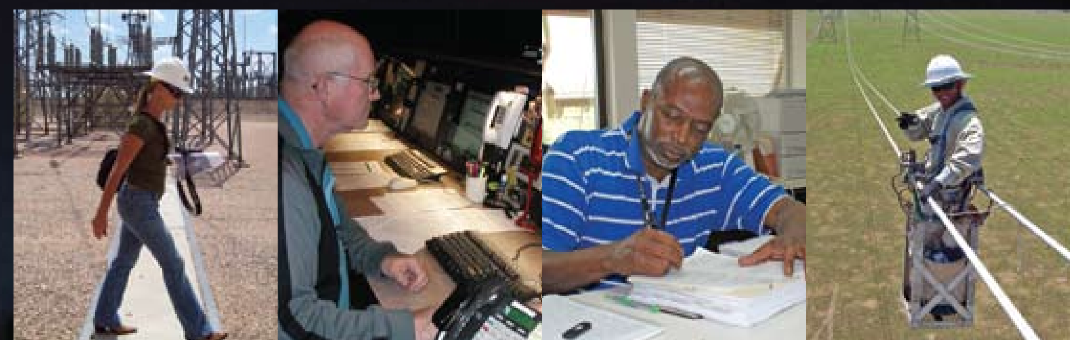
WESTERN AREA POWER ADMINISTRATION

FY 2008 ANNUAL REPORT

on Hydroelectric Power Operations

POWERFUL PERSPECTIVES



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Hour by hour, we deliver

Around the clock, Western employees keep a watchful eye on the ever-changing energy demands and do their part to support the energy industry. As the seconds, minutes and hours tick by, their individual perspectives make up the powerful way Western delivers Federal hydroelectric power to our customers, who in turn keep the lights on in millions of homes throughout the West. Western's Fiscal Year 2008 Annual Report on Hydroelectric Power Operations captures the different viewpoints that Western employees contribute on any given day to reliably deliver on our mission.

Snapshot perspectives

The photos on the front cover represent a cross section of functions and regions within Western. From left to right are: An engineer from Western's Corporate Services office walking within the Cheyenne Substation yard in the Rocky Mountain Region; a dispatcher in the Western Area Colorado Missouri, or WACM, Balancing Authority in Loveland; a Procurement manager in the Desert Southwest Regional office; and a lineman in the field from a DSW field office.

Expanding the title

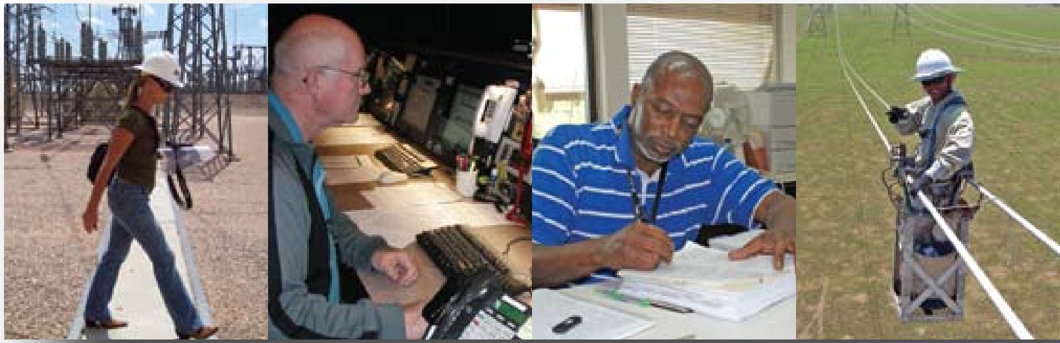
Western included an expanded title to clarify that this year's audited financial data includes Western's hydroelectric power program only. While Western markets power from hydroelectric powerplants, as well as the coal-fired generation of the Central Arizona Project, or CAP, in Arizona, the FY 2008 Annual Report on Hydroelectric Power Operations excludes any financial data from CAP and does not include any comparison data to FY 2007. The combined hydroelectric power system financial statements exclude the portion of Western and the generating agencies' programs and activities that are not reimbursable through the rate-setting process.

About Western

Western is a Federal agency under the U.S. Department of Energy that markets and transmits wholesale electrical power through an integrated 17,000-circuit mile, high-voltage transmission system across 15 western states.

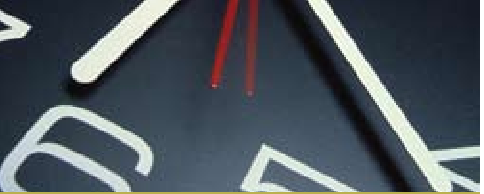
Employees work around the clock to sell power, operate transmission and provide maintenance and engineering services to:

- Municipalities
- Cooperatives
- Public utility and irrigation districts
- Federal and state agencies
- Marketers
- Native American tribes



In turn, our customers provide electric service to millions of people from as far south as Texas all the way north to the Dakotas, and from the plains of Minnesota to the California coastline.

For more than 30 years, Western employees have been dedicated to providing public service, including promoting environmental stewardship, energy efficiency and renewable energy, as well as implementing new technologies to ensure our transmission system is the most reliable possible. From each of their perspectives, the job of delivering power and related services to customers is a No. 1 priority.



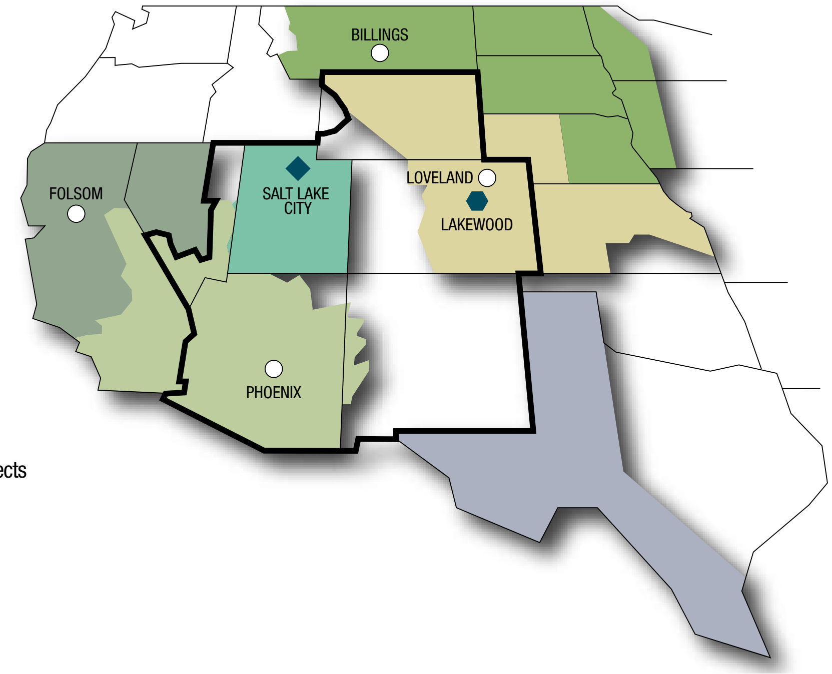
Marketing and Service Areas

Western's role in delivering power includes managing 10 different rate-setting systems. These rate systems are made up of 13 multipurpose water projects, one coal-fired project[1] and one transmission project. 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 U.S. State Department's International Boundary and Water Commission (generating agencies). We set power rates to recover all costs associated with our activities, as well as the Federal investment in the power facilities (with interest) and certain costs assigned to power for repayment, such as aid to irrigation development.

[1] The coal-fired project relates to the Central Arizona Project, which is not included in the financial data.

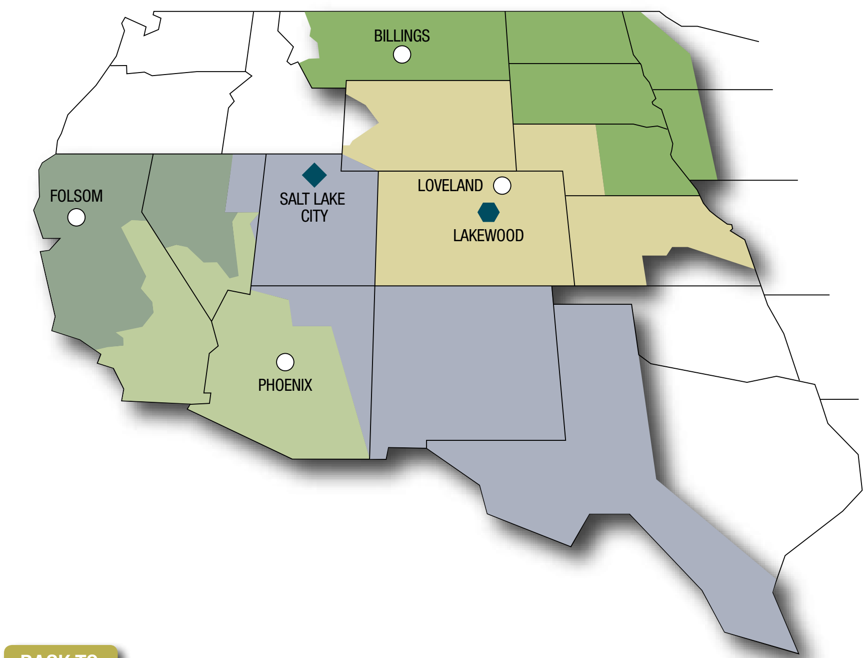
MARKETING AREAS

- Central Valley and Washoe projects
- Parker-Davis, Boulder Canyon and Central Arizona projects
- Falcon-Amistad Project
- Provo River Project
- Loveland Area Projects Pick-Sloan Missouri Basin Program—Western Division and Fryingpan-Arkansas Project
- Pick-Sloan Missouri Basin Program—Eastern Division
- Salt Lake City Area/Integrated Projects Colorado River Storage Project, Collbran, Rio Grande, Seedskadee and Dolores projects
- State Boundaries
- Regional Office
- Corporate Services Office
- CRSP Management Center



SERVICE AREAS

- Sierra Nevada Region
- CRSP Management Center
- Upper Great Plains Region
- Desert Southwest Region
- Rocky Mountain Region
- State boundaries
- Regional office
- Corporate Services Office
- CRSP Management Center



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Western at a glance

Marketing profile	FY 2008
Long-term energy sales	33.1 billion kWh
Other energy sales	2.9 billion kWh
Total	36.0 billion kWh

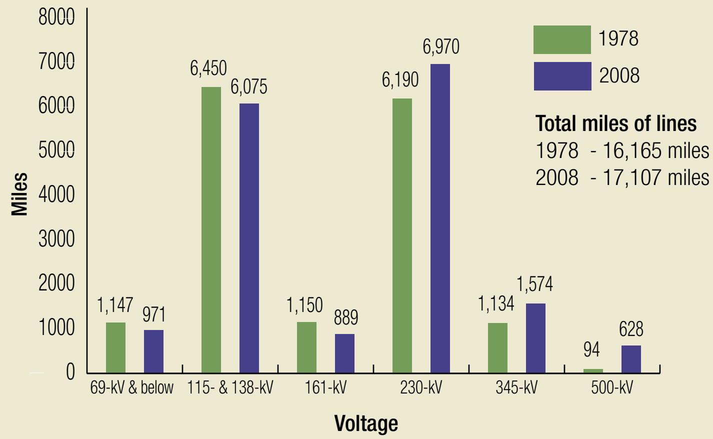
Financial profile	
Sales of electric power	$908.6 million
Total operating revenues	$1,194.4 million
Total operating expenses	$1,154.2 million
Purchased power and transmission expenses	$634.2 million

Assets	
Powerplants	57
Installed capacity (MW)	10,482
Substations	302
Transmission line miles	17,107

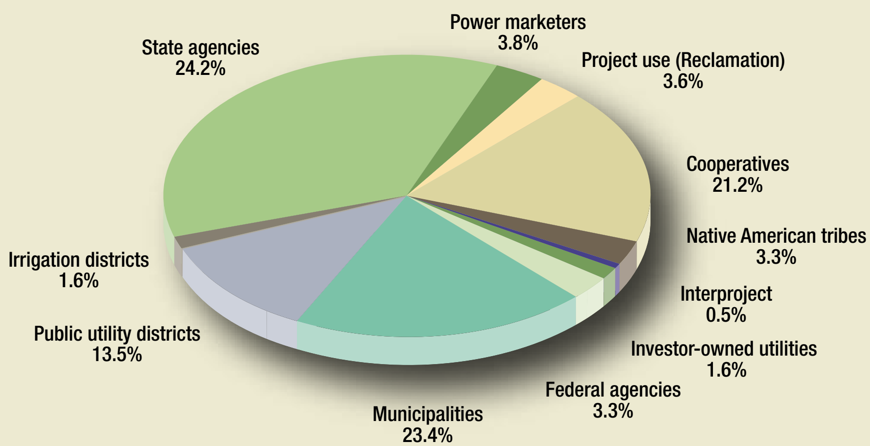
Our people	
Customers	665
Employees	1,369

Peak load	
July 31, 2008	6,476 MW

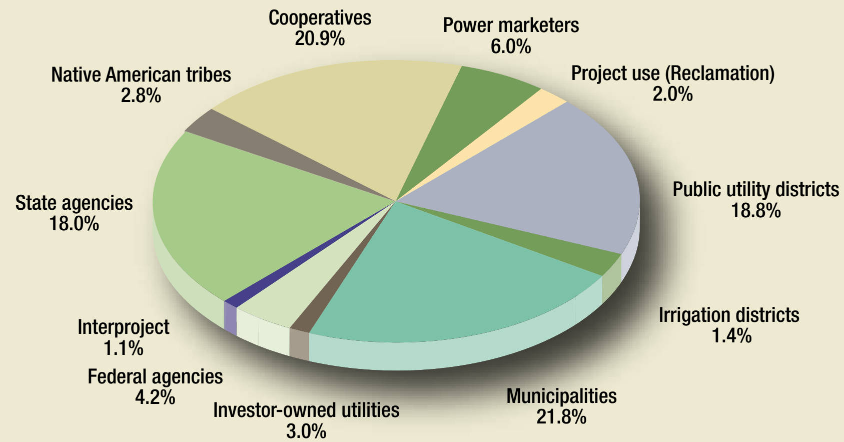
TRANSMISSION LINES IN SERVICE
as of Sept. 30, 2008



WHERE OUR ENERGY GOES (MWh)



WHERE OUR REVENUES COME FROM ($)



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Administrator's letter

The events of Fiscal Year 2008 gave me a powerful perspective of Western's mission and what our customers value. We, at Western, continued doing our part to support energy demands by delivering clean, renewable, cost-based hydroelectric power and related services, while our nation watched oil prices leap at an alarming rate.

Other events that defined our year were several major storms, including the tornados in Windsor, Colo., the ice storms in Northern California and the 124-mph winds that mangled lines in Sully County, S.D. Each time, employees and customers rose to the challenge, rerouting power to maintain the grid's stability, repairing the lines and fixing substations quickly, diligently and safely.

We were able to successfully meet the power needs in the West because of the strong relationship with our 665 power customers who helped us fund our $1.5 billion Federal hydropower program in FY 2008. And our repayment of the Federal investment was well within the annual goals set for us by the Department of Energy.

We kept a grounded perspective about Western's roles in the industry as our nation prepared to transition to a new administration and with legislation, industry developments and new expectations knocking on our door.

From my perspective, these are our most significant highlights in FY 2008:

Increased hydropower production

With a 290-gigawatt-hour increase in water generation this year, Western delivered about 36 billion kilowatt-hours of energy—enough to keep the lights on in more than 3.4 million homes throughout our territory. While the hydro conditions were better than those we faced in FY 2007, we're still battling the persistent drought, and water levels are still shy of some of the historical averages.

Operating to meet energy demands

Again we exceeded industry and reliability expectations. We achieved the highest rating for balancing resources and loads in our balancing authorities. Our staff also worked dynamically on July 31, 2008, to meet the demands of the highest daily peak load—6,476 megawatts—Western has seen since FY 1999.

Western also kept its FY 2008 accountable outages well below the goal, earning us a "green rating," or the highest level of compliance within Department of Energy's performance standards. We take pride in our compliance with national reliability standards as our operations and maintenance staff continue to set and exceed the highest professional standards for industry reliability and safety.

We also took on the effort to consolidate the operations of our Desert Southwest and Rocky Mountain regional operations functions to save customers about $2.1 million in annual operating costs.

Customer partnerships help solve challenges

We continued to enhance our partnerships by bringing different parties together to solve long-standing energy and transmission needs. For example, we connected the Fort Mojave Indian Tribe with the City of Needles, Calif., using technologically advanced conductor that's designed for additional capacity to meet future load growth. And we energized the Wessington Springs Substation in South Dakota to interconnect a new wind farm to the grid. Together, we worked to address energy challenges, as well as ongoing drought, limited funding sources and new industry initiatives, such as the Market Redesign and Technology Upgrade in California.

Moving toward energy independence

Western's Strategic Plan, scheduled for release in 2009, is helping us address all our roles within the industry. This past year, the value of clean, renewable energy came into focus more than ever before in Western's history. Since our service territory covers nine of the 10 windiest states, and we have such a vast transmission network, our unique role continues to get national attention.

In FY 2008, we managed 78 active wind transmission interconnection requests, enough to add about 18,800 MW of energy to the grid. Additionally, several major transmission projects to deliver renewable resources to market are in various stages of planning and development in our service territory. We also issued a solicitation of interest to firm our hydrogeneration with renewable energy and prepared to issue a draft wind/hydro study, which aims to determine how to develop wind resources on our Native American customer reservations.

Carrying the perspective forward

We continue to stand firm in our commitment to delivering hydropower; yet we also find ourselves on the precipice of change as we balance all our roles, provide stewardship of our environmental resources, meet our commitment to keep costs as low as possible and to ensure project beneficiaries pay for the project costs.

The most powerful perspective about Western's role in the industry is one of progress and promise. We've achieved so much in the last 31 years—strengthening the grid, streamlining operations, maintaining reliability—making it possible to deliver on our promise of cost-based hydroelectric power and related services. We will continue delivering on that promise well into the future. From my perspective, to our customers' perspective and our employees' perspective, Western has a lot to offer. Let's continue to work together to power our industry for years to come.

Tim Meeks
Administrator

Powerful perspectives

Energy: There when you need it!

With blistering heat permeating the Arizona deserts and the Colorado valleys on July 31, 2008, Western reached a milestone—our peak load for the year, and the highest peak since Fiscal Year 1999. On that warm July summer day, customers requested 6,476 megawatts, or MW, of power to meet consumers' power needs. While well below the 10,482 MW of capacity that Western has available, this coincident peak—or the highest maximum Westernwide peak load—was representative of what employees can deliver to customers each and every day.

Simple, individual actions in one household or business after another across Western's service territory are behind this statistic. A light switches on at dawn in Watertown, S.D., an air conditioning unit is turned up in Phoenix, Ariz., a computer powers up in Sacramento, Calif.—one after another, those energy-using decisions led from our customers' service territories into Western's balancing authorities, where energy schedulers determined how to match our hydroelectric power resources to meet the demands for additional power.

That balancing act required the cooperation of hundreds of employees across the agency. To meet our customers' loads, dispatchers coordinated with powerplant operators at the generating agencies, whose hydropower resources happened to be stretched that day due to the persistent drought. Without enough hydroelectric power resources, they coordinated with Western marketers, who skillfully searched for the best prices to buy or trade power with other utilities through an online energy marketplace.

Once enough resources were located, dispatchers arranged for power deliveries across Western's transmission lines or via neighboring utilities' lines. Close coordination was also taking place back in the balancing authorities among energy schedulers, dispatchers and line crews. Transmission switching employees were prepared to re-route the electricity on alternate lines to ensure the power kept flowing if crews had to make repairs to downed lines, broken insulators, damaged structures or substation equipment.

Ensuring supplies and replacement parts were quickly ordered and received required the attention of procurement, finance and budget staff, whose work was essential to keeping all these tasks operating smoothly. Also vital to this


A Fort Peck electronic equipment apprentice gets the view from atop a microwave antenna tower.

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JULY 31, 2008

system were the engineers and contracts and rates staff, whose dedication months—and even years—before this July milestone set the stage for the tasks being done today by dispatchers, marketers and line crews. The engineers' transmission line and structure designs ensured Western could move that power from the powerplants to the customers. Contracts negotiated with customers specified Western's capacity and energy commitments and provided the guidebook for that day's energy deliveries, while the rates that staff implemented helped ensure Western was adequately recovering its costs to sell and deliver that power at the lowest cost to customers.

Meanwhile, in meeting rooms across our service area, managers and staff were looking ahead to the future—to a day that might eclipse this particular July peak load. Transmission planning engineers were meeting with industry partners in Phoenix, Ariz., to discuss future system upgrades. And in Western's offices from Washington, D.C., to Lakewood, Colo., to Sacramento, Calif., teams were analyzing how to address the impacts of industry regulations on our daily operations.

Whether it's a hot day in July or a frigid day in the middle of December, Western employees work every day to make sure the system is in peak condition to manage deliveries to customers and to meet our mission. From each employee's perspective, the job of keeping the power flowing reliably to our customers is the goal that drives each of their tasks. In this year's report, we'll look at a sample 12-hour day, where we will feature different employees' critical roles and perspectives in ensuring that when a light switches on in Watertown, or an air conditioning unit gets turned up in Phoenix or a computer in Sacramento is turned on, the power will be there.

Western's Fargo electrician crew is one of the many teams that maintain our system.

The job of keeping the power flowing reliably to our customers is the goal that drives each employee's tasks.

6 a.m. — TRADERS FIND ENERGY IN HIGH-DEMAND

WATERTOWN, SOUTH DAKOTA: As the sun begins to warm the small Midwestern community on July 31, 2008, dispatchers and energy traders beginning their daily shift at the Watertown Operations center don't yet know of the day's historic precedence. But by the end of their 12-hour shift, they will have helped deliver enough power to the grid to set a Westernwide record for peak load—6,476 megawatts to be exact.

In the humid, blistering heat, many Watertown residents head out to the lake, while others begin turning up the air conditioning. From Watertown to Bismarck, N.D., to Sioux City, Iowa—all major cities within Western's Upper Great Plains Region and served by the Watertown Operations center—residents, businesses and industries contribute to the system-wide demand for additional power.

For staff on duty, the clue that this will be a day of heavy demand comes with the weather forecast. The day calls for a high temperature of 82 degrees Fahrenheit and 71 percent humidity, while elsewhere in the region, temperatures are reaching historic highs.

Energy traders at the Watertown merchant function check the day's weather forecast to predict whether the higher temperatures might lead to the need to purchase power.

"The business of providing power for the system load was anything but routine," said Byron Callies, a long-term energy trader in Watertown, the hub for delivering power to customers served by the Pick-Sloan Missouri Basin Program—Eastern Division, or P-SMBP-ED. "Heat builds over a period of time and system load steadily increases. The difficulty of finding energy on a high-demand day increases the energy trader's awareness of what the energy market will look like," he said.

After determining customer load needs based on the forecast and historic load patterns, traders at the merchant function in Watertown enter in customer energy schedules and coordinate with dispatchers on how much daily genera-

tion is needed. On this day, the ongoing drought continues to hamper hydroelectric power resources and Western's ability to meet the additional demands for power. By the end of the water year 2008, the U.S. Army Corps of Engineers reported record low generation for P-SMBP-ED of 4,900 gigawatt-hours, or GWhs, compared to an annual average 9,800 GWhs.

An additional problem of congested transmission paths set the traders on a quest not only for power to purchase, but also for open transmission paths. The added heat means that transmission lines don't have the capacity to carry as much load and utilities will have to re-route the power on other lines, which is called transmission loading relief.

"That day, we started with plenty of energy to handle the day, but transmission loading relief caused incoming schedules to be curtailed or even cut," said Callies. "The best laid plans of the next-day and long-term marketers can all be for naught if line loading occurs," he added.

Using thrifty detective skills, the traders then go to an online purchase power market and to the Open Access Same-time Information System, or OASIS, for available transmission capacity. Otter Tail Power Company and our customer, Omaha Public Power District, are among those entities with power for sale.

With each transaction, traders leave no stone unturned to find the most economical price of power and transmission, searching energy trading sites on the Internet for the best deal. "All employees strive to keep costs at a minimum and negotiate the best possible price for purchased power," Callies said.

An electrician peers out from a confined space at Jamestown Substation, one of the 104 Upper Great Plains substations through which traders and dispatchers in Watertown route power.

Watertown energy traders confer about the day's customer load at the Watertown merchant office, which is a separate function from dispatch within the Watertown operations office.

8 a.m. — SETTING THE RATE STRAIGHT

LOVELAND, COLORADO: Purchase power is on Steve Cochran's mind on this 95-degree day in Loveland, as he prepares for public meetings later in the summer. A public utilities specialist in Rocky Mountain's Rates group, he sees how purchase power costs can drive up rates. With the region's reservoir storage and precipitation below average, drought has led to a $10 million shortfall in the revenue requirement for Loveland Area Projects, or LAP, leading the Rates group to propose a rate adjustment and introduce a special component that factors in drought-related purchase power expenses.

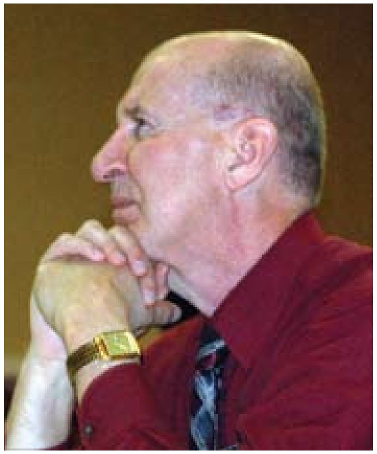
As the temperature rises to 95 with no sign of rain, Cochran's group prepares for a public process to discuss plans to adjust the current composite rate by 14.9 percent beginning Jan. 1, 2009. Specifically, Cochran is crunching numbers on spreadsheets that indicate the need for the rate adjustment and discusses making arrangements for public meetings on Sept. 9 and 10, 2008 in Denver and Sioux Falls, S.D.

"In early spring, we begin making evaluations for a potential rate adjustment. We meet with customer groups and the generating agencies—the U.S. Bureau of Reclamation and the U.S. Army Corps of Engineers—and discuss estimates for future water deliveries," Cochran said.

He continued, "Our rates are set in such a way to cover expenses, and the goal is to keep the rates as low as possible using sound business principles." Since 2003, the LAP firm electric service rate has increased nearly 72 percent—a definite concern for everybody.

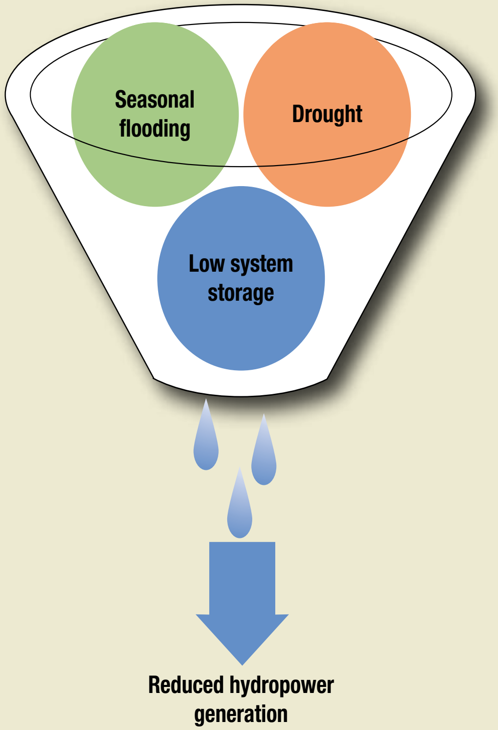
The Rocky Mountain Rates team prepares for customer meetings to discuss an adjustment to the customer's composite rate.

Cochran explains that Rates staff worked cooperatively with our customers to establish a drought-related component to the rate. This portion of the rate, called a drought adder, is designed to be increased or decreased—depending on drought-related costs—without a public process. He explains that a little over a third of the rate is related to drought. "With the two components listed on the bill, the customers can see changes to the drought adder component. When we get past this drought, rates should stabilize and the drought adder component will go down," Cochran said.



Steve Cochran

Contributing factors to reduced hydro generation



Keeping rates as low as possible is always a priority among Western staff—from Dispatch to Rates and all other functions in between. Western's mission of marketing and delivering cost-based hydroelectric power drives every decision, as does our commitment to ensuring we can repay annual expenses and the investment in the power-related facilities from which we market power. For example, the drought adder is designed to repay LAP's drought debt within 10 years from the time the debt was incurred.

Cochran said, "The drought has made repaying the Treasury a little slower. We are attentive to that goal, while still providing our customers the best rates we can. Staying in touch with our customers throughout the year about the rates process keeps us all focused on the big picture—providing reliable power at a reasonable price."

Continued drought conditions, seasonal flooding and low system storage have all contributed to reduced hydropower generation, which has required Western to incorporate a drought adder component to some of its rates.

"Staying in touch with our customers throughout the year about the rates process keeps us all focused on the big picture—providing reliable power at a reasonable price."

10 a.m. — ENERGIZED BY A BETTER WATER YEAR

SALT LAKE CITY, UTAH: At Western's Colorado River Storage Project Management Center, or CRSP MC, the high snow pack and spring runoff are proving to be good signs to Burt Hawkes, Power Resources and Contracts manager. Glen Canyon and Aspinall—the major powerplants of the Salt Lake City Area Integrated Projects, or SLCA/IP—are generating about 16 percent more hydroelectric power this summer, which is a welcome change from years of low water. With increased generation, there is more energy to deliver to customers and hope that purchase power expenses will stabilize.

Specifically, inflow into Lake Powell in June 2008 was about 3,614,000 acre feet, which is 117 percent of average. Higher inflows this spring and summer raised the reservoir elevation to 3,633 feet on July 10, which is 43 feet higher than the March low point and about 143 feet above the 3,490-foot minimum power generation elevation. With these promising numbers and the decision by the U.S. Bureau of Reclamation to implement "equalization" between Lake Powell and Lake Mead, CRSP MC was able to deliver additional capacity and energy to firm power customers above contractual obligations from May 2008 through the last day of July 2008, and Hawkes anticipates continuing this trend in August and September.

Analyzing the amount of water available for the Colorado River Basin is something Contracts staff do continually to ensure Western meets its contract commitments for energy and capacity.

On this 96-degree day of July 31, 2008, Hawkes and other CRSP MC staff work to analyze the hydrological outlook for the Upper Colorado River Basin and expected CRSP operations for the upcoming winter season. They share this data with customers at an August 2008 informal meeting.

While Western is committed to fulfilling as much as possible of each customer's summer or winter contract rate of delivery amount—or CROD—the unique operational constraints to protect environmental resources downstream of Glen Canyon sometimes create a gap between available resources and customers' energy needs. "They can use their CROD every month, but if we don't have the capacity available because Glen Canyon is restricted, they can't get all the way to full CROD without other purchases," Hawkes explained.

"If more water is released, then we generally update the monthly available energy and capacity amounts. We use a power modeling program of additional energy available, which allocates it among all the customers, and we give them notification of how much additional energy is available to them. It's an ongoing process, sometimes throughout the year, to update the customers," stated Hawkes.

Hawkes added, “With this analysis using water releases, probably the most important thing is trying to maximize the amount and value of the hydroelectric power. We are re-evaluating our operations continually. We try to work with Reclamation to maximize power production in July and August when electrical needs are the highest and so we don’t have to buy power when it’s the most expensive.”

However, higher prices in the purchase power market and very low releases from Glen Canyon the previous fall and winter unfortunately caused purchase power expenses to be higher than anticipated. Yet because the CRSP MC staff, working with the customers, had the foresight to structure SLCA/IP contracts to allow more flexibility in buying purchase power, those increased costs haven’t had as big an impact on rates. “We’ve given customers the option of letting us buy the additional power or supplying the additional power themselves and use our transmission system to get that power delivered,” Hawkes explained. “If they choose to have us do it for them, they pay on a pass-through basis. The costs don’t go into the rate, but go directly to them. It keeps the rate low; that’s the reason we structured our contracts that way.”

A cloud rises as water released from Glen Canyon Dam fills the canyon below.

11 a.m. — TRADING FOR POWER

“We could be buying up to 200 megawatts an hour—and your chances of buying from six to seven entities are a lot greater than on a normal day.”

MONTROSE, COLORADO: On this 98-degree July day, the Energy Marketing and Management Office, or EMMO, is buzzing with activity as energy marketers hunt for the best deals in the purchase power market for customers of the Salt Lake City Area Integrated Projects and Loveland Area Projects. Rivaling an active day on Wall Street, all the buyers and sellers at this trading hub are online and in the market for power. With hydropower shortages, staff search for the best price for on- and off-peak energy.

Who is selling? Which companies are buying? What are customers’ daily schedules? Are there any line outages? The answers to these questions all factor into staff decisions. “On one desk, we have different firm customers calling in every hour requesting energy. At the top of the hour, we start right in on balancing our load to resource,” said Jeanette Telschow, team lead over the Real-time function, which balances resources and loads in the same hour the energy is being generated and used.


Jeanette Telschow

“Marketers compare generation available against hourly loads to serve and buy or sell accordingly. They look at the water, see how it is scheduled and look at the elevation limits on the reservoir, and they do this for multiple reservoirs at the same time,” she said.

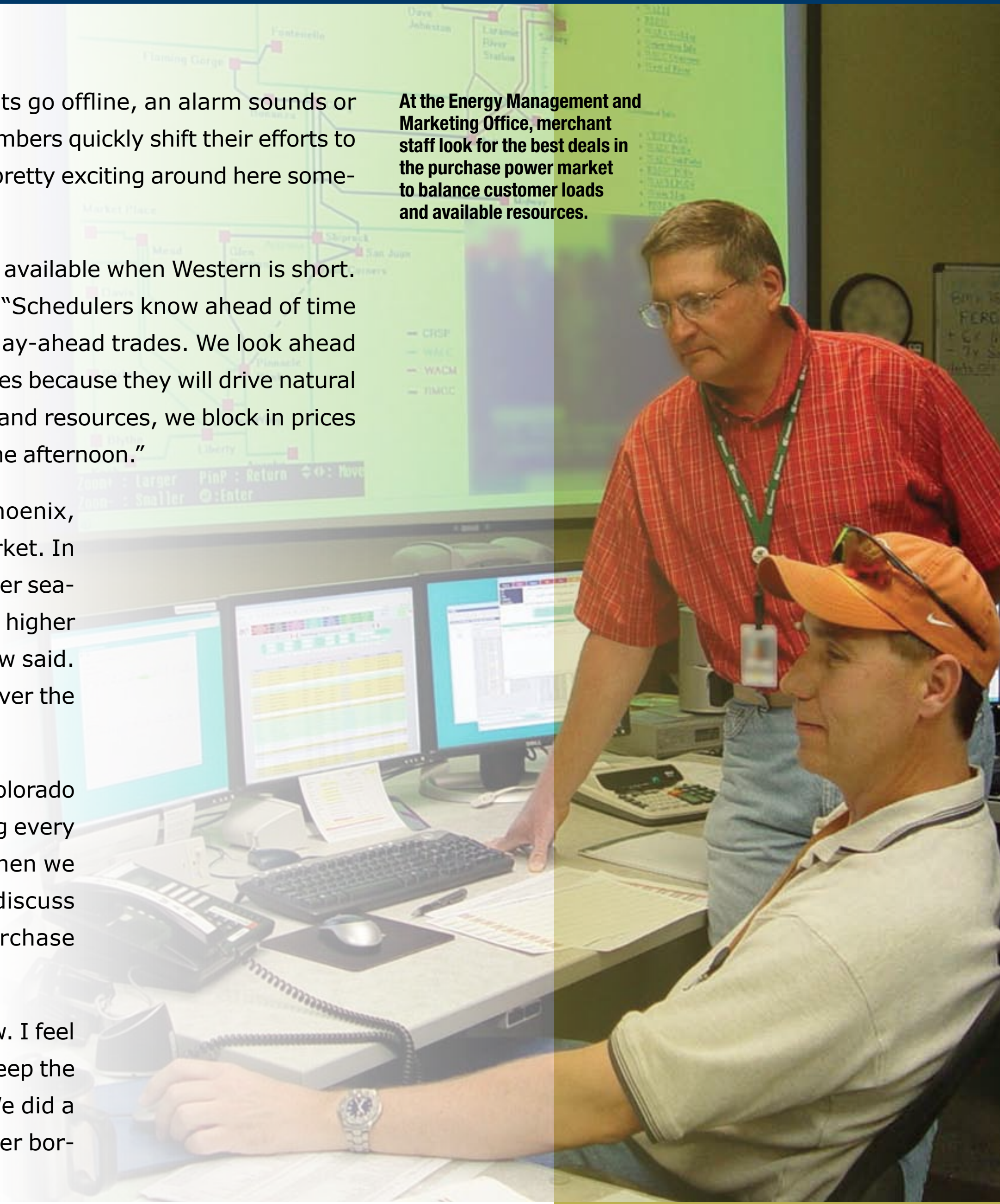
She further explains each of the roles in the EMMO to ensure a balance of power. “Pre-schedule staff schedules the generation to cover pre-scheduled loads. Real-time assesses the load and resource balancing and the real-time market prices for the day, then may reschedule the generation to better optimize how generation is used to keep the high price purchases to a minimum,” she said. At this time, on-peak energy is averaging a 30-percent increase from FY 2007.

While hydrology has been less than stellar in prior years, July 2008 gives marketers reason to hope that they have to purchase less. “We got water last year and everyone was excited,” stated Telschow. In fact, Western made a $10 million payment to the U.S. Treasury in 2008 for the Colorado River Basin Fund—the first payment of its kind in nine years.

On this day, however, Western was more of a buyer than seller in the marketplace. Telschow explained how peak load days cause marketers to extend the search for available resources. “We could be buying up to 200 megawatts an hour—and your chances of buying from six to seven entities are a lot greater than on a normal day.” On this day, marketers purchased up to 150 MW an hour from Colorado Springs Utilities, Tri-State Generation and Transmission, Salt River Project, Public Service Company of New Mexico, PowerEx and Platte River Power Authority.

If anything is out of balance, transmission lines relay or generating units go offline, an alarm sounds or energy "tags" (document of an energy trade) are curtailed, and staff members quickly shift their efforts to help the marketer get schedules re-routed or re-dispatched. "It can get pretty exciting around here sometimes," she admitted.

However, Telschow explained that it's rare that we can't find the energy available when Western is short. Most often, staff can plan ahead to lock in the most economical prices. "Schedulers know ahead of time to make monthly purchases or a pre-scheduler in the morning will do day-ahead trades. We look ahead at the weather. At this time of year, we discuss the possibility of hurricanes because they will drive natural gas prices up. If we have trouble on the real-time desk balancing loads and resources, we block in prices early in the day so we don't have to go and hunt for energy the rest of the afternoon."



At the Energy Management and Marketing Office, merchant staff look for the best deals in the purchase power market to balance customer loads and available resources.

On the real-time desk, they deal from Wyoming and down south to Phoenix, Ariz. "We have what we refer to as the north market and the south market. In the south, prices are generally higher than in the north during the summer season due to the high temperatures. And in the north, the prices tend to be higher during the winter season because of the colder temperatures," Telschow said. Staff on the real-time desk also purchase transmission resources to deliver the energy across other utilities' lines when necessary.

Coordinating with the Western Area Lower Colorado and Western Area Colorado Missouri balancing authorities is another priority, as well as documenting every energy trade with an energy "tag." Telschow explains the process, "When we purchase from an entity, we call them on a recorded phone line. We discuss which project we are purchasing for and agree on the quantities, purchase price and point of delivery.

"It's very detailed work. I like the job because it's always something new. I feel like I am really accomplishing something here—we're working hard to keep the power going for our customers. Some days you go home and think, 'We did a really good job and did the best we could.' I really love the job—it's never boring," she concluded.

"Every July, we meet with them [customers] to discuss their operations and maintenance priorities for the next 10 years. We listen to what projects they would like us to undertake, and they tell us about their own needs."

PHOENIX, ARIZONA: As temperatures rise to 112 degrees in Phoenix, Power Systems Operations Manager Ron Moulton reviews 10-year system planning documents, which he's discussed earlier this month with his Transmission Planning and Transmission Business Unit staff members and Desert Southwest firm power and transmission customers. Substation interconnections, voltage upgrades, transformer installations and increased capacity ratings—as well as the money to fund these upgrades—are among the topics that Parker-Davis, Boulder Canyon and Pacific Northwest-Southwest Intertie customers discuss to ensure Western's system reliability well into the future.

Rewind the clock back 10 years before this July day and these same topics are being debated to ensure that on July 31, 2008—as on every other day in the future—the DSW transmission network would be up to the task of reliably meeting customer needs. What years ago were conceptual plans, transmission studies or engineering designs became energized additions to DSW's system in FY 2008, including the conductor upgrade on the Davis—Mead 230-kV transmission line and a new Firehouse-Topock 69-kV line interconnecting the Fort Mojave Indian Tribe and the City of Needles to provide additional capacity to accommodate their growing energy needs.

Looking simultaneously at today's needs while predicting tomorrow's system requirements always involves customers. In fact, in FY 2008, DSW formalized a program to better coordinate customer outreach among the Federal Power Programs and maintenance and operations functions. "Planning is something we do year round with our customers," says Moulton. "Every July, we meet with them [customers] to discuss their operations and maintenance priorities for the next 10 years. We listen to what projects they would like us to undertake, and they tell us about their own needs." Yet Moulton points out that the coordination extends industrywide. "We have a seat at the table at a number of local, sub-regional and regional transmission planning committees and transmission groups to ensure any system additions, interconnections or upgrades are well thought out on a regional level," he said.

Parker Dam holds back Lake Havasu, prepared to generate hydroelectric power for DSW customers.

These committees and groups provide a forum to discuss continuing transmission needs in southern California, southern Nevada, Arizona and New Mexico all of which are located within DSW's service territory. The transmission constraints and bottlenecks that exist in these areas are always on the minds of transmission planners and engineers, as are the ever-increasing numbers of generator interconnection, transmission interconnection and transmission service requests that must be studied, managed and analyzed under our tariff.

DSW Power Systems Operations Manager Ron Moulton keeps an eye on congested transmission paths when planning for future system upgrades.

"There is always a lot of interest in interconnecting to our system and acquiring transmission service from Western, but we have to carefully examine how those changes will impact reliability and whether there is adequate transmission capacity available," said Moulton. "Our priority is meeting our commitments first to firm power customers, providing cost-based transmission service and ensuring the record of reliability that Western is known for throughout the industry."

Western staff help cut the ribbon that signals the completion of the Firehouse-Topock line in Arizona that links Western's customer, the Fort Mojave Indian Tribe, with the City of Needles, Calif., distribution system.

Western lines march across the sands of Yuma, Ariz., as the sun beats down.

1 p.m. — PLANNING BEYOND TODAY'S ENERGY NEEDS

Top 6 trends

Customers' most frequent Demand-Side Management activities include:

- Lighting technologies
- Heating, Ventilation and Air Conditioning technologies with emphasis on cooling and ventilation
- Audits for residential, commercial and industrial facilities
- Domestic hot water technologies
- Irrigation system improvements
- Load management programs

LAKEWOOD, COLORADO: From cities and towns across our Great Plains to Native American reservations in Arizona, the afternoon sun promises a source of potential energy as Western customers are planning for their energy futures. Cost, reliability, environmental stewardship, national security, economic growth and climate change are among their top concerns. Keeping a wise perspective on future resources through Integrated Resource Planning, or IRP, is how they can address those concerns years in advance.

"Integrated Resource Planning helps each customer keep the lights on at a reasonable cost," said Ron Horstman, Western's Energy Services manager.

Customers have alternatives

Required by the Energy Policy Act of 1992 and by Western's Energy Planning and Management Program, IRPs encourage firm power customers to evaluate a full range of alternative energy resources that still provide reliable service to consumers at the lowest cost.

"The dilemma facing many customers today is restrictions placed on what types of generation are acceptable given the environmental concerns and economic and national security issues," Horstman said. In fact, Horstman noted that energy auditing programs "are hot right now because they identify efficiency and conservation options for end- users that reduce demand."

Western's Energy Services programs provide technical assistance and training to help customers choose such options by hosting webinars, workshops and seminars, developing publications, loaning equipment and providing online resources.

IRP rules revised

Western gives customers several options to meet the IRP requirements. Updated in FY 2008, the requirements recognize the changes occurring in the utility industry and our customer's varying size and structure.

Western made three changes to its IRP requirements to streamline regulations and make documents more accessible, including:

- Eliminating the requirement that a member-based association's members unanimously approve the IRP. Now approval is only required by the Member Based Associations governing body, not all members
- Encouraging customers to prepare regional IRPs, even if a customer is not a member of an MBA
- Making customer IRPs more readily available to the public by posting them on a publicly available Web site

FY 2008 IRP highlights

All firm power customers have submitted some form of IRP. In FY 2008, Western received 96 IRPs from individual customers, 21 plans from cooperatives, 83 minimum investment reports and 85 small customer plans. These plans represent 815 long-term, firm power customers, customer members and project-use customers.

Customer-reported trends include:

- More investment in renewables, efficiency and Demand-Side Management activities
- Increased influence of climate change issues
- Increased demand for renewable energy technologies in all (commercial, industrial, residential and institutional) market segments
- Increased requests for education and information transfer on energy efficiency and renewable energy technologies
- Water management issues including efficient use, conservation, irrigation and pumping efficiency
- Continued interest in Demand-Side Management and efficiency activities and programs

Top 5 renewable resources

- Hydro (large and small)
- Wind generation
- Solar—PV
- Geothermal
- Biomass/gas

Types of IRPs

Customers can choose to submit their IRPs individually or cooperatively. The IRP regulations allow customers to set action plan timelines (instead of a five-year minimum) to better correspond with individual situations. Any customer, including a member of member-based associations and joint-action agencies, can file a small customer plan if its sales/use is under 25 gigawatt-hours per year.

All of these options are designed to help customers gain a fresh perspective beyond today's energy needs.

FY 2008 customer IRP accomplishments

Item	CRSP[1]	DSW	RM	SN	UGP	Totals[2]
DSM savings[3] (kW)	13,489	131,871	160,879	76,698	798,971	**1,181,908**
DSM savings (kWh)	62,197,183	324,646,645	141,116,301	314,816,511	(27,424,254)[4]	**815,352,386**
DSM expenditure ($)	13,251,572	36,221,180	6,064,576	72,860,960	39,027,099	**167,425,387**
DSM deviations[5] ($)	7,294,460	(843,660)	942,973	3,476,163	4,650,681	**15,520,617**
Renewables (kW)	71,392	2,095,759	206,292	618,254	6,207,930	**9,199,627**
Renewables (kWh)	229,936,672	1,442,500,401	660,925,829	2,161,569,902	1,062,398,034	**5,557,330,838**
Renewable expenditure ($)	4,401,136	68,336,676	13,610,824	67,692,505	100,899,009	**254,940,150**
Renewable program types	WTE[6], solar, wind, small scale hydro	Small hydro, solar PV	Small hydro, wind, Co-gen, biogas, solar	Solar, wind, RECs[7]	Medium/large wind, PV, WTE[6], hydro	**Solar, wind, small hydro, WTE[6]**

[1] Numbers based on a 3-year average.
[2] Total numbers include 3-year averages for CRSP and actuals for all other regions.
[3] DSM refers to Demand-Side Management activities the utility conducts to change customer energy use.
[4] The DSM savings figures can be negative due to fuel shifting from gas to electric and load control activities by our customers for air conditioning use.
[5] Deviations are any difference from the customer's Integrated Resource Plan.
[6] WTE means waste to energy.
[7] RECs are Renewable Energy Credits.

2 p.m. — FOLLOWING THE MONEY TRAIL

FOLSOM, CALIFORNIA: Sierra Nevada's Financial Management staff have been planning for this 91-degree summer day of July 31 for more than two years. In spring 2006, they were setting the stage for today's operations, maintenance and construction needs by submitting SN's FY 2008 budget request of $61 million to Congress. After two years of traveling from SN to Western's Corporate Services Office, the U.S. Department of Energy, Office of Management and Budget and finally to Congress and then back again, the same FY 2008 budget that SN requested in 2006 is now more than a figure in a document—it's money that's being invested by crews this July as they replace breakers at Folsom Substation, relays at Airport Substation or build a bay addition at Tracy Substation.

"We were in the final quarter of FY 2008, and a high priority was to ensure the FY 2008 appropriations were not only fully executed, but that any available resources—if needed—were either allocated to the highest SN priority areas or made available to other regions," Janice Nations, SN's Financial manager says as she reflects on that time in the budget cycle. "Alternatively, if there were any budgetary shortfalls, it was the responsibility of SN's Budget and Finance unit to make sure those shortfalls were properly covered."

Because SN's operations and maintenance, or O&M, needs in FY 2008 exceeded the budget amounts, SN turns to customer advanced funding. "SN used the Central Valley Project O&M customer advances to bridge the gap between total O&M requirements and appropriations received," Nations explains. These advanced funds allow Western to ensure a construction or O&M project is fully funded up front and ensure timely system maintenance.

Partnering with SN's 79 preference customers on the region's needs is a key priority for Nations every summer, and she and other SN managers meet with them annually to go over the region's 10-year construction plan and discuss alternative financing arrangements, if needed.

Trying to anticipate what SN's future will bring in 10 years can be hit or miss; financial priorities yesterday can shift quickly in the face of equip-

A Sierra Nevada Rates employee, right, confers with his counterpart at the Bureau of Reclamation.

The SN Financial manager, standing at left, takes a break from reviewing financial documents with the Bureau of Reclamation staff.

ment failures, unplanned industry developments or winter storms, such as those in January 2008 in northern California that stranded thousands without power for days. Nevertheless, Nations must perform a constant balancing act between the critical funding requirements of today and those of tomorrow.

For example, the Sacramento Voltage Support project, Trinity-Weaverville transmission line, environmental scoping for the Transmission Agency of Northern California project and mandatory reliability standards are all key elements of the FY 2009 and FY 2010 budgets, which Nations is monitoring this summer. Another initiative—the Market Redesign Technology Upgrade, or MRTU, by the California Independent System Operator, or CAISO—is likely to have impacts to SN budgets even farther out in the future. "A major effort for SN during July 2008 was the big push to be ready for going forward with MRTU," Nations says. MRTU is intended to fix design flaws in the CAISO markets (which caused the California energy crisis of 2000-2001), enhance grid reliability and protect wholesale consumers from price volatility and gaming. In addition, the technology component refreshes and upgrades business applications and software that CAISO has used since its inception in 1998.

Sierra Nevada's Financial staff makes it possible for the region to meet its maintenance and construction needs, such as the funds needed for this lineman to maintain this 500-kV transmission line in California.

It's a lot of work behind the scenes to make sure Western has the resources when customer loads are at their maximum. Yet Nations' commitment to balancing SN's budget ensures continued safe and reliable operations all year long.

Nations states, "My staff and I are committed to ensuring that the field crews, engineers and power system dispatchers have the funds to purchase the tools and equipment they need to operate and maintain the system safely and reliably. In addition, I'm committed to ensuring that our office staff have the resources they need to perform their tasks efficiently and effectively."

3 p.m. — PROCURING SUPPORT FOR THE SUMMER MONTHS

PHOENIX, ARIZONA: As a blazing hot afternoon wears on, Desert Southwest Procurement Manager Byron McCollum focuses on another hot topic—a piece of equipment at Blythe Substation has just gone down and now they need to purchase an emergency replacement. While the Procurement department generally plans purchases almost 15 months in advance, in emergencies, staff can make purchases within a matter of just a few days. Without the replacement equipment, the substation is forced to run off battery power, which limits the substation's battery life. Once the battery power fails, we lose the capability to open and close circuit breakers and total substation control.

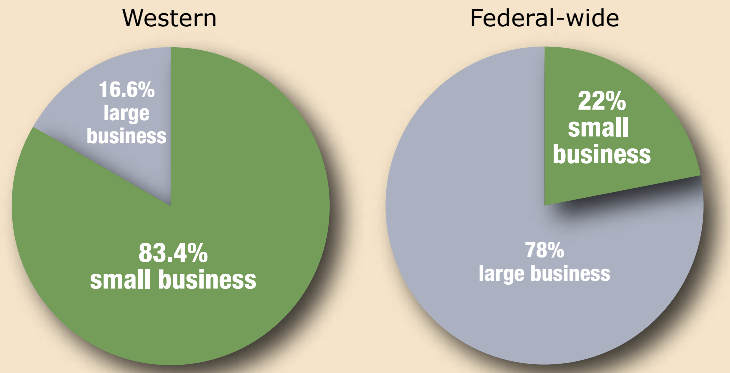
"In the summer, at least one or two emergencies occur because of the extreme heat and amount of people using our system, which puts heavy strain on the grid," said McCollum. "If purchases haven't been planned, then the question becomes, 'How can we meet our customers' needs based on available resources?' We [customers and Procurement staff] pull together to get things done."

He continued, "If it's an emergency and the lights are going to turn off, we try to find the best source and best product as quickly as possible." In many cases, that source is a small or minority-owned business, which Western is recognized for supporting.

Western's Procurement manager, left, reviews Federal procurement regulations with a staff member.

"Generally for items that cost more than $100,000, we have to plan well in advance," he explained. Under Western's Acquisition guidelines, each fiscal year employees must submit Planned Procurement Profile forms for new projects, acquisitions, interagency agreements or planned modifications, including options with an estimated value more than $100,000. "We historically have purchased items like transformers and circuit breakers, so this allows us to find sources quickly to support our summer emergencies," he said.

Percent of contracts to large and small businesses



Note: Small business contracts include those owned by women, veterans, and disabled veterans, as well as disadvantaged, 8(a) and Hubzone small businesses. (Source: Small Business Administration)

Contracting for the future

In fact, Procurement staff takes a proactive approach by trying to compete and find quality vendors to provide the best value as well as highest quality. "We partner with our internal customers to develop Statements of Work or specifications as part of the acquisition process to allow time for conduct market research," McCollum explained. For commercial items, Western usually allows vendors 10 to 30 days to respond to our solicitations. "We subsequently review the packages and we work to make award within 14 days after receiving responses. We normally distribute our awards electronically, which helps to get the vendors started as quickly as possible."

In the case of the Blythe emergency, McCollum and his staff had the equipment and a statement of work ready for someone to install it. The value of the expedited process is that it allows parts to be on hand so Western can meet customer needs. "At that point, it was just a matter of scheduling installation," he said.

Western's contracts: mostly small businesses

Western's Small Business Program continues to get recognition from the Small Business Administration for finding innovative ways to open up opportunities for small businesses throughout Western's territory. In fact, in FY 2008, 83 percent of Western's contracts were filled by small businesses. This means that small businesses made up about $113 million of the $136 million in procurement contracts Western selected in FY 2008.

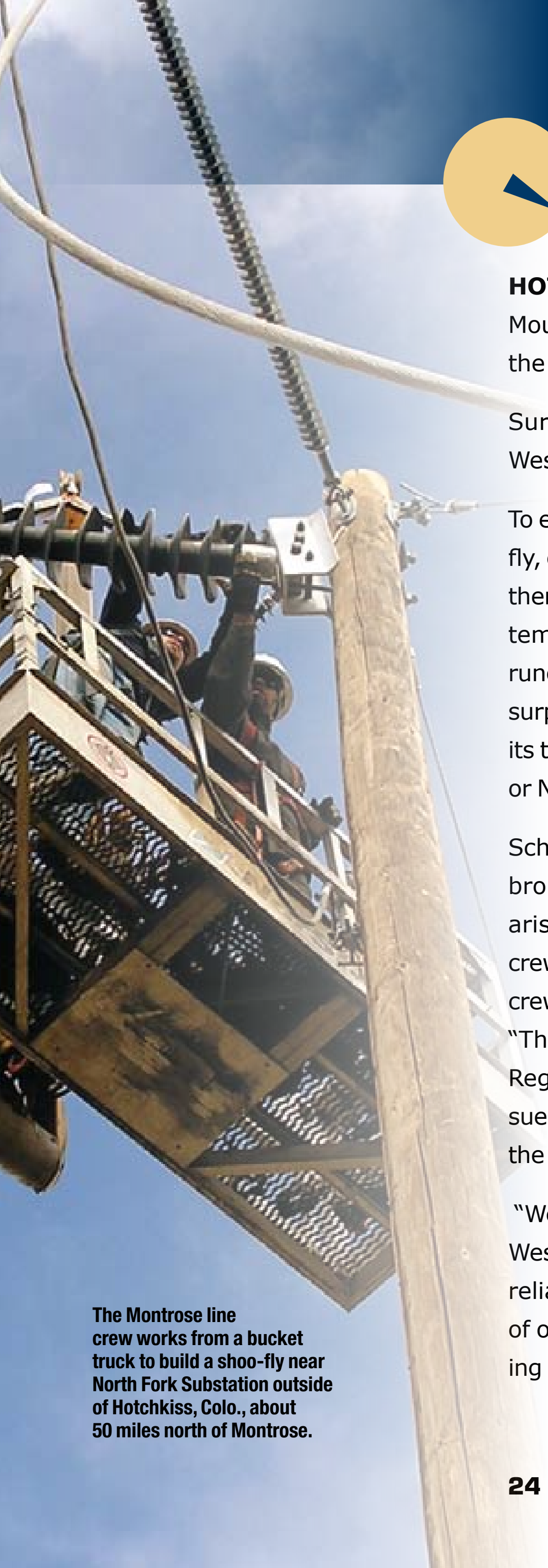
Keeping the system humming

From his perspective, McCollum's priorities are figuring out how long it will take to get products or services ordered and shifting the workload, if necessary. "It's tough when we have an emergency because we have to readjust all other office priorities," he added. "Typically, July and September are stressful months because we need to obligate the upcoming fiscal year dollars before the finance system closes," which can be challenging during the summer since McCollum said DSW is "doing about five or 10 awards per day," compared to less than three per day in quieter months.

Contracting Officers Westernwide are working everyday to make sure the right people and equipment are available to keep the system humming and delivering power to consumers. Often they consolidate their purchases to get a better price from vendors. "We all realize that we're working not only with appropriated tax dollars, but also with customers' money, so we try to get the best bang for the buck. The more they plan, the more we can save," said McCollum.

The DSW Regional Procurement manager looks over a contract award for a piece of equipment that DSW field crews need to repair a substation in Arizona.

4 p.m. — MAINTAINING A RELIABLE PRESENCE



The Montrose line crew works from a bucket truck to build a shoo-fly near North Fork Substation outside of Hotchkiss, Colo., about 50 miles north of Montrose.

HOTCHKISS, COLORADO: Near the picturesque Continental Divide, Will Schnyer, a foreman III lineman in the Rocky Mountain Region, or RM, is observing the Montrose line crew wrap up a day's work on the Curecanti-Rifle 230-kV line in the North Fork area near Hotchkiss, Colo., as storm clouds form to cool them off from 98-degree sweltering heat.

Surrounded by the Uncompahgre Valley and the majestic West Elk Mountain, this transmission line brings power to Western's customers on Colorado's western slope, including the communities of Delta and Gunnison, Colo.

To ensure reliable power delivery, the Cheyenne and Phoenix line crews are helping the Montrose line crew to build a shoo-fly, or interim connection for a transmission line into the substation for Tri-State Generation and Transmission. Tri-State will then upgrade the new substation to meet the area's growing load demand. Additionally, RM line crews are building several temporary wood structures so that they can repair structural damage on a steel tower from a landslide. Heavy spring runoff and overgrown vegetation this season, as well as a tornado that touched down in May 2008, provide never-ending surprises for RM line crews in their quest for system reliability. Yet time and again, industry auditors recognize Western for its top notch commitment to reliable power delivery. The 2008 audit by the North American Electric Reliability Corporation, or NERC, praised Western for "one of the best audits they have conducted to date, if not the best."

Schnyer credits annual ground patrol inspections and semi-annual aerial patrols for spotting potential problems. From broken cross-arms to rejected wood poles to overgrown trees, crews identify and tackle maintenance issues as they arise—a monumental task considering RM line crews patrol 5,400 miles of transmission line and crews Westernwide patrol another 11,700 miles. "There are lots of areas in the Rocky Mountain Region where there are potential vegetation issues," he said, noting Western's partnership with the Forest Service on Vegetation Management.

"We are also accountable for meeting NERC and Western Electricity Coordinating Council system reliability requirements. Patrolling 100 percent of our transmission lines annually and addressing vegetation issues are our priorities," he said.

The majestic West Elk Mountain about 50 miles north of Montrose, Colo., frames the background of shoo-fly installation work that the Montrose line crew is doing.

He notes that Western crews also put a special priority on transmission lines that NERC has identified as constrained. Seven major constrained transmission paths—where lines are loaded to capacity—are in RM's service area alone, two of them just east of the Curecanti-Rifle line the crew is working on. Knowing that these lines are scheduled to capacity, Schnyer and RM crews coordinate closely with Dispatch in Loveland on peak load days like today.

Another added challenge for reliability, Schnyer noted, is the aging face of the bulk interconnected electric system—70 percent of Western's wood structures are 45 years and older. "A community plans for growth by upgrading or building new schools, roads and community infrastructure, but the electric grid hasn't kept up with the growth."

He continued, "Until we build new generation and transmission lines, constrained paths and unplanned outages will continue to be the norm. Visualize Denver with only two lane roads: vehicles would have to operate in a continual traffic gridlock. Instead, Denver has four-, six-, and eight-lane roads to allow traffic to move more freely and without congestion. A lack of generation and constrained transmission paths are like the Denver illustration. Years ago, 69-kV worked fine for many communities, but because of load growth, we now need to anticipate constructing or rebuilding these paths to 230-kV or greater."

Schnyer and the RM line crews worked eight combined-crew line projects in 2008 that improved system reliability. Fiscal year 2009 will bring nine more. Westernwide, crews have added 73 miles of transmission line, built two new substations, added four new transformers and participated in hundreds of other maintenance repairs.

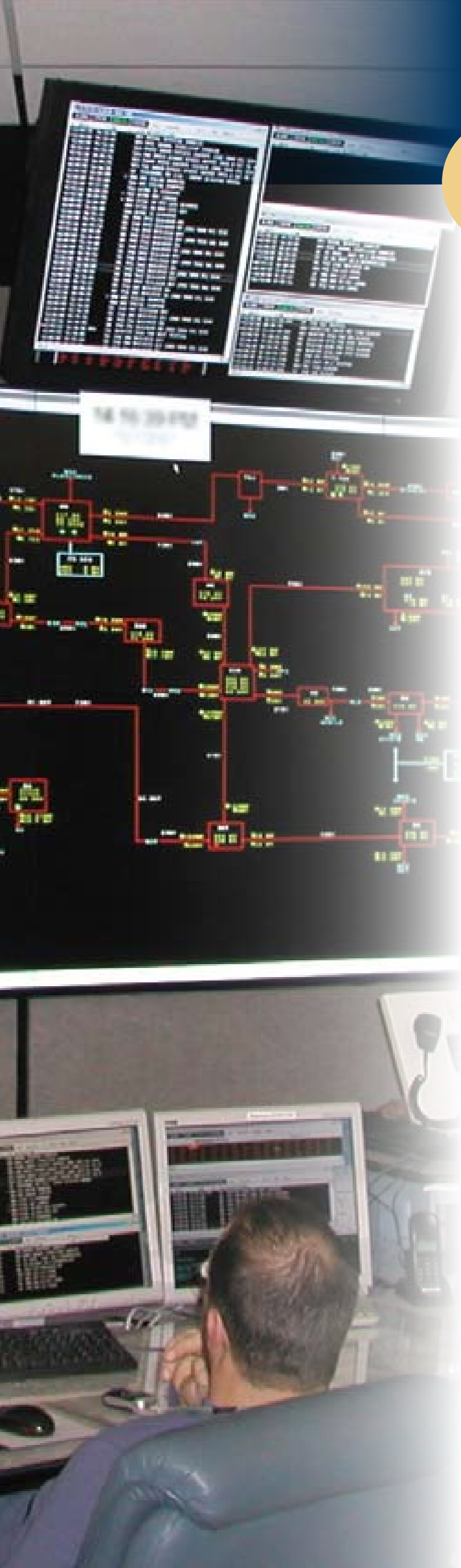
"It doesn't matter to me if it's a customer in the Rocky Mountain Region or in another region," Schnyer said. "All of Western's employees work hard to deliver power throughout our entire service territory. Our agency vision and mission is the same. I like to believe Western is already a premier power marketing and transmission organization and that all of us at Western work hard to market and deliver reliable, cost-based hydropower and related services. That's how I see it," Schnyer concluded.

Line crews from Montrose, Cheyenne and Phoenix combined efforts to install a shoo-fly for Tri-State Generation and Transmission.

Increasing the infrastructure

In FY 2008, Western expanded the grid to provide the necessary capacity for additional energy demands. In total, Western saw infrastructure additions of:

73 miles of conductor
4 transformers
2 substations



6 p.m. — MONITORING THE SYSTEM: A ROUTINE COMMITMENT

WATERTOWN, SOUTH DAKOTA: As the day winds down to a close and temperatures cool from a high of 82 down to the low 70s, day-shift dispatchers on the generation desk in Watertown go over the day's logs with the incoming staff before heading home after 12 hours of monitoring the system. While this July day wasn't a record breaker for UGP—its actual yearly peak hit 16 days earlier—it was the region's third day in a row of high humidity and heavy air conditioning use, leading to a daily peak of 1,791 MW and a near all-time high for total load served Westernwide.

On peak load days like these, UGP Generation Team Lead Craig Speidel said the dispatchers constantly monitor the electric system load assuring there are enough resources to cover the peak demand. "If we have hot, humid days for several days in a row where the air conditioning is running all the time instead of being intermittent, we will have a more saturated load," Speidel says. "Normally, the peak will be on the second or third day. Knowing the system is requiring more energy and we have to meet load with generation or with the purchase of energy, we work with the generation units to verify that they have capacity available and also work with UGP marketing. The real-time dispatcher is always looking into the future to verify that they will have enough resources available to meet this increased demand."

Luckily, with such heavy loads, nothing about this day threw Speidel and the other dispatchers any surprises at this Balancing Authority in Watertown, serving the Western Area Upper East and Western Area Upper West. "It was routine business," he says as he reviews the day's events. "There were no major limitations on the generating units. Our hydro and purchases were providing 1,286 MW. Normally we would have a lot more hydro generation available to us if the UGP Region was not being affected by the current drought conditions," he said.

Basin Electric Power Corporation's steam units were available for nearly full load during this period. Earlier in the day Basin also had some wind generation available from its wind farms, but the "generation was down because it was a calm day. In

In Watertown, dispatchers are constantly keeping track of the happenings on the North and South transmission dispatch boards.

A Jamestown electronic equipment craftsman works up high at Jamestown Substation.

the morning, we had a small storm go through which provided some generation, but in the peak part of day, wind generation was down to 30 MW, a quarter of its capability."

Having a range of resources available is part of the balancing act. In FY 2008, Western had 327 MW of wind interconnected that was available to meet customer load, and a new substation built by Western crews at Wessington Springs was ready to add another 51 MW of wind into the grid. Wind capacity may be more available to Speidel and other dispatchers at Western's four balancing authorities in the future since Western is managing 78 requests to interconnect an additional 18,800 MW of wind. And in late 2008, UGP marketing staff were determining interest in long-term suppliers of renewable energy to firm Western's hydro resources.

On this busy day, dispatchers did have alternatives both for generation and for transmission, if any lines were to go down and they had to re-route the power. But on the transmission side, everything was also operating normally—no lines were down for maintenance and there was enough line capacity to move the power across the system.

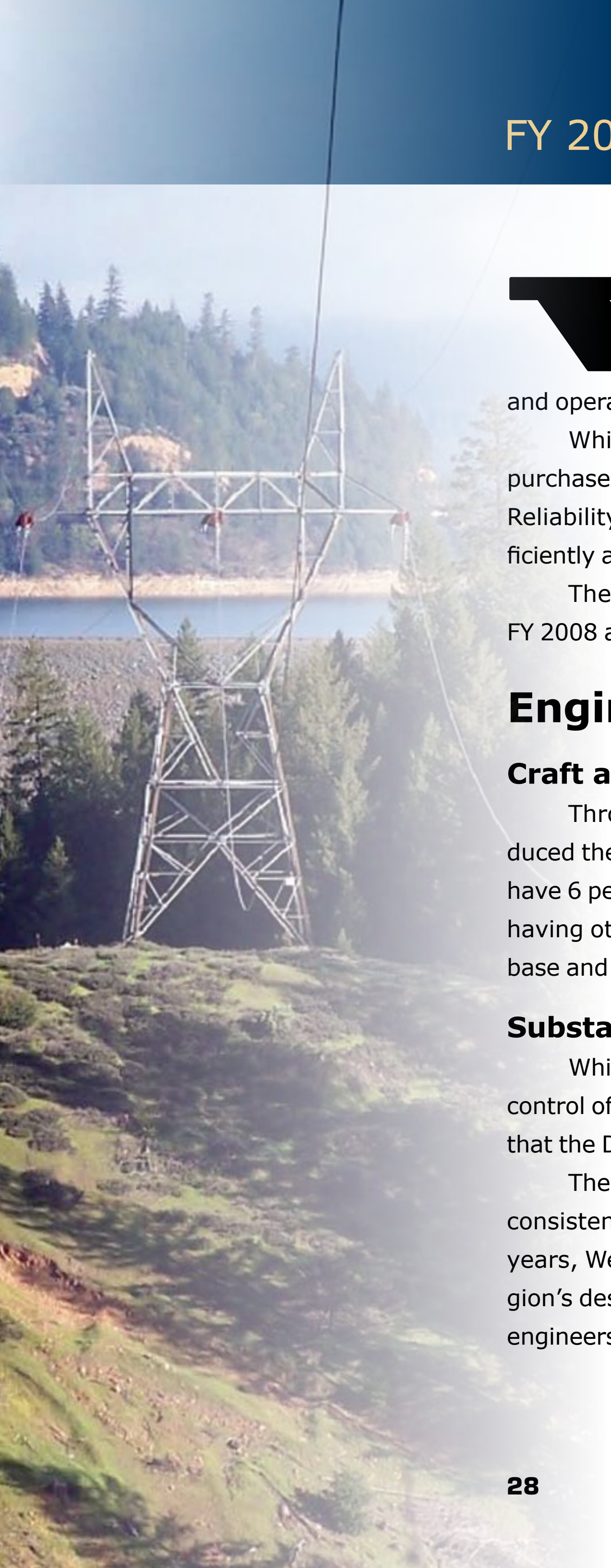
Speidel says most of the time, operations go smoothly. But occasionally on any given day, "you'll lose generation somewhere and it causes added stress to the day. It can be really routine one minute and then the next minute things fall apart, causing turmoil for the rest of the day."

But not on this day. For today's shift, as with every other shift that they work, dispatchers Westernwide are committed to balancing loads and resources 24 hours a day to ensure customers have the power when they need it. "I always like the challenges that you come across in this line of work and being able to react to situations and take care of them," Speidel says. "I just like the feeling that you are doing some good to keep everyone energized," he continued. "A lot of people in Watertown don't know what we do or understand what it takes to keep the system up and reliable. They don't care how the power gets to their air conditioner, they just rely on it. That's what we're here for—to make sure they are getting served."

Watertown dispatchers go over the day's logs, a routine to ensure continuity between those starting their shifts and those leaving for the day.

Energy is our focus...around the clock

From the start of the day in Watertown, throughout the morning hours in Loveland, Salt Lake City and Montrose, into the afternoon in Folsom, Phoenix and Hotchkiss, and finishing off the day out back at Watertown, a tremendous amount of coordination made this peak load day of July 31, 2008, a success. Employees are on a mission each and every day to make a difference in the smooth operations of the bulk interconnected power grid. While each employee may have a different perspective about his or her role in moving this hydroelectric power through the interconnected system, they all work together to make it happen every hour of every day.



Western's major Fiscal Year 2008 operational highlights were defined by responding to new market initiatives in the electric utility industry, implementing new programs or features to offset the effects of the drought, introducing process improvements in transmission service and operations and finding innovative solutions to maintenance issues.

While Western continued to be challenged in FY 2008 with available hydroelectric power generation, increasing purchase power costs and availability of resources to respond to new reliability rules set by the North American Electric Reliability Corporation, or NERC, employees gained new perspectives on how to do business more effectively and efficiently and to look at solutions in new ways.

The highlights below outlined by each major function give a Westernwide perspective on what we achieved in FY 2008 and the benefits we gained from our accomplishments.

Engineering/Maintenance perspective

Craft administrative time reduced

Through a new Westernwide initiative outlined in strategic planning, Western's maintenance staff members reduced the time they spend on administrative tasks by 12,000 hours. Reducing their administrative burden means they have 6 percent more time to devote to maintenance tasks. Western's maintenance staff have achieved this reduction by having other staff handle such tasks as reconciling credit cards, managing data entry in Western's maintenance database and paperwork.

Substation equipment control standardized

While microprocessor-based relaying and control equipment has allowed regional maintenance staff to customize control of substation equipment, this customization has led to inconsistencies Westernwide. However, a new guidebook that the Digital Control Systems team finalized in FY 2008 is helping to standardize how this equipment is installed.

The Digital Control System team worked for two years to produce this guide, which defines the minimum level of consistency for new substation control systems. By adopting a digital control standard, which will be effective for five years, Western saves money by limiting the number of hours that designers traditionally spend customizing each region's design. Similar cost savings occur during a project's commissioning phase since the design is well known to field engineers and technicians, eliminating training time for familiarization with the new substation design products.

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Environment perspective

Sacramento Area Voltage Support progresses

Western completed National Environmental Policy Act environmental compliance documentation, published its Record of Decision and obtained funding from the customer governance board for the Sacramento Area Voltage Support Project. When completed, the 31-mile long, 230-kV transmission line will improve the voltage stability and increase reliability of the interconnected transmission facilities in the Sacramento, Calif., area. The project will interconnect the Sierra Nevada Region's O'Banion Substation to a point near the Elverta Substation owned by the Sacramento Municipal Utility District, or SMUD. The project will also upgrade nearly five miles of 115-kV transmission lines owned by SMUD to 230-kV. Pre-construction and design activities are currently underway, and the project should be ready for commercial operation in time for the peak 2011 summer operating season.

Public notified of intent to evaluate wind energy development

Western issued a Notice of Intent to prepare a Programmatic Environmental Impact Statement, or EIS, to evaluate wind energy development in Iowa, Minnesota, Montana, Nebraska, North Dakota and South Dakota. Western is partnering with the U.S. Department of the Interior's U.S. Fish and Wildlife Service to develop a regionwide management program to process wind energy project interconnection requests. Currently, Western addresses each request separately, in the order it is received. Western's proposed program would support how these requests are processed, including environmental analyses, by already addressing generic environmental interconnection concerns and issues in a Programmatic EIS. The Programmatic EIS would analyze impacts resulting from wind energy development and the effectiveness of mitigation measures. The program would be structured to complement Western's Open Access Transmission Service Tariff, which includes procedures for addressing wind-energy project interconnection requests.

Operations perspective

Operations Consolidation Project initiated

To save an estimated $2.1 million annually and optimize limited resources, Western decided in FY 2008 to consolidate the operational functions of Western's Desert Southwest, or DSW, and Rocky Mountain, or RM, regions. When reorganization is implemented in FY 2009, this new consolidated function will report under one regional manager in RM. The consolidation will combine the operations and transmission services of both regions, including dispatch, transmission planning and scheduling and tariff administration.

The Operations Consolidation Project, or OCP, arose during strategic planning as a way to manage stringent industry reliability standards with limited dollars and staff. OCP project managers presented four viable options and invited customers to comment before recommending consolidation in June 2008.

This project aims to save costs by integrating life-cycle facility investments, sharing common tools and leveraging limited resources to maintain and operate the consolidated electrical system for two regions. For example, Western will eliminate the alternative control center for each region so each operations balancing authority will back each other up, avoiding duplicative costs.

Reliability performance standards achieved

Consistently showing its commitment to reliability, Western's balancing authorities achieved 100-percent compliance for standards set by NERC. These include NERC's Control Area Performance Standards 1 and 2 and System Reliability Performance measures—standards aimed at reducing errors in balancing loads and resources, system frequency and accountable outages. Because Western is exceeding industry averages with respect to these standards, it means fewer accountable outages for customers and a more reliable system.

Operators participate in reliability drills

As part of ensuring reliable operations for the summer peak season, SN power system operators and system engineers participated in table top exercises and drills in spring 2008 with their counterparts from the California-Mexico Reliability Coordinator, the California Independent System Operator—or CAISO, as well as the Bonneville Power Administration, SMUD, the three California investor-owned utilities, and load-serving entities from the public power community. The drills not only ensured that appropriate contingency plans and measures were in place, but that Western power system operators could test them in a non-emergency situation to confirm their procedures were functional and would help prevent customer outages. Fortunately, the summer operating season was much cooler than the previous year and did not require CAISO to declare any "heat" emergencies.

Watertown Alternate Control Center established

Western constructed and took possession of a building in 2008 to house its Alternate Control Center, which will duplicate the systems used at the Upper Great Plains' primary control center in Watertown. NERC standards require a plan for operating the power system if our primary control center is inoperable. Our current plans meet the existing NERC standards and include some manual processes if the primary control center is inoperable. The new facility will eliminate the manual processes and allow Western to continue meeting not only the existing NERC standard, but to meet the requirements of the proposed NERC standard on backup facilities. The Alternate Control Center should be functional by the end of FY 2009.

MISO energy market service studied

Western continued evaluating a proposal from the Midwest Independent System Operator, or MISO, to offer market coordination service under its Transmission and Energy markets tariff. This proposal would allow transmission serving entities to place their load and generation in MISO's energy markets without requiring them to include their transmission assets in the MISO tariff.

Market redesign readied

Western made many adjustments to business systems in FY 2008 to prepare to actively participate in the Market Redesign and Technology Upgrade, or MRTU. CAISO initiated the MRTU to improve reliable management of California's grid by using an accurate model of the transmission system. CAISO's intentions were also to correct some of the market design flaws it said existed in its market that were uncovered during the California energy crisis of 2000-2001. By design, the MRTU includes a forward or day-ahead market where power flows during the next 24 hours are scheduled and modeled according to actual grid conditions and the laws of physics. The new upgrade is intended to give market participants and Western a more accurate picture of transmission congestion and the true cost of getting power to areas that may not have enough local generation or where transmission capacity is lacking. As a result of MRTU's new operating parameters, Western's Sierra Nevada Region was required to adjust its own business systems and processes to prepare to actively participate in MRTU and reliably schedule resources into and out of CAISO.

Power Marketing perspective

Minor rate adjustment process introduced

Western staff initiated a rate adjustment process during the first public rate process on the Parker Davis Project in the past 11 years. After informal meetings with the Parker-Davis Project customers, Western's DSW used the minor rate adjustment process to accomplish the rate adjustment. The minor rate adjustment process allowed for customer comments while eliminating the requirement for a formal public process and an environmental exclusion.

Transmission prepayment approved

Western developed a method and gained customer approval through the rates process to revise billing terms to collect payments one month in advance for Parker-Davis long-term firm transmission services. Western also gained customer support to collect prepayment for Pacific Southwest-Northwest Intertie transmission service payments. This will ensure all parties are subject to the same billing terms and conditions. If customer payments are late or uncollectible, rates may be insufficient to recover revenue requirements. This could result in a rate increase, adversely affecting all Parker-Davis customers. In response to the customers' request, Western modified the billing practices so that customers will be required to pay for long-term firm transmission service one month in advance of service.

Drought Rate Adder initiated

Western successfully implemented a new method to accurately identify which rate components are associated with drought-related costs. The rate is split into two components. The base-rate component is a revenue requirement that includes annual operation and maintenance expenses, investment repayment and associated interest, normal timing power purchases and transmission costs. The drought adder rate component is a formula-based revenue requirement that includes costs attributable to past and present drought conditions within the Pick-Sloan Missouri Basin Program, or P-SMBP. Identifying the firm electric service revenue requirement using base and drought adder rate components helps Western present the effects of the drought within the P-SMBP, demonstrating repayment of the drought-related costs, and allows Western to be more responsive to changes in drought-related expenses.

Request for purchase power proposals evaluated

In FY 2008, Western received 15 responses to a Request for Proposal for up to 200 megawatts of power to help offset the shortage of hydroelectric power from Missouri River dams. Western selected an offer from the Omaha Public Power District, or OPPD, for 50 megawatts for five years and finalized the contract in mid-FY 2008. Additionally, Western entered into negotiations with two wind developers, including Just Wind, which plans to have its Napoleon, N.D., wind farm in service in 2010, and Iberdrola, which plans to have its South Dakota wind farm in service by 2010 and a second farm in service by 2011. The mid-term purchase of power from OPPD, and potential purchases from Just Wind and Iberdrola will help mitigate purchase power costs on our firm power rate.

Wind/Hydro Study draft released

Western continued work on the Wind/Hydro Integration Study to meet the Secretary of Energy's obligation under the Energy Policy Act of 2005. The study is examining how to integrate wind energy generated by Indian tribes and hydropower generated by the U.S. Army Corps of Engineers on the Missouri River to supply power to Western's UGP Region. The report will be submitted to Congress in 2009. Section 2606 of the Act required Western to prepare a report describing the study results, which will analyze and compare potential energy costs or benefits to Western customers from combining wind and hydropower. Results will also include an economic and engineering evaluation of whether a combined wind and hydropower system can reduce reservoir fluctuation, enhance efficient and reliable energy production and provide Missouri River management flexibility.

Transmission perspective

WestConnect Pricing Experiment studied

In FY 2008, Western continued its active participation on a number of issues with WestConnect, a voluntary, collaborative group of 15 electric utilities representing a mix of entities that provide transmission services within the Western Interconnection. WestConnect is a Regional Transmission Entity for purposes of the Pricing Experiment only, but overall it's got a much larger scope.

Western participated and led WestConnect's Pricing Work Group in developing a market enhancement for transmission in the form of a two-year pricing experiment. This WestConnect Pricing Experiment eliminates the stacking (or pancaking) of transmission and reactive power charges on non-firm hourly transactions across participants' available transmission paths. Eliminating these fees and using this market enhancement could result in fewer costs for transmission customers in the West, including Western's merchants, in wheeling power across other utilities' transmission systems.

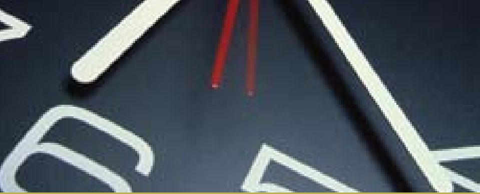
The Pricing Work Group plans to initiate the experiment in 2009, and obtained the Federal Energy Regulatory Commission's approval that it would not subject non-jurisdictional utilities participating in the WestConnect two-year pricing experiment to additional rate review under Section 205 of the Federal Power Act. (Jurisdictional refers to whether the utility is under FERC's authority.)

Salt Lake transmission reservation software designed

In conjunction with the Information Technology, or IT, group in Loveland, Energy Management and Marketing Office staff designed and implemented transmission reservation tracking software to assist pre-scheduling and real-time staff with tracking and using Colorado River Storage Project, Loveland Area Projects and Basin Electric Power Corporation transmission rights. This reservation tracking software helps them better document and keep track of reservations for transmission to deliver customer loads. It complements the TIGER system, or Transmission, Interties, Generation, Energy and Reserves, which allows staff to handle the complexities of managing Federal resources and meeting customers' load requirements through electronic "tags" that document energy transactions.

While this section captures Western's major highlights this last fiscal year, there are countless other projects, programs and activities that engage our staff in meeting our mission of delivering hydroelectric power at a low cost.

Each year we gain a new perspective on our role within the industry and our responsibility to customers to keep the power flowing not only on peak load days, but on each day of the fiscal year.



Financial Data

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Western Combined Hydroelectric Power System
Balance Sheet

As of September 30, 2008

Assets	$000
Completed utility plant	$5,993,778
Accumulated depreciation	(2,865,164)
Net completed plant	3,128,614
Construction work-in-progress	235,487
Net utility plant	3,364,101
Cash	600,853
Accounts receivable, net	123,219
Regulatory assets	123,377
Other assets	81,500
Total assets	**$4,293,050**

Federal investment and liabilities	
Net Federal investment	4,943,744
Accumulated net deficit	(1,012,228)
Total Federal investment	**$3,931,516**
Commitments and contingencies (notes 1, 9 and 10)	
Long-term liabilities	161,496
Customer advances and other liabilities	116,060
Accounts payable	65,366
Environmental liabilities	18,612
Total liabilities	**361,534**
Total Federal investment and liabilities	**$4,293,050**

See accompanying notes to combined hydroelectric power system financial statements.

Western Combined Hydroelectric Power System
Statement of Revenues and Expenses

For the year ended September 30, 2008

Operating revenues	$000
Sales of electric power	$908,611
Transmission and other operating revenues	285,802
Total operating revenues	**$1,194,413**
Operating expenses:	
Operation and maintenance	385,718
Purchased power	568,513
Purchased transmission services	65,727
Depreciation	88,876
Administration and general	45,347
Total operating expenses	**$1,154,181**
Net operating revenues	**$40,232**
Interest expenses:	
Interest on Federal investment	199,910
Allowance for funds used during construction	(10,743)
Net interest on Federal investment	**189,167**
Interest on non-Federally financed funding	10,730
Net interest expense	**199,897**
Net deficit	**$(159,665)**

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Western Combined Hydroelectric Power System Statement of Changes in Net Federal Investment

For the year ended September 30, 2008

	Net Federal Investment ($000)	Accumulated Net Deficit ($000)	Total Federal Investment ($000)
Net Federal Investment balance as of September 30, 2007:	**$4,598,387**	**$(852,563)**	**$3,745,824**
Additions:			
Congressional appropriations	634,877	–	634,877
Interest on Federal investment	199,910	–	199,910
Total additions to Federal investment	**$834,787**	**–**	**$834,787**
Deductions:			
Funds returned to the U.S. Treasury	(482,501)	–	(482,501)
Transfers of property and services, net	(6,929)	–	(6,929)
Total deductions to Federal investment	**$(489,430)**	**–**	**$(489,430)**
Net deficit:	**–**	**(159,665)**	**(159,665)**
Net Federal investment balance as of September 30, 2008:	**$4,943,744**	**$(1,012,228)**	**$3,931,516**

See accompanying notes to combined hydroelectric power system financial statements.

Western Combined Hydroelectric Power System Statement of Cash Flows

For the year ended September 30, 2008

Cash flows from operating activities:	$000
Net deficit	$(159,665)
Adjustments to reconcile net deficit to net cash provided by operating activities:	
Depreciation	88,876
Interest on Federal investment, net	189,167
Gain/loss on disposition of assets	1,315
Decrease in assets:	
Accounts receivable, net	8,567
Regulatory assets	1,087
Other assets	20,921
Increase (decrease) in liabilities:	
Accounts payable	3,273
Customer advances and other liabilities	(37,767)
Net cash provided by operating activities:	**115,774**
Cash flows from investing activities:	
Investment in utility plant	**(149,998)**
Cash flows from financing activities:	
Net Federal investment	157,293
Principal payments on non-Federally financed funding	(14,002)
Proceeds from non-Federally financed funding	3,371
Net cash provided by financing activities	**146,662**
Net increase in cash	**112,438**
Cash, beginning of year	**488,415**
Cash, end of year	**$600,853**

Supplemental schedule of noncash investing and financing activities	$000
Transfer of construction work-in-progress to completed utility plant	$152,912
Capitalized interest	10,743
Changes in cost allocation and assignment of generating agency balances to hydroelectric power generation affecting:	
Construction work in progress and completed plant	(7,380)
Accumulated depreciation	23,410
Net Federal investment	(11,052)
Regulatory assets	(6,001)
Other assets	946
Customer advances and other liabilities	77
Changes in actuarially determined workers compensation liability	2,669
Changes in unfunded regulatory assets and liabilities	19,316

See accompanying notes to combined hydroelectric power system financial statements.

Notes to Western Combined Hydroelectric Power System Financial Statements

For the year ended September 30, 2008

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

(a) Principles of Combination

The combined hydroelectric power system financial statements include the combined financial position, results of operations and cash flows of the reimbursable power activities of the Western Area Power Administration (Western), an agency of the U.S. Department of Energy (DOE), and the hydroelectric power generating functions of the U.S. Department of the Interior (DOI), 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 referred to as the generating agencies) for the individual power systems for whom Western markets and transmits hydroelectric power. Western, a Federal power marketing administration, markets and transmits hydroelectric power generated from these power systems, which are operated and maintained by the generating agencies, throughout 15 western states.

The combined hydroelectric power system financial statements do not include a complete presentation of the financial position, results of operations, changes in net federal investment, and cash flows of Western. In accordance with regulatory requirements prescribed by DOE and the Federal Energy Regulatory Commission (FERC), the combined hydroelectric power system financial statements exclude the portion of Western and the generating agency programs and activities that are not reimbursable through the rate setting process. Western's non-reimbursable activity is described further in Note 11.

The hydroelectric power system financial statements are prepared in accordance with accounting principles generally accepted in the United States of America (GAAP). Accounts are also subject to FERC regulations, the prescribed uniform system of accounts for electric utilities and DOE's accounting practices.

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

(b) Allocation of Costs to Hydroelectric Power

Amounts reflected in the accompanying financial statements represent reimbursable power activity of Western and the generating agencies for purposes of repayment to the U.S. Treasury. The costs of multi-purpose Reclamation and Corps projects are assigned to specific hydroelectric power functions through a cost allocation process. As discussed below, only the portion of total assets, liabilities and project costs allocated to hydroelectric power, and reimbursable through the rates, are included in these financial statements. Western has the responsibility to ensure that costs subject to repayment are reflected in the combined hydroelectric power system financial statements.

Reclamation hydroelectric power amounts are allocated to the combined hydroelectric power system financial statements based on power repayment responsibility (see Note 6(b)). Reclamation has certain multi-purpose water resource projects and these costs are allocated among project activities, which primarily include power, irrigation, recreation, municipal and industrial water, navigation and flood control. Completed utility plant and equipment costs are allocated based upon the hydroelectric power portion of the Statement of Project Construction Cost and Repayment (SPCCR) prepared by Reclamation economists. Current assets and liabilities, excluding cash, are allocated based upon the amounts directly recorded to power accounts. Revenue and expense accounts are also allocated based on the amounts directly recorded to power activities.

Corps and IBWC hydroelectric power amounts are also allocated based on legislatively-determined rates of power repayment responsibility. Only the power portion of the Corps and IBWC assets, liabilities and expenses are submitted to Western for inclusion in the combined hydroelectric power system financial statements.

Cash balances for the generating agencies represent fund balances at the U.S. Treasury and estimates of the amount of funds required to satisfy current hydroelectric power obligations.

To the extent possible, Western and the generating agencies identify costs as direct costs. Direct costs are costs which can be specifically identified to a power system, program or activity. In some cases, costs benefit two or more power systems, programs or activities and it is not economically feasible to identify these costs as direct costs. Such costs include administrative support costs, space rental, utilities and office equipment. These costs are accumulated in indirect cost pools and allocated to the benefiting activities through a labor surcharge rate based on direct labor charges.

(c) Confirmation and Approval of Rates

Western is not a public utility within the jurisdiction of FERC under the Federal Power Act. The Secretary of Energy (Secretary) has delegated authority to Western's Administrator to develop hydroelectric power and transmission rates for the individual power systems included in the accompanying combined hydroelectric power system financial statements. The Deputy Secretary of Energy has the authority to confirm, approve and place such rates in effect on an interim basis. FERC has the exclusive authority to confirm, approve and place into effect on a final basis, to remand or to disapprove rates developed by the

Administrator. FERC's review is limited to: 1) whether the rates are the lowest possible consistent with sound business principles; 2) whether the revenue levels generated are sufficient to recover the costs of producing and transmitting electric energy including repayment within the period permitted by law; and 3) the assumptions and projections used in developing the rates. FERC shall reject decisions of the Administrator only if it finds them to be arbitrary, capricious or in violation of the law. Refunds with interest, as determined by FERC, are authorized if rates finally approved are lower than rates approved on an interim basis. However, if at any time FERC determines that the administrative cost of a refund would exceed the amount to be refunded, no refunds will be required. No such refunds have been required or made in 2008 and none are anticipated in connection with rates approved on an interim basis through September 30, 2008.

Accounting policies also reflect specific legislation and executive directives issued by departments of the Federal government. Certain balances within the combined hydroelectric power system financial statements are accounted for under the provisions of Financial Accounting Standards Board (FASB) 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. The rate actions of Western's Administrator, subject to the limited authority of FERC, can provide reasonable assurance of the existence of an asset; reduce, eliminate or amortize the value of an asset; or impose a liability on a regulated enterprise.

(d) Operating Revenues and Accumulated Net Deficit

Operating revenues are recognized when goods or services are provided to the public or another government agency. Except for power systems using revolving funds and customer advances, cash received from sales is deposited directly with the U.S. Treasury and is reflected as funds returned to the U.S. Treasury, which is included in Net Federal Investment in the combined hydroelectric power system balance sheet. As such, these funds are unavailable for power system operating needs. For power systems using revolving funds and customer advances, 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 (see Note 6(a)).

Approved hydroelectric 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 10(b)). Costs allocated to power include repayment of Federal investment in power facilities and associated interest. Rates are structured to provide for repayment of Federal investment in power facilities, generally over 50 years, while operating expenses and interest on Federal investment are recovered annually. Replacements of utility plant are generally to be repaid over their expected service lives.

The service lives of utility plant are different between financial reporting and repayment measures. 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 hydroelectric power systems, accumulated net deficit represents timing differences between the recognition of expenses and related revenues. Western and the generating agencies are nonprofit Federal agencies; therefore, accumulated net revenues, to the extent that they are available, are committed to Federal investment repayment.

Transmission and other operating revenues include items such as transmission services, power wheeling and recreational fees.

(e) Cash

Cash held by Western represents the undisbursed balance of funds authorized by Congress, customer advances and revolving fund balances at the U.S. Treasury.

(f) Accounts Receivable, Net

Accounts receivable, net represents amounts billed to customers but not collected as of September 30, 2008, net of the related allowance. The estimate of the allowance is based on past experience in the collection of receivables and an analysis of the outstanding balances. There was no allowance amount in 2008. Interest is charged on the principal portion of delinquent receivables based on rates published by the U.S. Treasury for the period in which the debt became delinquent. Delinquent accounts are written off when they are determined to be uncollectible.

Billing methods used by Western include net billing and bill crediting. Net billing is a two-way agreement between Western and a customer, whereby both parties 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 whereby all three parties are involved in purchase and sale transactions. Under both billing methods, purchases and sales transactions are reported "gross" in the combined hydroelectric power system financial statements.

(g) Stores Inventory

Inventory consists of hardware, maintenance parts and supplies and is included in Other Assets on the combined power system balance sheet. Inventory is valued using the average cost method. When stock is received, the cost is averaged based on the number of items purchased at each different value. The average cost is charged for subsequent issues.

(h) Utility Plant, Moveable Equipment and Internal use Software

Utility plant includes items such as dams, spillways, generators, turbines, substations and related components, and transmission lines and related components. Utility plant is stated at original cost, net of contributions from entities outside of the combined power system, under FERC. Costs include direct labor and materials; payments to contractors; indirect charges for engineering, supervision, overhead; and interest during construction. The costs of additions, major replacements and betterments are capitalized; whereas, repairs and maintenance are charged to operation and maintenance expense as incurred.

Plant assets of the combined power system are currently depreciated using the straight-line method over the estimated service lives ranging from 8 to 50 years for transmission assets and 10 to 100 years for generation assets. Power rights are amortized over 40 years. The cost of retired utility plant, net of accumulated depreciation, is charged to operation and maintenance expense as a gain (loss), net of cash proceeds, if any.

Moveable equipment includes computers, copiers, cranes, energy testing equipment, helicopters, trucks and wood chippers. Moveable equipment is currently depreciated using the straight-line method over the estimated service lives ranging from 3 to 20 years. Moveable equipment is classified as other assets on the combined hydroelectric power balance sheet (see Note 4).

Internal use software includes software purchased from commercial vendors "off the shelf," internally developed software, or contractor developed solely to meet internal or operational needs. Western's internal use software is depreciated over 5 years, using the straight-line method. Internal use software is classified as other assets on the combined hydroelectric power balance sheet (see Note 4).

Western is subject to SFAS No. 90, *Regulated Enterprises—Accounting for Abandonments and Disallowances of Plant Costs* (see Note 3). All completed utility plant, as required by law, is recovered through the hydroelectric power rates regardless of whether an asset is abandoned, loses value, is disposed of significantly before its estimated useful life or is destroyed. Consequently, the cash flow is not impaired regardless of the condition of the asset. Western maintains all assets under established maintenance protocols to ensure the highest level of reliability.

The policy of Western and the generating agencies is to move capitalized costs into completed utility plant at the time a project or feature of a project is deemed to be substantially complete. A project is substantially complete when it is providing benefits and services for the intended purpose, and is generating project purpose revenue, where applicable.

(i) 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 hydroelectric power system financial statements. Western calculates interest annually based on the unpaid Federal investment owed to the U.S. Treasury using rates set by law, administrative orders following law or administrative policies. Interest rates on unpaid Federal investments ranged from 2.50 to 11.375 percent for the year ended September 30, 2008.

As provided by Federal law, interest is not assessed on Federal investment in irrigation facilities anticipated to be repaid through power sales (see Note 10(b)).

(j) Allowance for Funds used During Construction

Allowance for funds used during construction (AFUDC) represents interest on funds borrowed from the U.S. Treasury during the construction of all generation and transmission facilities. Western calculates AFUDC based on the average annual outstanding balance of construction work-in-progress and is calculated through the date in which assets are placed in service. AFUDC is capitalized and recovered over the repayment period of the related plant asset. Applicable interest rates ranged from 4.62 to 8.54 percent for the year ended September 30, 2008, depending on the year in which construction on the transmission and generation facilities was initiated and requirements of the authorizing legislation.

(k) Transfer of Property and Services, Net

Transfer of property and services, net is a component of total Federal investment that represents the cumulative receipt of unfunded transfers of assets or costs offset by the cumulative receipt of unfunded transfers of revenues. Transfers are recognized upon physical delivery of the asset or performance of the service. Transfers occur between projects, project types and other Federal entities. Transfers between Western and the generating agencies eliminate upon combination.

(l) Pension and Other Post-retirement Benefits

Western and generating agency 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 11.2 percent for FERS. These contributions are submitted to benefit program trust funds administered by the Office of Personnel Management (OPM). Western and generating agency contributions for the two plans amounted to $23.2 million for the year ended September 30, 2008. The contribution levels as legislatively mandated do not reflect the full cost requirements to fund the CSRS or FERS pension plans. The additional cost of providing CSRS and FERS benefits is about 25.2 and 12.0 percent of base salary, respectively, and is funded by OPM as discussed below.

Other post-retirement benefits administered and partially funded by OPM are the Federal Employees Health and Benefits Program (FEHB) and the Federal Employee Group Life Insurance Program (FEGLI). FEHB is calculated at $5,220 per employee in fiscal year 2008, 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 and related liability for the pension and other post-retirement benefits in the combined hydroelectric power system financial statements of $21.7 million for the year ended September 30, 2008. This amount reflects the contribution made on behalf of Western and the generating agencies by OPM to the benefit program trust funds. This expense will be recovered from power customers through the future sale of power.

As a Federal agency, all post-retirement activity is managed by OPM, therefore, neither the assets of the plans nor the actuarial data with respect to the accumulated plan benefits or the pension liability relative to Western and generating agency employees are included in this report.

(m) Use of Estimates

Management of Western and the generating agencies have made several estimates and assumptions relating to the reporting of assets and liabilities and the disclosure of contingent assets and liabilities to prepare these combined hydroelectric power system financial statements in conformity with GAAP. Significant items subject to such estimates and assumptions include the useful lives of completed utility plant; allowances for doubtful accounts; the valuation of completed utility plant and inventory; and reserves for employee benefit obligations, environmental liabilities and other contingencies. Actual results could differ significantly from those estimates.

(n) Derivative and Hedging Activities

Western analyzes derivative financial instruments in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* as amended. 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 the combined statement of revenues and expenses, 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 combined statement of revenue and expense to the extent effective. SFAS No. 133 requires that the hedging relationship be highly effective and that an organization 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 purchases or normal sales 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 Western's 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 generally accepted accounting principles. As of September 30, 2008, Western has no contracts accounted for as derivatives.

(o) Concentrations of 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 that are generally large, stable and established organizations which do not represent a significant credit risk. Although Western and the generating agencies are affected by the business environment of the utility industry, management does not believe a significant risk of loss from a concentration of credit exists.

(p) Regulatory Assets (see Note 3)

Regulatory assets are assets that result from rate actions of the Administrator and other regulatory agencies. These assets arise from specific costs that would have been included in the determination of net revenue or deficit in one period, but are deferred until a different period for purposes of developing rates to charge for services, per the requirements of SFAS No. 71. Western defers costs as regulatory assets so that the costs will be recovered through the rates during the periods when the costs are scheduled to be repaid so there is a matching of revenues and expenses. Western does not earn a rate of return on its regulatory assets. The assets listed below are regulatory in nature:

Workers' Compensation Actuarial Cost

The U.S. Department of Labor (DOL) determines an actuarial liability associated with cases incurred for which additional future claims may be made on a yearly basis. DOL determines 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 is deferred for rate-making purposes until such time as the claims are submitted to and paid by DOL. Therefore, the recognition of the expense associated with the actuarially determined liability has been deferred as a regulatory asset in the combined hydroelectric power system balance sheet to reflect the effects of the rate-making process.

Abandoned Project Costs, Net

Occasionally, Congressionally-authorized projects originally planned for service are discontinued due to political and/or economic reasons. Per the requirements of SFAS No. 90, Western classifies these discontinued projects based on Congressional action as abandoned projects and amortizes them in the same manner as that used for rate-making purposes. The amortization period is a maximum of 50 years. These abandoned projects are considered regulatory assets because the costs are amortized into the power rates over a period of time, rather than being expensed in the year of the Congressional action.

Environmental Liabilities (see Note 10(f))

Environmental liabilities are recorded when the future remediation costs are known and estimable. The estimated remediation cost is recorded as a regulatory asset, which will be amortized according to a predetermined schedule coordinated with the rate-making process.

Recovery Implementation Program (RIP)

Section 8 of the Colorado River Storage Project (CRSP) Act of 1956, as amended, mandates that DOI 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 an example 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 and provided to Reclamation to finance capital costs. Amounts borrowed from the State of Colorado for the RIP are currently accruing interest, but Western will not begin repayment of the debt until October 1, 2012. Prior to the start of repayment, accrued interest charges are accreted into the outstanding principal balance. Preservation costs are classified as a regulatory asset until repayment begins, at which time costs will be amortized to expense.

Accrued Annual Leave

Accrued annual leave represents benefits that will 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 a regulatory asset to reflect the effects of the rate-making process.

Transmission Termination Settlement

Western renegotiated certain CRSP long-term contractual obligations with third-party power providers in 2007. Under the terms of the settlement agreements, annual payments of $0.6 million will be made through 2017 to PacifiCorp for a total of $6 million. The unpaid portion of the settlements has been deferred as a regulatory asset to reflect the effects of the rate-making process.

(q) Interchange Energy and Energy Exchange (see Note 4)

Western's power contracts may include a provision for energy transfers and exchanges between Western and a supplier that result in claims or obligations to be settled at a future date, based on contractual obligations. Energy claims or obligations represent the valuation of excess energy delivered or received under the energy interchange and exchange contract provisions. The energy balance is recorded either as an other asset when Western is the net supplier, or as an other liability when Western is the net user. Transactions are valued at the fair value, in accordance with the provisions of Accounting Principles Board Opinion No. 29, *Accounting for Nonmonetary Transactions*, and SFAS No. 153, *Exchanges of Nonmonetary Assets*, and are netted within purchase power expense as incurred under FERC regulations and rulings.

(r) Customer Advances

Customer advances represent the current balance of advance payments received from power customers under co-sponsoring agreements 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 advanced customer funds 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. Revenue is recognized upon application of bill credits.

(s) Taxes

As agencies of the U.S. Government, Western and the generating agencies are exempt from all income taxes imposed by any governing body, whether it is a Federal, state or commonwealth of the United States or a local or foreign government.

(t) Recently Issued Accounting Standards

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurement*. SFAS No. 157 defines fair value, establishes a framework for measuring fair value based on generally accepted accounting principles, and expands disclosures about fair value measurements. The statement does not require any new fair value measures, and is effective for fair value measures already required or permitted by other standards for fiscal years beginning after November 15, 2007. SFAS No. 157 is required to be applied prospectively, except for certain financial instruments. In November 2007, the FASB proposed a one-year deferral of

SFAS No. 157's fair-value measurement requirements for nonfinancial assets and liabilities that are not required or permitted to be measured at fair value on a recurring basis. SFAS No. 157 is effective for Western in fiscal year 2009. Western is evaluating the effect of the adoption and implementation of SFAS No. 157, which is not expected to have a material impact on Western's financial condition, results of operations or cash flows.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities*. SFAS No. 161 requires enhanced disclosures about an entity's derivative and hedging activities and thereby improves financial reporting transparency. SFAS No. 161 is effective for Western in fiscal year 2009. Western is evaluating the effect of the adoption and implementation of SFAS No. 161, which is not expected to have a material impact on Western's financial condition, results of operations or cash flows.

(2) Power Systems and Generating agencies

Western markets and transmits hydroelectric power for 14 power systems. The expenses and net assets of the 14 power systems, which are expected to be recovered, are included in the accompanying combined hydroelectric power system financial statements. Reclamation generates power for all power systems with the exception of Amistad-Falcon. The Pick-Sloan power system is unique in that both Reclamation and the Corps generate hydroelectric power for the power system. IBWC is Western's sole generation partner for the Amistad-Falcon power system. The Pacific Northwest-Pacific Southwest Intertie (Intertie) has only transmission facilities. A listing of these power systems by generating agency includes:

Reclamation Power Systems

- Boulder Canyon
- Central Valley
- Collbran
- Colorado River Storage Project
- Dolores
- Fryingpan-Arkansas
- Pacific Northwest-Pacific Southwest
- Parker-Davis
- Pick-Sloan Missouri River Basin
- Provo River
- Rio Grande
- Seedskadee
- Washoe

Corps Power System

- Pick-Sloan Missouri River Basin

IBWC Power System

- Amistad-Falcon

(3) Regulatory Assets

Regulatory Assets (see note 1(p)) as of September 30, 2008 consist of the following (in thousands):

	2008
Workers' compensation actuarial cost	$49,041
Abandoned project costs, net	26,089
Environmental liability (see note 10(f))	18,612
Recovery implementation program	13,285
Accrued annual leave	11,150
Transmission termination settlement	5,200
Total regulatory assets	**$123,377**

Abandoned project costs, net include the Celilo-Mead transmission line of $11.0 million as of September 30, 2008, which is being amortized over 23 years, through 2019. Also included in the abandoned project costs are $15.1 million of various abandoned Reclamation projects. The most significant Reclamation abandoned projects include the Fryingpan-Arkansas project for $5.9 million; the Colorado-Big Thompson Project for $3.4 million; and in the Yellowtail Unit for $2.2 million, as of September 30, 2008, which are being amortized for up to 50 years.

(4) Other Assets

Other assets as of September 30, 2008 consist of the following (in thousands):

	2008
Moveable equipment, net (see Note 1(h))	$35,423
Stores inventory (see Note 1(g))	15,137
Interchange energy and energy exchange (see Note 1(q))	22,133
Internal use software, net (see Note 1(h))	7,067
Other	1,740
Total other assets	**81,500**

Under FERC requirements, the net activity in interchange energy and energy exchange is included in purchased power expense in the combined hydroelectric power system financial statements. The net activity included in purchased power expense was $3.6 million for the year ended September 30, 2008.

(5) Utility Plant

Utility plant as of September 30, 2008 consists of the following (in thousands):

Utility plant	2008
Structures and facilities	$5,304,137
Buildings	359,344
Land	167,432
Power rights	162,865
Gross completed plant	5,993,778
Less: Accumulated depreciation	(2,865,164)
Net completed plant	$3,128,614
Construction work-in-progress	235,487
Net utility plant	**$3,364,101**

(6) Federal Investment and Cost Allocation

(a) General

Federal investment consists of congressional appropriations and accumulated interest on unpaid Federal investment, less net transfers of property and services from other Federal agencies and funds returned to the U.S. Treasury and accumulated net deficit. Congressional appropriations are comprised of the cumulative appropriations received, net of expenses legislatively deemed non-reimbursable. All power systems, except Dolores, Seedskadee, Boulder Canyon and the operations and maintenance and purchased power programs of the Colorado River Storage Project (CRSP), are primarily financed through congressional appropriations. Dolores, Seedskadee, Boulder Canyon and the operations and maintenance programs of CRSP, are funded through the use of a revolving fund. Revolving funds allow Western and Reclamation to retain resources for reinvestment in power operations without congressional appropriations. A portion of construction and rehabilitation, operation and maintenance 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 billing methods, such as net billing and bill crediting or any combination of these methods.

Operating expenses (excluding depreciation expense) and interest on the unpaid Federal investment should be repaid annually. In cases where revenues are not available for repayment, unpaid annual net deficits become payable from the future years' revenues. Interest is accrued on cumulative annual net deficits until paid. Deficits for operating expenses begin to accrue interest in the year they occur, while interest expense deficits begin to accrue interest in the following year. In cases where funds are available, unless otherwise required by legislation, repayment of Federal investment is applied first to the increment bearing the highest interest rate.

(b) Federal Investment in Multipurpose Facilities

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

Final studies will be performed by the generating agencies, as appropriate, upon completion of each individual power project and are still pending for all but the Fryingpan-Arkansas Power System (FryArk), which was completed in 1993. The Boulder Canyon and Parker-Davis power systems are not subject to cost allocation studies since the power systems' enacting legislation requires the total costs of the dams and appurtenant structures 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.

(7) Long-term Liabilities (in thousands)

Long-term liabilities (as of September 30, 2008)	Principal	Accrued Interest	Total
Long-term construction financing	$147,725	$486	$148,211
State of Colorado loan (see Note 1(p))	13,285	–	13,285
Total long-term liabilities	**$161,010**	**$486**	**$161,496**

Long-term Construction Financing

The majority of long-term construction financing consists of three significant contractual arrangements. The first significant arrangement provides customer financing for the Boulder Canyon power system to upgrade each of the generating units at Hoover Dam. The obligation to these customers began in 1987 and is scheduled to be satisfied through issuing credits on power bills through fiscal year 2017. Interest rates ranged between 5.1 and 7.2 percent during fiscal year 2008. As of September 30, 2008, the outstanding obligation was $95.8 million.

The second significant arrangement consists of the principal payable to the State of Wyoming for providing partial financing for improvements at the Buffalo Bill Dam (Pick-Sloan Missouri Basin power system) and associated hydroelectric 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 $20.3 million as of September 30, 2008.

The third significant arrangement is principal due to Griffith Energy LLC for providing financing for the construction of the Griffith-McConnico and Griffith-Peacock transmission lines along with certain assets at Peacock Substation and McConnico Switching Station within the Intertie and Parker-Davis power systems. Repayment is through power bill credits beginning in 2001 and ending in 2018. The interest rate is 8.5 percent. As of September 30, 2008 the outstanding obligation totaled $20 million.

Other components of long-term financing include Mohave Electric Cooperative, Inc., which provided $8.9 million in financing to Western to construct the network upgrades required for the Zorb Project within the Parker-Davis power system. Repayment through crediting of transmission service bills begin in December 2008. The monthly amounts are unknown at this time, as the rates have yet to be established for that period. However, based on estimates, repayment should be completed within a 56-month period, with an estimated monthly bill credit of $162,000.

State of Colorado Loan

Western received a loan from the State of Colorado for $5.5 million in December 2002 (fiscal year 2003) at an interest rate of 4.5 percent per year. Another $5.9 million was received in December 2004 (fiscal year 2005) with an interest rate of 3.25 percent. The purpose of these loans was to fund Reclamation's endangered fish recovery implementation programs (see Note 1(p)). Interest began accruing at the time loans were granted and is accreted into the outstanding principal balance until repayment begins. The loan will be repaid through power revenues beginning in 2012. These balances, with accrued interest and fees, total $13.3 million as of September 30, 2008.

Outstanding long-term liabilities, as of September 30, 2008 are scheduled to be credited or repaid as follows (in thousands):

Year ending September 30:	Principal	Interest	Total
2009	$12,245	$9,585	$21,830
2010	15,250	9,018	24,268
2011	14,702	8,403	23,105
2012	15,033	8,341	23,374
2013	15,178	7,593	22,771
2014 and thereafter	88,602	45,136	133,738
Total	**$161,010**	**$88,076**	**$249,086**

(8) Customer Advances and Other Liabilities (in thousands):

	2008
Workers' compensation actuarial liability	$49,041
Customer advances (see Note 1(r))	25,602
Accrued annual leave	11,150
Accrued payroll benefits	10,016
Workers' compensation accrual	9,220
Transmission termination settlement	5,200
Other	5,831
Total	**$116,060**

(9) Lease Commitments

Western has one non-cancelable operating lease that expires in 2015 for Western's Electric Power Training Center. The lease represents an annual expense of about $0.25 million.

Non-cancelable lease commitments (in thousands)

Year ending September 30:	Cost
2009	$246
2010	246
2011	279
2012	279
2013	279
2014 and thereafter	558
Total	**$1,887**

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. The right to relinquish space on cancelable leases is available with 120-day notice to terminate. The General Services Administration is generally the leaseholder for all cancelable equipment and building leases.

These leases generally contain renewal options for periods ranging from three- to five-years and require the lessee to pay all costs, such as maintenance and insurance.

Rental expense for operating leases was approximately $5 million as of September 30, 2008.

(10) 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 hydroelectric power system financial statements, are based on reported pending claims, estimates of claims incurred but not yet reported, actuarial reports and historical analysis (see Note 1(p)). It is management's opinion that the ultimate disposition of these claims will not have a material adverse effect on the combined hydroelectric power system financial statements.

(b) Irrigation Assistance

Federal statute requires that certain individual power systems repay the U.S. Treasury the 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. Reclamation made no irrigation assistance payments for the year ended September 30, 2008.

(c) 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
2009	$43,142	$8,889	$52,031
2010	65,994	7,617	73,611
2011	47,186	7,617	54,803
2012	26,891	7,617	34,508
2013	5,748	7,617	13,365
2014 and thereafter	–	69,085	69,085
Total	**$188,961**	**$108,442**	**$297,403**

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.

(d) Central Valley Project

Western is currently litigating its liability for grid management charges levied by the California Independent System Operator (CAISO) and passed through by the Pacific Gas and Electric Company (PG&E) under a legacy power integration and transmission agreement. Settlement of the legal issues in this instance was delayed pending resolution of other precursor matters. Oral arguments on the merits were held on March 25, 2009. Following the oral arguments, the court issued an order requiring a supplemental brief, which was filed by PG&E on April 9, 2009. The parties are currently awaiting a ruling from the court. Western has paid $8 million to PG&E as of September 30, 2008. These payments were made between 2001 and 2003, and recorded as purchased power expense. Contingent on the court's final decision, Western could be liable for an additional $7 million or receive a refund for $8 million.

(e) Construction in Abeyance

Construction in abeyance refers to long-term construction projects that have been suspended for a period of time due to legal, political or other reasons. There are several Reclamation construction projects that were placed in abeyance in the past. The Auburn dam, powerplant and reservoir project was placed in abeyance due to a risk of major damage to the dam as a result of an earthquake in 1975. Although Reclamation has allocated a portion of the initial construction costs to hydroelectric power, these costs continue to be excluded from Western's rate-making processes until a final determination is made by Congress as to whether the project will be revised or deauthorized. As of September 30, 2008, power repayment is considered remote and, therefore, construction costs of $46.2 million, including AFUDC, are not included in the combined hydroelectric power system financial statements. If the project is ultimately completed, there is a possibility that the associated costs may be repaid through future hydroelectric power rates.

(f) Environmental Liabilities

The Desert Southwest Region of Western has been engaged since 1991 in remediating the Basic Substation, located in Henderson, Nevada. This site, which was built in 1942 to provide power to a local magnesium plant, was decommissioned in 2002. Rather than address all contamination at the site at once, the remediation has been pursued in a staged process, in parallel with demolition work to reduce the impact on annual budgets. As of September 30, 2008, the estimated liability to remediate the Basic Substation is $18.6 million. The estimated costs are expected to be recovered as incurred through the rate-setting process. The unpaid portion of the estimated costs has been deferred as a regulatory asset to reflect the effects of the rate-making process (see Note 3).

(11) Other Non-Reimbursable Activity

As discussed in Note 1(a), the combined hydroelectric power system financial statements represent amounts expected to be recovered through the sale of power and other related revenues in accordance with DOE and FERC rulings and regulations. In addition to the activity presented in the accompanying combined hydroelectric power system financial statements, Western participates in various activities that are not reimbursable by hydroelectric power customers and, therefore, are not included in the combined hydroelectric power system financial statements. As of September 30, 2008, and for the year then ended, Western's non-reimbursable activity excluded from the accompanying financial statements was as follows (in thousands):

Non-reimbursable assets/liabilities	**2008**
Total non-reimbursable assets	$488,944
Total non-reimbursable liabilities	(120,037)
Net non-reimbursable assets	$368,907
Non-reimbursable operations	
Total non-reimbursable operating revenues	$296,365
Total non-reimbursable operating expenses	(325,907)
Net non-reimbursable operating deficit	$(29,542)

As of September 30, 2008, the non-reimbursable asset balances primarily consist of contributed plant and the funds received from the Federal Communications Commission (FCC) to change Western's bandwidth (referred to as the Spectrum Relocation fund). The contributed capital was paid for by external entities and is, therefore, not reimbursable by the hydroelectric power customers. The net contributed plant balance included in total non-reimbursable assets was $291.2 million as of September 30, 2008. The Spectrum Relocation fund paid for the cost of Western and the generating agencies to relocate their bandwidth when the FCC sold the former bandwidth. The net assets in this fund totaled $108.2 million as of September 30, 2008.

The remaining non-reimbursable asset and liability balances primarily consist of agreements Western has with Federal and non-Federal customers to provide services on a fee basis, where the fee is generally paid in advance. There were approximately $72 million in non-hydroelectric power customer advances as of September 30, 2008. The majority of the non-reimbursable operating revenues and expenses are a result of services provided to non-hydroelectric power customers and are excluded from the rate-making process.

(12) Subsequent Event

On February 17, 2009, Congress passed the American Recovery and Reinvestment Act (the Act), an effort aimed at stimulating the American economy, creating and saving employment, and addressing existing and future challenges within the country. During fiscal year 2009, Western and the generating agencies are scheduled to receive funds under the Act. A portion of the funds may be used to repair, upgrade or expand the existing hydroelectric power system. Between February and May 2009, Federal agencies receiving funds under the Act will develop plans for the use of funds. Western and the generating agencies are in the process of assessing the impact of this significant new program.

Western's Senior Management Team*

Administrator	TIM MEEKS
Washington Liaison	
Assistant Administrator for Washington Liaison	JACK DODD
Regional Managers	
Sierra Nevada Region	TOM BOYKO
Desert Southwest Region	DARRICK MOE
Upper Great Plains Region	BOB HARRIS
Rocky Mountain Region	vacant
Colorado River Storage Project Management Center	BRAD WARREN
Corporate Services Office Managers	
General Counsel	LIOVA JUÁREZ
Senior Planning Advisor	LAVERNE KYRISS
Equal Employment Opportunity Officer	CHARLES MARQUEZ
Chief Operating Officer	TONY MONTOYA
Chief Information Officer	EUN MOREDOCK
Chief Financial Officer	HARRY PEASE
Corporate Communications	THERESA WILLIAMS

*Note: While this is the FY 2008 Annual Report, this reflects the current Senior Management Team

Western thanks its many contributors for the photos and illustrations displayed in this report. Contributors include:

Ron Burbridge, Dana Fairchild, Carol Hartley, Carolyn Hinkley, Karla Gottsleben, Roger Harris, Grant Kuhn, Jennifer Neville, Ross McFate, Petrina Potts, Steve Richardson, Dennis Schaefer, Will Schnyer, Elaine Stewart, Theresa Williams and the Bureau of Reclamation

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

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