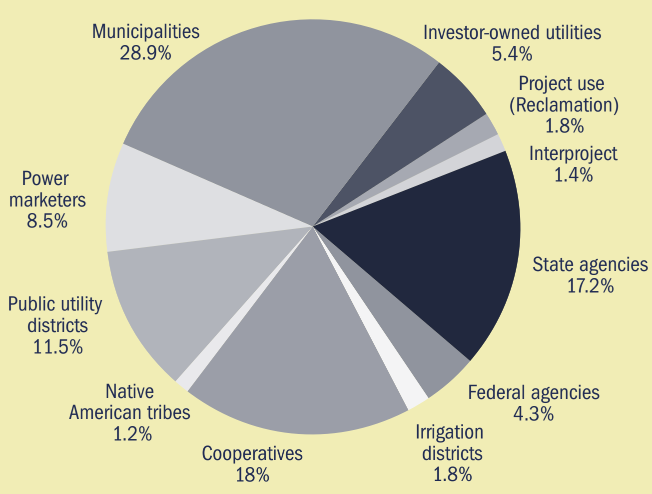
Transmission system profile

Communication sites	435
Substations	272
Transmission lines	16,938 miles
Transformer capacity	25,387,160 kVA

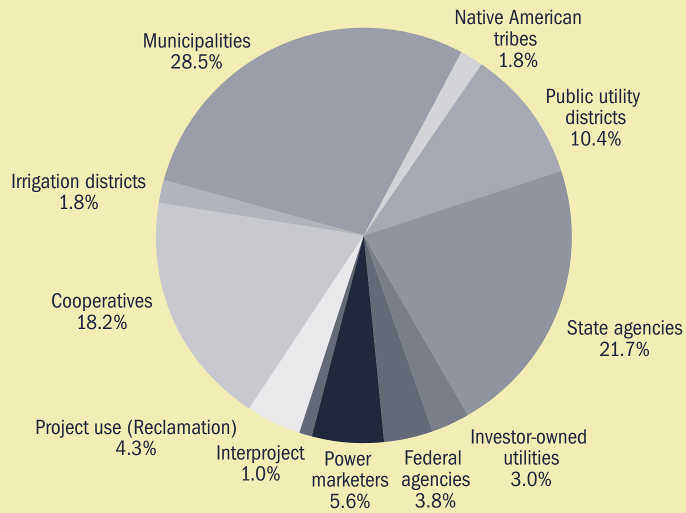
Employee profile

Federal Full-Time Equivalent usage	1,320

WHERE OUR REVENUE COMES FROM ($)



WHERE OUR ENERGY GOES (kWh)



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Administrator's letter

The Honorable Samuel Bodman
Secretary of Energy
Washington, D.C. 20585

Dear Secretary Bodman:

I am pleased to submit to you Western's FY 2004 Annual Report, which outlines areas where Western is opening up new opportunities to advance our mission or enhance the reliability of the bulk interconnected power system.

In keeping true to our mission of marketing and delivering reliable, cost-based hydroelectric power and related services, Western marketed more than 39.6 billion kilowatthours of energy to 678 wholesale customers in FY 2004. This resulted in revenues from the sale of power totaling more than $833 million.

"While we are often inundated with challenges to how we operate—due to system constraints, reduced budgets, escalating costs or even Mother Nature—we were uplifted by the solutions that emerged in FY 2004 to help us address such issues."

While we often are inundated with challenges to how we operate—due to system constraints, reduced budgets, escalating costs or even Mother Nature—we were uplifted by the solutions that emerged in FY 2004 to help us address such issues.

For example, constrained transmission in Central California is alleviated with the completion of the Path 15 Upgrade Project, which added a new 500-kV line to resolve a long-standing transmission bottleneck. The project, commissioned in December 2004, also opened up new possibilities for future private-public partnerships to address other constrained transmission paths on the 17,000 miles of transmission lines in our service territory.

Western is looking into solutions for two additional constrained areas in Western's Rocky Mountain and Upper Great Plains regions. These bottlenecks could be improved pending the outcome of the Dakotas Wind Transmission Study that Western is leading and the Rocky Mountain Area Transmission Study in which Western is participating. These studies will not only examine which technologies could be applied to constrained paths in the regions but will also determine whether unused capacity on certain transmission lines could be tapped to accommodate the addition of wind generation.

Looking for innovation in an industry often characterized by price volatility and a limited supply of generation has made wind generation and other renewable energy options look more promising to Western's 678 customers. While Western has no responsibility to meet load growth, we are helping our customers—including Native American tribes—find solutions to their increasing energy needs. For our tribal customers, low-cost Federal power allocations are helping them pursue economic self-sufficiency.

"Looking for innovation in an industry often characterized by price volatility and a limited supply of generation has made wind generation and other renewable energy options look more promising to Western's 678 customers."

Increased self-reliance emerged as a solution for Western's Sierra Nevada Region in FY 2004 when they were facing contracts that were about to expire. These decades-old contracts with Pacific Gas and Electric Company had shielded us from escalating purchase power costs and control area operator fees. The answer surfaced last summer when the region decided to implement an innovative contract-based sub-control area under the control area operated by the Sacramento Municipal Utility District. Such an agreement helps us move forward with more certainty, knowing that we can better control our costs.

Managing our costs is always central to Western's mission, especially in light of continuing budget constraints. To help us deal with the effects of the drought and the ensuing reduction in hydropower generation, in FY 2004 we worked on implementing a new marketing plan that reduces our contract commitments to customers of the Salt Lake City Area/Integrated Projects. We have also continued to pursue advanced purchase power contracts to take advantage of lower market prices for supplemental power.

As we look forward to initiating more solutions to the daily challenges we face, our employees remain committed to opening up new opportunities to better serve the West with Federal hydropower.

Mike Hacskaylo
Administrator

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Western profile

Western markets and transmits about 10,000 megawatts of power from 56 hydropower plants. Western also markets the United States' 547-MW entitlement from the coal-fired Navajo Generating Station near Page, Ariz.

Western sells about 40 percent of regional hydroelectric generation in a service area that covers 1.3 million square miles in 15 states. Our customers include municipalities, cooperatives, public utility and irrigation districts, Federal and state agencies, investor-owned utilities (only one of which purchases firm power from Western), marketers and Native American tribes. They, in turn, provide retail electric service to millions of consumers in Arizona, California, Colorado, Iowa, Kansas, Minnesota, Montana, Nebraska, Nevada, New Mexico, North Dakota, South Dakota, Texas, Utah and Wyoming.

Key focus on transmission

Providing this diverse customer base with reliable transmission is central to Western's mission. Using an integrated 17,000 circuit-mile, high-voltage Federal transmission system, Western delivers reliable electric power to most of the western half of the United States. Since Western's inception in 1977, Western has added more than 3,700 additional miles of lines to its system and has managed hundreds of requests for interconnection. Yet the endless stream of developments in the industry—regional transmission organization formations, changes in control areas and the emergence of Federal Energy Regulatory Commission regulations and policies—have further increased Western's challenge to maintain system reliability.

Western's rates

Western's role in delivering power also includes managing 11 different rate-setting systems (not including the Central Arizona Project's Navajo generation). These rate systems are made up of 14 multipurpose water resource projects and one transmission project. The systems include Western's transmission facilities along with power generation facilities owned and operated primarily by the U.S. Bureau of Reclamation, the U.S. Army Corps of Engineers and the International Boundary and Water Commission.

Employees' dedication

While Western's role in the industry has evolved over the years, the dedication of employees at Western's 51 duty stations has not wavered. Employees scattered throughout Western's vast territory work around the clock to provide power sales, transmission operations and maintenance and engineering services. These duty locations include Western's Corporate Services Office in Lakewood, Colo., and four regions with offices in Billings, Mont.; Loveland, Colo.; Phoenix, Ariz.; and Folsom, Calif. We also market power from our Management Center in Salt Lake City, Utah, and manage system operations and maintenance from offices in Bismarck, N.D.; Fort Peck, Mont.; Huron, S.D.; and Watertown, S.D.

Legislative authority

Congress established Western on Dec. 21, 1977, under Section 302 of the Department of Energy Organization Act. Under this statute, power marketing responsibilities and the transmission system assets previously managed by Reclamation were transferred to Western.

Financing methods

Western receives appropriations from Congress each year to finance the operation and maintenance as well as construction and rehabilitation activities for many of our power and transmission systems—including the Pick-Sloan Missouri Basin Program, Central Valley Project, Parker-Davis Project, Fryingpan-Arkansas Project and the Pacific Northwest-Pacific Southwest Intertie Project. The appropriations provide only a portion of our total funding. In fact, in FY 2004, appropriations of $180.3 million made up only 20 percent of our total authorized funding.

Other sources include 21 percent from power sale receipts, 22 percent from revolving funds and 37 percent from customer advances for reimbursable work. With these other sources, Western's FY 2004 program budget was $885.2 million.

Our FY 2004 appropriation included an annual contribution to the Utah Reclamation Mitigation and Conservation Account as specified in the Reclamation Projects Authorization and Adjustment Act of 1992. Existing legislation allows for the Colorado River Storage, Central Arizona, Seedskadee, Dolores and Fort Peck projects to operate with power receipts through a reimbursable agreement with Reclamation to access permanent appropriations of receipts from the Colorado River Dam Fund. Under the Foreign Relations Authorization Act for FY 1994 and FY 1995, a separate appropriation is provided to operate and maintain Falcon and Amistad project facilities for the International Boundary and Water Commission. We also do work for other Federal and non-Federal organizations under authority of the Economy Act, the Contributed Funds Acts and the Interior Department Appropriations Act of 1928.

Because legislation requires that the U.S. Treasury be repaid by those who benefit from Federal investments in the projects, power sales must produce enough revenue to cover power users' share of annual operation and maintenance project costs. Therefore, we set power rates to recover all costs associated with our activities, as well as the Federal investment in the power facilities (with interest) and certain costs assigned to power for repayment, such as aid to irrigation development.

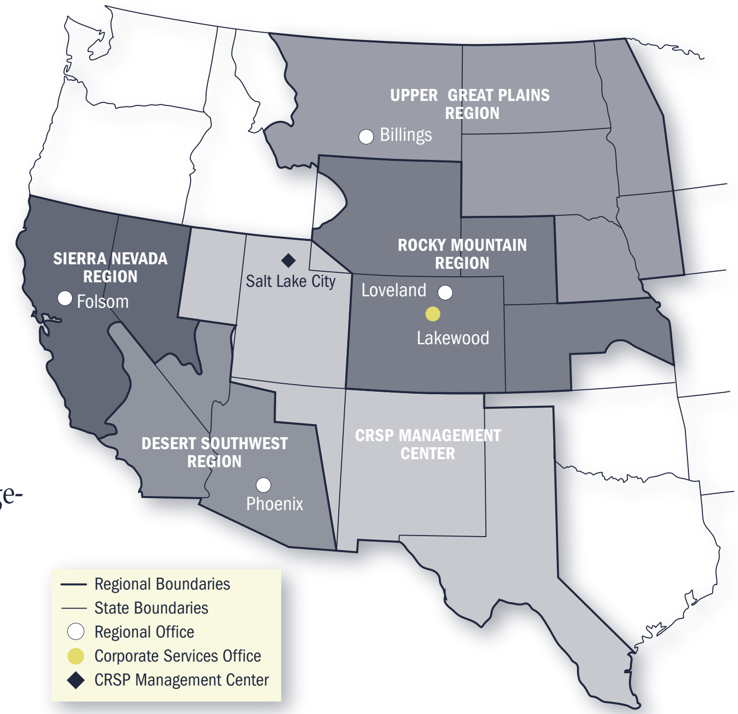
Power revenue is also used to fund Western's purchase power and wheeling activities. Drought conditions—like those we continued to experience in FY 2004—and other factors sometimes require us to purchase power from other suppliers to meet long-term firm power contract commitments. In FY 2001, Congress gave Western interim authority to fund these activities annually through the receipts we receive from selling power to our customers. The new receipt funding authority, combined with traditional alternative financing methods, eliminated the need for an annual appropriation to meet planned Purchase Power and Wheeling program needs. (To finance unplanned purchase power expenses during below normal generating conditions, Western can receive emergency funding through Continuing Fund authorities.)

While we wait to see if Congress will pass legislation to expand the use of customer receipts, we will likely see more alternative financing for needs directly related to our mission.

In FY 2004, we expended significant non-appropriated financing to reduce bottlenecks and improve reliability of the interconnected power grid. The Path 15 Upgrade Project is an example of how non-Federal financing within our existing authorities can be applied to improve the interconnected transmission system without the need for appropriations. This project is almost entirely non-Federally financed and has no impact on Western's ratepayers.

With the right mix of resources and authorization, as well as continued cost management by employees, the Federal hydropower program can run well—even during severe drought cycles—without impacting other appropriation-funded programs.

CUSTOMER SERVICE REGIONS

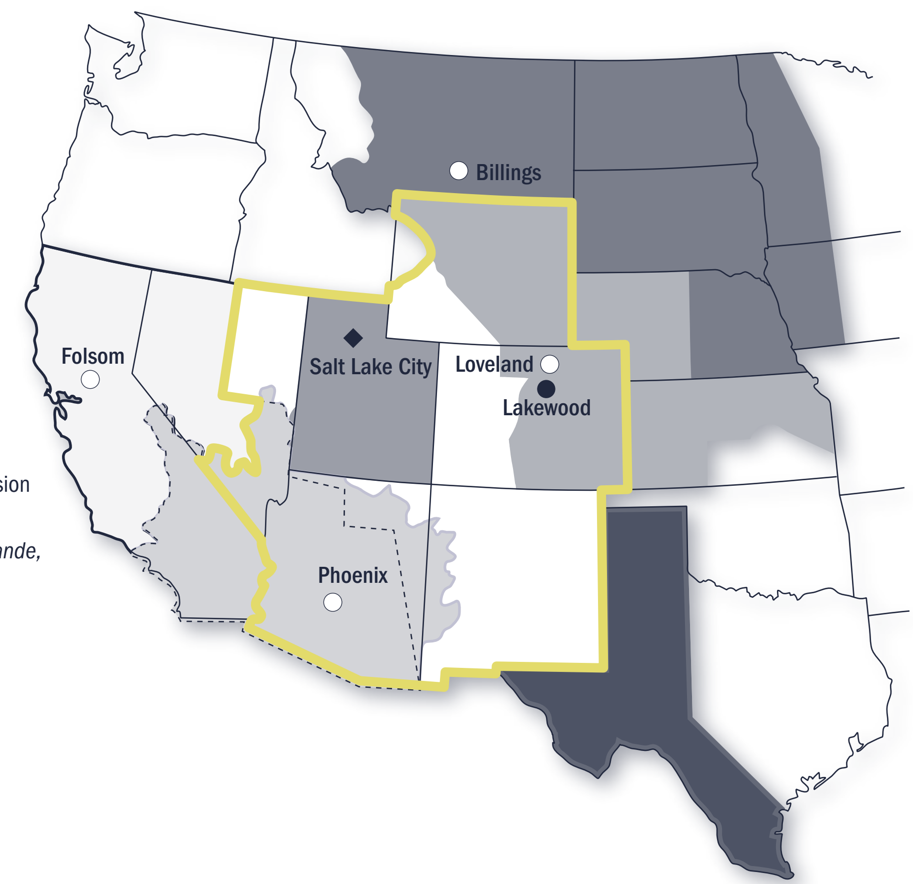


PROJECT MARKETING AREAS

MARKETING AREA BOUNDARIES

- Central Valley and Washoe projects
- Parker Davis
- Boulder Canyon, Pacific NW-SW Intertie and Central Arizona Project
- Falcon-Amistad Project
- Provo River Project
- Loveland Area Projects
  Pick-Sloan Missouri Basin – Western Division and Fryingpan-Arkansas Project
- Pick Sloan Missouri Basin Program – Eastern Division
- Salt Lake City Area/Integrated Projects
  Colorado River Storage Project, Collbran, Rio Grande, Seedskadee and Dolores projects

- State Boundaries
- Regional Office
- Corporate Services Office
- CRSP Management Center



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Opening up new opportunities

Deadline spurs Sierra Nevada to explore new operating agreements

Deadlines are great motivators when it comes to change. For Western's Sierra Nevada Region, that date was Dec. 31, 2004, when decades-old contracts with Pacific Gas and Electric Company were set to expire. The deadline signaled the end of an era and an opportunity to explore uncharted territory.

Under these contracts—originally implemented in the 1950s before Western was even formed—PG&E integrated its own generation and transmission resources with the Central Valley Project and operated the combined facilities as a single power system. That meant that PG&E arranged for supplemental power when Western's resources weren't enough to meet contract commitments.

These agreements shielded Western from dealing with droughts, forced outages, control area performance requirements and searches for markets for surplus generation. Consequently, the contracts' impending end caused uncertainty.

When California's costly restructuring in the mid-1990s prompted PG&E's decision not to renew these contracts, SN staff knew they needed to explore alternate operating arrangements. And they would soon find out how time would accelerate in the face of such a monumental task.

"There was so much to do and so little time to do it," said **Tom Carter**, SN Operations manager. "There were times around here that everyone thought, 'oh no,' not another task. But there was no going back. With the contracts expiring at midnight Dec. 31, 2004, those were essentially our walking papers. The integrated arrangements—where purchase power rates were locked in and PG&E agreed to firm up whatever we marketed—weren't going to be there any more."

But losing the agreement was just the beginning of the region's workload.

"Compounding the challenge was the need to implement Western's new post-2004 Power Marketing Plan," said **Tom Boyko**, SN Power Marketing manager. "The existing marketing plan and the associated power contracts were also scheduled to expire on Dec. 31. So not only were we faced with the challenge of either self-providing or purchasing the required services previously provided by PG&E, we were required to simultaneously develop the detailed agreements essential to the new marketing plan."

When you add to those daunting tasks the need to implement a new rate design for post-2004 operations—plus the commitment to involve the public in all these processes—you have more than

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opportunity knocking, you have potential pandemonium. Yet, the many multi-tasking employees who worked on these projects were more than up to the challenge of transforming their old work processes and ways of doing business in the "old world" and transitioning into a post-PG&E era.

"To carry out the transition to the new marketing and operating environment, we had to implement 11 new major computer systems," said SN Regional Manager **Jim Keselburg**. "Each of these would have been a major project on its own. But on top of that, we also had to negotiate a series of new agreements with PG&E and other parties, invent new business processes and systems and install new metering and communications equipment.

"Finally, to assure that Western would recover its costs, SN staff conducted a public process to implement a new rate design for post-2004 operations," continued Keselburg. "The fact that we were able to do all this simultaneously is a credit to Western staff and others who worked on the transition."

Sub-control decision

As the date of the impending PG&E contract expiration drew nearer, SN began a public process on June 24, 2003, by identifying alternative operating scenarios. On Dec. 2, 2003, Western published its proposed decision to implement a contract-based sub-control area. This decision was finalized on Feb. 23, 2004. As part of its final decision, Western entered into negotiations with both the California Independent System Operator and the Sacramento Municipal Utility District to develop a contract-based sub-control area agreement which met the five-factor test (flexibility, certainty, durability, operating transparency and cost-effectiveness) identified in the public process.

On July 13, 2004, Western announced that SMUD would host SN's sub-control area operations beginning Jan. 1, 2005. A contract-based

New marketing plan offer customized services

While dispatchers were preparing to adjust to their new roles and new operating environment, SN contracts and power marketing staff were preparing to offer customers new products and services.

Starting with its proposed Post-2004 Marketing Plan, published in 1997, SN began exploring the option of providing a range of customized products and services to customers. Western also proposed offering a resource extension to existing customers and offering a portion of the resource to new customers.

After conducting numerous public meetings, SN finalized its marketing plan in June 1999, establishing its final criteria for marketing CVP and Washoe Project power for a 20-year period beginning Jan. 1, 2005 and ending Dec. 31, 2024. Under the new marketing plan, Western offers a supplemental custom product to interested customers to firm their base resource deliveries, as well as portfolio management and scheduling coordinator services.

The new marketing plan recognizes that individual entities may not always fully use their Base Resource allocation. The new marketing plan has an exchange program, which allows interested SN customers to use their unused base resource percentages of other customers. So any power allocated by Western to a customer that cannot be fully used on a real-time basis can be used by other exchange power participants to maximize the benefits of the Federal power program.

sub-control area agreement was executed on Aug. 9, 2004. The Western Electricity Coordinating Council's Board of Directors unanimously and formally approved SMUD's application to expand its control area boundaries to include Western on Dec. 3, 2004.

As a sub-control area, Western schedules power deliveries for project use loads (energy provided to project pumping plants to deliver water to meet irrigation and environmental needs) and for customers directly connected to its transmission system. Western also schedules deliveries from and through its sub-control area and SMUD's control area to entities on the ISO-controlled grid.

Western's sub-control area duties include matching generation and load, providing reserves and frequency support to meet reliability criteria and submitting generation schedules to the host control area. Western also manages net power flows at the sub-control area interconnection points.

"We will operate just like a control area, but are not directly responsible to the Western Electricity Coordinating Council as the host control area—or SMUD—is for the reliable control area operation," said Carter. However, under our sub-control area agreement with SMUD, we are responsible to SMUD to ensure that our sub-control area operates and performs reliably."

Under the new arrangements, SN will now assume more responsibility for meeting its own resource needs. SN dispatchers no longer have the safety net provided by the PG&E contracts. But they have stepped into their new environment and successfully met the challenge.

"For 40 years this region was living under the PG&E contracts. It was almost a culture change," said Carter. "It was like learning to walk all over again. Now we have to operate in the real-time world. But I was amazed at how smoothly the transition has gone."

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Studies open the door to renewable opportunities

The windy Dakotas are home to some powerful resources. Already leading the nation in wind power, this blustery Midwestern area has the potential to generate 100 times more electricity than its residents and businesses currently use. But whether the existing transmission system can support additional wind generation is a question Western is trying to answer in a new study.

"To support our renewable energy goals, we need a high-voltage transmission system that is able to get the wind energy to the market load centers and to where people need it," said **Sam Miller**, project manager for the Dakotas Wind Transmission Study.

"This study fulfills the wishes of Congress, which appropriated $750,000 (of non-reimbursable funds) for Western to examine effects to the transmission system of adding 500 MW of new wind generation in North Dakota and South Dakota," he said.

With total generation more than twice consumption, the Dakotas are an exporting region. Many opportunities abound to export the region's wind resources to meet demand in neighboring states. Yet the area lacks sufficient transmission to deliver that power from the remote generating sites to metropolitan load centers hundreds of miles away. This lack of transmission capacity—manifested in problems such as voltage stability and thermal loading—has hampered efforts to take advantage of those exporting prospects.

The opportunities to address such challenges piqued Western's interest as early as 2002, when we initiated the Montana/Dakotas Transmission Study. This study targeted transmission system reinforcements and upgrades to support an additional 1,000 MW of new wind and lignite coal energy generation in North Dakota, South Dakota and Montana. One year later, at the request of Congress, Western narrowed the study scope to investigate the potential impacts of adding 500 MW of wind energy to the Dakotas—enough electricity to serve about 120,000 households that consume an average of 10,000 kWh of electricity annually.

"It is widely known that South Dakota has the ability to provide a significant portion of the electrical needs for the United States through wind generation." said South Dakota PUC Vice-Chairman Gary Hanson in a March 8, 2004, news release calling for input on Western's study.

Western solicited public comment in February 2004 and heard from 70 individuals and organizations seeking to help define the study scope, including sites for wind generation projects and potential projects and issues related to transmission interconnections with the North Dakota grid. The study began just after the close of FY 2004 on Oct. 7, 2004, and is on track to provide a final report by September 2005.

"We are committed to public input in the technical study and keeping the public informed in the study process as it proceeds to aid with business decisions involving wind development," Miller observed. A Web site is available where relevant study material is posted, and wind stakeholders, interested groups and others with a technical background have the opportunity to hear and provide feedback during technical status report sessions.

With the cost of wind slowly declining—it's now between 4 and 6 cents/kWh— wind developers are popping up on the horizon and requesting to interconnect their proposed wind farm projects with Western's system. In fact, Western's Upper Great Plains has three requests for wind interconnection in the queue. It can take from one to three years from the time an interconnection request is made to the time the wind farm is connected to Western's transmission system, depending on the environmental review process, construction time and the number of requests in the queue, Miller said.

Such new developments would complement the existing wind farms in the region, including the 40-MW Edgeley Wind Energy Center and 21-MW Wind II Energy Center in North Dakota and the 40-MW Highmore Wind Farm in South Dakota.

'Energizing the nation'

While wind currently accounts for 1 percent of total U.S. electricity generation—or 6,000 MW—wind energy capacity has more than tripled since 2000, says the American Wind Energy Association. The Administration's goal is to increase that to 5 percent by 2020—a goal that is consistent with the current growth rate of wind energy nationwide, according to the Department of Energy's Energy Efficiency and Renewable Energy Office. Since the wind projects are likely to be built in remote areas, transmission will be a key issue for the wind industry's development over the next two decades.

Wind power accounts for less than 1 percent of the electricity generation in the United States. By contrast, the total amount of electricity that could potentially be generated from wind in the United States has been estimated at 10,777 billion kWh annually—three times the electricity generated in the nation today. Wind has become the fastest-growing type of generation in the United States—averaging more than 23 percent growth annually in the past five years.

—American Wind Energy Association

In fact, the American Wind Energy Association proposed constructing several 345-kV transmission lines to deliver wind energy from the upper Midwest to the western and eastern United States. AWEA estimates its "wind pipeline" would deliver 30 to 60 gigawatts of wind capacity and cost between $10 billion and $20 billion.

Western's study may help provide the anticipated answers to the goals of increasing wind generation. As public demand for clean energy grows, and as the cost of producing energy from the wind continues to decline, it is likely that wind energy will provide a growing portion of the nation's energy supply.

"There is a huge amount of interest in the outcome of the study," Miller said. "A lot of developers want to build wind farms because of the interest in renewable energy and the opportunity for the Dakotas to energize the nation."

Dakotas Wind Study outlines four tasks

1 The draft scope for the Dakotas Wind Study outlines four tasks. The first is analyzing whether wind power can be delivered through long-term, non-firm access and whether wind power deliveries can be curtailed during congested periods to maximize current capacity.

Since the scheduled capacity under long-term contracts is often less than the total available capacity—leaving unused capacity many hours of the year—Western will compare how much wind power is administratively committed and how much is actually used on an hourly, daily and seasonal basis.

"As a variable, non-dispatchable energy source, wind power may fit in the transmission grid in certain hours," said Project Manager **Sam Miller**. "We hope that the results show that there are times during the year that there is non-firm capacity available, which will give wind developers an idea of which projects are viable."

Three key corridors to be studied in this task include:

- The North Dakota Export Boundary (18 transmission lines in North Dakota, South Dakota and Minnesota)
- The Watertown-Granite Falls 230-kV line
- A group of eight 345-, 230-, and 115-kV lines running east and southeast from Fort Thompson and west and northwest from Fort Randall

2 The second task is assessing if transmission technology could increase existing line capacity. Normal power flow on the system often hampers full use of the physical transmission capacity because one or more lines may be loaded up to their thermal limits, while remaining lines are loaded to levels far below their thermal capacity. New technologies to be studied include:

- Static var compensation to improve transmission system performance by controlling dynamic voltage swings
- Series compensation to improve voltage stability (keeping generation and load in balance)
- Phase-shifting transformers to improve voltage stability and thermal loading (the amount of heat an energized conductor can withstand before sagging) by assisting with the control of power flow
- Dynamic line ratings to increase transfer capacity based on real-time monitoring of lines and weather conditions
- Reconductoring to increase transfer capacity by replacing transmission line conductors with newer composite materials that can carry more current at the same or higher voltage

3 The third task is to examine the interconnection of 500 MW of wind power in seven wind generation zones in North and South Dakota. The zones are located near: Garrison, Wishek/Ellendale/Edgeley and Pickert, N.D.; Rapid City, Mission, Fort Thompson and Summit/Watertown/Toronto/White/Brookings/Flandreau, S.D. This task will help determine the local impacts of adding 50, 150, 250 or 500 MW of new wind generation at each site.

4 The fourth task is to study how new wind generation can be delivered to markets both inside and outside the Dakotas. Delivery studies will be performed on the four most favorable interconnection zones identified in Task 3. Each zone will be examined to determine whether it can deliver increments of wind power generation and handle necessary transmission improvements for each generation level. Transmission improvement options will be ranked by technical feasibility, right-of-way impact and cost.

Further, two additional tasks, depending on funding availability, may be undertaken: developing a cost-sharing loan and/or grant program to partially fund transmission studies for wind projects and regularly updating the study models to incorporate ongoing changes to the Dakotas' transmission system.

New tribal allocations provide mutual benefits

With 300 tribes in Western's service territory, there is plenty of opportunity to extend the benefit of low-cost Federal hydropower to Native Americans. And as we continue to serve more of those tribes, we are discovering the many benefits that our unique relationship provides to both parties.

"We have a lot to offer the tribes, but they have a lot to offer us as well," said Western's Administrator **Mike Hacskaylo** after meeting with the Hopi Nation, one of 52 new tribal customers of the Salt Lake City Area/Integrated Projects.

Because of a provision in Western's Energy Planning and Management Program, which allows the tribes to receive an allocation even if they don't operate their own utilities, Western has more than doubled the number of Native American customers we serve.

To help these new customers begin receiving power from Western, contracts staff in Western's Desert Southwest, Sierra Nevada and Rocky Mountain regional offices and Colorado River Storage Project Management Center worked expeditiously in FY 2004 on delivery arrangements. With these new contracts—plus four additional tribes in SN—Western now serves 91 Native American customers, each bearing a distinct culture and historical perspective.

Unique situations

Because the tribes' needs are unique, Western regularly consults with them to gain insight into their concerns. For example, soon after allocations were offered, Western customer service representatives took to the road to meet these new customers face to face, discussing everything from alternative financing arrangements to contract terms.

"Western staff met with each of the tribes that received an allocation, most of them more than once," said **Lyle Johnson**, a public utilities specialist at the CRSP MC who works regularly with the Colorado Plateau tribes. "Since Western is new to them, we need to explain who we are and how we do business. Correspondence alone is not adequate to convey the complexities of Western's business, especially how our allocations and contracts work," he said. Often several meetings are required to reach mutual understanding, Johnson added.

Working with these tribes to explain Western's complex contracting process and avoiding misconceptions are the first steps to establishing what Western hopes will be mutually beneficial relationships.

"We proceeded to introduce ourselves and Western into their world," said DSW Contracts Manager **Mary Oretta**. "It was a wonderful experience! The tribes are very different to work with because not everybody understands their culture, but we made it our primary goal to learn more about the tribes' cultures. Increasing our understanding helped us to work effectively with them.

"The tribes were always friendly and courteous," she continued. "Many had never worked with this type of service, but the tribes mastered this complex subject quickly. You can see that knowledge in the questions that they ask and comments they make at our customer meetings now."

Importance of culture

Consultations with tribes also gives Western the chance to find out which issues or current projects are significant to them. Many important cultural and sacred sites and locations are found throughout Western's service territory. Our transmission line rights of way cross 900 miles of reservation and tribal lands, requiring easements across about 10,500 acres. Tribes want to ensure that preservation of their cultural heritage is an integral part of Western's mission, whether on private, state, Federal or tribal land.

"We need input from tribes to help interpret archaeological sites, identify traditional cultural properties and provide details on Native American use of the project area, both historically and currently," said **Mark Wieringa**, an environmental specialist at Western's Corporate Services Office.

Monitoring of cultural resource sites builds trust

To minimize impacts to culturally significant areas—such as ancient village sites, rock formations and sites used for religious ceremonies—Western invites Native American cultural resources monitors to participate on certain projects.

"It is common on projects to go out to a wide range of tribes who may have a cultural affinity to the project area," said **Mark Wieringa**, an environmental specialist in Western's Corporate Services Office.

"Including Native American monitors provides an additional perspective on these places, one that is more meaningful to them," he said. That's why cultural monitors from the Santa Rosa Rancheria, a small reservation whose tribe had originally occupied a large portion of the San Joaquin Valley, were invited to be involved on the Path 15 Upgrade Project in Central California during construction in FY 2004.

"Since the land is nearly entirely in private ownership, tribal members in the past were denied access to the area," said Wieringa. He said the project allowed tribal monitors to access areas they had only heard about, to coordinate with archaeologists working with identified cultural resources, and to ensure that tribal interests in sites, traditional cultural properties and possible burials (if present) were properly and respectfully treated.

On the benefits of cultural monitoring, Wieringa said, "There are great rewards gained by working with the tribes. They see that their voice is heard and respected. "The monitors are in a good position to see that we are serious about environmental and cultural resources protection, which builds trust," he continued. "From our perspective, good relations are built with tribes whose lands may be impacted by a future Western project."

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Renewable opportunities

Strengthening our relationships with tribal customers has presented opportunities not only for Western to learn more about distinct Indian cultures and values, but also for the tribes to learn more about renewable resources available on their lands.

For example, Western's Renewable Resource Program representatives have introduced benefits of wind power generation to meet tribal energy needs. We work with DOE's Wind Powering America Initiative to loan wind anemometer equipment to help tribes determine if wind is a viable alternative energy option on their lands. We also help install photovoltaic power systems so tribes can tap into solar power.

In addition, Western has distributed Resource Planning Guides to tribes, providing information on resource planning and analysis, energy load forecasting and market evaluation.

Receiving the benefit of low-cost hydro-power and tapping into other sources of energy may assist the tribes in many ways. With revenue received from bill crediting arrangements—in which a third-party entity receives the allocation and provides revenue to the tribes—they can focus on increasing employment and educational opportunities.

For example, we have had initial discussions with the Hopi about establishing a partnership between Western's Electric Power Training Center and Mohave College in Arizona to train tribal youth to fill critical positions at Western, such as lineworkers.

"Some tribes are interested in ways to get tribal members employed by Western and their local utilities," said Johnson. "We have been invited to the Hopi's energy fair where we plan to provide information on careers at Western."

Benefiting both sides

By providing tribes with these opportunities, Western hopes that the tribes will strongly support Western's mission.

"Some tribes are interested in ways to get tribal members employed by Western and their local utilities."

"We hope that tribes will join other customers in supporting Western," said Johnson. "For example, a member of a tribal council who also represents his tribe on the Glen Canyon Dam Adaptive Management Program remarked that the tribe now has an interest in how Glen Canyon Dam is operated, and that it should be more supportive of Western in the committee meetings."

Hacskaylo is confident that the tribes will be "valuable customers to Western." Emphasizing Western's commitment to establishing and maintaining a strong relationship, he said, "We will work with them to help them achieve their goals."

Transmission study addresses the needs of the new frontier

While the frontier days are long gone, people continue migrating West in search of a better life. Little do they realize, however, that their decision has triggered lively debate, in-depth studies and a transmission planning group that is intent on finding the best way to meet their growing power needs.

As a transmission provider, Western is an integral part of the Rocky Mountain Area Transmission Study, which is evaluating generation and transmission projects in five western states. Initiated in 2003 by the governors of Utah and Wyoming, the RMATS group provides a forum for many government agencies, utilities, industry representatives and energy developers to discuss load growth and transmission constraints within the Rocky Mountain area of the western power grid, or Western Interconnection. This includes Colorado, Idaho, Montana, Utah and Wyoming.

"The transmission system was built with plenty of margin, but that margin has been used up due to new load growth and addition of a variety of new generating plants," said **Bob Easton**, Operations Engineering and Planning manager in Western's Rocky Mountain Region. Easton represents Western on the RMATS Steering Committee and is Co-Chair of the Transmission Additions Work Group.

With energy and capacity needs in the region expected to grow by 16,400 GWh and 3,500 MW, respectively, within the next eight years, the group is exploring all possibilities to meet those growing needs—from installing new wind generation to building new high-voltage transmission lines to determining which lines have unused capacity.

"The present system of transmission planning is in need of an overhaul. It is time we work together to improve the way we deliver reliable energy to citizens and business in the West," said former Utah Governor Mike Leavitt on convening the group in 2003.

Addressing transmission constraints

Western sees its participation in this transmission planning group as an opportunity to address long-standing problems with constrained transmission, especially in Wyoming and Colorado. Without investment in the area's infrastructure, the region may not be able to tap lower-cost coal and wind generation for Rocky Mountain load growth, or to export the vast wind, natural gas and coal resources to other parts of the Western Interconnection.

"With the price of natural gas so volatile, the group saw the need to look at what alternative resources were available. But to build large coal plants or wind farms, you need the transmission to get those resources delivered," said Easton.

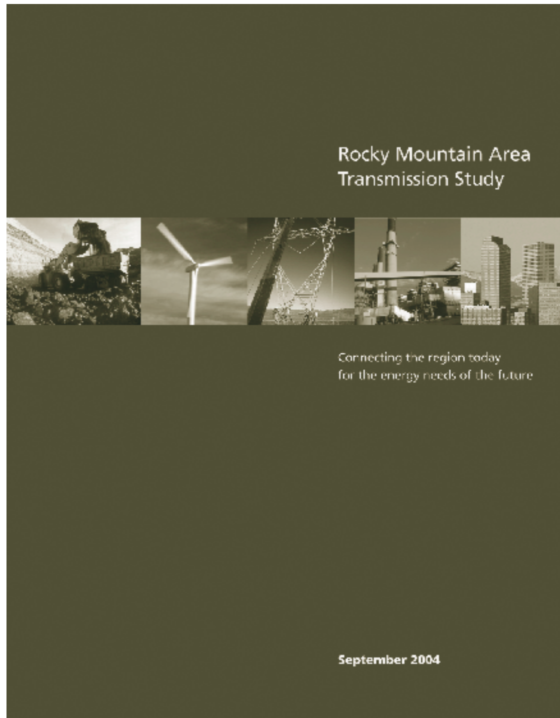
One of the group's recommendations is to invest in new transmission. Western is involved in discussions regarding the Wyoming-to-Colorado Transmission Project, which calls for adding a 345-kV line from northeastern Wyoming across the constrained path between Wyoming and Colorado known as TOT 3. The new line could increase capacity by up to 750 MW, which group members say would be needed to deliver the addition of 500 MW of wind capacity and 700 MW of coal-fired generation capacity.

"Upgrading this path will allow increased opportunity to import low-cost resources into the Front Range loads from Fort Collins in northern Colorado to Pueblo in southern Colorado," Easton said.

"Western can be instrumental in constructing new transmission to alleviate congestion," said Easton. But with project costs estimated at $318 million, he cautions, "We're willing to explore this project, but nothing can move forward until we get interested investors. Western might be able to partner with entities like we did on the Path 15 Upgrade Project in California to come up with a way to share costs and benefits of new construction."

In the near term, Western is participating in a RMATS study group exploring how to use the existing transmission system more efficiently to encourage additional wind generation development. This transmission study work group is also examining available transmission capacity as posted on the Open Access Same-time Information System in the TOT 3 area. Western's Rocky Mountain Regional Office operates this path out of the Loveland, Colo., office.

After comparing wind output and existing flow data on three specific transmission paths in the region, the group found that based on the data set studied, substantial capacity is available at most times of the year. However, the unused portion is set aside as long-term committed use and is only re-posted on a short-term or non-firm basis. Additional study work will be required to take into account the scheduled use of the transmission system as well as the actual power flows, including loop flows. "There is a possibility that the unused capacity could be sold to market participants on a long term basis as non-firm service," said Easton.



Real-time solutions

While these studies and discussions are certainly critical to regional planning, Western is involved with meeting more immediate needs by upgrading system facilities. For example, Western plans to replace two transformers at Flaming Gorge in 2006 and 2007 to increase transfer capacity on existing lines in southwest Wyoming and northeast Utah, and Northwestern Energy, Idaho Power and PacifiCorp intend to place a phase shifter on the line between Montana and Idaho to increase the control of actual flow and usability of the path from Montana.

"The Northeast blackout of August 2003 showed us that we need to do something to ensure the system remains reliable," he added. "Western welcomes the opportunity to support these efforts within our service regions."

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2004 Accomplishments

Annual plan identifies performance targets

We continued our focus on performance by publishing the FY 2004 Annual Performance Plan that defines the specific ways we will accomplish our mission. Annual performance targets are based on industry-appropriate national, Federal and regional standards for reliability, information technology security levels, safety and other measurements. We developed progressive goals to quantify our effectiveness and to maintain the same historically high levels of performance that we've achieved in recent years.

Bonus goals track indicators

Employees achieved 100-percent payout for three of the five bonus goals—all relating to safety—during the FY 2004 program year. These goals have helped motivate employees to prevent injuries, lost work days and recordable motor vehicle accidents. While we didn't meet the reliability and cost containment goals, employee focus on safety paid off. Through the Bonus Goal Program, we continue to set realistic, but meaningful, goals to improve our business.

Career Progression Program kicks off

Western's Human Resources community introduced a new career development program in FY 2004 for employees in positions with limited advancement potential. This program will help participants develop skills and related competencies required for another position they are interested in while helping Western retain knowledge in critical job skills. The 12-month, self-directed program is for permanent, non-supervisory employees with a full performance grade level of GS-10 and below who have worked one year or more at Western.

CAT-1 line monitors measure real-time sag

Western's Sierra Nevada Region began monitoring four 230-kV transmission lines near Sacramento using CAT-1 line monitors, which measure the amount of sag in a transmission line segment in real time. This helps system operators ensure minimum safe clearance distances between a transmission line, other transmission lines or distribution lines and the ground. The monitoring will also help Western benchmark assumptions about line ratings and determine whether to increase a rating. Specifically, the CAT-1 system could be used to ensure Western's transmission lines are being used to their full capacity and are not overloaded during planned or unplanned outage conditions. Monitors are currently installed on the Hurley-to-Tracy lines No. 1 and 2, the Elverta-to-Hurley line No. 1 and the O'Banion-to-Elverta line No. 2.

Combined Federal Campaign raises thousands

During the 2004 Combined Federal Campaign, the Federal workplace charity drive, Western employees raised more than $152,900 for local, national and international charities. The annual fund-raising drive conducted by Federal employees in their workplace each fall collectively raises millions of dollars that benefit thousands of non-profit charities at home and around the world.

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Common OASIS provides one-stop shopping

In March 2004, Western's control areas joined a group of utilities offering transmission customers one-stop shopping through wesTTrans.net. Through this site, transmission shoppers can schedule transmission on paths owned by 14 utilities, including Western. WesTTrans.net is the official site for serving much of the Western Interconnection. This common Open Access Same Time Information System Web site lets market participants view and purchase transmission capacity electronically, which has improved the way industry buys and sells power by expanding availability of access to and efficient use of existing transmission capacity.

Construction continued on Path 15 Upgrade Project

Construction on the Path 15 Upgrade Project, which includes a new 500-kV transmission line between Los Banos and Gates substations in Central California, continued in FY 2004. The estimated $306 million project—built under a unique public-private partnership—was designed to increase transfer capacity along the strategic transmission corridor in central California by 1,500 MW, or enough to power 1.5 million homes.

While preparing the land for the tower foundations in late December 2003 and mid-January 2004, Western's construction contractor uncovered horse, bird and tortoise bones in two ancient burial beds—one from the Early or Middle Miocene age, and one from the Late Miocene age. Before stringing transmission line, Western worked with the Bureau of Land Management to excavate the sites. The areas were also mapped for future recovery.

Cottonwood-Roseville line rerouted

Western began re-routing its Cottonwood-Roseville 230-kV line in May 2004 so the California Department of Transportation could construct a cloverleaf onramp and make other improvements to two highways north of Oroville, Calif. Because these highways intersect at such sharp angles, creating limited visibility for drivers, the site has been the scene of many accidents throughout the years. The project involved changing out lattice towers with tubular steel poles and moving the line about 200 yards so Caltrans could widen the highway.

Dakotas Wind Study kicked off

In September 2004, Western finalized the scope of the Dakotas Wind Transmission Study that will examine options to place 500 MW of wind generation in North Dakota and South Dakota. This study will analyze nonfirm transmission, assess transmission technology relative to new wind generation and examine how new wind generation in North and South Dakota would interconnect to the existing transmission system and be delivered into the market. In 2003, Congress authorized Western to undertake this study.

Desert test for composite conductor launched

In the second test segment of a cooperative effort involving Western, the Department of Energy and the 3M Company, DSW crews installed composite conductors on a 1,800-foot segment of the Liberty-Parker No. 2, 230-kV transmission line in early January 2004. The composite conductor, developed by the 3M Company, can carry up to three times the electricity as the same size conductor now in common use and is being tested to see how well it functions in the extreme desert climate. Western's first installation of this new conductor is on a one-mile test segment of the Jamestown-Fargo No. 1 230-kV line to see how well the conductor withstands the rigors of North Dakota wind and weather. Operating since October 2002, monitoring equipment measures line tension and sag and tracks temperature and wind conditions.

EPTC unveils new NERC-required courses

Western's Electric Power Training Center unveiled its new, week-long Real Time System Operations and Reliability Readiness class in April 2004. The course provides dispatchers with North American Electric Reliability Council-mandated training they need to be prepared for an emergency situation. This course, the first to meet NERC's training requirement, provides dispatchers with an overview of events that triggered the Aug. 14, 2003 blackout and other recent disturbances to help them prepare for future challenges.

Fiber optics installed

In a joint project with Tri-State Generation and Transmission Association, Western's Rocky Mountain crews worked together last spring on the 10-mile Cheyenne-Archer South 115-kV line to replace the existing analog backbone communications network in Wyoming with a digital system. The project includes replacing existing three-eighth-inch ground wire with a .465-inch ground wire containing 48 embedded optical fibers. Once completed, the system will include a ring network from Cheyenne to Casper, then a linear segment up to the Cody area.

Flaming Gorge Dam Draft EIS released

Western worked with the Bureau of Reclamation in 2004 on an Environmental Impact Statement for the Flaming Gorge Dam to meet flow recommendations for endangered fish species in the Green River. Western is a cooperating agency on this EIS and is jointly consulting with Reclamation under the Endangered Species Act. A change in operation at Flaming Gorge Dam, as described in this EIS, will have adverse impacts to power generation. Western and Reclamation are helping to implement scientific studies that may lead to reduced impact to power.

Green achieved on President's Management Agenda

Western fully supports the President's Management Agenda to make the government more efficient. In FY 2004, we received a passing or "green" rating for the e-government Initiative Scorecard and green on all areas, including improved financial performance, budget and performance integration, competitive sourcing and human capital management.

MISO testing

Western's UGP marketing and operations staff participated in the Midwest Independent System Operator's Market Initiative in October and November 2003 in preparation for MISO to launch its wholesale energy market in the Midwest. The market is part of MISO's transition to performing all the functions of a regional transmission organization, or RTO. To buy and sell energy and serve our firm customers located within the MISO footprint, Western needs to become a MISO market participant.

Monitoring equipment prevents problem

Keeping up with the latest in system monitoring tools helped Western prevent a potentially explosive problem from developing within a transformer at the Gallegos Substation in Farmington, N.M., in November 2003. The 50,000-kVA transformer, which serves tribal loads in the area, was analyzed for dissolved gases during a routine test. When crews noticed an accumulation of explosive gases—indicating the possibility of a serious internal problem—they retested the unit using a tool developed in Canada called Duval's triangle. This tool uses an analysis technique that plots the concentration of three specific gases, then points to a possible cause, such as arcing or thermal hot spots within the transformer. The tool helped crews catch the problem before the transformer exploded, allowing crews to repair it and return it to service.

Native American customers doubled

Western worked throughout FY 2004 to implement bill crediting and benefits contracts for new Native American tribal customers. Fifty-two tribes in the Colorado River Storage Project Management Center's marketing territory and four tribes in the Rocky Mountain Region became eligible to receive the benefits of Federal power from Western beginning Oct. 1, 2004. These allocations bring economically affordable, environmentally friendly power into Native American communities.

NERC readiness audits completed

North American Electric Reliability Council Readiness Audits of Western's Area Upper Missouri East control area and a Western Electricity Coordinating Council compliance audit of the WAUM-West control area were conducted in August 2004. The audits determine the readiness of all North American reliability coordinators and control areas to ensure that system operators have the tools and processes to operate reliably. Initially, these audits are focusing on deficiencies identified by the Aug. 14, 2003, blackout investigation. The audits found Western's Upper Great Plains control areas have the appropriate reliability plans, procedures, tools and trained staff to respond to unplanned system events. The audit team did not find any significant operational problems, but Western is now developing corrective action plans to address the team's recommendations, including fully implementing the under-frequency load-shedding program, improving alarm processing and establishing a fully redundant backup facility.

Nine regional Science Bowls sponsored

Providing service to the community and advancing math and science among high school students were the reasons Western staff showed their strong support of regional science bowl tournaments throughout Western's service area. From the South Dakota Regional in Rapid City to the Native American science bowl in Colorado Springs, Colo., and the Sacramento Regional competition in California, dedicated Western volunteers spent their weekends in February and March helping their communities promote education. The nine regional science bowls, included three that UGP staff helped with in Montana, North Dakota and South Dakota; two in Colorado where RM employees volunteered, including the Native American Science Bowl; one in Arizona that involved DSW employees; and three in the SN region in northern California.

Pick-Sloan Resource Pool allocations decided

Under the Energy Planning and Management Program in March 2004, Western's Upper Great Plains Region proposed allocations of up to 2,113 KW in summer and 3,072 KW in winter for three customers—the cities of Auburn, and Pocahontas, Iowa, and Montana State University-Bozeman—from a resource pool of the Pick-Sloan Missouri Basin Program—Eastern Division's long-term marketable resource. In October 2004, the region planned to announce the final allocations, which become available Jan. 1, 2006.

Rapid City DC tie comes on line

The Rapid City DC tie became operational on Oct. 15, 2003. The tie is used primarily to import energy from the eastern grid to serve loads in Wyoming. Much of this new load growth is due to coal bed methane development that requires power to pump the coal bed water out and compress the methane gas. Western operates this 200-MW tie for owners Black Hills Power and Light and Basin Electric Power Cooperative. The Rapid City DC tie is one of six interconnections within the United States that join the eastern and western U.S. power grids.

SLCA/IP marketable resources allocated

Western announced in May 2004 its allocations of the post-2004 marketable resources from the Salt Lake City Area Integrated Projects developed under the Energy Planning and Management Program. Western evaluated hydrologic studies that indicated the need to reduce the energy component of the marketable resources for 20 years. Beginning in fiscal year 2005, the energy component will begin at its lowest level and then gradually increase over the next five years. In the fifth year, energy allocations level off and reach a level that remains constant through the remaining contracting period, subject to change only under contract terms. Firm electric service contracts between Western and its existing and new customers, which began with the October 2004 billing period, continue through September 2024.

Sierra Nevada Post-2004 Marketing Plan

Sierra Nevada Regional staff worked tirelessly to transition the region from operating under long-time contracts with Pacific Gas and Electric Company, which were set to expire on Dec. 31, 2004. Under these contracts, SN's Federal generation was integrated with PG&E's, so Western had to consider transmission as well as generation in its business planning effort. Under SN's new 2004 Marketing Plan, Western will give customers an allocation consisting of hourly net generation. Customers may supplement the hourly net generation with an optional "firming" purchase. To recognize new industry operating protocols, the marketing plan also allows customers to contract with SN for scheduling coordinator and/or portfolio management services.

Sierra Nevada sub-control area selected

In a decision announced July 13, 2004, Western selected the Sacramento Municipal Utility District to host sub-control area operations for the Sierra Nevada Region beginning Jan. 1, 2005. Western selected SMUD based on the five criteria identified through a public process. Western completed a nine-month public process to identify a preferred operating configuration for use after its existing contracts with Pacific Gas and Electric Company expire Dec. 31, 2004. As a sub-control area, Western will schedule power deliveries for Project Use loads and customers directly connected to our transmission system and in other control areas. Western will match generation and load, provide reserves and frequency support to meet reliability criteria, and submit generation schedules to the host control area. Western will manage net power flows at the sub-control area interconnection points.

Thailand hosts Western trainers

From July 27 to 30, 2004, Electric Power Training Center instructors **Charlie Gray** and **Brad Nickell** trained about 30 engineers from the Metropolitan Electric Authority of Thailand, in Bangkok, Thailand, in some of the finer points of power system operations. The challenge was to convey to them the concepts and theories of power system operation and control.

Western garners Small Business program awards

Western's Small Business Program was honored for its exceptional efforts for supporting small businesses. The Secretary of Energy presented **Judy Madsen**, Western's Small Business Program manager, the award for outstanding achievements in socioeconomic goals. The Small Business Administration's Region VIII Administrator Elton Ringsak presented two awards—one to Western for continuously supporting the small business community and one to **Amy Wright**, RM's small and disadvantaged business utilization specialist, for her contribution to the Denver Federal Acquisition Council's procurement Web site.

Western receives Human Capital Breakthrough Award

DOE presented a Human Capital Breakthrough Award to Western at the 2004 DOE Human Resources and EEO Diversity Symposium July 1, 2004. The Human Capital Breakthrough Award was created specifically to recognize Western for raising awareness and providing an understanding of human capital issues, tools and strategies.

Williston-to-Wolf Point Upgrade continues

The Williston-to-Wolf Point Upgrade project along Highway 2 in northwestern North Dakota took about four weeks to finish upgrading the second phase for a total of 20 miles completed so far. This is the second year of the 10-year line upgrade plan. The project will replace the original 115-kV line built in 1946 with a new 230-kV line, including new structures, conductor and fiber optic overhead ground wire.

45-day process accelerates hiring

Western began implementing a new 45-day hiring model in FY 2004 to accelerate the time it takes to get a new hire on board. The 45 working days include five days each to screen, rate and rank applications and prepare certificates; up to five days to review applications and up to 15 days to schedule and conduct interviews. It also includes up to five days to check references, two days to make selections and up to three days to extend job offers. In some cases, these new guidelines cut the current process in half, especially when it's delayed by scheduling conflicts among interview panel participants or by delays in checking references.

FY 2004 IRP Summary

Western's Integrated Resource Planning requirements outlined in Section 114 of the Energy Policy Act of 1992 give customers several options to meet or streamline these requirements. The requirements, which were updated in 2000, recognize the changes occurring in the utility industry and our customer's varying size and structure. These changes also streamlined the reporting requirements without sacrificing the EPAct's intent.

Customers must submit annual progress reports and new integrated resource plans every five years, but they may now submit them individually or cooperatively when they belong to member-based associations.

The IRP regulations allow customers to set action plan timelines (instead of a five-year minimum) to better correspond with their own situations. The regulations no longer require customers to provide a complete load forecast, only a brief summary verifying that one was conducted. Customers no longer must provide methods of validation predicted performance to determine whether they met IRP objectives. Instead, they can submit a brief description of measurement strategies from the options identified in the IRP.

Western also made changes to IRP alternatives. Member-based association members and joint action agencies may now file a small customer plan if their sales/use is under 25 GWh per year.

Another alternative to the IRP is the minimum investment report. Customers required by a state, tribal or Federal regulation to make minimum financial/resource investment in demand-side-management or renewable programs may file a minimum investment report consisting of an initial report and an annual letter.

With the Energy Efficiency/Renewable Energy Report, state, tribal or Federal end-use customers required by state, tribal or Federal mandate to conduct energy efficiency or renewable energy programs can provide an initial report and an annual report on these activities to comply with Western's requirements.

All firm power customers have submitted one of these options. In FY 2004, Western received 111 IRPs from individual customers, 34 plans from cooperatives, 71 minimum investment reports and 83 small customer plans. These plans represent 715 long-term firm power customers and customer members.

Customer reported trends include:

- High interest/demand for renewable energy technologies in all (commercial, industrial, residential and institutional) market segments
- Increased requests for education on energy efficiency and renewable energy technologies
- Water management, efficient use, conservation, and pumping efficiency
- Continued re-emergence of demand-side-management efficiency activities/programs
- Key account programs

The most frequent demand-side-management activities cited by Western's customers are:

- Lighting technologies
- Heating, ventilating and air conditioning technologies with emphasis on cooling and ventilation
- Audits for residential, commercial and industrial facilities
- Load management

The top five renewable energy resource choices are:

- Hydro (large & small)
- Wind generation
- Solar – PV
- Geothermal
- Biomass

IRPs are driven by customer need and requests. Cost and reliability are still the highest priority, but factors such as renewable energy technologies have an ever-increasing influence on both of them. Additional factors include: foreign energy dependence, environmental issues, security issues, developing technologies, affordable options and regulations.

FY 2004 Customer IRP Accomplishments

Item	CRSP MC	DSW	RM	SN	UGP	Totals
DSM kW savings	66,212	142,877	110,162	78,359	504,500	902,110
DSM kWh savings	$136,342,051	$172,584,909	$81,330,951	$170,928,913	$1,038,370,000	$1,599,556,824
DSM expenditure	$14,301,376	$29,487,098	$4,564,877	$68,282,231	$14,600,000	$131,235,582
DSM deviations	$1,623,027	$6,124,524	$84,506	$837,874	$3,200,000	$11,869,931
kW renewables	73,139	1,249,014	81,620	134,690	381,642	1,920,105
kWh renewables	140,964,822	1,674,788,211	203,721,485	779,998,549	862,078,965	3,661,552,032
Renewable expenditure	$1,905,483	$8,110,964	$4,380,583	$4,106,076	$39,129,896	$57,633,002
Renewable program types	Solar, biomass, small hydro	Wind, solar, hydro	Small hydro, wind	Small hydro, geothermal, photovoltaics, methane	Large wind, waste-to-energy, PV, hydro	Solar, hydro, wind, biomass, geothermal
Top 5 most frequent DSM activities	Commercial & industrial lighting, audits, residential heating, irrigation lighting, HVAC	Pump motors, commercial and industrial HVAC	Residential audits, lighting, Leadership in Energy and Environmental Design green building rating system, commercial audits, time-of-use load management	Residential lighting, pump repair/ replacement., water management, residential weather, commercial HVAC	Load mgmt, lighting, weatherization, new construction, motors/pumps	Lighting, HVAC, pumps, audits, load mgmt
Top 5 renewable energy activities	Solar, biomass, small hydro	Wind, solar, hydro	Wind, hydro, solar, biomass	Small hydro, geothermal, PV, methane	Large wind, small wind, waste-to-energy, PV, hydro	Wind, solar, hydro, geothermal, biomass
Top 3 customer reported trends	Renewables, efficiency, audits	Renewables, pump efficiency	Customer demand for renewable energy, residential efficiency, key accounts	Pump upgrades, water mgmt., residential efficiency, commercial efficiency	Renewable energy, programs, capital/ cash constraints	Renewables, efficiency, key accounts

Repayment Summary

Western Consolidated Status of Repayment (Dollars in millions)	Cumulative 2003	Adjustments	Annual 2004	Cumulative 2004
Revenue:				
Gross operating revenue	20,380	57	1,012	21,449
Income transfers (net)	(1,018)	0	(102)	(1,120)
Total operating revenue	**19,362**	**57**	**910**	**20,329**
Expenses:				
O & M and other	7,107	(15)	348	7,440
Purchase power and other	5,924	25	440	6,389
Interest				
Federally financed	3,479	(19)	158	3,618
Non-Federally financed	173	(0)	9	181
Total Interest	3,651	(20)	168	3,799
Total expense	**16,683**	**(10)**	**956**	**17,628**
(Deficit)/Surplus revenue	(185)	56	(130)	(258)
Investment:				
Federally financed power	5,282	(1)	76	5,357
Non-Federally financed power	202	(0)	(0)	202
Nonpower	3,555	0	(1,176)	2,379
Total investment	**9,039**	**(1)**	**(1,101)**	**7,937**
Investment repaid:				
Federally financed power	2,766	11	78	2,856
Non-Federally financed power	55	(0)	4	59
Nonpower	41	0	(0)	41
Total investment repaid	**2,862**	**11**	**82**	**2,955**
Investment unpaid:				
Federally financed power	2,516	(13)	(2)	(2,501)
Non-Federally financed power	147	0	(4)	143
Nonpower	3,515	0	(1,176)	2,338
Total investment unpaid	**6,178**	**(13)**	**(1,183)**	**4,982**
Fund balances:				
Colorado River Development	2	(0)	1	3
Working capital	0	0	2	2
Percent of investment repaid to date:				
Federal	52.37%			53.31%
Non-Federal	27.23%			29.21%
Nonpower	1.15%			1.72%

Note: Repayment Status is primarily based on audited data as of 9/30/04.
Difference between the Annual 2004 data in this table and the Combined Power System Statements of Revenues and Expenses on page 38 are footnoted in the individual power systems' Status of Repayment tables in the Statistical Appendix.

Financial Data

Management's Discussion and Analysis

Outlook

The importance of hydropower as a reliable energy source in our Nation's economy cannot be overstated. In recognizing the significance of our role in ultimately providing power to millions of consumers, Western continually emphasizes operational efficiencies in the use of Federal power assets.

Transmission facilities, as a key element of our national electricity network, are being impacted by utility industry deregulation, load growth, open access, and interconnections of merchant power plants. This environment places unprecedented demands on the interconnected power system, where Western must maintain the reliability and safety of its transmission system while managing power delivery costs and meeting operational and repayment responsibilities. In response to these and future challenges by industry, Western strengthened partnerships with generating agencies and customers to control costs, realize operational efficiencies, coordinate funding agreements, and modernize Federal hydropower infrastructure. Western and our generating partners are responsive and accountable to our customers and the needs of the utility industry. We will continue to provide cost-based resources and services through transmission and financial alternatives to ensure a stable, long-term power supply.

FY 2004 was the fifth year of below-average generation with drought continuing throughout most of the western United States. The drought has significantly reduced reservoir inflow and storage levels affecting the capability of hydroplants to produce power. Continuing drought conditions will further increase the risk of reservoirs dropping below minimum storage levels required to generate power. Several years of above-average precipitation and runoff are needed for reservoir recovery.

In FY 2004, in response to prolonged drought, Western took steps to further contain operating costs; developed strategies regarding power allocations and purchases; and enhanced operations through planning, coordination, and communication with our generating partners. Continued drought is affecting power rates as Western works to secure resources to maintain hydropower assets, meet transmission reliability requirements, and satisfy obligations to Treasury.

Results of Operations

Below-normal precipitation across most of Western's service area in FY 2004 translated to 3 percent lower power generation than in FY 2003 as a result of lower annual water releases.

Despite the drought, Western's power systems contributed $93.6 million toward repayment of investment. Specifically, we repaid $78.1 million of Federally financed power investment, up substantially from $31.2 million in FY 2003, and an additional $4.1 million of non-Federally financed power investment. The Central Valley Project ($38.3 million) and the Colorado River Storage Project ($29.2 million) provided the majority of these funds. Adjusting entries within power repayment studies resulted in an additional $11.4 million available for repayment.

Revenues[1]

Total operating revenues for FY 2004 were $909.8 million, down $32.4 million (3 percent) as compared to FY 2003. Specifics include increased sales of electric power of $48.7 million (7 percent) to $743.1 million, as offset by a decrease in other operating revenue of $93.2 million (37 percent).

Power sales revenue increased from firm power rate increases for the Pick-Sloan Missouri River Basin Program of $12.9 million. There were also increases in non-firm sales for the Pick-Sloan Missouri River Basin Program of $11.6 million and the Colorado River Storage Project of $19.9 million.

Power revenue was offset by a 37 percent decrease of $93.2 million in other operating income. This significant change was due primarily to repaying of customer contributions and advances at the Central Valley Project. Specifically, customers received energy credits because of the Rate Adjustment Clause of $47.5 million and the California Independent System Operator Grid Management Charge of $7.0 million. Adding to the above difference were accounting adjustments, recorded in FY 2003 to correct energy credits and purchase power revenue.

Average revenue per megawatt hour (MWh) on total sales, both firm and non-firm, was $21.20 in FY 2004 on sales of 35.2 GWh and $19.57 in FY 2003 on sales of 35.9 GWh.

Expenses[1]

Total operating expenses for FY 2004 increased by $20.7 million, or 2 percent, to $893.0 million from the comparable FY 2003 level, supporting Western's objective to maintain costs at or below the rate of inflation. Specifically, purchase power costs increased in FY 2004 by $5.1 million, or 1 percent, to $385.0 million, while operations and maintenance (O & M) expense remained relatively flat, decreasing only slightly by $0.7 million to $297.4 million. Purchased transmission expense increased by $6.3 million, or 13 percent, to $54.7 million in FY 2004, largely due to a Pacific Gas and Electric transmission rate increase for the Central Valley Project. Administrative and general expenses also increased in FY 2004 by $5.8 million, or 12 percent, to $52.7 million, attributable to increases in regional support service contract costs, the upgrade of Western's financial management system, and staffing increases at Western's Corporate Services Office.

Capital Program

During FY 2004, Western and the generating agencies transferred $96.4 million from construction work-in-progress to completed plant, as compared with $133.3 million in FY 2003. New capital investments included substations, warehouse and maintenance facilities, switching stations, fiber optic installation, expansion of communication systems, and assorted replacements of transmission and generation assets to fortify or enhance the grid. Completed plant of $71.2 million within the Pick-Sloan Missouri River Basin Program included various substation upgrades, transmission line improvements, and microwave projects. The Parker-Davis Project required $7.9 million in substation upgrades and the Colorado River Storage Project required $11.8 million in capitalized interest accounting adjustments for various substations and switchyards.

During FY 2004, the Federal hydropower program initiated new construction and/or continued previous uncompleted construction projects totaling approximately $99.8 million, as compared to $96.1 million in FY 2003. Construction projects included upgrades to switchyards, substations, transmission lines, and microwave systems, with $63.1 million of activity in the Pick-Sloan Missouri River Basin Program, $15.9 million in the Central Valley Project, $9.1 million in the Parker-Davis Project, and $8.9 million in the Colorado River Storage Project.

[1] Financial statement numbers and revenue and energy sales include interproject and project use activities but exclude Central Arizona Project transactions.

Performance Measurements

The Chief Financial Officers Act of 1990 requires Federal entities to develop performance measures to assist managers in evaluating the efficiency of Federal programs. This requirement was further emphasized in the Government Performance and Results Act of 1993.

The financial performance measures outlined below relate to the organizational objectives and management responsibilities of Western and the generating agencies (Bureau of Reclamation, U.S. Army Corps of Engineers and the International Boundary and Water Commission) and were selected from industry standard financial ratios used by public power systems for comparison in assessing electric utility performance. The operational measures outlined below are Western specific and were selected from utility industry and Federal safety, reliability and financial standards, to compare and assess Western's operational performance.

Financial Performance Measures[1]

The investment repayment indicator measures cumulative investment (Federally and non-Federally financed power projects and irrigation assistance) repaid as a percentage of total investment at the end of each year. Total investment at the end of FY 2004 was approximately $8 billion. During FY 2004, $93.6 million was applied toward investment repayment. The FY 2004 investment repayment ratio of 37.23 percent increased from the FY 2003 ratio of 31.66 percent.

During FY 2004, $78.1 million from current year operations (up from $31.2 million in FY 2003) was available to repay the Federally financed power investment. Similarly, $4.1 million of non-Federally financed power investment was applied, increasing the level of repaid non-Federally financed power investment to 29.21 percent up from 27.23 percent in FY 2003 and adjustments of $11.4 million were made as a result of power repayment study true-ups. Additionally, nonpower investment decreased by $1.2 billion due to a revised cost allocation from the Bonneville Unit of the Central Utah Project. In FY 2004, repayment for nonpower investment increased to an overall level of 1.72 percent from 1.15 percent in FY 2003.

The variance in planned payments indicator measures the ratio of all payment activity to planned investment payments. This indicator is zero if the actual payment is equal to the planned payment. During FY 2004, power generation and transmission activities provided for repayment of $82.2 million ($78.1 million Federal and $4.1 million non-Federal), up from $36.3 million in FY 2003. Additional net repayment of $11.4 million was made as a result of adjusting entries within power repayment studies. Total payment activity equaled $93.6 million. This adjusted amount exceeded the planned principal repayment of $65.0 million by $28.6 million, resulting in a variance ratio of 43.99 percent.

Western tracks several financial performance measures, which allow Western to benchmark its efficiency against other power generating utilities. The most recent utility industry statistics, which are used because there are no industry comparables for the generation and sale of hydroelectric power, are listed in Selected Financial and Operating Ratios of Public Power Systems, 2002, dated April 2004, as prepared by the American Public Power Association. Statistics are calculated based on data from more than 400 of the largest consumer-owned electric utilities in the United States.

Operation and Maintenance and Administrative and General Expense costs per net kWh generated and sold is a measure of the cost to operate and maintain the generation and transmission systems. The ratio increased in FY 2004 ($0.0146/kWh) over FY 2003 ($0.0139/kWh) and was attributable to increases in regional support service contract costs, the upgrade of Western's financial management system and staffing increases at Western's Corporate Services Office. The most recent industry average was $0.052/kWh.

The operating ratio measures the proportion of revenues received from power sales and other activities required to cover operating costs (which include operations and maintenance, administrative and general expenses, purchased power and purchased transmission) associated with producing and selling electricity. Western's FY 2004 ratio decreased to 87.6 percent from the FY 2003 ratio of 90.3 percent primarily due to relatively flat operating cost while power sales increased. The most recent industry ratio was 77.9 percent.

Revenues received per kWh of electricity sold increased slightly in FY 2004 to $0.0212/kWh from $0.0196/kWh in FY 2003 largely due to the impact of rate increases and additional sales of non-firm power which generated additional power sales revenue. The most recent industry rate was $0.073/kWh.

The total power supply expenses per kWh sold measures all power supply costs, including generation and purchased power, associated with the sale of each kWh of electricity. The FY 2004 rate of $0.0224/kWh was slightly higher than the FY 2003 rate of $0.0215/kWh primarily due to increases in administrative and general expenses, purchase power expenses and transmission rate increases. The most recent industry average was $0.041/kWh.

[1] Financial statement numbers presented here include interproject amounts for sales of $10.4 million, other operating income of $6.8 million, purchased power of $11.9 million, and purchased transmission services of $5.3 million. Additionally, the Central Arizona Project has been excluded, which reduced sales by $85.4 million, other operating income by $25.3 million, O&M by $0.3 million and increased net income transfers by $110.4 million. Revenue and energy sales include interproject and project use.

Consolidated Financial Performance Indicators (Dollars in thousands)

Investment repaid	2004[1]	2003[1]
Ratio	37.23%	31.66%
Paid investment	$2,955,136	$2,861,525
Total investment	$7,937,493[2]	$9,039,335
Variance in planned payments		
Ratio	43.99%	29.87%
Excess payment (actual payment plus adjustments less planned principal payment)	$28,599	$7,437
Planned principal payment	$65,012	$24,901
O&M cost per net kWh generated		
Rate	$0.0146	$0.0139
O&M and AGE	$350,119	$345,014
MWh generated-net	23,926,000	24,740,000
Operating ratio		
Ratio	87.56%	90.28%
O&M, AGE, PP, PT	$789,816	$773,358
Total sales revenues	$902,040	$856,592
Revenue per kWh sold		
Rate	$0.0212	$0.0196
Total firm and nonfirm sales revenue	$747,088	$702,723
MWh sold	35,237,912	35,900,992
Total power supply expenses per kWh sold		
Rate	$0.0224	$0.0215
O&M, AGE, PP, PT	$789,816	$773,358
MWh sold	35,237,912	35,900,992

[1] Financial statement numbers and revenue and energy sales include interproject and project use activities but exclude Central Arizona Project transactions.

[2] Change in 2004 nonpower obligation data reflects a revised cost allocation of $1.2 billion for the Bonneville Unit of the Central Utah Project.

Operational Performance Measures

Western is committed to maintaining a safe, accident-free work place. This commitment is demonstrated by Western's Safety and Health program, dedicated to increasing awareness of safe work practices, and including safety goals in Western's Bonus Goals Program. Western is also committed to a safe, efficient and reliable transmission system and reports on a number of operational measures for occupational safety and health and transmission system efficiency.

Occupational safety and health performance measures, as adopted by the U.S. Department of Energy for occupational injuries, are recognized throughout the electric utility industry (public and private utilities) and by information-gathering entities which include the National Safety Council, the U.S. Department of Labor Bureau of Labor Statistics, and the National Institute for Occupational Safety and Health. Industry statistics are provided on a calendar year basis. Accordingly, Western's measures have been calculated for the same time period. The latest statistics currently available (calendar year 2003) are as provided by the U.S. Department of Labor Bureau of Labor Statistics.

Lost workday case rate measures the lost-time injury frequency rate by multiplying the number of cases that involve days away from work by 200,000 (common base of 100 full-time workers), then dividing by the total hours worked. Western's CY 2004 rate of 0.6 was less than the CY 2003 rate of 0.9. The CY 2003 standard industry rate was 2.4

Total recordable case rate measures the recordable accident frequency rate by multiplying the number of recordable cases by 200,000 (common base of 100 full-time workers), then dividing by the total hours worked. Western's CY 2004 rate of 1.8 decreased from the CY 2003 rate of 2.1. This decrease represents an ongoing emphasis by Western to focus employee awareness on hazard recognition and avoiding hazardous working conditions. The CY 2003 standard industry rate was 4.9

The motor vehicle accident rate measures the accident frequency rate by multiplying the number of recordable accidents by 1 million (rate calculated per million miles driven), and then dividing by the recorded miles driven. This rate does not distinguish between preventable or non-preventable accidents. Western's CY 2004 rate of 1.4 increased slightly from the CY 2003 rate of 1.2. Currently there is no industry standard with which to compare Western's rate.

Transmission system performance is measured using the instantaneous difference between loads and generation. Good control performance is required to maintain system reliability and to reduce losses, as well as to maintain equity among interconnected systems.

Performance for each control area is measured using North American Electric Reliability Council's control area performance standards 1 and 2 (CPS1 and CPS2). A Control Compliance Rating of "Pass" is achieved when a power system receives, for each month of the fiscal year, a CPS1 performance level of 100 percent minimum and a CPS2 performance level of 90 percent minimum. Western's performance for FY 2004 was 184.19 percent for CPS1 and 98.25 percent for CPS2. The industry averages were 165.11 percent for CPS1 and 96.66 percent for CPS2. Western's FY 2004 reliability results are consistent with FY 2003 (CPS1 – 185.61 percent and CPS2 – 98.09 percent).

Independent Auditor's Report

The Administrator
Western Area Power Administration,
United States Department of Energy:

We have audited the accompanying combined power system balance sheets of the Western Area Power Administration (Western), an agency of the U.S. Department of Energy, and the Western affiliated power generating functions of the U.S. Department of the Interior, Bureau of Reclamation; the U.S. Department of Defense, Army Corps of Engineers; and U.S. Department of State, International Boundary and Water Commission (collectively, the generating agencies), as of September 30, 2004 and 2003, and the related combined power system statements of revenues and expenses, and accumulated net revenues, and cash flows for the years then ended. These combined power system financial statements are the responsibility of Western and the generating agencies' management. Our responsibility is to express an opinion on these combined power system financial statements based on our audits. We did not audit the financial statements of the affiliated power generation function of the U.S. Department of the Interior, Bureau of Reclamation (Reclamation), which statements reflect total assets constituting 31% and 30%, respectively, of combined total assets as of September 30, 2004 and 2003 and total revenues constituting 25% and 21%, respectively, of combined total revenues for the years then ended. Those statements were audited by other auditors whose report has been furnished to us, and our opinion, insofar as it relates to the amounts included for Reclamation, is based solely on the report of such other auditors.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America; the standards applicable to financial audits contained in Government Auditing Standards, issued by the Comptroller General of the United States; and Office of Management and Budget (OMB) Bulletin No. 01-02, Audit Requirements for Federal Financial Statements. Those standards and OMB Bulletin No. 01-02 require that we plan and perform the audit to obtain reasonable assurance about whether the respective financial statements are free of material misstatement. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of Western and the generating agencies' internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the respective financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, based on our audits and the report of other auditors, the combined power system financial statements referred to above present fairly, in all material respects, the combined financial position of Western and its affiliated power generating agencies, as of September 30, 2004 and 2003, and their combined operations, changes in accumulated net revenues, and cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

In accordance with Government Auditing Standards, we have also issued our report dated May 10, 2005, on our consideration of Western and the generating agencies' internal control over financial reporting and our tests of its compliance with certain provisions of laws and regulations. The purpose of that report is to describe the scope of our testing of internal control over financial reporting and compliance and the results of that testing, and not to provide an opinion on the internal control over financial reporting or on compliance. That report is an integral part of an audit performed in accordance with Government Auditing Standards and should be read in conjunction with this report in considering the results of our audits.

Deloitte & Touche LLP

Denver, Colorado
May 10, 2005

Combined Power System Balance Sheets

As of September 30, 2004 and 2003 (in thousands)

	2004	2003
Assets		
Utility plant:		
Completed plant	$ 5,608,553	$ 5,532,623
Accumulated depreciation	(2,484,856)	(2,402,599)
Net completed plant	3,123,697	3,130,024
Construction work-in-progress	202,764	192,750
Net utility plant	3,326,461	3,322,774
Cash	538,013	512,330
Accounts receivable, net	138,625	208,133
Other assets	153,814	160,446
Total assets	**$ 4,156,913**	**$ 4,203,683**
Federal investment & liabilities		
Federal investment:		
Congressional appropriations	$ 11,126,870	$ 10,682,634
Interest on Federal investment	4,296,515	4,129,875
Transfer of property & services, net	638,729	655,143
Gross Federal investment	16,062,114	15,467,652
Funds returned to U.S. Treasury	(12,146,661)	(11,695,236)
Net outstanding Federal investment	3,915,453	3,772,416
Accumulated net deficit	(267,825)	(117,189)
Total Federal investment	**$ 3,647,628**	**$ 3,655,227**
Commitments and contingencies (notes 1,4,6,7 and 8)		
Liabilities:		
Accounts payable	127,280	106,370
Other liabilities	382,005	442,086
Total liabilities	**509,285**	**548,456**
Total Federal investment & liabilities	**$ 4,156,913**	**$ 4,203,683**

See accompanying notes to combined power system financial statements.

Combined Power System Statements of Revenues and Expenses, and Accumulated Net Deficit

For the Years Ended September 30, 2004 and 2003 (in thousands)

	2004	2003
Operating revenues:		
Sales of electric power	$ 818,115	$ 764,104
Other operating income	174,235	270,916
Gross operating revenues	992,350	1,035,020
Income transfers, net	(99,516)	(109,859)
Total operating revenues	**892,834**	**925,161**
Operating expenses:		
Operation and maintenance	297,641	298,059
Administration and general	52,742	46,955
Purchased power	373,083	364,811
Purchased transmission services	49,407	46,526
Depreciation	103,199	98,927
Total operating expenses	**876,072**	**855,278**
Net operating revenues	**16,762**	**69,883**
Interest expenses:		
Interest on Federal investment	168,935	186,381
Interest on customer funded financing	8,326	11,604
Allowance for funds used during construction	(9,705)	(33,036)
Net interest expenses	**167,556**	**164,949**
Net deficit	**(150,794)**	**(95,066)**
Accumulated net deficit, beginning of year	**(117,189)**	**(19,279)**
Irrigation assistance	**158**	**(2,844)**
Accumulated net deficit, end of year	**$ (267,825)**	**$ (117,189)**

See accompanying notes to combined power system financial statements.

Combined Power System Statements of Cash Flows

For the Years Ended September 30, 2004 and 2003 (in thousands)

	2004	2003
Cash flows from operating activities:		
Net deficit	$ (150,794)	$ (95,066)
Adjustments to reconcile net deficit to net cash provided by operating activities:		
Depreciation	103,199	98,927
Interest on Federal investment	157,244	153,345
Loss on disposition of assets	2,808	6,260
(Increase) decrease in assets:		
Accounts receivables	69,508	(31,212)
Other assets	2,002	(18,595)
Increase (decrease) in liabilities:		
Accounts payable	20,910	(21,909)
Other liabilities	(84,177)	128,244
Net cash provided by operating activities:	**120,700**	**219,994**
Cash flows from investing activities:		
Investment in utility plant	**(99,763)**	**(96,096)**
Cash flows from financing activities:		
Congressional appropriations, net	431,917	455,777
Funds returned to U.S. Treasury	(451,425)	(479,722)
Principal advances (payments) on customer funded financing	24,096	(7,361)
Irrigation assistance	158	(2,844)
Net cash provided by (used in) financing activities	**4,746**	**(34,150)**
Net Increase in cash	**25,683**	**89,748**
Cash, beginning of year	**512,330**	**422,582**
Cash, end of year	**$ 538,013**	**$ 512,330**

Supplemental schedule of noncash investing and financing activities		
Transfer of construction work-in-progress to completed plant	$ 96,367	$ 133,270
Capitalized interest during construction	$ 9,705	$ 33,036

See accompanying notes to combined power system financial statements.

Notes to Combined Power System Financial Statements

As of and for the years ended September 30, 2004 and 2003

(1) Basis of Presentation and Summary of Significant Accounting Policies

(a) Principles of Combination

The combined power system financial statements include the financial position, results of operations and cash flows of Western Area Power Administration (Western), an agency of the U.S. Department of Energy (DOE), and the power generating function of the U.S. Department of the Interior, Bureau of Reclamation (Reclamation); the U.S. Department of Defense, Army Corps of Engineers (Corps); and the U.S. Department of State, International Boundary and Water Commission (IBWC) (collectively known as the generating agencies) for the individual power systems. The jointly owned power systems are separately managed, financed and maintain separate accounting records. Western, as a Federal power marketing administration, markets and transmits hydroelectric power generated from these power systems operated and maintained by the generating agencies throughout 15 western states. The power systems, with the exception of the Central Arizona Project (CAP) and the Pacific Northwest-Pacific Southwest Intertie (Intertie), are part of multipurpose water resource projects and include certain Western transmission facilities and certain generating agency facilities.

Operating expenses and net assets of multipurpose water resource projects are allocated among projects' activities, which are primarily power, irrigation, recreation, municipal and industrial water, navigation and flood control (see Note 4). The combined power system financial statements include only those expenses and net assets which are expected to be recovered through the sale of power and other related income.

Although Reclamation holds an entitlement to power from the Navajo Generating Station and capacity from the CAP transmission facilities, the Federal government has no ownership in these facilities. As such, neither the CAP assets nor the associated Navajo entitlements are included in the combined power system financial statements.

Accounts are maintained in accordance with accounting principles generally accepted in the United States of America (GAAP) and the Federal Energy Regulatory Commission's (FERC) prescribed uniform system of accounts for electric utilities. Accounting policies also reflect specific legislation and executive directives issued by departments of the Federal government. The combined power system financial statements are presented in accordance with the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, Accounting for the Effect of Certain Types of Regulation. The provisions of SFAS No. 71 require, among other things, that regulated enterprises reflect the regulator's rate actions in their financial statements, when appropriate. These rate actions can provide reasonable assurance of the existence of an asset, reduce or eliminate the value of an asset, or impose a liability on a regulated enterprise.

For purposes of financial reporting, the facilities and related operations of Western and the generating agencies are considered one entity. All intraentity balances and transactions have been eliminated from the combined power system financial statements.

The facilities and net revenues included in these combined power system financial statements are exempt from taxation.

(b) Confirmation and Approval of Rates

The Secretary of Energy (Secretary) has delegated authority to Western's Administrator to develop power rates for the power systems. The Deputy Secretary of Energy has the authority to confirm, approve and place such rates in effect on an interim basis. The Secretary delegated to FERC the authority to confirm, approve and place such rates in effect on a final basis, to remand, or to disapprove such rates. Refunds with interest, as determined by the FERC, are authorized if rates finally approved are lower than rates approved on an interim basis. However, if at any time FERC determines that the administrative cost of a refund would exceed the amount to be refunded, no refunds will be required. No refunds are anticipated in connection with rates approved on an interim basis through September 30, 2004.

(c) Operating Revenues

Operating revenues are recognized when goods or services are provided to the public or another government agency. Except for power systems using revolving funds, cash received from sales is deposited directly with the U.S. Department of the Treasury (U.S. Treasury) and is reflected as Funds Returned to U.S. Treasury in the Combined Power System Balance Sheet. As such, these funds are unavailable for power system operating needs. For power systems using revolving funds, cash received is deposited in the U.S. Treasury and remains available to the power system. Cash collected into revolving funds in excess of operating requirements is used for repayment of Federal investment and interest.

Power and transmission rates are established under requirements of the power systems' authorizing legislation and related Federal statutes and are intended to provide sufficient revenue to recover all costs allocated to power and, in some power systems, a portion of irrigation-related costs (see Note 7). Costs allocated to power include repayment of Federal investment in power facilities and associated interest. Rates are structured to provide for repayment of Federal investment in power facilities, generally over 50 years, while operating expenses and interest on Federal investment are recovered annually. Replacements of utility plant are generally to be repaid over their expected service lives.

The power systems' legislation does not recognize annual depreciation based on actual service lives as a measure of the required repayment for investment in utility plant. This results in some assets being fully depreciated before costs are recovered; whereas, annual depreciation costs on other assets may continue after such costs have been recovered through revenues. Over the life of the combined power systems, accumulated net revenues represent timing differences between the recognition of expenses and related revenues. Because Western and the generating agencies are nonprofit Federal agencies, accumulated net revenues, to the extent which they are available, are committed to Federal investment repayment.

Other operating income represents the amount of funds collected from sources other than the sale of electric power. These revenues include rental of electric property, power wheeling and transmission service.

Net income transfers represent the amount of funds collected but subsequently transferred to Reclamation. This amount relates to the surplus generation billed from the Navajo Generating Station by Western, on behalf of Reclamation's CAP.

For the Central Valley Power System (CVP), the net revenue forecasted in the rate case is compared to the actual net revenue by December 31 for the previous fiscal year. If the actual net revenue is less than the projected net revenue, a surcharge may be assessed. If the actual net revenue is greater than the projected net revenue, a credit may be granted. The surcharge or credit is then applied to CVP firm power customers' bills from January through September.

Billing methods used by Western include net billing and bill crediting. Net billing is a two-way agreement between Western and a customer, where both buy and sell power to each other. Monthly sales and purchases, including any customer advances received, are netted between the two parties and the customer is provided either an invoice or a credit. Bill crediting involves a three-way net billing arrangement among Western, a customer and a third party. For example, Western purchases power from a third-party supplier, delivers it to the customer and the customer will pay the third-party supplier and receive a credit on its bill from Western.

(d) Cash

For purposes of the Combined Power System Financial Statements, cash consists principally of the undisbursed balance of funds authorized by Congress, customer advances and revolving fund balances at the U.S. Treasury.

(e) Accounts Receivable, Net

The estimate of the allowances is based on past experience in the collection of receivables and an analysis of the outstanding balances. The amounts due for receivables are stated net of an allowance of $1.5 million and $7.1 million for uncollectible accounts for fiscal year 2004 and fiscal year 2003, respectively, from a gross amount of $140.1 million and $215.2 million respectively.

(f) Stores Inventory

Inventory consists of hardware, tools and maintenance parts and supplies. Inventory is valued using the average cost method.

(g) Utility Plant

Utility plant is stated at original cost, net of contributions in aid of construction by entities outside of the combined power system. Costs include direct labor and materials; payments to contractors; indirect charges for engineering, supervision and administrative and general expense; and interest during construction. The costs of additions, major replacements and betterments are capitalized; whereas, repairs are charged to operation and maintenance expense.

The cost of retired utility plant, net of accumulated depreciation, is charged to operation and maintenance expense as a gain (loss) and the net of removal costs and salvage credits is capitalized as part of the direct replacement asset. If there is not a replacement asset, the net of removal costs and salvage credits is charged to operation and maintenance expense. Plant assets of the combined power system are currently depreciated using the straight-line method over estimated service lives ranging from 10 to 50 years for transmission assets and 13 to 100 years for generation assets. Power rights are amortized over 40 years.

(h) Interest on Federal Investment

Interest is accrued annually on the Federal investment based on the Federal statute and power system legislation. Such interest is reflected as an expense in the Combined Power System Statement of Revenues and Expenses. Western calculates interest annually based on the unpaid Federal investment owed to the U.S. Treasury using rates set by law, administrative orders pursuant to law or administrative policies.

All power systems recognize an annual interest credit for payments of interest on obligations that are due annually to the U.S. Treasury. Interest rates on unpaid Federal investments ranged from 2.5 to 12.4 percent for the years ended September 30, 2004 and 2003.

As provided by Federal law, interest is not assessed on Federal investment in irrigation facilities anticipated to be repaid through power sales (see Note 7).

(i) Allowance for Funds Used During Construction

Interest During Construction (IDC or Allowance for Funds Used During Construction) represents interest on funds borrowed from the U.S. Treasury during the construction of all generating and transmission facilities. Western calculates IDC based on the average annual outstanding balance of construction work-in-progress. Western and the generating agencies' policy is to capitalize IDC through the end of the fiscal year in which assets are placed in service. IDC is recovered over the repayment period of the related plant asset. Applicable interest rates ranged from 4.8 to 11.4 percent for the years ended September 30, 2004 and 2003, depending on the year in which construction on the transmission and generation facilities was initiated or the authorizing legislation.

(j) Pension and Other Retirement Benefits

Statement of Federal Financial Accounting Standards (SFFAS) No. 4, Managerial Cost Accounting Concepts and Standards for the Federal Government, and SFFAS No. 5, Accounting for Liabilities of the Federal Government, direct the full cost reporting of employment benefits by employing entity. These statements require Federal agencies to record the government's cost of providing pension, life and health insurance and other post-employment benefits (severance payment, counseling and training, workers' compensation benefits, etc.) regardless of the funding agency.

(k) Use of Estimates

Management of Western and the generating agencies has made many estimates and assumptions relating to the reporting of assets and liabilities and the disclosure of contingent assets and liabilities to prepare these combined power system financial statements in conformity with GAAP. Actual results could differ significantly from those estimates.

(l) Derivative and Hedging Activities

Western analyzes derivative financial instruments in accordance with SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities. This statement requires that all derivative instruments, as defined by SFAS No. 133, be recorded on the balance sheet at fair value unless exempted. Changes in a derivative instrument's fair value must be recognized currently in earnings unless the derivative has been designated in a qualifying hedging relationship. The application of hedge accounting allows a derivative instrument's gains and losses to offset related results of the hedged item in the statement of operations, to the extent effective. SFAS No. 133 requires that the hedging relationship be highly effective and that a company formally designate a hedging relationship at the inception of the contract to apply hedge accounting.

Western enters into contracts for the purchase and sale of electricity for use in its business operations. SFAS No. 133 requires Western to evaluate these contracts to determine whether the contracts are derivatives. Certain contracts that literally meet the definition of a derivative may be exempted from SFAS No. 133 as normal purchases or normal sales. Normal purchases and normal sales are contracts that provide for the purchase or sale of something other than a financial instrument or derivative instrument that will be delivered in quantities expected to be used or sold over a reasonable period in the normal course of business. Contracts that meet the requirements of normal are documented and exempted from the accounting and reporting requirements of SFAS No. 133.

Western's policy is to fulfill all derivative and hedging contracts by either providing power to a third party or by taking delivery of power from a third party as provided for in each contract. Western's policy does not authorize the use of derivative or hedging instruments for speculative purposes such as hedging electricity pricing fluctuations beyond Westerns estimated capacity to deliver or receive power. Accordingly, Western evaluates all of its contracts to determine if they are derivatives and, if applicable, to ensure that they qualify and meet the normal purchases and normal sales designation requirements under SFAS No. 133. Normal purchases and normal sales contracts are accounted for as executory contracts as required under other generally accepted accounting principles.

(m) Concentrations of Credit Risks

General Credit Risk

Financial instruments, which potentially subject Western and the generating agencies to credit risk, include accounts receivable for customer purchases of power, transmission, or other products and services. These receivables are primarily with a group of diverse customers who are generally large, stable and established organizations that do not represent a significant credit risk. Although Western and the generating agencies are affected by the well being of the utility industry, management does not believe a significant risk of loss from a concentration of credit exists.

Credit Risk from California

On April 12, 2004, the Federal bankruptcy court in San Francisco approved Pacific Gas and Electric Company's (PG&E) petition to emerge from the Chapter 11 bankruptcy reorganization proceedings which the company initiated on April 6, 2001. The bankruptcy filing was the direct result of the financial instability associated with the California energy crisis during calendar years 2000 and 2001. PG&E's subsequent emergence from bankruptcy proceedings allowed the utility to pay off all valid creditor claims.

The subsequent diminution of California's energy crisis has also allowed Southern California Edison (SCE) to regain its financial health.

With the financial standing of both investor-owned utilities (PG&E and SCE) restored, previous concerns about the ability of the California Independent System Operator (CAISO) to meets its repayment obligations have abated.

The California Power Exchange (Cal PX) filed for Chapter 11 bankruptcy protection on March 9, 2001. Consistent with the directions provided by its board of directors, representatives of the Cal PX are actively engaged in the process of winding up its business affairs in an orderly manner.

Some uncertainty still continues to exist while the Cal PX remains in bankruptcy proceedings and market/price manipulation cases continue to be litigated at FERC. Given the status of ongoing litigation, Western estimates that the allowance for loss on Cal PX accounts receivable to be $1.1 million, as of September 30, 2004.

(n) Moveable Equipment

Moveable equipment represents the acquisition cost of capitalized movable equipment having a unit cost of $15,000 or more and an estimated useful life of two years or more. The capitalization threshold was increased in fiscal year 2004 from the previous threshold of $5,000. Examples of capitalized moveable equipment include computers, copiers, cranes, energy testing equipment, helicopters, pickups, trucks and wood chippers.

Internal use software is capitalized when the software has a service life of 3 years or more and a cost of $150,000 or more upon the completion of the software development phase or upon purchase of commercial off-the-shelf software. The capitalization threshold for internal use software increased in fiscal year 2004 from the previous threshold of $50,000.

(o) Abandoned Projects

In accordance with FERC regulations, Western's policy is to move capitalized costs into plant-in-service at the time the asset is placed in service. Occasionally, congressionally authorized projects originally planned for service are discontinued due to political and/or economic reasons. Western's policy is to classify these discontinued projects based on congressional action as abandoned projects and amortize them into the power rates over a reasonable period.

(p) Interchange Energy

Western's power contracts may include a provision for energy transfers between Western and a supplier that result in deferred energy debts or credits. The deferred energy debts or credits represent the valuation of excess energy delivered or received under the interchange energy contract provisions. The interchange balance is posted either as a deferred debit (other asset) when Western is the net supplier, or as a deferred credit (other liabilities) when Western is the net user.

(q) Recovery Implementation Program (RIP)

Section 8 of the Colorado River Storage Project Act of 1956, as amended, mandates that the Department of the Interior establish and implement programs to conserve fish and wildlife. Under this Act and other legislation, Reclamation has established programs to preserve the habitat and otherwise aid endangered fish and wildlife. The RIP is one such program and is managed by the U.S. Fish and Wildlife Service.

On October 30, 2000, Congress passed Public Law 106-392 that authorized additional funding to Reclamation to continue the RIP. The legislation specifies that a total of $17.0 million is to be collected by Western from its power customers to finance capital costs and up to $6.0 million a year for operating expenses. Furthermore, the legislation states that operating expenses are considered non-reimbursable to the U.S. Treasury and a repayment of the Federal investment. Conversely, capital funded costs must be repaid to the U.S. Treasury through future power sales. Non-reimbursable costs were $5.8 million and $5.4 million for the years ended September 30, 2004 and 2003 respectively. Reimbursable costs for the years ended September 30, 2004 and 2003, respectively, were $2.3 million and $0.1 million.

(r) Unused Annual Leave

Unused annual leave represents accrued benefits which would be payable to employees upon retirement or separation from employment with the government. The amount not funded by revolving funds has been deferred as an other asset in the Combined Power System Balance Sheet in accordance with SFAS No. 71.

(s) Purchase Power Termination Settlement

Western renegotiated certain CRSP long-term contractual obligations with third-party power providers. Under the terms of the settlement agreements, annual payments of $0.6 million will be made through 2007. The recovery of these payment obligations will be deferred for rate-making purposes until the obligations become due. Therefore, the recognition of the expense associated with the settlements has been deferred as an other asset in the Combined Power System Balance Sheet in accordance with SFAS No. 71 (see Note 2).

(t) Customer Advances

Customer advances represent the current balance of advance payments received from power and other customers pursuant to a cosponsoring agreement with entities for construction, operation and maintenance, or other furnished items. Subsidiary accounts are maintained by customer to reflect the status of each advance. Also included are revenue financing contracts that provide for customer funds to be advanced for construction, maintenance, or purchase power expenses. For these contracts, the customer is provided revenue credits on future power bills up to the amount of the advanced funds and, if applicable, any interest or fees.

(u) Workers' Compensation

Workers' compensation consists of two elements: a liability for expenses from actual claims incurred and paid by the Department of Labor (DOL) that Western and the generating agencies must reimburse; and an actuarial liability associated with cases incurred for which additional future claims may be made. In conjunction with SFFAS Nos. 4

and 5, DOL determined the actuarial liability associated with future claims using historical benefit payment patterns discounted to present value (37 years) using economic assumptions for 10-year U.S. Treasury notes and bonds.

The recovery of future claims will be deferred for rate-making purposes until such time the claims are submitted to and paid by the DOL. Therefore, the recognition of the expense associated with the actuarially determined liability has been deferred as an other asset in the Combined Power System Balance Sheet in accordance with SFAS No. 71 (see Note 2) to reflect the effects of the rate-making process.

(V) Capital Credits

Capital credits represent the investment made in non-profit organizations that result in equity ownership (patronage credits) that will result in a cash collection refund at a later date, which sometimes can be as long as 30 years. These credits are reported as income and deferred asset at the time of notification until the actual cash collection is made.

(2) Other Assets

Other assets as of September 30, 2004 and 2003 consist of the following (in thousands):

	2004	2003
Workers' compensation (see Note 1(u))	$47,507	$57,234
Moveable equipment, net (see Note 1(n))	37,335	36,407
Abandoned project costs, net (see Note 1(o))	19,067	14,941
Stores inventory (see Note 1(f))	13,071	12,667
Accrued annual leave (see Note 1(r))	7,675	11,703
Internal use software, net (see Note 1(n))	5,911	4,576
Capital credits (see Note 1(v))	5,572	445
Recovery Implementation Program (see Note 1(q))	5,500	5,500
Interchange energy (see Note 1(p))	4,872	7,937
Deposit funds available	2,938	1,608
Energy banking deferral	1,915	1,837
Purchase power termination settlement (see Note 1 (s))	1,600	2,200
Other	851	3,391
Total	**$153,814**	**$160,446**

Abandoned project costs, net include the Celio-Mead transmission line of $14.2 million and $14.9 million as of fiscal year 2004 and fiscal year 2003, respectively, which is being amortized over 23 years, through 2019.

The energy banking deferral is an arrangement between Western and a customer whereby excess power and/or transmission capacity is banked with the customer until power is needed to meet contractual obligations. Banked power and/or transmission capacity is recorded at a contractually agreed-upon amount. The net revenue associated with the banking activity is deferred and recorded as an other liability.

(3) Utility Plant

The Net Utility Plant as of September 30, 2004 consists of buildings, facilities, land and intangible power rights. Land costs for Western were $73.5 million and $73.3 million as of September 30, 2004 and 2003, respectively. Land costs for the generating agencies were $93.2 million and $93.6 million as of September 30, 2004 and 2003, respectively. Completed plant includes $114.0 million and $117.9 million of power rights, net of amortization of $48.9 million and $44.8 million as of September 30, 2004 and 2003, respectively.

(4) Federal Investment and Cost Allocation

(a) General

Federal investment consists of congressional appropriations, accumulated interest on unpaid Federal investment and the net transfers of property and services from other Federal agencies. Congressional appropriations is comprised of the cumulative appropriations received, net of expenses legislatively deemed nonreimbursable, and post-retirement benefits (see Note 8). Cumulative appropriations received, net of nonreimbursable expenses, totaled $11.1 billion and $10.7 billion as of September 30, 2004 and 2003, respectively. Postretirement benefits for the same time period totaled $88.4 million and $71.8 million, respectively. All power systems, except Dolores, Seedskadee, Boulder Canyon (BC) and the operations and maintenance and purchased power programs of the CRSP, are primarily financed through congressional appropriations for operation and maintenance, construction and rehabilitation and purchased power expenditures. A portion of construction and rehabilitation and purchased power expenditures are financed through other methods, such as advances from non-Federal entities; reimbursements from other Federal agencies; use of receipts authorization; and alternative methods such as net billing and bill crediting; or any combination thereof.

Operating expenses (excluding depreciation expense) and interest on the unpaid Federal investment should be repaid annually. In cases where funds are not available for repayment, such unpaid annual net deficits become payable from the subsequent years' revenues. Interest is accrued on cumulative annual net deficits until paid. Deficits for operating expenses begin to accrue interest in the year they occur, while interest expense deficits begin to accrue interest in the following year they occur. As of September 30, 2004 and 2003, certain power systems have incurred operating and interest expense deficits aggregating approximately $258.5 million and $187.3 million, respectively. In cases where funds are available, unless otherwise required by legislation, repayment of Federal investment is applied to the increment bearing the highest rate of interest.

(b) Federal Investment in Multipurpose Facilities

The Federal investment in certain multipurpose facilities, primarily dams and structures integral to the generation of power, required to be repaid from the sale of power, has been determined from preliminary cost allocation studies based on project evaluation standards approved by Congress. Allocations between power and non-power activities may be changed in future years; however, the project evaluation standards cannot be changed unless approved by Congress.

Final studies will be performed by Reclamation and the Corps, as appropriate, upon completion of each individual power project and are still pending for all but the Fryingpan-Arkansas Power System (FryArk). Reclamation completed the final FryArk study in 1993. The BC and Parker-Davis power systems are not subject to cost allocation studies since the power systems' enacting legislation require the total costs of the dams and appurtenant structures to be repaid through power revenues.

With final cost allocation studies still pending for many of the individual power systems, the potential exists for significant future adjustment in the Federal investment for the cost of multi-purpose facilities allocated to power and the related accrued interest on the unpaid Federal investment. Such reallocations could affect the individual power system rates. For example, in 1997, Reclamation studied the implications of a cost reallocation of the Pick-Sloan Missouri Basin Program (P-SMBP) on existing water and power rates. The study resulted in additional costs, ranging from $0 to $416 million (depending on the assumptions of the cost methodologies used), which may be reallocated to power facilities.

(5) Other Liabilities

Other liabilities as of September 30, 2004 and 2003 consist of the following (in thousands):

	2004	2003
Long-term construction financing	$164,542	$169,132
Customer advances	110,783	140,016
Workers' compensation	56,447	66,594
Accrued annual leave	12,378	10,688
Custodial liability	12,279	0
Accrued payroll benefits	7,170	10,879
Recovery Implementation Program	5,500	5,500
Interchange energy (see Note 2)	4,872	7,937
Deposit funds available	2,965	1,699
Energy banking deferral (see Note 2)	1,915	1,837
Purchased power termination settlement (see Note 1 (s))	1,600	2,200
Other	1,554	5,205
Deferred revenue	0	20,399
Total	**$382,005**	**$442,086**

The majority of long-term construction financing consists of three significant contractual arrangements. The first significant arrangement provides customer financing for the Boulder Canyon power system to upgrade each of the generating units at Hoover Dam. The obligation to these customers is scheduled to be satisfied through the issuance of credits on power bills over a period through fiscal year 2017, at interest rates ranging between 5.5 and 8.2 percent. As of September 30, 2004 and 2003, the outstanding obligation was $118.1 million and $122.5 million, respectively.

The second significant arrangement consists of the principal payable to the State of Wyoming for providing partial financing for improvements at the Buffalo Bill Dam (P-SMBP Power System) and associated power plants. This liability is being repaid over a period of 35 years, which began in 1996, at an approximate interest rate of 11.1 percent. The outstanding obligation amounted to $21.0 million and $21.2 million as of September 30, 2004 and 2003, respectively.

The third significant arrangement is principal due to a customer for providing financing for the construction of the Griffith-McConnico and Griffith-Peacock transmission lines along with certain assets at Peacock substation, and McConnico Switching Station. The obligation incurs interest at a rate of 8.5 percent and is being repaid through fiscal year 2018, which began in 2001. As of September 30, 2004 and 2003, the outstanding obligation totaled $24.4 million and $25.3 million, respectively.

Outstanding long-term construction financing as of September 30, 2004 is scheduled to be credited or repaid as follows (in thousands):

2005	$5,222
2006	5,649
2007	6,668
2008	9,932
2009	10,659
Thereafter	126,412
Total	**$164,542**

Custodial liabilities represent the amount of accrued revenue for the Central Arizona and Boulder Canyon power systems. The custodial revenue is transferred upon actual receipt of funds.

Western and the generating agencies included $47.5 million and $57.2 million as an actuarial liability for future workers' compensation claims in the Combined Power System Balance Sheet as of September 30, 2004 and 2003, respectively.

Cumulative unpaid expenses associated with actual claims incurred for Western and the generating agencies were $8.9 million and $9.4 million as of September 30, 2004 and 2003, respectively.

Deferred revenue is in recognition of IDC reconstruction for the CRSP power system. The reconstruction project was as a result of inconsistent application of interest rates on investments and the use of preliminary numbers in the Power Repayment Studies during fiscal years 1963 through 1998. The reconstruction determined that IDC had been understated, and Interest on Federal Investment (IOI) expense had been overstated. The deferred revenue was the result of excess revenue collected due to the overstated IOI during the reconstruction period. The deferred revenue was earned and recognized as revenue during fiscal year 2004.

Western received a loan of $5.5 million from the State of Colorado in fiscal year 2003 to fund the Reclamation endangered fish RIP (see note 1(r)). The obligation incurs interest at a rate of 4.5 percent and is to be repaid through power revenues beginning in 2012.

(6) Lease Commitments

Western and the generating agencies have several cancelable operating leases, primarily for general purpose motor vehicles and office and warehouse space that expire over the next 14 years.

Western has a non-cancelable lease that expires in 2009 for Western's Corporate Service Office. In addition, Western is currently awaiting authorization to proceed into the renewal of a non-cancelable superseding lease for the Electric Power Training Center (EPTC). These two leases represent an annual expense of approximately $2.3 million for the next five years. The General Services Administration is the leaseholder for all locations with the exception of the EPTC to which Western is a leaseholder.

The right to relinquish space on cancelable leases is available with 120-day notice to terminate. These leases generally contain renewal options for periods ranging from three to five years and require the lessee to pay all executory costs such as maintenance and insurance. Rental expense for operating leases was approximately $8.5 million and $7.8 million for the years ended September 30, 2004 and 2003, respectively.

(7) Commitments and Contingencies

(a) General

Western and the generating agencies are involved in various claims, suits and complaints routine to the nature of their business. These Federal government organizations are self-insured for claims pertaining to litigation, unemployment, long-term disability and health and life insurance. Liabilities for these claims, as reported in the combined power system financial statements, are based on reported pending claims, estimates of claims incurred but not yet reported, actuarial reports and historical analysis. It is management's opinion that the ultimate disposition of these claims will not have a material adverse effect on the combined power system financial statements.

(b) Irrigation Assistance

Federal statute requires that certain individual power systems repay the U.S. Treasury that portion of Reclamation's project capital costs allocated to irrigation purposes determined by the Secretary of the Interior to be beyond the ability of the irrigation customers to repay. Although these repayments may be recovered through power sales, they do not represent an operating cost of the individual power systems and are treated as distributions from accumulated net revenues at the time of repayment.

Power repayment studies indicate that approximately $2.4 billion of existing non-power Federal investment will be repaid from future power revenues over a period not to exceed 60 years. Reclamation made irrigation assistance payments of $0.2 and $2.8 million for the years ended September 30, 2004 and 2003, respectively.

(c) Boulder Canyon Power System Improvements

In 1987, Reclamation initiated a project designed to increase (uprate) the generating capacity of the BC power system. Certain BC customers agreed to provide funding for these improvements, primarily through the issuance of long-term bonds. In some cases, proceeds from the bonds exceeded the amount required to fund the improvements.

For purposes of measuring the liability related to the Uprating Program (the Program), Reclamation reports the total amount of the advances received from customers in the Combined Power System Balance Sheet (see Note 5). Bond issuance costs are included in the determination of interest expense and are recognized over the term of debt repayment. Net proceeds from the issuance of the debt, in excess of the amount advanced to Reclamation, have similarly been excluded from the assets of the power system. Interest expense on the liability is measured based on the total outstanding bonded indebtedness. Interest income from excess proceeds reduces interest costs subject to arbitrage regulations. Until any remaining excess funds are applied against outstanding debt, the total interest cost of financing the Program will be subject to uncertainty.

(d) Colorado River Storage Project

In October 1992, Congress passed the Grand Canyon Protection Act of 1992 (the Act) to "protect . . . and improve the values for which the Grand Canyon National Park and Glen Canyon National Recreation Area were established."

The Act relieves CRSP power customers of repayment obligations for costs equivalent to certain expenses of environmental impact studies, associated purchased power, and other miscellaneous expenses related to the Glen Canyon Dam. For the fiscal years ended September 30, 2004 and 2003, Western and Reclamation combined incurred $11.5 million and $24.1 million, respectively, in environmental costs which were deemed nonreimbursable. Accordingly, such costs have been recognized as a reduction of congressional appropriations in the Combined Power System Balance Sheet.

(e) Power Contract Commitments

Western has entered into various agreements for power and transmission purchases that vary in length but generally do not exceed 20 years. Western's long-term commitments for these power and transmission contracts, subject to the availability of Federal funds and contingent upon annual appropriations from Congress, are as follows (in thousands):

Year ending September 30:	Purchased power	Purchased transmission	Total
2005	$20,593	$5,803	$26,396
2006	19,014	5,803	24,817
2007	18,971	5,687	24,658
2008	13,529	5,162	18,691
2009	10,365	5,000	15,365
Thereafter	2,605	29,824	32,429
Total	**$85,077**	**$57,279**	**$142,356**

In addition to these contracts, Western maintains other long-term contracts which provide the ability to purchase unspecified quantities of transmission services within a contractually determined range and rate. To fulfill its contractual obligations to deliver power, Western has historically had to purchase a certain level of transmission services under these agreements. Western intends and anticipates it will be necessary to acquire resources under these contracts up to a maximum of $83.9 million through the life of the current contracts.

(f) Pacific Gas & Electric Company Settlement

Under the terms of the integration contract between PG&E and Western, Western pays PG&E an estimated rate each year for energy purchases and records this amount as purchased power expense in the Combined Power System Statement of Revenues and Expenses. Provisions of the contract require the estimated rate to be adjusted to reflect PG&E's actual annual average thermal production costs, resulting in either Western paying an additional amount or receiving a refund for any overpayment. In the Combined Power System Statement of Revenues and Expense for fiscal year 2004, Western recorded a reduction to purchased power expense for a refund of $23.0 million related to calendar year 2002. During that time period, Western purchased approximately $75.8 million in power from PG&E. No adjustment to the estimated rate has been made for purchases during calendar years 2003 or 2004. Western is unable to estimate the potential adjustment for those years because the cost data is maintained by PG&E and is outside of Western's control. Accordingly, any adjustment to purchased power expense will be recorded when it becomes known.

(g) FERC Proceedings

As a result of concerns related to the California energy crisis during calendar year 2000, a number of stakeholders, including the State of California, initiated proceedings at FERC to determine if energy sellers improperly manipulated the California wholesale electricity market. FERC initiated its own independent investigation. These proceedings confirmed that a number of independent power producers and marketers of electricity manipulated the California wholesale electricity market. As these individual market manipulators were identified and their inappropriate profits calculated, the alleged price manipulators entered into settlement discussions with FERC to disgorge any unjustified profits.

The State of California filed a claim for up to $9 billion against a number of independent power producers at FERC based on its own independent estimate of unjustified price manipulations of the wholesale electricity market. FERC has ordered energy companies to refund approximately $3.3 billion, but the State of California appealed this ruling to the 9th Circuit Court of Appeals arguing that the refunds were inadequate as it did not recover sufficient over payments associated with unfair pricing practices. The 9th Circuit ruled in favor of the State of California's position on September 10, 2004, but instead of ordering additional refunds, the court remanded the case back to FERC for further proceedings.

As such, it is not yet determinable as to the scope or how further investigations might impact Western and the generating agencies. Any refunds or costs incurred would be adjusted through the future power rates.

(h) Central Valley Project

Western is engaged in legal discussions with a customer/supplier regarding disputed transmission rate and grid management charges. There is a reasonable possibility that Western could be liable for additional charges estimated at $22 million.

(8) Pension and Other Retirement Benefits

Western, Reclamation, the Corps, and IBWC employees participate in one of the following contributory defined benefit plans: the Civil Service Retirement System (CSRS) or Federal Employees Retirement System (FERS). Agency contributions are based on eligible employee compensation and total 7.0 percent for CSRS and up to 10.7 percent for FERS. These contributions are submitted to benefit program trust funds administered by the Office of Personnel Management (OPM). Western and the generating agencies' contributions for the two plans amounted to $18.3 million and $17.2 million for the years ended September 30, 2004 and 2003, respectively.

The contribution levels as legislatively mandated do not reflect the full cost requirements to fund the CSRS or FERS pension plans (approximately 25.0 and 12.0 percent of base salary, respectively). Other post-retirement benefits administered and partially funded by the OPM are the Federal Employees Health and Benefits Program (FEHB) and the Federal Employee Group Life Insurance Program (FEGLI). FEHB is calculated at $4,419 and $3,766 per employee in fiscal year 2004 and 2003, respectively, and FEGLI is based on 0.02 percent of base salary for each employee enrolled in these programs. In addition to the amounts contributed to the CSRS and FERS as stated above, Western and the generating agencies recorded an expense for the pension and other retirement benefits in the Combined Power System Statement of Revenues and Expenses of $16.6 million for the year ended September 30, 2004 and $14.8 million for the year ended September 30, 2003. This amount reflects the contribution made on behalf of Western and the generating agencies by OPM to the benefit program trust funds.

As a Federal Agency, all post-retirement activity is managed by OPM. Accordingly, disclosure requirements of FASB SFAS No.132 will be accomplished by OPM.

WESTERN AREA POWER ADMINISTRATION

- Administrator A0000
  - Power Marketing Advisor A0020
  - General Counsel A0200
  - Economic Impact & Diversity A0300
  - Power Marketing Liaison A0500
  - Corporate Communications A0600
  - Chief Information Officer A2000
    - Operations Center A2100
    - Technology Center Regional Support A2200
  - Chief Operating Officer A7000
    - Procurement A7100
    - Human Resources A7200
    - Electric Power Training Center A7300
    - Natural Resources A7400
    - Safety & Security A7700
    - Technical Services A7800
    - Design A7900
  - Chief Financial Officer A8000
    - Budget and Analysis A8100
    - Accounting A8200
    - Compliance & Audit Liaison A8300
  - Upper Great Plains Region B0000 (Billings, MT)
    - Environment B0400
    - Safety & Security B0700
    - Management B1000
    - Information Technology B2000
    - Operations B4000
    - Maintenance B5000
    - Power Marketing B6000
    - Financial Management B8000
  - Rocky Mountain Region J0000 (Loveland, CO)
    - Utility Restructuring J0003
    - Environment J0400
    - Safety & Security J0700
    - Management J1000
    - Information Technology J2000
    - Operations J4000
    - Maintenance J5000
    - Power Marketing J6000
    - Financial Management J8000
  - Desert Southwest Region G0000 (Phoenix, AZ)
    - Environment G0400
    - Safety & Security G0700
    - Management Services G1000
    - Information Technology G2000
    - Operations G4000
    - Maintenance G5000
    - Power Marketing G6000
    - Financial Management G8000
  - Sierra Nevada Region N0000 (Folsom, CA)
    - Industry Restructuring N0010
    - Business Practices Advisor N0020
    - Program Support N1000
    - Information Technology N2000
    - Operations N4000
    - Maintenance N5000
    - Power Marketing N6000
    - Financial Management N8000
  - CRSP Management Center L0000 (Salt Lake City, UT)
    - Transmission System Planning L4400
    - Rates Analysis L6100
    - Power Marketing and Contracts L6200
    - Resource Scheduling L6300
    - Environment & Resources Planning L6400
    - Financial Management L8000

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Western's Statistical Appendix on CD

This year we continue to offer you our statistical appendix in a convenient electronic format. The enclosed CD contains project-level data about Western's sales and revenues, generation, facilities and transmission lines, repayment, rates and finances. The information is presented in a consolidated, Westernwide format and also by project. This data is also available on our Web site at **www.wapa.gov**. You can find it under Newsroom, then Publications, then 2004 Statistical Appendix to the Annual Report, or directly by browsing to **www.wapa.gov/newsroom/sa04/sa04.htm**.

This CD was designed to run using an Internet browser. We have provided links to two browsers for your convenience. An autostart program launches the CD automatically on a Windows-based PC after you insert it into your CD drive. Macintosh users must open the sa2004.htm file with an Internet browser. Look for the Read Me file on the CD if you experience any problems.

Because the CD is browser-based, you can use it to access Western's Web site, including each regional office's home page. We encourage you to click on the Western Contacts button to e-mail us your comments and suggestions about our Annual Report or Appendix. We have also included a brief questionnaire on the CD for you to submit by e-mail so that we can gauge its usefulness to you.

Contact Western

Call or write your local Western office or the Corporate Communications Office at our Corporate Services Office in Lakewood, Colo., to share your comments or to find out more about Western. Our addresses and phone numbers are listed below.

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For no-cost energy-related technical assistance within Western's service territory, call 1-800-POWERLN (1-800-769-3756), or log on to www.wapa.gov/es.

Western AREA POWER ADMINISTRATION

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