SHAPING THE GRID | ONE PROJECT AT A TIME

ANNUAL REPORT 2003

WESTERN AREA POWER ADMINISTRATION

CONTINUE

SHAPING THE GRID—ONE PROJECT AT A TIME

It's 3 a.m. and an eerie sound jolts you from a sound sleep. You get up and switch on the porch light—an effortless action that entails the intricate coordination of many powerplant operators, dispatchers and maintenance and communication crews who command our nation's power grid. To transport power from the plants where it's generated to the homes and businesses that depend on its instant availability, these valuable workers delicately balance supply and demand and coordinate power flow over 150,000 miles of transmission lines managed by 130 different control areas nationwide. And all this synchronization happens 24 hours a day, without you knowing the minute-by-minute, behind-the-scenes work on your behalf.

In our nation's vast electricity network, the system's components are highly interrelated, both economically and operationally. Transmission facilities are a key element of this system because they tie large powerplants, often located in remote locations, across long distances to load centers where consumers depend on the electricity.

At Western, we play a major role in allowing people all over the western United States to take energy for granted. Our employees ensure that power constantly flows through Western's 17,000-plus circuit-mile transmission system so that customers can turn on air conditioners in the arid Arizona desert, run irrigation pumps in Kansas wheat fields or illuminate homes on Native American reservations.

But how do we make sure the grid—actually the three grids in this country—provide reliable electric power when transmission lines are aging and supply can't always continues up with increasing demand? The answer lies in carefully shaping and molding the grid with smarter technologies, transmission line upgrades or enhanced system coordination.

Western's 2003 Annual Report highlights five projects that are keeping the western grid reliable. One project at a time, Western is helping to ensure that the power continues flowing when industry, businesses, schools and homes need it. In each of these projects, Western formed partnerships with customers, other utilities or private companies and research organizations to ensure the grid reliably delivers the power that is vital to our economy and our way of life. ▼

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Western at a glance

Marketing profile

	FY 2003
Firm energy revenue	$649 million
Nonfirm energy revenue	$136.7 million
Firm energy sales	35.6 billion kWh
Nonfirm energy sales	4.4 billion kWh
Composite firm rate	16.60 mills/kWh
Composite transmission rate	$1.67 kW/mo
Coincident peak load (est.)	5,863 MW
Ancillary service revenue	$7.2 million
Transmission service revenue	$172.1 million

Customer profile

	Number	Percent	Sales (billion kWh)	Revenue (million $)
Municipalities	301	44.1%	11.8	235.8
Cooperatives	55	8.1%	7.9	148.4
Public utility districts	17	2.5%	4.0	92.6
Federal agencies	37	5.4%	1.5	32.9
State agencies	47	6.9%	8.4	136.8
Irrigation districts	48	7.0%	0.7	13.7
Native American tribes	31	4.5%	0.7	9.8
Investor-owned utilities	24	3.5%	1.2	38.0
Power marketers	32	4.7%	1.5	48.0
Project use (Reclamation)	84	12.2%	1.8	14.6
Interproject	7	1.0%	0.4	15.1
Total	**683**	**100.0%**	**39.9**	**785.7**
Firm customers	533			
Firm and nonfirm customers	71			
Nonfirm customers	79			
Total	**683**			

IRP profile

IRPs submitted	297
Small customer plans submitted	107
IRPs from cooperatives	40
Minimum investment reports	70
Customers and members represented	750

Repayment profile	
Principal repaid in FY 2003	$36 million
Federal	$31 million
Non-federal	$5 million
Federally-financed non-power	$0.3 million
Total investment	$9.0 billion
Federal	$8.84 billion
Non-Federal	$.20 billion
Total repaid	$2.86 billion
Federal	$2.81 billion
Non-federal	$.05 billion

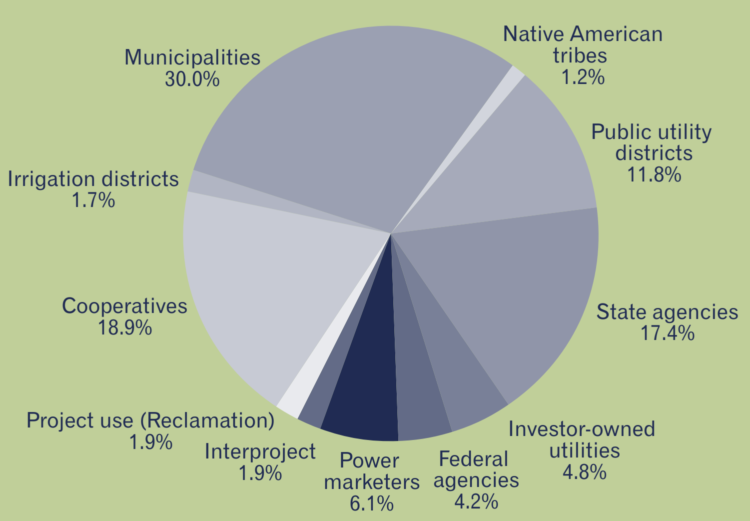
Financial profile (in thousands)	
Assets	$4,203,683
Liabilities	$548,456
Gross operating revenues	$1,035,020
Sales of electric power	$764,104
Other operating income	$270,916
Operating expenses	$855,278
Operation and maintenance expense	$298,059
Administration and general expense	$46,955
Purchased power expense	$364,811
Purchased transmission expense	$46,526
Depreciation	$98,927
Net interest expense	$164,949

Resource profile	
Hydro powerplants	55
Thermal powerplants	1
Actual operating capability — July 1, 2003	10,244 MW
Total units	179
Net generation	28,811 GWh
Purchased power	12,635,603 MWh

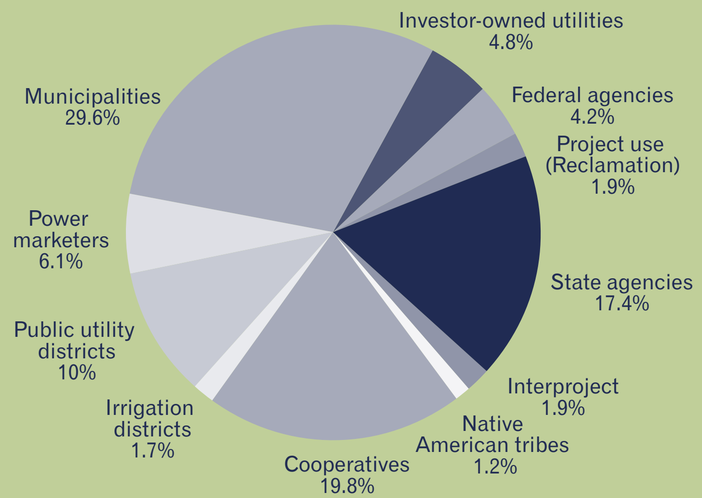
Transmission system profile	
Communication sites	435
Substations	268
Transmission lines	17,401 miles
Transformer capacity	23,469,200 kVa

Employee profile	
Federal full-time equivalent usage	1,303

WHERE OUR REVENUES COME FROM ($)



WHERE OUR ENERGY GOES (kWh)



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Administrator's letter

The Honorable Spencer Abraham
Secretary of Energy
Washington, D.C. 20585

Dear Secretary Abraham:

I am pleased to submit to you Western's FY 2003 Annual Report, highlighting the projects that keep our nation's power grids operating reliably. In FY 2003, constraints across congested transmission paths in California, unending drought conditions and additional load growth in Wyoming put additional demands on our system. Despite these challenges shared by the entire western grid, our partnerships with customers and private industry have repeatedly proven that we can provide reliable service to our 683 wholesale customers.

Today's utility industry requires us to transmit electricity over longer distances across aging lines and through older substation equipment, so we continually look for cost-effective and technologically advanced solutions to maintain our 17,000-plus-mile transmission system. One answer lies in sharing our expertise with our industry counterparts.

Our employees frequently lead or actively participate in industrywide committees and working groups whose main goals are to ensure system reliability. For example, Western continues to participate in efforts to form three regional transmission organizations in the Western Interconnection. Western is also actively participating in RTO Seams subcommittees, which are developing standards in pricing, transmission planning and congestion management and other coordination efforts.

"Our unique needs also involve determining how to fund transmission system upgrades in light of tight budgets."

Western is also involved in industry discussions on Federal Energy Regulatory Commission's initiatives such as Standard Market Design, which proposes to enhance a competitive bulk power system and consistent rules and practices for emerging RTOs. We need to ensure the resulting market designs through tariffs accommodate our unique needs as a power marketing administration.

Our unique needs also involve determining how to fund transmission system upgrades in light of tight budgets. Our partnership with Trans-Elect and Pacific Gas and Electric Company to build the Path 15 Upgrade Project—a new 500-kV line in Central California to resolve a long-standing transmission bottleneck—serves as a model of public-private partnerships and is being closely watched in the industry as an example for other transmission system improvements. Western will continue to explore in non-Federal financing opportunities as we try to resolve constrained transmission paths in other areas.

One answer may involve technologically advanced power system equipment and transmission lines. Western and the 3M Company have teamed up in two research projects to determine if a new composite conductor, that could triple the amount of power carried across existing transmission lines, is the answer to transmission line congestion. And our partnership with the Colorado School of Mines and EPRI could help develop "smart" substation technology, resulting in fewer scheduled outages for routine maintenance.

Western strives for fewer outages daily. Because we recognize the important role we play in the interconnected bulk power system, employees take pride in reliably operating and maintaining our 15-state system. In fact, in 1995, our goal was 152 or fewer accountable outages. Today, we've set the goal at 18 or fewer accountable outages.

Employees' commitment to reliability has also helped us accomplish many other projects in FY 2003. These include:

- Registering as a market participant with the Midwest Independent System Operator.
- Installing monitoring devices on Western transmission lines between Elverta and Hurley substations in California to verify transmission line sagging and safe operating limits.
- Posting regionally available Federal transmission capacity on one Open Access Same Time Information System Web site.
- Examining alternatives for operating the Central Valley Project hydropower system beginning Jan. 1, 2005, when Western's contract with PG&E expires.
- Releasing the final Environmental Impact Statement outlining potential upgrades to Western's transmission system in a 100-mile radius around the Sacramento area to meet increasing energy needs.
- Operating the Rapid City AC-DC-AC Converter Station, one of six interconnections joining the eastern and western U.S. power grids, which will allow for power transfers to meet load growth in Wyoming.
- Uprating the Shiprock-Four Corners 345-kV line on Navajo Nation land.
- Dedicating the Virgil Fodness Substation, which will meet the increasing demand for electricity in the growing area around Sioux Falls, S.D.
- Replacing analog microwave radio equipment with digital equipment west of the Havre, Mont., Substation.

While we will face new and continuing challenges in 2004, Western's employees will continue to provide the power that runs industrial equipment and lights the mountains and plains across the West.

Michael S. Hacskaylo

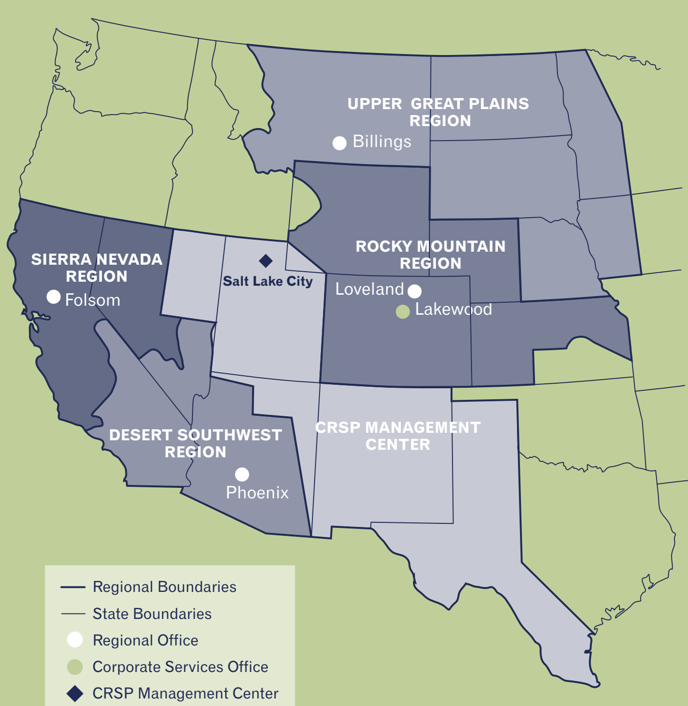
Michael S. Hacskaylo
Administrator

Western profile

Western markets and transmits about 10,000 megawatts of power from 55 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.

CUSTOMER SERVICE TERRITORIES



Transmission: Central to Western

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

Rate components

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

Employees' commitment

While Western's role in the industry has evolved over the years, the dedication of employees at our 52 duty stations has not wavered. Employees stationed throughout Western's vast territory work around the clock to provide power sales, transmission operations and maintenance and engineering services. These duty

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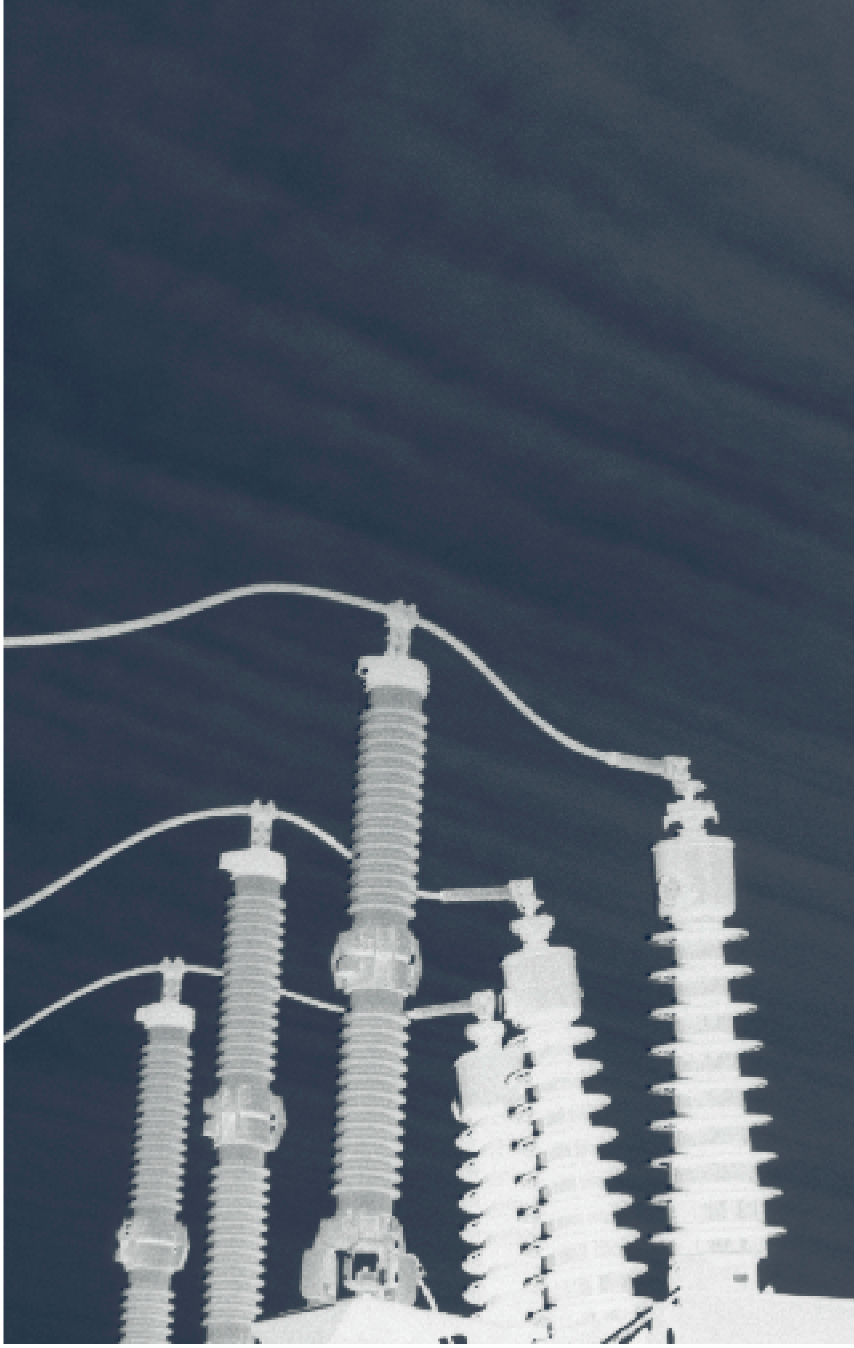
locations include Western's Corporate Services Office in Lakewood, Colo., and four Customer Service Regions with offices in Billings, Mont.; Loveland, Colo.; Phoenix, Ariz.; and Folsom, Calif. We also market power from our Colorado River Storage Project Management Center in Salt Lake City, Utah, and manage system operations and maintenance from offices in Bismarck, N.D.; Fort Peck, Mont.; Huron 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

Our program includes three principal activities: operation and maintenance, purchase power and wheeling; and construction and rehabilitation. Each year, Congress appropriates funds to finance operation and maintenance and construction and rehabilitation activities for many of our power 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. Our appropriations also include 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 the Colorado River Storage, Central Arizona, Seedskadee, Dolores and Fort Peck projects to operate with power receipts through a revolving fund. Boulder Canyon Project is financed through permanent appropriations of receipts from the Colorado River Dam Fund. In accordance with 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.

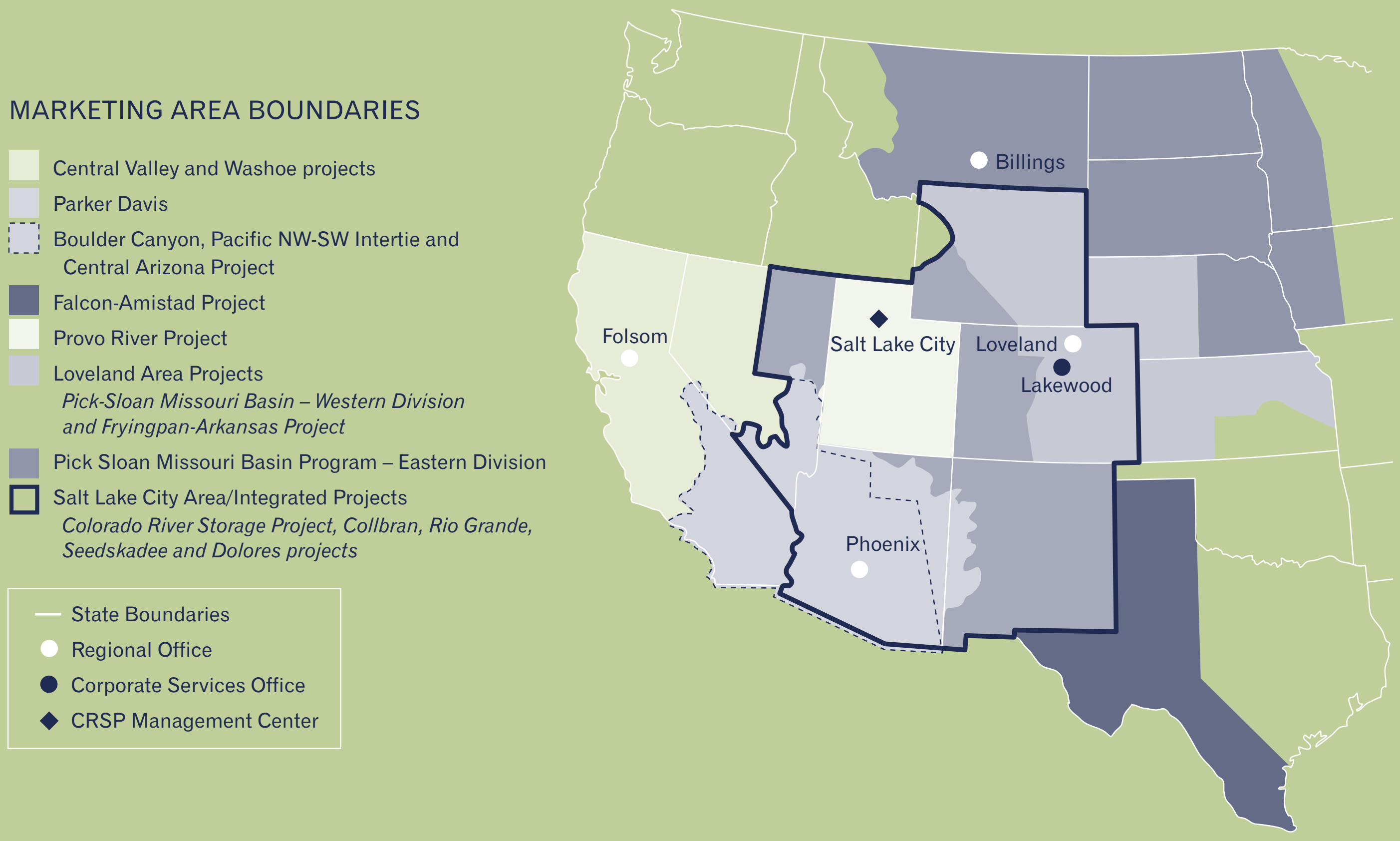
Because legislation requires that the U.S. Treasury be repaid by those who benefit from Federal investments in the projects, power sales must produce enough revenues to cover power users' share of annual operation and maintenance project costs. We set power rates to recover all costs associated with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

Power revenue also pays for portions of Western's purchase power and wheeling activities. Drought conditions—like those we experienced in FY 2003—and other factors sometimes require us to purchase power from other suppliers to meet long-term firm power contract commitments. Congress gave Western interim authority in FY 2001 to fund these activities from power receipts. The receipt funding authority, combined with alternative financing methods, such as net billing, bill crediting and customer advanced funding, eliminated the need for an annual appropriation to meet planned Purchase Power and Wheeling program needs. Western's continuing fund authorities also provide emergency funding under below-normal generating conditions to finance unplanned purchase power expenses.

Customers also provide advance funding to finance certain power system expenses and capital improvements.

Customers provide advance funding to finance other power system expenses and capital assets. We also do work for other Federal and non-Federal organizations. The authority for these activities is under the Economy Act, the Contributed Funds Acts and the Interior Department Appropriations Act of 1928.

PROJECT MARKETING AREAS



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Common OASIS—an electric supermarket improves transmission access

Buyers looking for available transmission in the West will now shop at a new electric transmission market. A Web site called wesTTrans.net promises to simplify the search for available transmission paths and serves as a central plaza for transmission owners that have excess transmission for sale.

Transmission owners like Western build and use transmission lines to deliver electricity to their customers. But excess transmission capacity is often available. "WesTTrans.net provides a convenient way for entities that want transmission to acquire it for their needs," said **Bob Fullerton**, Western's power marketing advisor.

WesTTrans.net was formed by a variety of public power, private utilities and government agencies in the Western Interconnection, including Western, to improve transmission access. The concept of a common Open Access Same-Time Information System was fostered by a group of nonprofit utilities called the Public Power Initiative of the West, which aims to improve the way the energy industry buys and sells available transmission capacity. This group also includes Western customers Imperial Irrigation District, Los Angeles Department of Water and Power, Sacramento Municipal Utility District, Salt River Project, Southwest Transmission Cooperative, Transmission Agency of Northern California and Tri-State Generation and Transmission Association.

Simplifying transmission shopping

The new Web site will specifically benefit transmission buyers who used to query numerous individual OASIS sites. Until it launched in Spring 2004, many participating utilities operated separate OASIS sites to display available transmission capacity—a cumbersome way to do business, say wesTTrans.net proponents. In the new system, participants, including investor-owned utilities as well as PPIW members, will replace their current individual transmission reservation systems with a common OASIS. Now utilities in Arizona, California, Colorado, western Nebraska, New Mexico, Nevada, Oregon, West Texas, Utah, Washington and Wyoming will benefit from wholesale market participant access to thousands of miles of high-voltage transmission line capacity through wesTTrans.net.

WesTTrans.net retains the identity of transmission owners, and also stresses system reliability and security. "We believe wesTTrans.net provides an innovative, solid foundation for enhancing the competitiveness of wholesale energy markets, while protecting consumers in the West from market manipulation, unnecessary blackouts and price spikes," said Frank Barbera, an assistant manager at the Imperial Irrigation District in California, a wesTTrans.net participant.

How wesTTrans.net will operate

Transmission owners like Western will continue using their transmission systems to serve their own customers. However, wesTTrans.net will allow transmission owners to market excess transmission capacity to other customers. WestTTrans.net publishes up-to-date information from numerous transmission providers using a single software platform that supports robust wholesale electricity competition in the Western Interconnection.

The system makes capacity available to transmission customers on a nondiscriminatory, transparent and voluntary basis. In one single query on wesTTrans.net, a transmission customer may view and reserve available transmission capacity from multiple sources, linking multiple transmission paths and providers, if necessary.

WesTTrans.net's goals

- Continue to provide low-cost, reliable service while maintaining existing control areas.
- Streamline transmission operations.
- Expand the information base of available transmission capacity.
- Enhance transmission reliability.
- Enhance the return on transmission investments by expanding revenue opportunities.
- Employ a common platform, allowing all participants easy access to information.
- Complement Federal Energy Regulatory Commission goals to meet the needs of customers.

"Before, transmission customers had to go to different utility OASIS sites, each with its own idiosyncrasies," said Fullerton. "Historic systems made it difficult for customers to determine what was available at what price, and sometimes they would have to go back and forth between sites to compare or reserve multiple transmission paths, only to find out one path wasn't available when they returned to the first site. By using a common OASIS, it's simpler to determine what's available."

Energy resources bulletin board

WesTTrans.net also offers a separate energy resources bulletin board to market available wholesale energy resources, expanding the versatility of the Internet site to utilities. It allows buyers to quickly access available energy resources to serve their loads.

The bulletin board will include voluntary postings of offers and bids for energy. Interested parties will negotiate energy transactions separately. The feature may help reduce grid congestion and may also allow for trading ancillary services and eventually make market monitoring easier.

"These features will make wholesale transactions easier between buyers and sellers," said Fullerton. "Anything that makes transmission more readily accessible benefits consumers," he added. ▼

Western tests new power line technology

Constrained transmission lines trigger perpetual frustration for dispatchers. While adequate generation is available in one area, they can't move it to meet demand in another area if the wire cables carrying the electricity aren't designed to carry the required loads. But a field test on Western's transmission system just might help provide an answer to this all-too-common dilemma.

Studies show that U.S. electric transmission capacity is declining, while demand for power is expected to increase 25 percent over the next decade. Hopes are high for this new technology because it could potentially triple the amount of electricity carried over existing high-voltage transmission lines.

"The new technology could offer many benefits for utilities and for the grid," said **Ross Clark**, Western's electrical engineering manager. "On some lines, it could alleviate transmission bottlenecks that prevent lower-cost energy from being dispatched to where it is needed."

Putting it to the test

In October 2002, as the brutal Midwestern winter began to debut, Western crews strung a one-mile test segment of a new composite conductor cable on Western's Jamestown-Fargo No. 1 230-kV line in northern North Dakota. Funded by the Department of Energy, the two-year field test will determine how well the conductor withstands the rigors of North Dakota wind and weather.

Developed by the 3M Company, the composite conductor can carry up to three times the electricity as a conductor now in common use. The conductor has aluminum matrix composite wires that can withstand higher operating temperatures, which means less sag in the line. This is groundbreaking since the core is three times stronger than steels, so power flow across the line can be increased without causing as much line sag.

"If existing transmission lines can carry more power, that means you don't have to build as many new lines," said **Steve Rock**, an electrical engineer at Western's Corporate Services Office.

During installation of the one-mile segment on Western's line, representatives from the various equipment manufacturers were on hand to observe how their products would work in real-world conditions. Western also documented the field test installation in a video to show to other transmission line owners interested in using the new conductor.

"We installed monitoring equipment to measure line tension and sag, as well as track temperature and wind conditions," said **Scott Scholl**, Fargo crew foreman and job supervisor.

"We picked this segment because the

Casey Blotske and Brian Heisler install a splice on the conductors during composite conductor testing on the Jamestown-fargo No. 1 230-kV line in North Dakota.

developers wanted a one-mile straight stretch of line. "It's just west of our Fargo Substation, so it's also easy for the crew there to keep an eye on the monitoring equipment," added North Dakota State Maintenance Manager **Brian Morris**. Western engineers also worked with 3M's hardware manufacturers to ensure that the existing material—structures, insulators, hardware fittings, vibration dampers—were compatible with the higher operating temperatures.

While there is one more year to gather data on how well the technology stands up to Mother Nature, so far the conductor is "operating like it should be," said Morris. The monitoring equipment measures information regarding line tensions, which correlates into the distance from the ground to where the line sags. "Mainly, 3M is interested in how well the line handles the extreme ice and wind that are typical here in the Dakotas. These monitoring devices can pick up even 1 millimeter of ice. We've had a few harsh conditions so far, but really we've had mild winters the last few years."

"If existing transmission lines can carry more power, that means you don't have to build as many new lines."

Morris said that depending on test results, such new technology Western may consider when it comes time to replace the 83-mile line, which was built in 1957. "It may need to be rebuilt and upgraded to 345-kV in another 50 years, when it significantly degrades or system studies show we need to increase line capacity," he said.

"Everyone is very excited about this new technology," said Clark. "DOE is calling it a potential showcase to relieve bottlenecks, which have occurred in these two areas." Western's other part of the test is to evaluate the cost-benefit of using 3M's new conductor to reconductor 20 miles of Western's Topock-Davis 230-kV and 60 miles of the Davis-Mead 230-kV lines in the Desert Southwest.

While Western's field test in North Dakota will show how well the new cable can mechanically withstand the extreme winter and summer conditions on the Great Plains of North Dakota, it won't measure the cable's ability to carry additional power because Western only put in a one-mile segment on an existing line.

But down south near the lush rolling hills in Tennessee, Oak Ridge National Laboratory is conducting just that sort of research. At an outdoor lab test site, Oak Ridge is testing three sizes of conductor on steel poles to measure its sag and tension at high-current and low-voltage conditions at the cable's rated operating temperature of 210 degrees—more than double the operating temperature of traditional conductors. The test, which began in March 2002, will last three years. Extensive studies have shown documented performance gains and increased power flow capabilities.

If the tests prove that these new Aluminum Conductor Composite Reinforced wires can indeed carry more power, they could be installed quickly with little disturbance to the environment, since no new towers would have to be built and existing rights-of-way could be preserved, said John Stovall at Oak Ridge.

"We could put up this new conductor on an existing line very quickly. It could probably be installed in four to six months, compared to about two years to site a new line where you have to go through the long processes of addressing environmental issues and acquiring land rights," Clark said. ▼

Western pioneers technology to make grid more intelligent

To handle the numerous constraints on our existing bulk power system, utilities aren't the only ones getting smarter these days—the equipment they manage is getting smarter, too. And Western is testing just how well this new "intelligent" equipment could enhance not only our system but the existing bulk power system as well.

Under a partnership with the Electric Power Research Institute and the Colorado School of Mines, Western's Ault Substation in northern Colorado is the test site for a new system that constantly monitors and diagnoses how substation transformers operate. The system uses a new technology called a neural—or fuzzy—network, which could help utilities reduce maintenance costs while increasing reliability.

For a nation with an insatiable appetite for electric power, such technological advances are invaluable. The United States is already at the point where it needs more energy but does not have the capability to provide it, as we witnessed in California just a few years ago. To prevent catastrophic failures of large power transformers and expensive outages, and to reduce scheduled outages for routine maintenance, utilities could improve how they operate our current transmission and distribution system.

"It's like having someone sitting in the substation watching the equipment all the time," said **John Work**, an electrical engineer at the Corporate Services Office and Western's project manager for the intelligent substations test.

Testing the system

The health of power transmission and distribution systems depends on transformers that step up and down transmission voltages, buses that split the distribution power in multiple directions and circuit breakers and switches that connect the substation to the transmission grid. With online monitoring, utilities can identify faults—or trends of faults in the equipment—in real time. That means utilities can avoid severe damage, increasing the reliability of the entire system.

To determine how to better monitor substation equipment health, School of Mines researchers in Golden, Colo., conducted a literature survey, developed a mathematical model of the way a transformer works and built a prototype monitor to help EPRI develop accurate monitoring devices. When the system is completed, devices will monitor transformers, breakers and other equipment and send large amounts of information to a data analysis engine, or "super brain" in the substation. The new technology won't be available commercially for about four years.

While the neural system at Ault is a beta, or test, system that will initially focus only on transformers, plans call for a network of neural devices, or monitors, attached to various types of substation equipment. Sensors will monitor the transformer's gas, temperatures, acoustics, currents, fans and cooling pump motors.

The neural network actually consists of five parts: sensors, signal conditioning, data acquisition and storage, data analysis and user interface. The most vital is the data analysis, which identifies potential equipment failures. The system's data engine interprets the data and identifies potential equipment failures. It can even notify maintenance staff when to take action.

"The neural network devices act like the human nervous system, collecting information and sending it to the brain. The system is adaptable, capable of making rapid decisions and can catch on to trends of specific pieces of equipment," Work said. "In other words, it's 'smart.'"

"It's artificial intelligence," explained **Tim Michaelis**, lead field engineer for Western's Rocky Mountain Region. He helped install the fiber optics into each of the Ault transformers and connected them to a monitoring computer. "The software learns about the equipment so well, it can predict trends and identify what is normal and what is not."

Managing the data

Western currently uses a Supervisory Control and Data Acquisition system to collect data and monitor and control equipment remotely using a modem, high-speed communication lines and fiber-optic cables. Computerized tools also allow crews to monitor equipment online. However, SCADA provides a snapshot of the equipment in real time, rather than providing a historical picture of the equipment, said **Bill Timmons**, Western's Reliability Centered Maintenance coordinator.

"SCADA is more like a central operator—it allows dispatchers to remotely control power system equipment, but it is limited as far as data storage because it operates in real time," said Timmons. "Maintenance folks want historical data, such as 'how has this transformer been operating for the past 20 years?,' while Operations folks are concerned about what's happening with the system in the next few seconds. Eventually the SCADA, intelligent monitoring and other maintenance management systems will come together, probably by default, since technology is moving so quickly."

To monitor substation equipment, Western already uses another advanced technology. Currently we have digital transformers and a breaker monitor system for many of our substations, Work said. However, they are rule-based monitors. Crews set parameters for the monitors to watch, and the monitors activate when the equipment falls outside those parameters. This usually means an event has occurred, or an alarm has sounded. By the time crews identify a situation, a problem has already occurred.

"The monitoring devices in place now protect the equipment, such as when there are sudden pressure change or low liquid levels in the transformer, by isolating the problem so the transformer won't sustain irreparable damage," said Michaelis.

"The School of Mines research project goal is to learn beforehand if you have a problem. It could then be isolated via SCADA at the Loveland dispatch office, and then a maintenance

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crew can go out to the substation. The intelligent system could help us recognize an upcoming failure so we can possibly save money," he said.

A fusion of technology

According to an EPRI report on neural network technology, substation equipment behaves in a nonlinear manner. In other words, instead of things happening one after another—in a straight line—it's more like a web, with events and influences coming from different sources. The new technology can identify that nonlinear behavior, using a process called sensor fusion. This process combines all of the factors measured by different sensors and combines it, creating a "whole picture" of the equipment's status. That means the neural network not only tracks information, but also interprets it.

The system also eliminates most equipment testing (gas and moisture sensors can be added), reducing the time system control devices are out of service. Instead, crews would maintain equipment when the neural devices detect a need. That fits well with Western's focus on reliability-centered maintenance and greatly extends equipment inspection intervals.

"RCM systematically examines Western's power equipment and determines the best maintenance practice to preserve the equipment's function by asking questions like: Which past and present maintenance practices are effective? What is important about the equipment? explained Timmons.

"RCM also helps crews plan and manage maintenance activities and justify maintenance technical decisions. Crews can determine which equipment is in good shape instead of basing repairs on time-scheduled maintenance. RCM makes the Western maintenance organization 'smarter' about equipment condition and is more cost effective," he said.

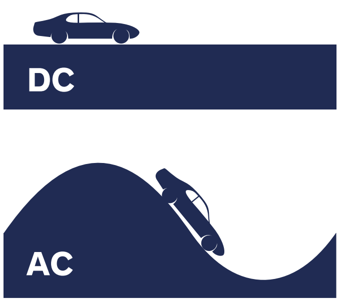
"The software learns about the equipment so well it can predict trends and identify what is normal and what is not."

With all the tools, processes and new technologies available, Western and other utilities have plenty of opportunities to feel smarter about how they can more effectively provide and deliver power in an interconnected system. "We like to keep up to date with technologies that can help us improve our reliability and control our costs," Work concluded. ▼

Rapid City DC tie provides grid link

When energy reserves are low in windy Wyoming but plentiful in South Dakota, a new intertie linking the eastern and western power grids keeps the power flowing across the two states. This new $70 million intertie—the Rapid City, S.D., Converter Station operated by Western—is one of six links in the United States between the two separate grids that allow utilities to import and export power to meet demand.

Because the cycles of electricity in the two grids are slightly out of sync, the Rapid City DC tie acts as a giant shock absorber to convert alternating current power on one side of the grid to direct current, then back to AC. DC converters allow energy to flow reliably between grids, but maintain the electrical separation so that a disturbance on one side won't affect the other. Access to power from the other grid allows utilities to delay power-plant construction while meeting peak demand, since they can buy energy from generators with surplus energy to sell.



The intertie also has a commercial benefit. The tie allows marketers more opportunity to buy energy where it is cheap and sell where it is worth more, said **Cyndy Beretta**, a pre-scheduling marketer at Western's Energy Management and Marketing Office in Montrose, Colo. "We use the tie to bring across 150 MW of transmission around the clock. We use a $5 to $6 spread in price to determine when to bring it across to the West," she said. "Lately the East has had higher on-peak (during peak demand periods) prices, and we've had higher off-peak prices."

Station owners Basin Electric Power Cooperative and Black Hills Power Corp., benefit from power flowing in either direction and now have access to the most reliable and least expensive power on either side of the system. At the converter station's dedication, Dan Landguth, Black Hills Corporation CEO, said, "This vital infrastructure provides tremendous reliability and support for electric suppliers and customers. It's like putting a 200-MW generator right at our back door."

The project also includes construction of a 18-mile, 230-kilovolt transmission line from a substation near New Underwood, S.D., to the tie. In August, Western employees helped build the new 230-kV terminal bay at New Underwood Substation. The project will also strengthen Western's transmission system by improving reliability at the substation. The tie is also connected to another substation owned by Black Hills Power.

When the new Rapid City tie became operational in October 2003, Western became the primary operator of four of six DC ties connecting the eastern and western grids in the United States. In addition to Rapid City, the other three ties Western operates are in Miles City, Mont., Stegall, Neb. and Sidney, Neb. Western's Rocky Mountain Region operates the Rapid City tie as part of its Western Area Colorado/Missouri control area.

While the five other DC ties in the U.S. (another is in Canada) use a single converter to transfer electrical capacity from east to west or from west to east, the Rapid City DC tie has two 100-MW converters connected in parallel.

"This allows maintenance crews to work on one converter without cutting off the power flow completely," said **Chuck Weaver**, lead transmission switching dispatcher for Western's Rocky Mountain Region. "This allows Basin and Black Hills to ensure they always have 100 MW to feed into the load area.

"Since they are using the tie to serve load, availability became a bigger factor. For example, with the Sidney Converter Station, if you need to do maintenance on the 200 MW converter, then all 200 MW are unavailable. At Rapid City, the station owners put in extra money to build the station so that 100 MW is always available," said Weaver.

The Rapid City DC tie is primarily used to import energy from the eastern grid to serve loads in Wyoming. Much of this new load growth is due to coal bed methane gas development that requires power to pump the coal bed water out and compress the methane gas.

While Basin Electric plans to build a new coal-fired powerplant to meet load growth, given the environmental challenges of coal use, it will be another eight to 10 years before they can get a new coal-based plant on line. In the meantime, Basin can import power from the eastern interconnection to help meet its increased demand in northeastern Wyoming.

Asea Utilities, from Ludvika, Sweden, built the DC tie using technology known as a capacitor commutated converter. These capacitors between the valve hall and the converter transformers produce reactive power in proportion to the current. This means that the station won't have to rely as much on the interconnected AC system.

"The older DC ties need strong AC systems on each side. By strong, I mean that there is a fair amount of generation nearby. This technology doesn't require as strong an AC system nearby, so interties can be placed in areas where it hadn't been possible before," Weaver said. ▼

Interconnection history

As the convenience of electricity spread across the country, two distinct alternating current power grids evolved in the lower 48 states. One grid connected utilities in the eastern United States, while the second grid extended across the western half of the country. The sparse population of the Great Plains led to the divide between the separate power systems. A third grid evolved in Texas.

As Americans began depending on the comfort of electric power, utilities needed to boost reliability and use all available resources to meet electrical demand. Attempts in the 1960s and '70s to "tie" power systems together failed because this interconnection resulted in disturbances in one grid affecting operations in the other grid. The answer came with construction of DC interties, which make it easier to exchange power between the grids.

Path 15 to relieve transmission line constraints

California—home to the Silicon Valley—has long been renowned for innovation, but in 2000 and 2001 it also became famous for an electric power crisis. A transmission bottleneck known as Path 15, where three 500-kV lines linking northern and southern California narrow to two lines for an 84-mile stretch through the Central Valley, contributed to this crisis. To eliminate the bottleneck and improve the grid, Western is managing a project to build a new 500-kV line under an innovative public-private partnership.

"Path 15 has been the pinch point for congestion since the early 1980s," said **Tom Boyko**, Western's Path 15 Upgrade project manager. While generation is available in southern California and the Desert Southwest, the transmission corridor's lack of transfer capacity hampers efforts to move that power north.

To relieve this constraint, in May 2001 Energy Secretary Spencer Abraham directed Western to determine if interest existed to finance and build a Path 15 upgrade. As a result, a public-private partnership emerged among Western, Trans-Elect, Inc.—the nation's largest independent transmission company—and Pacific Gas and Electric Company to build an 84-mile, 500-kV line and modify substations at both ends of the new segment.

"The new line will reduce congestion and improve power exchanges between northern and southern California," said **Tim Meeks**, Western's chief operating officer. Secretary Abraham also sees a larger benefit to the project. "The recent Northeast blackouts emphasize the need for investment to improve the nation's electric transmission infrastructure," he said.

The new 500-kV line will be built west of the existing Los Banos-Gates and Los Banos-Midway 500-kV lines, which are part of the Pacific AC Intertie. The new high-voltage line will increase Path 15's south-to-north capacity from 3,900 MW to 5,400 MW—a 1,500-MW increase, or enough to power 1.5 million homes.

The estimate from the Edison Electric Institute, the largest U.S. utility lobbying group, is that $56 billion is needed over the next nine years for upgrades nationwide. The Path 15 Upgrade Project, the first public-private partnership of its kind, is being closely watched in the industry as a possible model for other transmission system improvements.

"This project is being followed with great interest by the investment community, as well as the electric utility industry," said Bob Mitchell, president and chief operating officer of Trans-Elect' s New Transmission Development Company, which is funding the transmission line.

"The transmission grid is now being used in ways it was never meant to be," said Ted Humann, Basin Electric senior vice president of Transmission. "That is very evident in the northeast outage that occurred on August 14, 2003. The total cost of this outage is estimated to be from $7 billion to $10 billion. If we were to invest $10 billion in transmission, we could build

20,000 miles of 345-kilovolt transmission line. That is equal to 12 345-kV transmission lines between Bismarck, N.D., and Phoenix, Ariz."

Construction in progress

On Sept. 15, Trans-Elect's New Transmission Development Company provided Western with $76 million to start construction. Maslonka & Associates of Mesa, Ariz., is the transmission line construction contractor. PG&E is financing and building the expansions at Los Banos and Gates substations to connect this new line to its system, along with other 230-kV and 115-kV reinforcements.

Western's Administrator **Mike Hacskaylo** said he is pleased that construction is now in progress on this $306 million project, which should be completed in late 2004. "I am confident that with the expertise and dedication of Western employees, the project will come in on time and within budget, and serve as a model for future transmission expansion," he added.

The new high-voltage line will increase Path 15's south-to-north capacity from 3,900 MW to 5,400 MW—a 1,500-MW increase, or enough to power 1.5 million homes. The upgrade is expected to save Californians about $100 million per year in electricity costs in normal water conditions and more than $300 million during a dry year. The California Independent System Operator—which manages the flow of power across Path 15—predicts that due to these estimated savings, the project can pay for itself in as few as four years.

"This is a big improvement for California's grid," said ISO Board Chairman Michael Kahn, after the ISO Board of Directors approved the Path 15 Upgrade Project on June 23, 2002. "Not only will this lead to economic benefits for consumers, the upgrade means we will have a more reliable grid and a far better way to move megawatts up and down the state."

Transmission line, structure specifications

When designing the new line, engineers chose the conductor size to maximize how much power could be transferred through the line. "Because we wanted the most capacity possible, our structural engineers picked the biggest conductor size available based on the capacity of lattice tower structures," said **Steve Rock**, an electrical engineer in Western's Corporate Services Office in Lakewood, Colo.

> **"I am confident that with the expertise and dedication of Western employees, the project will come in on time and within budget, and serve as a model for future transmission expansion."**

An emergency restoration system has also been included in the design. "In the event of a structural failure due to some catastrophic event, we would want to get the line back in service as soon as possible, which is what the emergency restoration system is designed to do," said **Doug Hanson**, Western's civil engineering manager.

Accelerated schedule

The project is on a fast track. "With the ISO estimating that Path 15 congestion costs the California consumers about $100 million per year, it is vital that we construct and energize the project as soon as possible," said Boyko.

2003 Accomplishments

APPA Safety Award presented

Western once again earned recognition from the American Public Power Association for its safe operating practices at the association's annual Engineering and Operations Technical Conference in April 2003. Western placed second among utilities with 2 million to 4 million worker hours to earn the association's 2002 Electric Utility Safety Award.

Automated time and attendance system

Western successfully completed the transition to a new time and attendance system. The function was outsourced to the Defense Finance and Accounting System on Sept. 7, 2003, as part of a governmentwide program to consolidate timekeeping systems across agencies. Employees now use DOE's Employee Self Service tool for online access to their biweekly Leave and Earning Statements.

BMXi Initiatives Project completed

Western achieved a complex upgrade of its financial and maintenance management systems in FY 2003 under the BMXi Initiatives Project. Launched in 2002, this project improved data accuracy and integrity and audit and reconciliation tasks and ensured Western would keep pace with the vendor's supported software versions. During this project, Western's financial and IT community managed the upgrades to the Oracle Federal Financials version 10.7 to version 11i. This was the most complex upgrade to Western's financial system since the November 1998 conversion from Western's Financial Management System to Oracle. Release 11i offers improved security, new forms, new and improved reports and specific improvements within such modules as general ledger and accounts payable. The project also upgraded Western's Maintenance Management system to Maximo 4.1.1.

Bismarck warehouse completed

UGP employees and spouses celebrated the opening of the new Bismarck warehouse and maintenance facility at an open house on Dec. 11, 2002. The facility replaces two obsolete 50-year-old buildings didn't meet today's building electrical and fire codes and had sustained damage from several floods over the years. The new building sits four feet higher than grade to prevent flooding, meets the latest building codes and features a much-needed safe loading dock. The facility provides offices for more than 20 workers including warehouse and property staff, line crews, electricians, meter and relay craftworkers, communications groups and the North Dakota Maintenance safety specialist.

Bonus Goals reached

In July, Western employees reached the target goals for safety, reliability and cost containment in Western's annual Bonus Goal program. Program year 2003 is the second time in the program's history that we've achieved all our goals.

Corps of Engineers developed Customer Funding Agreements

Western began working with the U.S. Corps of Engineers and the Western States Power Corporation, a customer group in FY 2003 to develop a customer funding agreement. The contractual documents will consist of an umbrella agreement between Western, the Corps and Western States that outlines customer funding arrangements for a Corps project. A separate Big Bend Project Agreement is also being developed for the first customer-funded construction activity for the Corps under these arrangements. The project consists of a rewind of the Bend Units No. 4 and No. 6.

COTP anniversary marked

Western commemorated the 10th anniversary of the California-Oregon Transmission Project at a June 5, 2003, ceremony at Western's Tracy, Calif., Substation. The 340-mile electricity pipeline in California, which Western and its customers built, allows power sales between the Pacific Northwest and California. During the project, part of Western's existing 230-kV transmission system from Redding, Calif., south to Tracy was upgraded to 500-kV. Crews built new 500-kV lines from Redding to the Oregon border, and from Tracy to Tesla. Two-and-a-half years later, power began flowing between the Captain Jack and Tracy substations. At the event, Western also dedicated the new KT2A 500-230-kV transformer at Tracy Substation, which was added to address overloads to the existing transformer due to load growth. It was energized in May 2002.

Governor's Challenge Award granted

Western received the Colorado Governor's Challenge award in November 2002 for exhibiting a high level of environmental compliance, proactivity and leadership. The award recognized Western for achievements in pollution prevention, waste minimization, green energy programs and fish recovery efforts, as outlined in the Environmental Protection Agency's Environmental Performance Track.

Hoover Dam Highway Bypass built

Western staff joined with the U.S. Bureau of Reclamation, Federal Highway Administration, National Park Service and the states of Arizona and Nevada on a project to build a new bridge across the Colorado River, bypassing the highway that spans the crest of Hoover Dam. Phase one of Western's work, which was completed in May 2003, made room for the new bridge and the highway approach by making several changes to the existing transmission system and reconfiguring connections to two generators on the Hoover Dam powerhouse roof. Phase two of Western's work involves removing the Arizona and Nevada Switchyard and building a new double-circuit transmission line from Mead Substation to the Hoover Dam vicinity. Construction on Phase 2 was completed in June 2004.

Human Capital Planning Award earned from DOE

Western received DOE's 2003 HEROS Award on June 2 in Las Vegas, Nev., for developing a model Human Capital Plan that will help ensure Western's continued viability as a premiere Federal power marketing administration. To advance the plan's seven initiatives in FY 2003, Human Capital team members developed a strategic workforce planning program to address mid- and long-range staffing and recruitment programs; formed a recruiting council to develop a short-range plan for staffing and retention initiatives; created a new 12-month "Emerging Leaders Program" to better prepare non supervisory employees for supervisory positions; crafted an automated exit interview program to track why employees leave Western and revised Western's current employee hire survey program; created a Human Capital Training program to educate supervisors on using current pay and retention flexibilities; conducted employee focus groups on pay issues and administered a motivational survey.

MISO market initiative

Western's Upper Great Plains Region submitted its registration on Aug. 14, 2003, to participate in the energy market operated by the Midwest Independent System Operator, or MISO. The Midwest ISO's role is to ensure equal access to the transmission system and to maintain or improve electric system reliability in the Midwest. Registering will allow Western's merchant staff to continue to serve firm power customers within the MISO territory.

Monitoring devices to verify safe operating limits

Under a collaborative agreement, Western and Sacramento Municipal Utility District crews installed monitoring devices Spring 2003 on Western transmission lines between the Elverta and Hurley substations in California to check temperatures and power flows. The data collected will verify the transmission line sag limitation and safe operating limits, providing information on how system operators could get the most from existing transmission lines and increase deliveries. The analysis lasted until Spring 2004. Western provided the labor to install the equipment and take line sag readings and provided the use of our transmission lines.

OASIS sites consolidate

Western awarded a three-year contract on June 23, 2003, to consolidate transmission marketing managed by Western's Rocky Mountain Region into one OASIS Web site. On this Web site, available transmission capacity for different point-to-point transmission segments gets posted for market participants to view and purchase electronically. RM, which markets transmission for Loveland Area Projects, Salt Lake City Area Integrated Projects, Basin Electric Power Cooperative, Black Hills Power and Powder River Energy Corporation, is the largest transmission provider on this OASIS. Besides saving about $200,000 during the next three years due to lower maintenance costs and annual membership fees, Western will have reduced software and hardware requirements to process data and calculate real-time available transmission capacity.

Parker-Davis Project remarketing effort started

To extend resources to existing customers and make capacity and energy available to new customers, Western decided to apply the Energy Planning and Management Program's Power Marketing Initiative to the Parker-Davis Project. This decision, which became effective June 4, 2003, means that for existing customers, Western will extend 93 percent of the Parker-Davis firm electric service adjusted allocations for 20 years. The remaining 7 percent of the adjusted resources will form a resource pool to be allocated to new customers. Western's firm electric service contracts with customers expire on Sept. 30, 2008.

Path 15 construction began

Construction of access roads and structure foundations got under way last fall after the three Path 15 Project Upgrade Project participants signed a Coordinated Operations and Interconnection Agreement on Aug. 11, 2003. Western serves as project manager. The agreement between Western, Pacific Gas and Electric Company and Trans-Elect governs the interconnection of the Path 15 project facilities with the existing transmission system. The Path 15 Upgrade includes building a third 500-kV transmission line and substation modifications to reduce transmission constraints in central California. Western's Administrator approved Western's Mitigation Action Plan in January 2003. In addition, the U.S. Fish and Wildlife Service issued a Biological Opinion for the project on June 10. Transmission line construction will be completed in late 2004.

Participants graduate from Management Succession Program

Twenty-seven managers and supervisors graduated from Western's first Management Succession Program in February 2003. The three-year program included individually designed activities supplemented by periodic group training sessions. The program will ensure organizational continuity by developing well-qualified and competent employees ready to successfully compete for key managerial and executive level positions.

Pick-Sloan Post-2005 Resource Pool final procedures published

Western published *Federal Register* notices and held public information forums in FY 2003 to help determine the appropriate purpose for the Pick-Sloan Post 2005 proposed resource pool. The power will come from a resource pool made up of power withdrawn from current firm power customers and will be available for delivery beginning in 2006.

Post-2004 operations alternatives announced

Western announced a public process on June 24, 2003, to discuss alternative operational scenarios for the Central Valley Project hydropower system beginning Jan. 1, 2005. Western's Sierra Nevada Region identified alternative operating scenarios after contracts with PG&E expire on Dec. 31, 2004. The three contracts provide for integrated and interdependent operation of the Federal and PG&E transmission systems. Alternatives Western considered included joining the California Independent System Operator as a Participating Transmission Owner, participating in CAISO's control area as a nested subcontrol area under a Metered Subsystem agreement and forming a new control area. Western received and evaluated comments from interested stakeholders to prepare a decision document outlining a recommended course of action. Western's decision is to form a contract-based, subcontrol area, with either the California Independent system Operator or the Sacramento Municipal Utility district.

Post-2004 SN marketing plan ready to go

The existing Central Valley Project Power Marketing Plan and transmission contracts expire Dec. 31, 2004. We are working with customers to identify the products and services they wish Western to provide under the new marketing plan, which begins Jan. 1, 2005.

Rate adjustments for LAP, Pick-Sloan implemented

Western completed rate adjustments for the Pick-Sloan Missouri Basin Program—Eastern Division and the Loveland Area Projects. The preliminary FY 2003 Power Repayment Study showed the need for a rate increase of about 2.2 mills per kWh, mainly due to drought conditions that led to high purchase power costs. The rates went into effect on an interim basis on Feb. 1, 2004.

Sacramento Area Voltage Support Final EIS published

Western released the Final Environmental Impact Statement for the Sacramento Voltage Support Project in September. The SVS EIS outlines potential upgrades to its transmission system for a 100-mile radius around the Sacramento area to alleviate the current shortfall in the area's electric service. The proposed action is to build a 230-kV transmission line from O'Banion Substation near Marysville, Calif., to Elverta Substation north of Sacramento and upgrade existing 230-kV lines from Elverta to Tracy. The proposed action contains an alternative route in addition to the route described in the Draft EIS to avoid encroaching on Pleasant Grove Cemetery and some residential areas north of Sacramento. The findings from the EIS will form a basis for decisions on whether to proceed and, if so, how to proceed with transmission system upgrades. Actual construction is contingent on funding.

Science Bowl support continues

Western employees volunteered as coordinators, moderators, timekeepers and scorekeepers at eight regional science bowl competitions and the Native American Science Bowl involving more than 140 high schools in February and March. Science Bowl teams throughout the United States match wits against their high school peers in subjects like chemistry, astronomy and earth sciences for a chance to compete in the National Science Bowl in Washington, D.C., every spring. FY 2003 marked the 10th year that Western has participated in this annual event.

Shiprock-Four Corners 345-kV line uprate

Western teamed up with the Navajo Tribal Utility Authority, Tri-State Generation and Transmission Association, Inc., and Xcel Energy on the Shiprock-Four Corners 345-kV Line Uprate Project in FY 2003. The project includes removing existing 230-kV approach spans and towers; placing reinforced concrete foundations; installing new Western-furnished 345-kV lattice steel structures; furnishing and installing overhead ground wire, insulator assemblies and hardware; and stringing three two-conductor bundle conductors. The work is located on the Navajo Nation in San Juan County, N.M. The project was completed in Spring 2004.

Strategic Plan updated

Senior managers revised Western's Strategic Plan, reaffirming our mission, vision and direction. This fourth iteration of Western's strategic plan builds on the work done before. Western's mission—marketing and delivering reliable, cost-based hydroelectric power and related services—remains unchanged, as does Western's vision to be a premier power marketing and transmission organization. The Strategic Plan includes three main strategic goals: Products and Services, People and Industry. One difference in the new plan is that it identifies subordinate goals that support our three strategic goals. These goals identify the key areas where we can make a difference in our business results. A second change is that measures were moved to the Annual Performance Plan, where they are linked to annual targets. The annual targets are tied back to the strategic and subordinate goals in the Strategic Plan. The revised Strategic Plan was distributed to all employees in September.

Temporary Allocation Program

Western instituted its Temporary Allocation Program on Aug. 1, 2003, for the Central Valley Project. Under the program, customers who can't fully use their capacity and associated energy return a portion of it to Western for temporary reallocation to other customers.

Customers that return energy receive a cost adjustment to offset their replacement power expense and reduce their exposure to the minimum capacity charge that applies to firm power contracts. Customers that receive the temporary allocations reduce their need for higher-cost supplemental power purchases. Because the receiving customers can more fully use the capacity and energy, Western receives increased revenues, benefiting all customers. Ten customers currently participate in the program, which will remain in effect until Dec. 31, 2004, but Western may terminate it or return the energy to customers with 60-days notice.

Virgil Fodness Substation dedicated

Western joined with East River Electric Cooperative in dedicating the Virgil Fodness Substation on June 5, 2003, at Tea, S.D. The new $6 million substation, named after a previous president of East River and a 30-year board member, will provide reliable power delivery to Western's customers. Fodness is the first major power-supply substation built by East River since the 1980s and is designed to meet the increasing demand for electricity in the growing area around Sioux Falls, S.D. The substation taps into Western's Fort Randall/Ramussen-to-Sioux Falls 230-kV transmission line and will serve customers in the Sioux Falls area, including Brandon, Valley Springs and Lincoln and Minnehaha counties.

Wellton-Mohawk Generation Facility interconnection planned

Western published a Draft Environmental Impact Statement on the Wellton-Mohawk Generation Facility. The proposed project involves a natural gas-fired combined cycle electric generating facility that would interconnect with Western's transmission system at Ligurta Substation near Yuma, Ariz. Western is also negotiating the construction agreement and the interconnection to North Gila Substation. ▼

FY 2003 IRP Summary

Western's Integrated Resource Planning requirements outlined in Section 114 of the Energy Policy Act of 1992, gives customers several additional 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 new 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 for the options identified in the IRP.

Western also made changes to IRP alternatives. Members of Member Based Associations 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 energy 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 2003, Western received 80 IRPs from individual customers, 40 plans from cooperatives, 70 minimum investment reports and 107 small customer plans. These plans represent 750 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
- Bundling of a variety of services to improve customer satisfaction and increase revenues
- Continued re-emergence of demand-side-management efficiency activities/programs

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

- Lighting technologies
- HVAC technologies with emphasis on cooling and ventilation

- Audits for residential, commercial and industrial facilities
- Weatherization
- Load management

The top five renewable energy resource choices are:

- Hydro (large & small)
- Wind generation
- Solar – PV
- Geothermal
- Waste-to-energy

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 2003 Customer IRP Accomplishments

ITEM	CRSP	DSW	RM	SN	UGP	TOTALS
DSM kW savings	30,538	137,209	98,468	118,857	106,459	491,531
DSM kWh savings	55,457,910	198,615,315	79,177,232	249,788,492	62,189,967	645,228,916
DSM expenditure	9,116,363	42,619,340	79,275,700	54,407,320	5,515,559	190,934,282
DSM deviations	775,617	12,496,217	1,564,406	+5,843,389	119,470	20,799,099
kW renewables	70,257	2,276,311	83,309	242,580	588,952	3,261,409
kWh renewables	159,463,921	3,207,364,364	1,647,715	853,785,327	2,063,687,808	6,285,949,135
Renewable expenditures	8,579,325	20,201,500	3,295,725	9,325,077	2,158,000	43,559,627
Most frequent DSM activities	Commercial & Industrial lighting Resdential Heating Residential Lightg HVAC measures Domestic hot water	Commercial & Industrial HVAC Individual processes C&I lighting C&I audits C&I motors	Residential audits Lighting Commercial audits Time of Use load management	Residential HVAC, Residential lighting Residential rebates Commercial & Industrial HVAC Commercial & Industrial lighting	Load Mgmt. Sys. Lighting Weatherization programs New construction Motors/Pumps	
Top 5 renewable energy activities	Hydro Solar Geothermal Wind	Hydro Solar PV Solar thermal Purchase power from renewable resources	Wind Solar Small hydro Large hydro	Solar – PV Solar hot water Geothermal Wind Hydro	Large wind Small wind Muni. Waste to Energy Solar Hydro	

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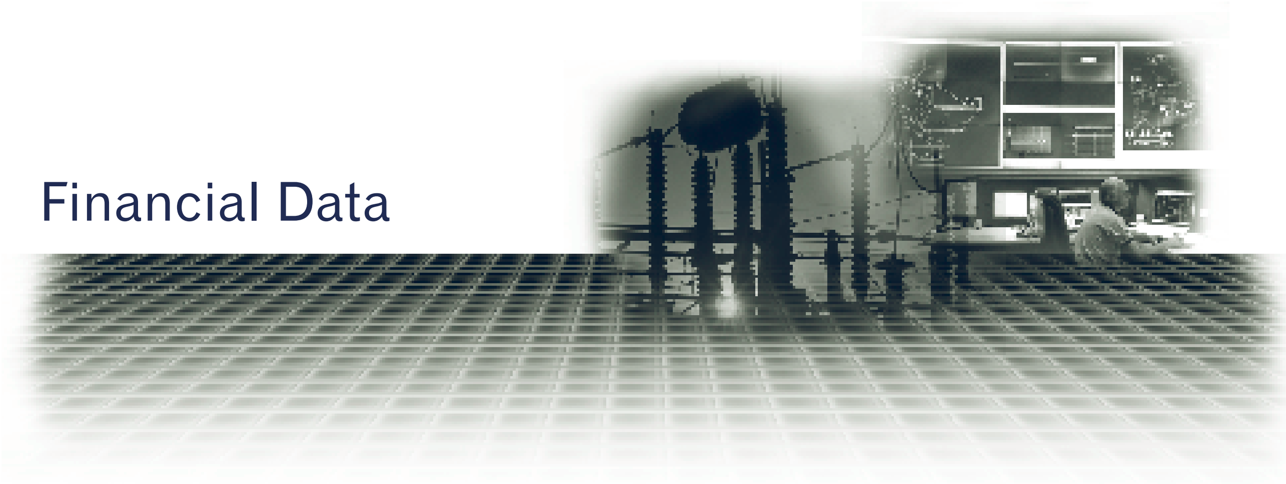
Repayment Summary

Western Consolidated Status of Repayment (Dollars in millions)	Cumulative 2002	Adjustments	Annual 2003	Cumulative 2003
Revenue:				
Gross Operating Revenue	19,364	(97)	1,112	20,380
Income transfers (net)	(908)	0	(110)	(1,018)
Total Operating Revenue	**18,456**	**(97)**	**1,003**	**19,362**
Expenses:				
O & M and other	6,767	(3)	344	7,107
Purchase power and other	5,520	(0)	404	5,924
Interest				
Federally financed	3,325	(2)	156	3,479
Non-Federally financed	163	(0)	9	173
Total Interest	3,488	(2)	165	3,651
Total Expense	**15,775**	**(5)**	**913**	**16,683**
(Deficit)/Surplus revenue	(151)	(88)	55	(185)
Investment:				
Federally financed power	5,240	(72)	114	5,282
Non-Federally financed power	200	(0)	2	202
Nonpower	3,548	0	8	3,555
Total Investment	**8,988**	**(72)**	**123**	**9,039**
Investment repaid:				
Federally financed power	2,739	(4)	31	2,766
Non-Federally financed power	50	0	5	55
Nonpower	40	0	0	41
Total Investment repaid	**2,829**	**(4)**	**36**	**2,862**
Investment unpaid:				
Federally financed power	2,501	(68)	82	2,515
Non-Federally financed power	150	(0)	(3)	147
Nonpower	3,507	0	7	3,515
Total Investment unpaid	**6,159**	**(68)**	**86**	**6,177**
Fund Balances:				
Colorado River Development (G)	3	1	(1)	2
Working capital (H)	0	0	0	0
Percent of investment repaid to date:				
Federal	52.27%			52.37%
Non-Federal	25.00%			27.23%
Nonpower	1.13%			1.15%

Note: Repayment Status is mostly based on audited data as of 9/30/03.

Difference between the Annual 2003 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

Western remains focused on its goal of maintaining the reliability and safety of its transmission system while managing power delivery costs and meeting our repayment responsibilities. To further this goal, Western is strengthening partnerships with affiliated generating agencies and customers by controlling costs, coordinating funding agreements, and prioritizing construction and rehabilitation projects. Western, in partnership with its customers, provides cost-effective resources and transmission alternatives to ensure a stable long-term power supply. Western and the generating agencies continue to be accountable and responsive to their customers and the needs of the utility industry.

Changes in the electric utility environment continue to affect Western, such as the President's National Energy Policy, which outlines priorities to secure and modernize the nation's future energy supply. In keeping with this mandate, Western continues to promote conservation, diversification, and expansion of the national energy supply and make improvements in the energy transportation systems. Western is also working to expand the grid with the construction of the Path 15 Upgrade Project, dedication of the Virgil Fodness Substation and commencement of the Rapid City DC Converter Station operation. In addition, Western is currently teaming up with the Navajo Tribal Authority and collaborating with various other customers to uprate the Shiprock-Four Corners line. Through these efforts, Western will maintain a leadership role in the changing electric generation and transmission environment.

After the August 14, 2003 regional blackout in the Northeast, which resulted in a subsequent congressional probe, the reliability of Western's infrastructure and computer systems has taken on increased importance. As a result, Federal Power Program entities (power marketing administrations, the Bureau of Reclamation, and the U.S. Army Corps of Engineers) conducted reviews of their infrastructure reliability and associated operational systems in Fiscal Year (FY) 2003 to identify vulnerabilities and enhance dependability. Because of this ongoing assessment process, Western and the generating agencies believe that risk is being managed.

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Results of Operations

Overall, hydrologic conditions for FY 2003, with the exception of the Central Valley Project (CVP), were still dry across Western's marketing area. Generation was relatively constant, up less than 1 percent from FY 2002 levels to 24,740 GWh (excluding the Central Arizona Project's 4,071 GWh of coal-fired generation). Although drought conditions continue across the West, results of operations improved in FY 2003 with a total operating revenue increase of approximately $105 million. This increase was primarily due to increased sales of surplus energy as well as firm power rate increases for both the Colorado River Storage Project (CRSP) and the Central Valley Project. Power systems not impacted by drought were able to contribute $36.3 million toward repayment. Western was able to repay $31.2 million of Federal financed power investment (up from $19.7 million in FY 2002), $4.8 million of non-Federal financed power investment, and $0.3 million of non-power investment (irrigation assistance). Leading the way in repayment was CVP ($26.6 million) and the Boulder Canyon Project ($4.4 million). An offset of $4.0 million in repayment was applied in FY 2003 after replacing estimates of revenues and expenses used in previous power repayment studies with actual amounts. Total repayment for FY 2003, as detailed in the power repayment studies for FY 2003, is about $32.3 million.

Revenues

Operating revenues for FY 2003 were $942.2 million (before elimination entries), an increase of $104.8 million (13 percent) when compared to FY 2002. Overall, sales of electric power (excluding the Central Arizona Project, project use and interproject transfers of $83 million in FY 2003, $73.4 million in FY 2002, and $75.8 million in FY 2001) amounted to $694.5 million (before eliminating entries) in FY 2003, $595.6 million in FY 2002, and $855.3 million in FY 2001. Increased sales were attributed to increased sales of surplus power and to rate increases at CRSP and CVP. Average revenue per MWh on these sales was $20.60 in FY 2003 on sales of 33.7 million MWh, $18.90 in FY 2002 on sales of 31.5 million MWh, and $24.50 in FY 2001 on sales of 34.9 million MWh.

Expenses

Total operating expenses for 2003 were $872.3 million (before elimination entries), an increase of $111.7 million (15 percent) from FY 2002 primarily due to increased purchased power costs of $91.5 million (32 percent). Total purchase power costs increased from $288.5 million in FY 2002 on purchases of 10.8 million MWh (26.71 MWh), to $379.9 million in FY 2003 (before eliminating entries) on purchases of 12.9 million MWh ($29.45 MWh).

Operation and maintenance expenses for FY 2003 were $298 million for an increase of $21.2 million (8 percent) from FY 2002. This increase was largely driven by one-time repairs and facility upgrades at Boysen Unit, North Platte, Fremont Canyon and Kortes Tunnel within the Pick Sloan Missouri Basin Program, various project generator repairs and rewinds, and increased worker's compensation costs. Administrative and general expenses remained relatively flat, decreasing 1 percent from FY 2002.

Capital expenditures

Because of reduced congressional funding and associated change in mission focus for construction projects, Western and the generating agencies have concentrated on maintaining, rehabilitating, and replacing generation and transmission assets. As a result, the power system's capital investment program has remained relatively flat over the last few years. During FY 2003 Western and the generating agencies spent $94.7 million for capital investments compared with $88.4 million in FY 2002. These included new substations, a warehouse and maintenance facility, switching stations, fiber optic installation, expansion of communication systems and assorted replacements to transmission and generation assets.

During FY 2003, Western and the generating agencies placed into service $133.3 million of utility plant, previously under construction. This amount included $31.2 million at CRSP for CRSP reconstruction and various other replacements, $17.2 million at the Parker-Davis Project, primarily for replacements on the Mariopa-Saguaro and Parker-Gila transmission lines and the Parker Switchyard, $8.7 million at CVP mostly for replacements at the Eleverta and the Tracy substations, $75.2 million at the Pick-Sloan Missouri Basin Program for the new Bismarck Maintenance Facility for replacements at the Huron Substation and for various rebuilds and upgrades of transmission lines and substations. ▼

Performance Measurements

The Chief Financial Officers Act of 1990 requires Federal entities to develop performance measures to assist managers in evaluating the efficiency and effectiveness of their programs. This requirement was further emphasized in the Government Performance and Results Act of 1993. The financial performance measures outlined here relate to Western's and the generating agencies' (Bureau of Reclamation, U.S. Army Corps of Engineers and the International Boundary and Water Commission) organizational objectives and management responsibilities 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 selected from Department of Labor and utility industry standards to compare and assess Western's operational performance.

Financial Performance Measures

The investment repayment ratio measures cumulative investment (Federal and non-federal 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 2003 was approximately $9 billion. During FY 2003, $32.3 million was applied toward repayment, offset in part by $51.1 million in new investment. As a result, the FY 2003 investment repayment ratio of 31.66 percent increased slightly from the FY 2002 ratio of 31.48 percent.

During FY 2003, $31.2 million from current year operations (up from $19.7 million in FY 2002) was applied to repay the Federal financed power investment. This additional repayment was offset by adjustments of $4.0 million after replacing estimates of revenues and expenses in previous power repayment studies with actual amounts. In total, repayment of Federal financed power investment increased by $27.2 million to an overall level of 52.37 percent. Similarly, during FY 2003, repayment of $4.8 million of non-Federal financed power investment was applied, which increased the level of repaid non-Federal financed power investment to 27.23 percent. During FY 2003, the repayment for non-power investment (irrigation assistance) exhibited a small increase ($0.3 million) to an overall level of 1.15 percent from 1.13 percent in FY 2002.

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 2003, power generation and transmission activities provided for total payment of unpaid investment of $36.3 million ($31.2 million Federal, $4.8 million non-Federal, $0.3 million non-power) up from $24 million in FY 2002. This additional repayment was offset by $4.0 million in adjustments after replacing estimates of revenues and expenses used in previous power repayment studies with actual amounts. As a result, total payment activity in FY 2003 equaled $32.3 million. This adjusted amount exceeded the planned principal repayment of $24.9 million by $7.4 million, resulting in a variance ratio of 29.87 percent.

Western tracks several financial performance measures, which allow Western to benchmark its efficiency and effectiveness 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, 2001, dated April 2003, 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 kilowatt-hour generated and sold is a measure of the cost to operate and maintain the generation and transmission systems. The ratio increased slightly in FY 2003 due to a proportionately larger increase in operation and maintenance and administrative and general expense (0.06 percent over FY 2002). The result was $0.0139/kWh in FY 2003 as compared with $0.0132/kWh in FY 2002. The most recent industry average was $0.055/kWh.

The operating ratio measures the proportion of revenues received from electricity sales and other activities required to cover operating costs (which include O&M, AGE, Purchased Power and Purchased Transmission) associated with producing and selling electricity. Western's FY 2003 ratio increased to 82 percent from the FY 2002 ratio of 79 percent primarily due to an increase in purchase power expenses ($91.5 million). The most recent industry ratio was about 81 percent.

Revenues received per kWh of electricity sold increased slightly from $0.0189/kWh in FY 2002 to $0.0206/kWh in FY 2003. The most recent industry rate was $0.058/kWh.

The total power supply expenses (O&M, AGE, PP and PT) per kWh sold measures all power supply costs, including generation and purchased power, associated with the sale of each kWh of electricity. The FY 2003 rate of $0.0230/kWh was higher than the FY 2002 rate of $0.0210/kWh primarily because of higher purchase power and O&M expenses. The most recent industry average was $0.046/kWh.

Consolidated Financial Performance Indicators

(Dollars in thousands)

Investment repaid	2003	2002
Ratio	31.66%	31.48%
Paid Investment	$2,861,525	$2,829,187
Total Investment	$9,039,335	$8,988,195
Variance in planned payments		
Ratio	29.87%	85.31%
Excess Payment (actual payment plus adjustments less planned principal payment)	$7,437	$26,356
Planned principal payment	$24,901	$30,893
O&M cost per net kWh generated		
Rate	$0.0139	$0.0132
O&M and AGE	$345,014	$324,530
MWh generated-net	24,740,000	24,574,000
Operating ratio		
Ratio	82.08%	79.01%
O&M, AGE, PP, PT	$773,358	$661,542
Total Revenues	$942,168	$837,339
Revenue per kWh sold		
Rate	$0.0206	$0.0189
Total revenues	$694,456	$595,598
MWh sold	33,692,000	31,525,000
Total power supply expenses per kWh sold		
Rate	$0.0230	$0.0210
O&M, AGE, PP, PT	$773,358	$661,542
MWh sold	33,692,000	31,525,000

Note: The above-noted financial performance indicators exclude Central Arizona Project assets, liabilities and operating expenses. Western, as the marketing agent, transfers all CAP revenue collected to Bureau of Reclamation, after deducting Western's associated costs. In addition, energy sales and generation exclude interproject and project use sales.

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 (CY 2002) are as provided by the DOL 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 2003 rate of 0.9 remained consistent with the CY 2002 rate of 0.9. The CY 2002 standard industry rate was 2.5.

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 2003 rate of 2.1 increased from the CY 2002 rate of 1.7. This increase was due to stricter definitions of first aid treatment implemented by DOL in CY 2003 resulting in more cases being identified as recordable. The CY 2002 standard industry rate was 3.7.

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 2003 rate of 1.2 increased from the CY 2002 rate of 0.7. 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 Control 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 2003 was 185.61 percent for CPS1 and 98.09 percent for CPS2. The industry averages were 169.07 percent for CPS1 and 96.49 percent for CPS2. Western's performance is well above both the minimum requirement and the industry average.

Western's FY 2003 reliability results are consistent with FY 2002 (CPS1 – 185.66 percent and CPS2 – 98.51 percent).

Independent Auditors' Report

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

We have audited the accompanying combined power system balance sheet 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, 2003, and the related combined power system statements of revenues and expenses, and accumulated net revenues, and cash flows for the year 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 audit. 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 30% of combined total assets as of September 30, 2003 and total revenues constituting 21% of combined total revenues for the year 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 audit 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 examining, on a test basis, evidence supporting the amounts and disclosures in the respective financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, based on our audit 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, 2003, and their combined operations, changes in accumulated net revenues, and cash flows for the year 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 July 30, 2004, on our consideration of Western's internal control over financial reporting and our tests of its compliance with certain provisions of laws and regulations. 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 audit.

Deloitte & Touche LLP

Denver, Colorado
July 30, 2004

Combined Power System Balance Sheet

As of September 30, 2003 (in thousands)

	2003
Assets	
Utility plant:	
Completed plant	$ 5,532,623
Accumulated depreciation	(2,402,599)
Net completed plant	3,130,024
Construction work-in-progress	192,750
Net utility plant	3,322,774
Cash	512,330
Accounts receivable	208,133
Other assets	160,446
Total assets	**$ 4,203,683**
Federal investment & liabilities	
Federal investment:	
Congressional appropriations	$ 10,682,634
Interest on Federal investment	4,129,875
Transfer of property & services, net	655,143
Gross Federal investment	15,467,652
Funds returned to U.S. Treasury	(11,695,236)
Net outstanding Federal investment	3,772,416
Accumulated net deficit	(117,189)
Total Federal investment	**$ 3,655,227**
Commitments and contingencies (notes 1,5,7,8 and 9)	
Liabilities:	
Accounts payable	106,370
Other liabilities	442,086
Total liabilities	**548,456**
Total Federal investment & liabilities	**$ 4,203,683**

See accompanying notes to combined power system financial statements.

Combined Power System Statement of Revenues and Expenses, and Accumulated Net Revenues

For the year ended September 30, 2003 (in thousands)

	2003
Operating revenues:	
Sales of electric power	$ 764,104
Other operating income	270,916
Gross operating revenues	1,035,020
Income transfers, net	(109,859)
Total operating revenues	**925,161**
Operating expenses:	
Operation and maintenance	298,059
Administration and general	46,955
Purchased power	364,811
Purchased transmission services	46,526
Depreciation	98,927
Total operating expenses	**855,278**
Net operating revenues	**69,883**
Interest expenses:	
Interest on Federal investment	186,381
Interest on customer funded financing	11,604
Allowance for funds used during construction	(33,036)
Net interest expenses	**164,949**
Net deficit	**(95,066)**
Accumulated net revenues, beginning of year, as previously reported	**21,265**
Adjustment (Note 10)	**(40,544)**
Accumulated net deficit, beginning of year, as adjusted	**(19,279)**
Irrigation assistance	**(2,844)**
Accumulated net deficit, end of year	**$ (117,189)**

See accompanying notes to combined power system financial statements.

Combined Power System Statement of Cash Flows

For the year ended September 30, 2003 (in thousands)

	2003
Cash flows from operating activities:	
Net deficit	$ (95,066)
Adjustments to reconcile net deficit to net cash provided by operating activities:	
Depreciation	98,927
Interest on Federal investment	153,345
Loss on disposition of assets	6,260
(Increase) decrease in assets:	
Accounts receivables	(31,212)
Other assets	(18,595)
Increase (decrease) in liabilities:	
Accounts payable	(21,909)
Other liabilities	128,244
Net cash provided by operating activities:	**219,994**
Cash flows from investing activities:	
Investment in utility plant	**(96,096)**
Cash flows from financing activities:	
Congressional appropriations, net	455,777
Funds returned to U.S. Treasury	(479,722)
Principal payments on customer funded financing	(7,361)
Irrigation assistance	(2,844)
Net cash used in financing activities	**(34,150)**
Net Increase in cash	**89,748**
Cash, beginning of year	**422,582**
Cash, end of year	**$ 512,330**

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

See accompanying notes to combined power system financial statements.

Notes to Combined Power System Financial Statements

As of and for the year ended September 30, 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 the 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 listed in Note 2. Each power system is separately managed, financed and maintains separate accounting records. Western, as a Federal power marketing administration, markets and transmits hydroelectric power generated from these power systems operated and maintained by Reclamation, the Corps and IBWC 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, principally power, irrigation, municipal and industrial water, navigation and flood control (see Note 5). 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 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.

(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 the 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 the 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, 2003.

(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. 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 8). Costs allocated to power include repayment to the U.S. Treasury 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' enacting 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 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.

Income transfers, net, 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 utilized by Western include net billing and bill crediting. Net billing is a two-way agreement between Western and a customer, whereby 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 $7.1 million for uncollectible accounts from a gross amount of $215.2 million.

(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 25 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 with a corresponding increase in Federal investment. Western and the generating agencies calculate 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, except for the CAP, Colorado River Storage, Dolores and Seedskadee, recognize an annual interest credit for payments of accrued 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 year ended September 30, 2003.

As provided by Federal law, interest is not accrued on Federal investment in irrigation facilities anticipated to be repaid through power sales (see Note 8).

(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 5.5 to 12.4 percent for the year ended September 30, 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) Taxes

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

(l) 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.

(m) 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 their 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.

In April 2003, the FASB issued SFAS No. 149, Amendment of Statement 133 on Derivative Instruments and Hedging Activities, which amends and clarifies accounting for derivative instruments, including certain derivative instruments embedded in other contracts and for hedging activities under SFAS No. 133. SFAS No. 149 clarifies the discussion around initial net investment, clarifies when a derivative contains a financing component and amends the definition of an underlying to conform it to language used in FASB Interpretation No. 45. In addition, SFAS No. 149 also incorporates certain implementation issues of a derivative implementation group. The provisions of SFAS No. 149 have been applied to contracts entered into or modified after June 30, 2003, with no impact on the combined power system financial statements.

In June 2003, for purposes of determining the applicability of the normal purchases and normal sales scope exception, the FASB issued SFAS No. 133 Implementation Issue No. C20 as supplemental guidance to SFAS No. 133 Implementation Issue No. C11. The effective date of the implementation guidance of Issue No. C20 is during the first quarter of fiscal year 2004 for Western. Western is currently in the process of reviewing, interpreting and implementing this guidance and does not currently anticipate any material adverse financial impact due to the implementation of Issue No. C20 guidance.

(n) 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 process it initiated on April 6, 2001. The bankruptcy proceedings were caused by the financial instability associated with the California energy crisis. PG&E's subsequent emergence from bankruptcy allowed the utility to pay off all valid creditor claims and restored the utility's investment grade credit ratings, thus allowing it to regain access to the capital markets to finance infrastructure improvements and the long-term procurement of energy supplies.

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

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, Cal PX is still emerged in the process of winding up its business affairs in an orderly manner. Although PG&E has emerged from bankruptcy, there are a number of ongoing cases at the FERC and in the Federal court system. Until the issues in those cases are resolved, the Cal PX will not be able to settle its business affairs.

Given the status of the court and FERC proceedings, Western has increased the allowance for loss on accounts receivable by $3.9 million for California Independent System Operation (Cal-ISO), and $3.0 million for Cal PX.

(o) Moveable Equipment

Moveable equipment represents the acquisition cost of capitalized movable equipment having a unit cost of $5,000 or more and an estimated useful life of two years or more. Beginning in FY 2004, the capitalization threshold increases to $15,000. Examples of capitalized movable equipment include computers, copiers, cranes, energy testing equipment, helicopters, pickups, trucks and wood chippers.

(p) 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.

(q) Interchange Energy

Western's power contracts may include a provision for energy transfers between Western and a supplier that result in deferred energy credits. These deferred energy credits represent the valuation of excess energy received over that delivered under an interchange energy contract provision. The interchange balance is posted at least annually, 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.

(r) 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. Operating expenses were $5.9 million for the year ended September 30, 2003. Capital costs for the same period were $0.1 million.

(s) Unused Annual Leave

Accrued unused annual leave represents benefits which would be paid out 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.

(t) CRSP Long-term Contractual Obligations

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 3).

(u) 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.

(v) 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, the 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 3) to reflect the effects of the rate-making process.

(2) Power Systems and Authorizing Legislation

The combined power system financial statements include the financial position, results of operations and cash flows of 15 separate power systems. The following is a list of the Federal power systems and related authorizing legislation with transmission and generating facilities operating as individual integrated power systems.

1) Boulder Canyon Power System
Boulder Canyon Project Act of 1928, as amended

2) Central Arizona Project
Colorado River Basin Project Act of 1968, as amended

3) Central Valley Power System
Act of Aug. 26, 1937, as amended

4) Collbran Power System
Act of July 3, 1952

5) Colorado River Storage Power System
Colorado River Storage Project Act of April 11, 1956, as amended

6) Dolores Power System
As a participating project of the Colorado River Storage Power System, it utilizes the same authorizing legislation

7) Falcon-Amistad Power System
Treaty between the United States and Mexico, Feb. 3, 1944; Acts of Oct. 5, 1949, June 18, 1954 and July 7, 1960

8) Fryingpan-Arkansas Power System
Act of Aug. 16, 1962, as amended

9) Pacific Northwest-Pacific Southwest Intertie Project
Act of Aug. 31, 1964

10) Parker-Davis Power System
Act of May 28, 1954

11) Pick-Sloan Missouri Basin Power System
Flood Control Act of 1944, as amended

12) Provo River Power System
Finding of Feasibility by the Secretary of the Interior, Nov. 13, 1935

13) Rio Grande Power System
Act of Feb. 25, 1905

14) Seedskadee Power System
As a participating project of the Colorado River Storage Power System, it utilizes the same authorizing legislation

15) Washoe Power System
Act of Aug. 1, 1956

(3) Other Assets

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

Workers' compensation (see Note 1(v))	$57,234
Moveable equipment, net (see Note 1(o))	36,407
Abandoned project costs, net (see Note 1(p))	14,941
Stores inventory (see Note 1(f))	12,667
Accrued Annual Leave (see Note 1(s))	11,703
Interchange energy (see Note 1(q))	7,937
Recovery Implementation Program (see Note 1(r))	5,500
Info Tech Software, net	4,576
Purchase power termination settlement (see Note 1(t))	2,200
Energy banking deferral	1,837
Deposit funds available	1,608
Other	3,836
Total	**$160,446**

Abandoned project costs, net include the Celio-Mead transmission line of $14.9 million for fiscal year 2003, which is being amortized over 23 years.

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.

(4) Utility Plant

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

(5) 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 9). Cumulative appropriations received, net of nonreimbursable expenses, totaled $10.7 billion as of September 30, 2003, while postretirement benefits for the same time period totaled $71.8 million. All power systems (except Dolores, Seedskadee, Boulder Canyon (BC) and the operations and maintenance and purchased power programs of the Colorado River Storage Power System (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, net of depreciation expense, begin to accrue interest in the year they occur. Interest expense deficits begin to accrue interest in the year following occurrence. As of September 30, 2003, certain power systems have incurred operating and interest expense deficits aggregating approximately $187.3 million. In cases where funds are available, while still complying with established repayment periods for each increment of Federal investment, and 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 appurtenant 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 nonpower 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.

(6) Other Liabilities

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

Long-term construction financing	$ 169,132
Customer advances	140,016
Workers' compensation	66,594
Deferred revenue	20,399
Accrued annual leave	10,688
Accrued payroll benefits	10,879
Interchange energy (see Note 3)	7,937
Recovery Implementation Program	5,500
Purchased power termination settlement	2,200
Energy banking deferral (see Note 3)	1,837
Deposit funds available	1,699
Other	5,205
Total	**$ 442,086**

Long-term construction financing consists of three contractual arrangements. The first 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, 2003, the outstanding obligation was $122.5 million.

The second 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 $21.2 million as of September 30, 2003.

The third 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 the Peacock Substation, and the 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, 2003, the outstanding obligation totaled $25.3 million.

Outstanding long-term construction financing as of September 30, 2003 is scheduled to be credited or repaid as follows (in thousands):

2004	$ 5,029
2005	5,222
2006	5,649
2007	6,668
2008	9,932
Thereafter	136,632
Total	**$ 169,132**

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

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

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 will be recognized as earned in future periods and is currently recorded as a deferred credit.

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.

(7) 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 15 years. Western has two non-cancelable leases that expire in 2004 and 2009 for the Electric Power Training Center (EPTC) and Western's Corporate Service Office, respectively. These leases represent an annual expense of approximately $2.3 million. The General Services Administration is the leaseholder for all locations with the exception of the EPTC to which Western is the 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 $7.8 million for the year ended September 30, 2003.

(8) 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 $3.5 billion of existing non-power Federal investment will be repaid from future power revenues over a period not to exceed 60 years. In fiscal year 2003, Reclamation made an irrigation assistance payment of $2.8 million to the U.S. Treasury.

(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 6). 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 year ended September 30, 2003, Western and Reclamation combined incurred $10.3 million 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
2004	$ 16,864	$ 8,790	$ 25,654
2005	5,800	5,803	11,603
2006	0	5,803	5,803
2007	0	5,687	5,687
2008	0	5,162	5,162
2009	0	5,000	5,000
Thereafter	0	29,824	29,824
Total	**$ 22,664**	**$ 66,069**	**$ 88,733**

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 $84.1 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 2003, Western recorded a reduction to purchased power expense for a refund of $40.3 million related to calendar year 2001. During that time period, Western purchased approximately $90.5 million in power from PG&E. No adjustment to the estimated rate has been made for purchases during calendar years 2002 or 2003. 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

The FERC proceedings, which began in August 2000, are a result of an investigation into wholesale power markets and in particular the California wholesale electricity market. This investigation has validated claims that wholesale generators and marketers of electricity manipulated the gas and electricity market. Initial findings are that generators and marketers inflated pricing and would be required to relinquish profits made from any illegal activity. FERC investigators found that the manipulation was wide-spread and recommended open investigations into a number of companies. 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.

(9) 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 $17.2 million for the year ended September 30, 2003.

The contribution levels as legislatively mandated do not reflect the full cost requirements to fund the CSRS pension plan (approximately 24.4 percent of base salary). 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 $3,766 per employee in fiscal year 2003 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 $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.

(10) Adjustment to September 30, 2002 Accumulated Net Revenues

Subsequent to the issuance of the combined power system fiscal year 2002 power financial statements, the combined power system's management became aware that accumulated depreciation in the Corps Power Purpose financial information included in the combined power system financial statements should be adjusted to reflect the conversion from the composite life straight-line method of depreciation to the individual asset straight-line method of depreciation. This change occurred during fiscal years 1997 and 1998 but was not reflected in the accounting records and financial statements as a change in accounting principle at that time. This change was requested by the Department of Defense Office of the Inspector General and implemented by the Corps in its financial statements for the year ended September 30, 2003, as the amounts were not considered material to the Corps as a whole. The adjustment to the combined power system financial statements was material. As a result, the combined power system accumulated net revenues as of September 30, 2002 have been reduced by $40.5 million, from the amount that was originally reported to reflect this change. The change did not have a material effect on the combined power system's operating results in fiscal year 2002.

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
    - Corporate Administrative Office A7100
    - CSO Administrative Operations 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)
    - Project Management G0100
    - 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
    - Program Support/ Financial Management 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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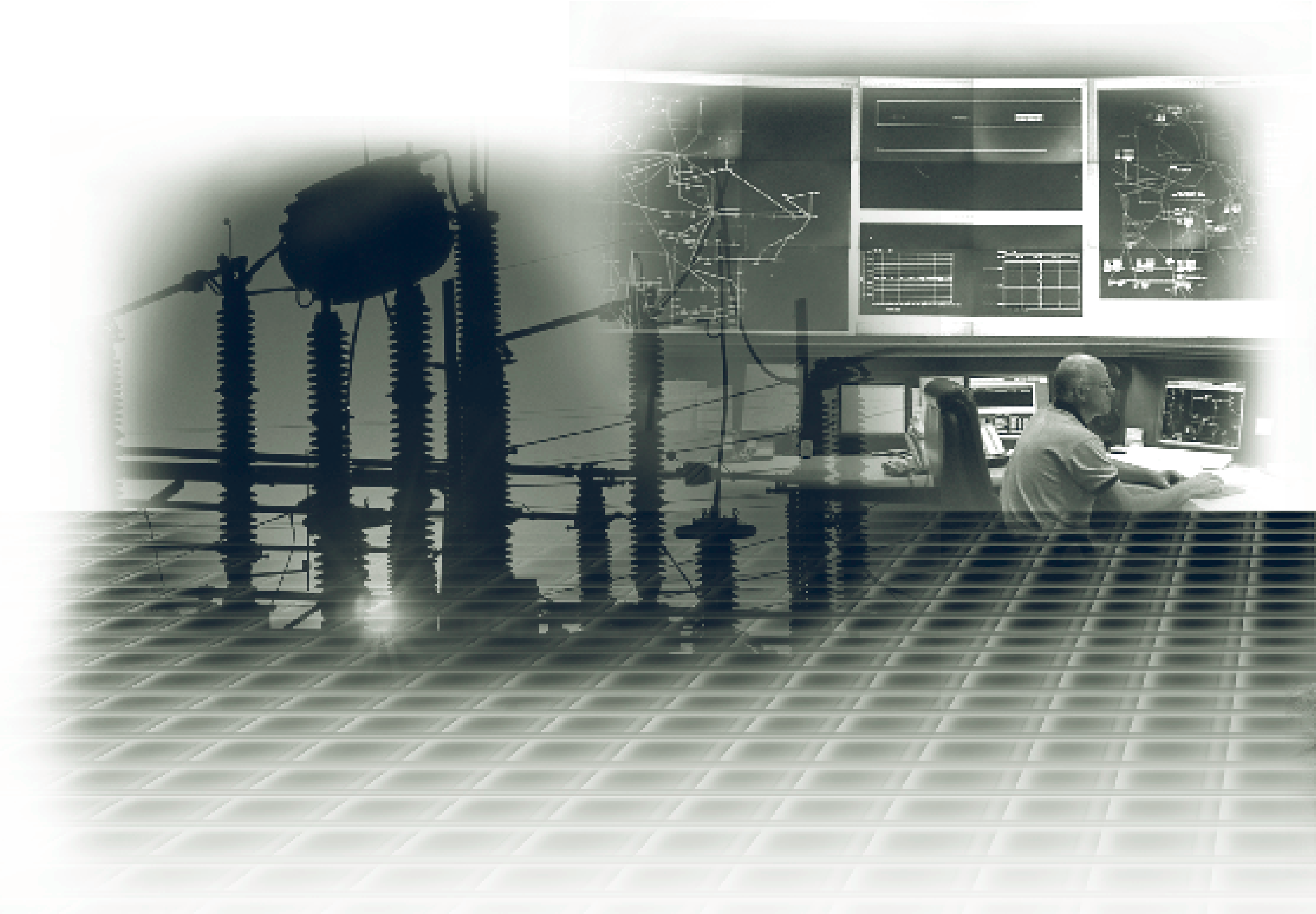

TO REACH US

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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Western AREA POWER ADMINISTRATION

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