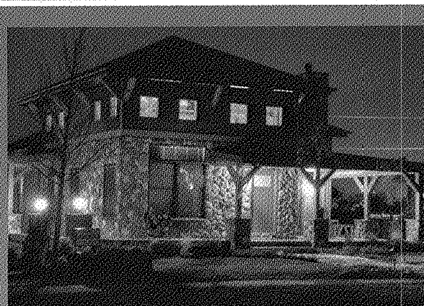
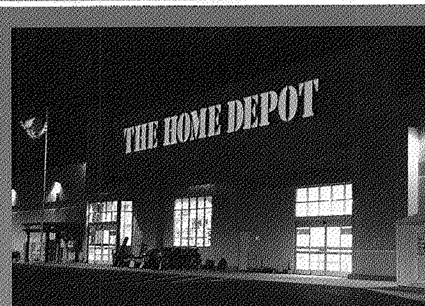
EMPIRE

SERVICES YOU COUNT ON

The Empire District Electric Company





The POWER to Rebuild

2011 Annual Report

Financial Highlights

DECEMBER 31,	2011	2010	Percentage Change
Operating Revenues (000)	$576,870	$541,276	6.6%
Operating Income (000)	$96,934	$80,495	20.4%
Net Income (000)	$54,971	$47,396	16.0%
Earnings Per Weighted Average Common Share (Basic And Diluted)	$1.31	$1.17	12.0%
Dividends Paid Per Share	$0.64	$1.28	-50.0%
Return On Common Equity (End Of Period)	7.90%	7.20%	9.7%
Book Value Per Share Of Common Stock	$16.53	$15.82	4.5%
Common Shares Outstanding (Year End) (000)	41,978	41,577	1.0%
Weighted Average Common Shares Outstanding (Basic) (000)	41,852	40,545	3.2%
Capital Expenditures (Including AFUDC) (000)	$101,150	$108,157	-6.5%
Gross Plant (000)	$2,176,650	$2,108,115	3.3%
On-System Electric Sales (MWh)	5,073,401	5,192,679	-2.3%
On-System Gas Sales (000) (Mcf)	8,491	8,910	-4.7%
Electric Customers (Year End)	166,477	169,047	-1.5%
Gas Customers (Year End)	44,082	44,487	-0.9%
Owned System Capability (Net MW)	1,392	1,409	-1.2%
System Electric Peak Demand (Net MW)	1,198	1,199	-0.1%
System Gas Peak Demand (Mcf)	67,789	73,280	-7.5%
Employees	746	750	-0.5%

On the cover: A welcome sight throughout the summer was construction in the retail corridor on Range Line Road. Many of the best-known businesses, including Academy Sports+Outdoors, Home Depot, Walgreens, Walmart, and Chick-fil-A, were destroyed in the tornado but, by late summer, they had begun reopening their doors. In the residential segment, neighborhoods continue to rebuild with one street enjoying an immediate change when ABC's Extreme Makeover: Home Edition built seven homes in seven days.

Fellow Investors,

This year was one of the most challenging in our history. We would like to express our deepest gratitude to you, our shareholders, for the loyalty and support you have provided as we have executed the recovery from the disaster of May 22, 2011. We are also extremely thankful for the overwhelming generosity of all those who came, and continue to come, to the aid of our customers, co-workers, and communities.

The EF-5 tornado that tore through Joplin and Duquesne packed winds in excess of 200 miles per hour and left a path of destruction thirteen miles long and up to three-quarters of a mile wide. More than 160 lives were lost, making it the deadliest tornado in the United States since 1950. Empire employees didn't escape the impact. Some lost family members and more than 20 lost their homes.

The damage to our system was extensive. More than 4,000 poles and over 100 miles of line were down. Six substations were impacted, with one being completely destroyed, and 31 of 60 circuits in Joplin were out, leaving approximately 20,000 customers without power.

The initial assessment was chilling, yet our mission was clear – provide the power to rebuild Joplin. Through it all, our employees displayed a resolve that is nothing short of amazing. Within ten days of the event, service to virtually all customers who were able to receive power had been restored. An estimated 8,000 customers were not able to return to service in the immediate aftermath.

Our initial estimates placed the storm costs at $20 to $30 million. As the damage toll continued to rise in the early days, the board made the difficult, yet necessary, decision to temporarily suspend the dividend. We recognized the hardship it caused, however, we also realized this would be an important step in our ability to recover from the most devastating weather event in our history and emerge more favorably positioned for the future. We thank you for weathering this trying time with us.

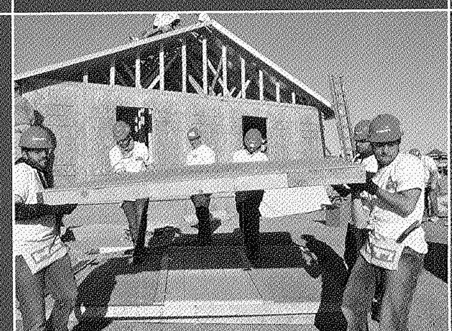
We are actively pursuing all avenues of recovery for costs related to the tornado. In June, we filed an Accounting Authority Order (AAO) with the Missouri Public Service Commission (MPSC). A stipulation and agreement related to the AAO was approved by the MPSC in December which allows Empire to defer actual incremental operating and maintenance expenses associated with the repair, restoration, and rebuilding activities resulting from the tornado.

Reconstruction is progressing at a healthy pace. After the initial ten-day restoration period, our customer count was down by 8,000. By August, the number was reduced to 3,900. As of the end of 2011, our system-wide customer count is down by approximately 1,800.

In late December, the city of Joplin announced that half of all affected property owners had secured permits to repair or rebuild homes that were damaged or destroyed by the tornado. Along the Range Line Road commercial corridor several major retailers including Walmart, Home Depot, Academy Sports+Outdoors, and Aldi's have reopened along with numerous other restaurants and businesses. St. John's Mercy Hospital, currently operating out of a modular facility, broke ground on a new 261-bed hospital on January 29, with targeted completion in 2015.

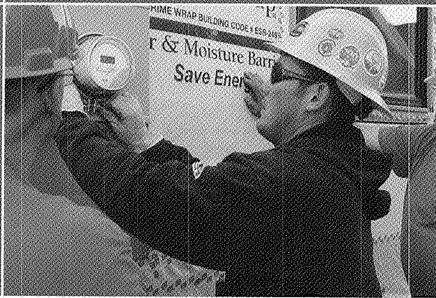
My predecessor, Bill Gipson, said many times, "We impact the lives of everyone in the Empire service territory every single day and, when we've done our jobs right, they don't even notice." Never has this been more evident than during the tornado recovery. Tremendous media attention was focused upon this event, with barely a mention of Empire. We take pride in that fact because it means we did our jobs right. As each milestone in the community was met, power was there. Power was available to open the temporary schools, to serve the FEMA temporary housing units, to light the Extreme Makeover and Habitat for Humanity homes, and to power Walgreens after it opened in record time. We have been and will continue to be an important part of the recovery.

Brad Beecher, President and Chief Executive Officer



Power was available to light ten new homes constructed in the devastation zone. The Ten for Joplin project involved the collaboration of Tulsa and Joplin Area Habitat for Humanity organizations, the city of Joplin, and hundreds of volunteers and sponsors.

Empire presented a check for $100,000 for the Temporary Energy Assistance Fund to help those affected by the tornado. **Martin, Executive Office (center), and John and Tammy, Economic Security Corporation representatives.**



The first meter is installed for one of the seven Extreme Makeover: Home Edition homes.

In only seven days, two blocks of Connor Avenue were transformed from barren lots to a vibrant street. The work began on October 19 with thousands of builders, tradesmen, and volunteers building seven homes in seven days. **Kayle, Joplin Line Operations.**

Neosho Line Operations employees were recognized by the Safety Council of the Ozarks for reaching an amazing safety milestone in 2011. The group of 19 employees achieved 500,000 work hours without a lost-time accident and over 12 years without a disabling injury.

While there has been much progress, the recovery is not limited to the devastation area. Many residents and businesses within the path of the tornado have relocated to vacant properties or begun new construction in other parts of Joplin and the surrounding communities we serve. In short, the recovery is going better than we had expected, but slower than we want.

While the tornado dominated the headlines this year, we could not delay the planning and execution of other critical tasks to keep your Company strong. We continued our focus on initiatives to address future environmental issues, system reliability enhancements, enterprise level resource and asset management solutions, and a host of other projects.

In 2011, we focused heavily upon our existing generation fleet. As we reported last year, the Integrated Resource Plan (IRP) filed with the MPSC identified potential strategies to comply with new regulations put forth by the U.S. Environmental Protection Agency. A plan for operational changes at our Asbury and Riverton generating facilities was developed to address the Cross State Air Pollution Rule (CSAPR), limiting NOx and SO2 emissions which was scheduled to take effect January 1, 2012. Then, in late December, a last-minute stay was issued by a federal court delaying the implementation of CSAPR. Separate regulations will require maximum achievable control technology for mercury and acid gases at existing generating units in early 2015. After extensive analysis, we are moving forward with the preferred plan to meet this requirement as identified in the IRP. The plan calls for the addition of air quality control systems at the Asbury Power Plant, exclusive use of natural gas fuel for Riverton Units 7 and 8, and the upgrade and conversion of the existing Riverton Unit 12 simple cycle gas turbine to combined cycle configuration.

Progress continued in 2011 on Operation Toughen Up, our reliability initiative introduced in 2010. Engineering and design work is under way in advance of the full-scale launch of the initiative that calls for $10 million per year for ten years beginning in 2012. Operation Toughen Up focuses on enhancements to our transmission and distribution system that will improve service reliability for our customers.

Power plants, substations, gas lines, wires, and poles are the visual elements of our business, but to effectively manage those resources in today's environment requires advanced, integrated software solutions. After laying the groundwork in 2010, a project team began rolling out the transformation to new enterprise level solutions for resource planning and asset management systems. The effort has been dubbed "Project Overhaul." Ultimately, the project will improve the way we record, transfer, and manage information, as well as provide us with advanced analysis and financial reporting capabilities. Every employee in the Company will experience the benefits of this complete overhaul of our business information and reporting systems.

On the regulatory front, we finalized the rate recovery process related to the historic construction cycle completed in 2010. New rates went into effect in our Missouri jurisdiction in June providing $18.7 million in additional annual revenue. In Kansas, rates reflecting an additional $1.25 million in annual revenue became effective January 1, 2012. Rates already being collected under a Capital Reliability Rider, became permanent for Oklahoma customers on January 6, 2012.

A number of other notable accomplishments rounded out the year for our Company. In November, the Southwest Power Pool Regional Entity conducted an on-site audit and found Empire to be in compliance with the North American Electric Reliability Corporation's (NERC) standards to ensure the reliability of the bulk power system. The installation of new movable gates took place at our Ozark Beach hydroelectric facility. After severe flooding impacted the area in 2010 and 2011, the gates are a welcome improvement. In addition, we posted positive results from efforts to educate customers about our energy efficiency programs, with a 19 percent increase in program utilization from the prior year. Current information about all of our energy efficiency programs can be found at **www.empiredistrict.com.**

In the natural gas business, we completed the largest construction project since acquisition of the property with the replacement of six miles of high pressure line in Nevada, Missouri. Another positive development is the increase in our certificated service area, which grew by 20 square miles with the addition of territory in eastern Nodaway County. The new area will be served by our Maryville Service Center.

Changes in financial leadership took place on August 1, as Laurie Delano became vice president – finance and chief financial officer, following the retirement of Greg Knapp. Also on August 1, Rob Sager became controller, assistant secretary, and assistant treasurer.

Despite the loss of customers due to the tornado, extremely warm temperatures in July and August culminated in a new summer peak demand record of 1,198 megawattts on August 2. The warm weather, along with activity related to the debris removal, FEMA temporary housing development, and the rebuilding process helped to partially offset revenue loss.

We closed 2011 with consolidated earnings of $54.9 million, or $1.31 per share. This compares to 2010 earnings of $47.4 million, or $1.17 per share. In 2012, commencing with our February 2, 2012, earnings release, we began providing annual earnings guidance. In addition, as reported in that earnings release, the board re-established the dividend at a rate of $0.25 per share.

As we move beyond a year forever defined by the May 22 tornado, we see many promising signs on the horizon. The rebuilding efforts have cushioned our region from the economic slowdown that has affected much of the nation. We know there are still challenges ahead of us on many fronts, yet we remain focused. Meeting our customers' expectations, increasing value to our shareholders, providing a safe and positive work experience for our employees, demonstrating environmental stewardship, and being a respected leader in the region – these are our goals, and our focus never wavers.

Brad Beecher

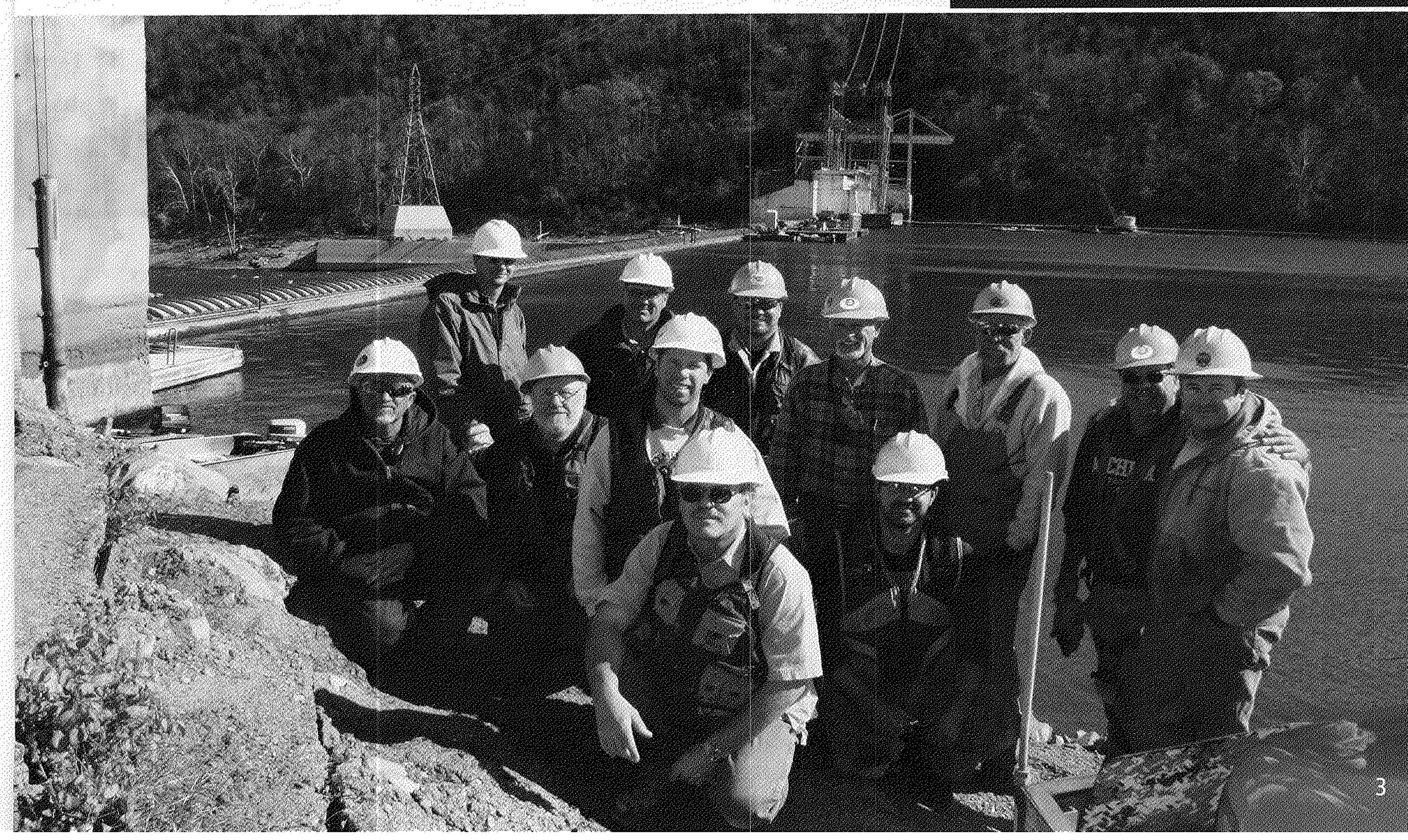
Ozark Beach

A team of employees from throughout the Company installed new steel gates at Ozark Beach Dam in the fall of 2011. The gates replaced the wooden flashboards which have historically been used.

The flashboards project above the crest of the dam to increase water elevation which, in turn, provides the potential for increased energy production. During past periods of flooding on Lake Taneycomo, the wooden flashboards along the dam's 600-foot long spillway were removed by our employees. The wooden flashboards would then be reconstructed over a period of several days. Both the removal and construction of wooden flashboards posed a safety challenge for employees.

The new gates allow the plant to operate more efficiently by utilizing automation to raise and lower the gates as necessary.

Employees from our Ozark Beach, Riverton, Asbury, Energy Center, and Aurora Water facilities and Ozark Beach retirees did nearly all of the work on the project.



Over 100 miles of line were lost and had to be replaced after the storm. **Chet, Aurora Line Operations, and David and Scott, Hollister Line Operations.**

At 5:41 p.m. on Sunday, May 22, the history of Empire District was forever changed by the impact of a massive EF-5 tornado that cut a deep swath through our service territory. Although the first moments after the storm were stunning, employees quickly sprung into action knowing our friends, our neighbors, and our customers were depending upon us.

Recent history has provided challenges for Empire – ice storms, tornados, inland hurricanes – but these storms served as our primer on how to react when the unbelievable occurs. Departments have become well-honed machines, knowing the role they must serve in order to get our customers back on service.

Immediately following the tornado, 31 of 60 circuits in Joplin were out. Communication was difficult as cell phone towers had been destroyed. Our fiber lines suffered tremendous damage, and ultimately 30 cuts had to be repaired or replaced.

Calls were made to our friends in the utility industry and more than 500 personnel worked tirelessly to restore our system – 145 Empire linemen, 243 mutual assistance and contract linemen, 100 vegetation management personnel, and 40 other employees.

Quickly, arrangements were made to house and feed the influx of personnel. Since Joplin was under a boil order, potable water was secured in order to provide workers with hot showers and meals. During the initial restoration, we provided over 13,000 meals and 2,400 room nights to crews in local hotels and employees handled 2,700 pounds of laundry for crews in just nine days.

Having enough materials to keep personnel well-equipped and the restoration moving was a challenge. Suppliers were notified the evening of May 22 and supported us by immediately shifting all available supplies our direction. Utilities throughout the country gave us overwhelming support by allowing their orders for materials to be diverted to Empire. Even transformers, which normally take approximately three weeks to arrive, began arriving only one day after the initial order.

Although supplies were flowing into Joplin, the incredible traffic congestion caused by the storm made it difficult and time consuming for crews to pick up materials. Storeroom personnel worked with vendors to create 12 drop zones around Joplin which were supplied at night to provide crews easy access to materials in order to expedite restoration.

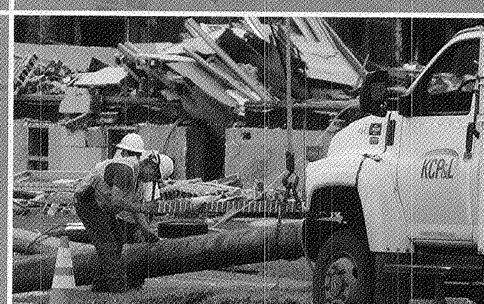
The storm provided us a unique opportunity to rebuild the electrical system with equipment designed to enhance reliable electrical service for all customers.

With the incredible devastation all around, it is amazing that only 10 days after the storm all customers who could receive service were back on. And it isn't over. At the end of 2011, Joplin had over $268.5 million in building permits filed since May 22. Permits for single-family homes totaled more than 540 for the same period. Each day, crews restore service to residential and commercial customers who have made repairs or rebuilt their structures, and it appears this trend will continue.

A pole is directed into place on 20th Street. **Michael and Matt, Bolivar Line Operations.**

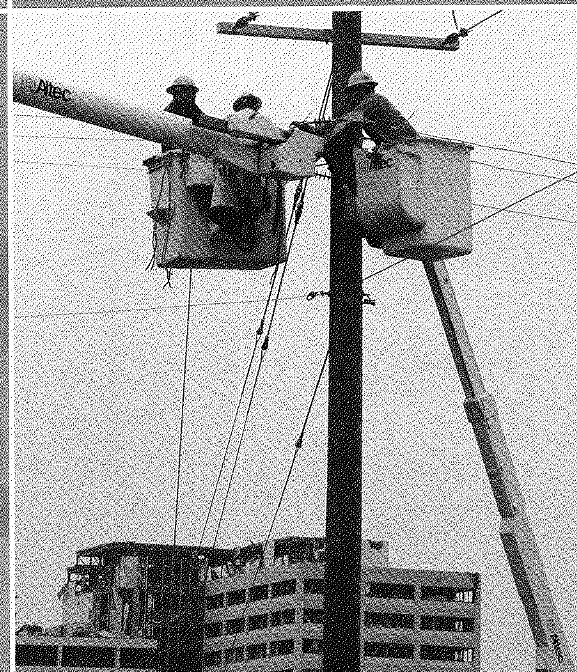
Empire crews from across the service territory work together to rebuild infrastructure on 26th Street near Main Street.

Devastation can be seen in all directions as work is done above Connecticut Avenue.
Jonathan and Newley, Joplin Line Operations.



Crews from Midwest Mutual Assistance Group members, KCP&L and Springfield's City Utilities, plus contractor crews were brought in to help with the restoration. Crew arrivals were staged throughout the restoration to ensure proper plans, materials, and equipment were in place in order to expedite work.

Empire worked with the Federal Emergency Management Agency (FEMA) to provide electrical service to nearly 600 temporary housing units at several housing sites. Empire personnel worked seven days a week in 100 degree-plus temperatures for more than two weeks to bring underground electrical service to a former empty field across from the Joplin Regional Airport. The first residents moved into their homes in early August.



Matt, Kevin, and Jimmy, Gravette Line Operations, restore power to temporary medical facilities near St. John's Mercy Hospital.

In the midst of restoration, strategy is discussed in the Joplin Line Operations office. **Martin, Executive Office, Brent, Customer Service, Justin, Energy Supply, and Sam, Commercial Operations.**

Historic snowfall provided challenges in early February.

Flood waters surrounded the Iatan Generating Station.

Record Weather Year

Weather was the dominant theme for Empire during 2011. In addition to the May 22 tornado, several other significant weather events affected our system.

A historic snow storm impacted a portion of our service area on February 1 and 2. Fortunately this event did not cause significant customer outages, due, in part, to our aggressive vegetation management program.

Flooding began on the Missouri and Mississippi Rivers and Lake Taneycomo in late spring and continued through the summer months and into the fall. Both Iatan 1 and 2 reduced their generation output due to flood damage to the railroad tracks preventing coal deliveries. Additionally, the high water at Iatan prevented employees from reaching the plant by car, so plant operator, KCP&L, used boats to transport employees to the units.

Plum Point experienced only a short outage due to flood waters reaching the pump house which sustained minor damage. The pump house had been designed to sit above the 100-year flood plain.

Heavy spring rains kept Lake Taneycomo at very high levels for much of the year. Due to this, our dam was not able to generate energy from late spring until early August.

The outages at the plants, however, allowed the opportunity for equipment testing and necessary maintenance to occur.

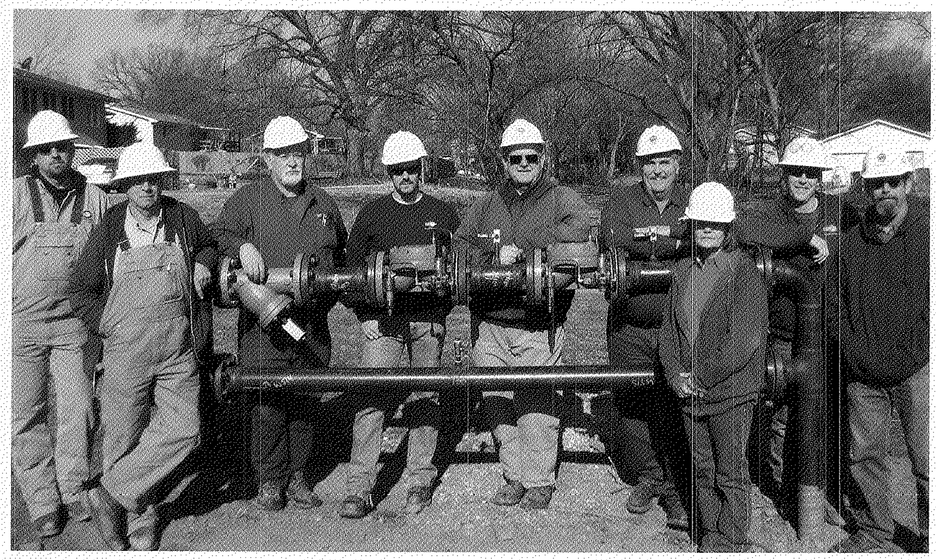
Although we had approximately 3,900 fewer customers as of September 30 due to the May 22 tornado, an all-time summer peak of 1,198 megawatts was established on August 2. July proved to be the third hottest July since modern record keeping began with an average high temperature of 100 degrees each day.

Natural Gas Developments

The largest construction project since the purchase of the gas operations was completed in 2011 – the final six miles of a 13-mile line replacement near Nevada, Missouri. The 1930's-era pipe was replaced with new eight-inch steel pipe designed to handle the delivery of high pressure natural gas. The project began in 2009, and the final section replacement started in August and wrapped up before Thanksgiving.

To finalize the project, employees from our Maryville, Sedalia, Clinton, and Nevada service centers were on hand to expedite connections for individual customers served by the new line.

Additionally, Empire District Gas Company expanded operations in 2011 to a potential 100 new residential customers and three commercial customers in the rural northwest Missouri communities of Conception, Conception Junction, and Clyde. The three commercial customers include Jefferson C-123 School District, Conception Abbey, and Benedictine Convent of Perpetual Adoration, which is the nation's largest religious producer of communion hosts. These customers will be served by the Maryville Service Center.



Nevada Project Crews

ERP

The Enterprise Resource Plan (ERP), also known as Project Overhaul, made great advances during 2011. A company-wide goal was set in 2010 to create a fully integrated system linking financial statements and business reporting systems. This will allow personnel, in every area of the Company, greater access to the information necessary to perform their jobs more efficiently. These improvements also create opportunities for productivity gains throughout the Company.

Project Overhaul is a significant undertaking; however, the system enhancements and productivity gains affecting every employee make the efforts worthwhile.

ERP Implementation Team

Mark, Substation Maintenance

Reliability Improvements

Improving reliability for customers in Welch, Oklahoma, was a focus for crews from the Baxter Springs Service Center in 2011. The community was fed from a single transmission line from Kansas. If an outage occurred, it could mean a lengthy interruption of service for those customers as lines were repaired and switching was completed.

This project, an early Operation Toughen Up initiative, upgraded equipment in Fairland and Bluejacket, Oklahoma. Smart grid technology was utilized as the automated equipment can sense any issues with voltage and automatically switch and adjust relaying so any customer outage time is minimized. It also notifies the dispatcher when an adjustment has occurred so crews can make necessary repairs. The skills of Engineering, Commercial Operations, Telecommunications, and System Operations personnel were utilized to put the latest in technology into place to better serve our customers.

Web Site Enhancements

In order to improve our customers' experience, we added new features to the Web site, **www.empiredistrict.com**. Now both residential and commercial customers can request new electric, natural gas, or water service by simply filling out a form online. The new process has been well received, so plans are in place for additional customer service features to be available online in 2012.

Seated: Palmer, Walters. **Standing:** Sager, Mertens, Delano, Beecher, Watson, Penning, Gatz.

Officers[1]

Bradley P. Beecher
President and Chief Executive Officer
(Age 46, 22 years of service)

Laurie A. Delano
Vice President – Finance and Chief Financial Officer
(Age 56, 21 years of service)

Ronald F. Gatz
Vice President and Chief Operating Officer – Gas
(Age 61, 10 years of service)

Blake A. Mertens
Vice President – Energy Supply
(Age 34, 10 years of service)

Michael E. Palmer
Vice President – Transmission Policy and Corporate Services
(Age 55, 25 years of service)

Martin O. Penning
Vice President – Commercial Operations
(Age 57, 31 years of service)

Kelly S. Walters
Vice President and Chief Operating Officer – Electric
(Age 46, 19 years of service)

Robert W. Sager
Controller, Assistant Secretary and Assistant Treasurer
(Age 37, 5 years of service)

Janet S. Watson
Secretary – Treasurer
(Age 59, 17 years of service)

Directors

Kenneth R. Allen
Vice President – Finance and Chief Financial Officer
Texas Industries, Inc.
Dallas, Texas
(Age 54, Director since 2005)

Bradley P. Beecher
President and Chief Executive Officer
The Empire District Electric Company
(Age 46, Director since 2011)

William L. Gipson
Retired President and Chief Executive Officer
The Empire District Electric Company
(Age 55, Director since 2002)

Ross C. Hartley
Co-Founder and Director NIC, Inc.
Teton Village, Wyoming
(Age 64, Director since 1988)

D. Randy Laney
Chairman of the Board of Directors
The Empire District Electric Company
Farmington, Arkansas
(Age 57, Director since 2003)

Bonnie C. Lind
Senior Vice President, Chief Financial Officer, and Treasurer
Neenah Paper, Inc.
Alpharetta, Georgia
(Age 53, Director since 2009)

B. Thomas Mueller
Founder and President
SALOV North America Corporation
Montclair, New Jersey
(Age 64, Director since 2003)

Thomas M. Ohlmacher
Retired President and Chief Operating Officer, Non-regulated Energy
Black Hills Corporation
Morrison, Colorado
(Age 60, Director since 2011)

Paul R. Portney
Professor of Economics and former Dean, Eller College of Management
University of Arizona
Tucson, Arizona
(Age 66, Director since 2009)

1 Ages shown as of March 1, 2012.
2 Audit Committee Financial Expert.

Herbert J. Schmidt
Executive Vice President Con-way Inc. and President Con-way Truckload
Joplin, Missouri
(Age 56, Director since 2010)

C. James Sullivan
Principal
The Sullivan Group LLC
Birmingham, Alabama
(Age 65, Director since 2010)

Committees of the Board

Audit Committee – Allen[2], Hartley, Lind[2], Mueller[2] (Chair)

Compensation Committee – Allen (Chair), Laney, Ohlmacher, Portney, Schmidt

Nominating/Corporate Governance Committee – Allen, Hartley (Chair), Laney, Lind, Sullivan

Retirement Committee – Gipson, Lind (Chair), Mueller, Ohlmacher, Sullivan

Strategic Projects Committee – Gipson, Ohlmacher, Portney (Chair), Schmidt, Sullivan

Executive Committee – Beecher (Chair), Gipson, Laney, Mueller, Schmidt

Risk Oversight Committee – Allen, Hartley, Laney (Chair), Mueller, Portney

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2011

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to .

Commission file number: 1-3368

THE EMPIRE DISTRICT ELECTRIC COMPANY
(Exact name of registrant as specified in its charter)

Kansas	**44-0236370**
(State of Incorporation)	(I.R.S. Employer Identification No.)
602 S. Joplin Avenue, Joplin, Missouri	**64801**
(Address of principal executive offices)	(zip code)

Registrant's telephone number: (417) 625-5100

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	*Name of each exchange on which registered*
Common Stock ($1 par value)	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☒	Accelerated filer ☐	Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The aggregate market value of the registrant's voting common stock held by nonaffiliates of the registrant, based on the closing price on the New York Stock Exchange on June 30, 2011, was approximately $807,349,000.

As of February 1, 2012, 42,023,966 shares of common stock were outstanding.

The following documents have been incorporated by reference into the parts of the Form 10-K as indicated:

The Company's proxy statement, filed pursuant to Regulation 14A under the Securities Exchange Act of 1934, for its Annual Meeting of Stockholders to be held on April 26, 2012	Part of Item 10 of Part III All of Item 11 of Part III Part of Item 12 of Part III All of Item 13 of Part III All of Item 14 of Part III

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FORWARD LOOKING STATEMENTS

Certain matters discussed in this quarterly report are "forward-looking statements" intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. Such statements address or may address future plans, objectives, expectations and events or conditions concerning various matters such as capital expenditures, earnings, impacts from the 2011 tornado, pension and other costs, competition, litigation, our construction program, our generation plans, our financing plans, potential acquisitions, rate and other regulatory matters, liquidity and capital resources and accounting matters. Forward-looking statements may contain words like "anticipate", "believe", "expect", "project", "objective" or similar expressions to identify them as forward-looking statements. Factors that could cause actual results to differ materially from those currently anticipated in such statements include:

- weather, business and economic conditions, recovery and rebuilding efforts relating to the 2011 tornado and other factors which may impact sales volumes and customer growth;
- the amount, terms and timing of rate relief we seek and related matters;
- the cost and availability of purchased power and fuel, and the results of our activities (such as hedging) to reduce the volatility of such costs;
- volatility in the credit, equity and other financial markets and the resulting impact on our short term debt costs and our ability to issue debt or equity securities, or otherwise secure funds to meet our capital expenditure, dividend and liquidity needs;
- the results of prudency and similar reviews by regulators of costs we incur, including capital expenditures, fuel and purchased power costs and Southwest Power Pool (SPP) regional transmission organization (RTO) expansion costs;
- operation of our electric generation facilities and electric and gas transmission and distribution systems, including the performance of our joint owners;
- the costs and other impacts resulting from natural disasters, such as tornados and ice storms;
- the periodic revision of our construction and capital expenditure plans and cost and timing estimates;
- legislation and regulation, including environmental regulation (such as NOx, SO_2, mercury, ash and CO_2) and health care regulation;
- competition, including the SPP Energy Imbalance Services Market;
- electric utility restructuring, including ongoing federal activities and potential state activities;
- the impact of electric deregulation on off-system sales;
- changes in accounting requirements (including the potential consequences of being required to report in accordance with IFRS rather than U. S. GAAP);
- the timing of accretion estimates, and integration costs relating to completed and contemplated acquisitions and the performance of acquired businesses;
- rate regulation, growth rates, discount rates, capital spending rates, terminal value calculations and other factors integral to the calculations utilized to test the impairment of goodwill, in addition to market and economic conditions which could adversely affect the analysis and ultimately negatively impact earnings;
- the effect of changes in our credit ratings on the availability and cost of funds;

- the performance of our pension assets and other post employment benefit plan assets and the resulting impact on our related funding commitments;
- interruptions or changes in our coal delivery, gas transportation or storage agreements or arrangements;
- the success of efforts to invest in and develop new opportunities;
- costs and effects of legal and administrative proceedings, settlements, investigations and claims;
- our exposure to the credit risk of our hedging counterparties;
- acts of terrorism, including, but not limited to, cyber-terrorism; and
- other circumstances affecting anticipated rates, revenues and costs.

All such factors are difficult to predict, contain uncertainties that may materially affect actual results, and may be beyond our control. New factors emerge from time to time and it is not possible for management to predict all such factors or to assess the impact of each such factor on us. Any forward-looking statement speaks only as of the date on which such statement is made, and we do not undertake any obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made.

We caution you that any forward-looking statements are not guarantees of future performance and involve known and unknown risk, uncertainties and other factors which may cause our actual results, performance or achievements to differ materially from the facts, results, performance or achievements we have anticipated in such forward-looking statements.

PART I

ITEM 1. BUSINESS

General

We operate our businesses as three segments: electric, gas and other. The Empire District Electric Company (EDE), a Kansas corporation organized in 1909, is an operating public utility engaged in the generation, purchase, transmission, distribution and sale of electricity in parts of Missouri, Kansas, Oklahoma and Arkansas. As part of our electric segment, we also provide water service to three towns in Missouri. The Empire District Gas Company (EDG) is our wholly owned subsidiary engaged in the distribution of natural gas in Missouri. Our other segment consists of our fiber optics business.

Our gross operating revenues in 2011 were derived as follows:

Electric segment sales*	90.9%
Gas segment sales	8.0
Other segment sales	1.1

* Sales from our electric segment include 0.3% from the sale of water.

The territory served by our electric operations embraces an area of about 10,000 square miles, located principally in southwestern Missouri, and also includes smaller areas in southeastern Kansas, northeastern Oklahoma and northwestern Arkansas. The principal economic activities of these areas include light industry, agriculture and tourism. As of December 31, 2011, our electric operations served approximately 166,500 customers.

Our retail electric revenues for 2011 by jurisdiction were derived as follows:

Missouri	88.8%
Kansas	5.3
Arkansas	2.8
Oklahoma	3.1

We supply electric service at retail to 120 incorporated communities as of December 31, 2011, and to various unincorporated areas and at wholesale to four municipally owned distribution systems. The largest urban area we serve is the city of Joplin, Missouri, and its immediate vicinity, with a population of approximately 157,000. We operate under franchises having original terms of twenty years or longer in virtually all of the incorporated communities. Approximately 50% of our electric operating revenues in 2011 were derived from incorporated communities with franchises having at least ten years remaining and approximately 20% were derived from incorporated communities in which our franchises have remaining terms of ten years or less. Although our franchises contain no renewal provisions, in recent years we have obtained renewals of all of our expiring electric franchises prior to the expiration dates.

Our electric operating revenues in 2011 were derived as follows:

Residential	42.4%
Commercial	30.1
Industrial	15.1
Wholesale on-system	3.7
Wholesale off-system	4.5
Miscellaneous sources*	2.6
Other electric revenues	1.6

* primarily public authorities

Our largest single on-system wholesale customer is the city of Monett, Missouri, which in 2011 accounted for approximately 3% of electric revenues. No single retail customer accounted for more than 2% of electric revenues in 2011.

Our gas operations serve customers in northwest, north central and west central Missouri. As of December 31, 2011, our gas operations served approximately 44,000 customers. We provide natural gas distribution to 45 communities and 315 transportation customers as of December 31, 2011. The largest urban area we serve is the city of Sedalia with a population of over 20,000. We operate under franchises having original terms of twenty years in virtually all of the incorporated communities. Seventeen of the franchises have 10 years or more remaining on their term. Although our franchises contain no renewal provisions, since our acquisition we have obtained renewals of all our expiring gas franchises prior to the expiration dates.

Our gas operating revenues in 2011 were derived as follows:

Residential	62.5%
Commercial	26.9
Industrial	1.5
Miscellaneous	9.1

No single retail customer accounted for more than 1% of gas revenues in 2011.

Our other segment consists of our fiber optics business. As of December 31, 2011, we have 97 fiber customers.

Electric Generating Facilities and Capacity

At December 31, 2011, our generating plants consisted of:

Plant	Capacity (megawatts)(1)	Primary Fuel
Asbury	207	Coal
Riverton — Coal	92	Coal
Riverton — Natural Gas	187	Natural Gas
Iatan (12% ownership)	187(2)	Coal
Plum Point Energy Station (7.52% ownership)	50(2)	Coal
State Line Combined Cycle (60% ownership)	297(2)	Natural Gas
Empire Energy Center	262	Natural Gas
State Line Unit No. 1	94	Natural Gas
Ozark Beach	16	Hydro
TOTAL	1,392	

(1) Based on summer rating conditions as utilized by Southwest Power Pool.

(2) Capacity reflects our allocated shares of the capacity of these plants.

See Item 2, "Properties — Electric Segment Facilities" for further information about these plants.

We, and most other electric utilities with interstate transmission facilities, have placed our facilities under the Federal Energy Regulatory Commission (FERC) regulated open access tariffs that provide all wholesale buyers and sellers of electricity the opportunity to procure transmission services (at the same rates) that the utilities provide themselves. We are a member of the Southwest Power Pool Regional Transmission Organization (SPP RTO). See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations — Competition."

We currently supplement our on-system generating capacity with purchases of capacity and energy from other sources in order to meet the demands of our customers and the capacity margins applicable to us under current pooling agreements and National Electric Reliability Council rules. The SPP requires its members to maintain a minimum 12% capacity margin. Our long-term contract with Westar Energy for the purchase of 162 megawatts of capacity and energy ended May 31, 2010. In order to replace this 162 megawatts of capacity and energy, we entered into contracts to add 202 megawatts of power to our system. This energy is from two new plants that became operational in 2010, with 100 megawatts from the new Plum Point Energy Station (50 megawatts of owned capacity and 50 megawatts of purchased power) and 102 megawatts from the new Iatan 2 generating facility, each of which is described below.

The Plum Point Energy Station is a 665-megawatt, coal-fired generating facility near Osceola, Arkansas which entered commercial operation on September 1, 2010. We own, through an undivided interest, 50 megawatts of the unit's capacity. Our share of the Plum Point initial construction costs through December 31, 2011 was approximately $85.3 million plus $16.5 million of allowance for funds used during construction (AFUDC). Recovery of these costs is reflected in our current rates. We also have a long-term (30 year) purchased power agreement for an additional 50 megawatts of capacity and have the option to purchase the undivided ownership interest in the 50 megawatts covered by the purchased power agreement in 2015.

We also own an undivided ownership interest in the coal-fired Iatan 2 generating facility operated by Kansas City Power & Light Company (KCP&L) and located at the site of the existing Iatan Generating Station (Iatan 1) near Weston, Missouri. We own 12%, or approximately 102 megawatts, of the 850-megawatt unit, which entered commercial operation on December 31, 2010. Our share of the Iatan 2 initial construction costs through December 31, 2011 was $233.3 million plus AFUDC of $19.1 million. Recovery of these costs is reflected in our current rates.

We have a 20-year purchased power agreement, which began on December 15, 2008, with Cloud County Windfarm, LLC, owned by EDP Renewables North America LLC (formerly Horizon Wind Energy), Houston, Texas to purchase the energy generated at the approximately 105-megawatt Phase 1 Meridian Way Wind Farm located in Cloud County, Kansas. We also have a 20-year contract, which began on December 15, 2005, with Elk River Windfarm, LLC, owned by IBERDROLA RENEWABLES, Inc., to purchase the energy generated at the 150-megawatt Elk River Windfarm located in Butler County, Kansas. We do not own any portion of either windfarm.

The following chart sets forth our purchase commitments and our anticipated owned capacity (in megawatts) during the indicated years. The capacity ratings we use for our generating units are based on summer rating conditions under SPP guidelines. The portion of the purchased power that may be counted as capacity from the Elk River Windfarm, LLC and the Cloud County Windfarm, LLC is included in this chart. Because the wind power is an intermittent, non-firm resource, SPP rating criteria does not allow us to count a substantial amount of the wind power as capacity. See Item 7, "Managements' Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources."

Year	Purchased Power Commitment[(1)]	Anticipated Owned Capacity	Total Megawatts
2012	65	1392	1457
2013	65	1392	1457
2014	65	1392	1457
2015	65	1368	1433[(2)]
2016	15	1422	1437[(3)]

(1) Includes 7 megawatts for the Elk River Windfarm, LLC and 8 megawatts for the Cloud County Windfarm, LLC.

(2) Reflects the planned retirement of Asbury Unit 2.

(3) Reflects the planned retirement of Riverton Units 7, 8 and 9, conversion of Plum Point purchased power agreement to ownership and conversion of Riverton Unit 12 to a combined cycle.

The maximum hourly demand on our system reached a record high of 1,199 megawatts on January 8, 2010. Our previous winter peak of 1,100 megawatts was established on December 22, 2008. Our maximum hourly summer demand of 1,198 megawatts was set on August 2, 2011. Our previous summer record peak of 1,173 megawatts was established on August 15, 2007.

Gas Facilities

At December 31, 2011, our principal gas utility properties consisted of approximately 87 miles of transmission mains and approximately 1,130 miles of distribution mains.

The following table sets forth the three pipelines that serve our gas customers:

Service Area	Name of Pipeline
South	Southern Star Central Gas Pipeline
North	Panhandle Eastern Pipe Line Company
Northwest	ANR Pipeline Company

Our all-time peak of 73,280 mcfs was established on January 7, 2010, replacing the previous record of 70,820 mcfs which was set on January 4, 2010.

Construction Program

Total property additions (including construction work in progress but excluding AFUDC) for the three years ended December 31, 2011, amounted to $341.8 million and retirements during the same period amounted to $48.0 million. Please refer to Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources" for more information.

Our total capital expenditures, excluding AFUDC and expenditures to retire assets, were $99.8 million in 2011 and for the next three years are estimated for planning purposes to be as follows:

	Estimated Capital Expenditures (amounts in millions)			
	2012	2013	2014	Total
New electric generating facilities:				
Iatan 2	$ 2.8	$ —	$ —	$ 2.8
Additions to existing electric generating facilities:				
Asbury	5.0	11.8	16.6	33.4
Environmental upgrades — Asbury	30.1	50.4	35.4	115.9
Other	11.2	8.4	8.7	28.3
Electric transmission facilities	15.0	13.3	26.2	54.5
Electric distribution system additions	63.7	52.1	39.3	155.1
Non-regulated additions	2.0	1.5	1.5	5.0
General and other additions	13.5	17.7	33.3	64.5
Gas system additions	3.9	3.5	3.3	10.7
TOTAL	$147.2	$158.7	$164.3	$470.2

Our estimated total capital expenditures (excluding AFUDC) for 2015 and 2016 are $286.5 million and $138.4 million, respectively. Construction expenditures for additions to our transmission and distribution systems and environmental upgrades at Asbury constitute the majority of the projected capital expenditures for the three-year period listed above. Expenditures for the combined cycle conversion of Riverton Unit 12 and the possible purchase, pursuant to our option, of an undivided ownership interest in 50 megawatts of capacity at the Plum Point Energy Station, also significantly contribute to capital expenditures for 2014 through 2016. No decision has yet been made to exercise this option.

Total estimated capital expenditures for 2013 and 2014 are lower than the estimates for such years that were disclosed in our quarterly report on Form 10-Q for the quarter ended September 30, 2011, primarily as a result of a reduction in the estimated cost of the environmental upgrades at Asbury.

Estimated capital expenditures are reviewed and adjusted for, among other things, revised estimates of future capacity needs, the cost of funds necessary for construction, costs to recover from natural disasters and the availability and cost of alternative power. Actual capital expenditures may vary significantly from the estimates due to a number of factors including changes in customer requirements, construction delays, changes in equipment delivery schedules, ability to raise capital, environmental matters, the extent to which we receive timely and adequate rate increases, the extent of competition from independent power producers and cogenerators, other changes in business conditions and changes in legislation and regulation, including those relating to the energy industry. See "— Regulation" below and Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations — Competition."

Fuel and Natural Gas Supply

Electric Segment

Our total system output for 2011, based on kilowatt-hours generated, was as follows:

Steam generation units	45.2%
Combustion turbine generation units	23.9
Hydro generation	0.8
Purchased power — windfarms	14.9
Purchased power — other	15.2

Approximately 65.0% of the total fuel requirements for our generating units in 2011 (based on kilowatt-hours generated) were supplied by coal and approximately 34.8% supplied by natural gas with fuel oil and tire-derived fuel (TDF), which is produced from discarded passenger car tires, providing the remainder. The amount and percentage of electricity generated by natural gas increased in 2011 as compared to 2010 while the amount of energy we purchased decreased, primarily reflecting that it was more economical to produce gas-fired generation than to purchase power during this period.

Our Asbury Plant is fueled primarily by coal with oil being used as start-up fuel and TDF being used as a supplement fuel. In 2011, Asbury burned a coal blend consisting of approximately 86.9% Western coal (Powder River Basin) and 13.1% blend coal on a tonnage basis. Our average coal inventory target at Asbury is approximately 60 days. As of December 31, 2011, we had sufficient coal on hand to supply full load requirements at Asbury for 47-94 days, as compared to 56-70 days as of December 31, 2010, depending on the actual blend ratio.

Our Riverton Plant fuel requirements are primarily met by coal with the remainder supplied by natural gas, petroleum coke and oil. Riverton Unit 12, a Siemens V84.3A2 gas combustion turbine installed in 2007, and three other smaller units are fueled by natural gas. During 2011, Riverton Units 7 and 8 burned an estimated blend of approximately 92.8% Western coal (Powder River Basin) and 7.2% petroleum coke on a tonnage basis. Our average coal inventory target at Riverton is approximately 60 days. We had sufficient coal as of December 31, 2011 to run 53 days on both units as compared to 40 days as of December 31, 2010. Our future plans are to transition Units 7 and 8 to natural gas and to convert Unit 12 to a combined cycle unit, which will make natural gas the primary fuel at our Riverton Plant.

The following table sets forth the percentage of our anticipated coal requirements we have secured through a combination of contracts and binding proposals for the following years:

Year	Percentage secured
2012	87%
2013	61%
2014	43%

All of the Western coal used at our Asbury and Riverton plants is shipped to the Asbury Plant by rail, a distance of approximately 800 miles, under a six and one-half year contract with the Burlington Northern and Santa Fe Railway Company (BNSF) and the Kansas City Southern Railway Company which began on June 30, 2010. Riverton receives its Western inventory from the coal transported by train to the Asbury Plant which is then transported by truck to Riverton. We currently lease one aluminum unit train full time and a second set is leased on a part-time basis to deliver Western coal to the Asbury Plant.

Unit 1 and Unit 2 at the Iatan Plant are coal-fired generating units which are jointly-owned by KCP&L, a subsidiary of Great Plains Energy, Inc., Missouri Joint Municipal Electric Utility Commission, Kansas Electric Power Cooperative (KEPCO) and us, with our share of ownership being 12% in each plant. KCP&L is the operator of these plants and is responsible for arranging their fuel supply. KCP&L has secured contracts for low sulfur Western coal in quantities sufficient to meet 100% of Iatan's requirements for 2012 and approximately 95% for 2013, 60% for 2014, and 20% for 2015. The coal is transported by rail under a contract with BNSF Railway, which expires on December 31, 2013.

The Plum Point Energy Station is a 665-megawatt, coal-fired generating facility near Osceola, Arkansas. The plant began commercial operation on September 1, 2010. We own, through an undivided interest, 50 megawatts of the plant's capacity. North America Energy Services is the operator of this plant. Plum Point Services Company, LLC (PPSC), the project management company acting on behalf of the joint owners, is responsible for arranging its fuel supply. PPSC has secured contracts for low sulfur Western coal in quantities sufficient to meet 92% of Plum Point's requirements for 2012 and approximately 86% for 2013, 85% for 2014 and 87% for 2015. We have a 15-year lease agreement, expiring in 2024, for 54 railcars for our ownership share of Plum Point. In December 2010, we entered into another 15-year lease agreement for an additional 54 railcars associated with our Plum Point purchased power agreement.

Our Energy Center and State Line combustion turbine facilities (not including the State Line Combined Cycle (SLCC) Unit, which is fueled 100% by natural gas) are fueled primarily by natural gas with oil also available for use primarily as backup. Based on kilowatt hours generated during 2011, Energy Center generation was 99.5% natural gas with the remainder being fuel oil, and 100% of the State Line Unit 1 generation came from natural gas. As of December 31, 2011, oil inventories were sufficient for approximately 2 days of full load operation on Units No. 1, 2, 3 and 4 at the Energy Center and 5 days of full load operation for State Line Unit No. 1. As typical oil usage is minimal, these inventories are sufficient for our current requirements. Additional oil will be purchased as needed.

We have firm transportation agreements with Southern Star Central Pipeline, Inc. with original expiration dates of July 31, 2016, for the transportation of natural gas to the SLCC. This date is adjusted for periods of contract suspension by us during outages of the SLCC. This transportation agreement can also supply natural gas to State Line Unit No.1, the Energy Center or the Riverton Plant, as elected by us on a secondary basis. We also have a precedent agreement with Southern Star, which provides additional transportation capability until 2022. This contract provides firm transport to the sites listed above that previously were only served on a secondary basis. We expect that these transportation agreements will serve nearly all of our natural gas transportation needs for our generating plants over the next several years. Any remaining gas transportation requirements, although small, will be met by utilizing capacity release on other holder contracts, interruptible transport, or delivered to the plants by others.

The majority of our physical natural gas supply requirements will be met by short-term forward contracts and spot market purchases. Forward natural gas commodity prices and volumes are hedged several years into the future in accordance with our Risk Management Policy in an attempt to lessen the volatility in our fuel expenditures and gain predictability. In addition, we have an agreement with Southern Star to purchase one million Dths of firm gas storage service capacity for a period of five years beginning in April 2011. The reservation charge for this storage capacity is approximately $1.1 million annually. This storage capacity will enable us to better manage our natural gas commodity and transportation needs for our electric segment.

The following table sets forth a comparison of the costs, including transportation and other miscellaneous costs, per million Btu of various types of fuels used in our electric facilities:

Fuel Type / Facility	2011	2010	2009
Coal — Iatan	$ 1.603	$ 1.193	$ 1.186
Coal — Asbury	2.315	1.877	1.763
Coal — Riverton	2.314	1.833	1.768
Coal — Plum Point	1.858	1.799	—
Natural Gas	5.475	6.061	7.376
Oil	21.304	15.443	14.318
Weighted average cost of fuel burned per kilowatt-hour generated	2.9558	2.9936	3.1698

Gas Segment

We have 10,000 MMBtus per day of firm transportation from Cheyenne Plains Pipeline Company. This provides us with up to 75% of our natural gas purchases from the Rocky Mountain gas area. Cheyenne Plains interconnects with all of the interstate pipelines listed below that feed our market area.

We have agreements with many of the major suppliers in both the Midcontinent and Rocky Mountain regions that provide us with both supply and price diversity. We continue to expand our supplier base to enhance supply reliability as well as provide for increased price competition.

The following table sets forth the current costs, including storage, transportation and other miscellaneous costs, per mcf of gas used in our gas operations:

Service Area	Name of Pipeline	2011	2010	2009
South	Southern Star Central Gas Pipeline	$6.1619	$6.7068	$7.8475
North	Panhandle Eastern Pipe Line Company	6.1449	6.1151	7.4055
Northwest	ANR Pipeline Company	5.4230	5.3216	7.1160
	Weighted average cost per mcf	$6.0542	$6.3745	$7.6395

Employees

At December 31, 2011, we had 746 full-time employees, including 51 employees of EDG. 336 of the EDE employees are members of Local 1474 of The International Brotherhood of Electrical Workers (IBEW). On October 17, 2011, the Local 1474 IBEW voted to ratify a new two-year agreement which will extend through October 31, 2013. At December 31, 2011, 34 EDG employees were members of Local 1464 of the IBEW. In June 2009, Local 1464 of the IBEW ratified a four-year agreement with EDG effective June 1, 2009.

ELECTRIC OPERATING STATISTICS[1]

	2011	2010	2009	2008	2007
Electric Operating Revenues (000's):					
Residential	$ 221,687	$ 204,900	$ 180,404	$ 179,293	$ 174,584
Commercial	157,435	146,310	135,800	132,888	129,035
Industrial	78,925	69,684	65,983	67,353	67,712
Public authorities[2]	13,653	12,099	11,411	10,876	9,933
Wholesale on-system	19,140	19,254	18,199	19,229	18,444
Miscellaneous[3]	8,194	7,573	6,814	6,976	5,703
Interdepartmental	201	199	178	154	123
Total system	499,235	460,019	418,789	416,769	405,534
Wholesale off-system	23,271	22,891	14,344	29,697	19,627
Total electric operating revenues[4]	**522,506**	**482,910**	**433,133**	**446,466**	**425,161**
Electricity generated and purchased (000's of kWh):					
Steam	2,805,744	2,650,042	2,259,304	2,228,716	2,074,323
Hydro	48,898	88,104	76,733	32,601	71,360
Combustion turbine	1,484,472	1,566,074	926,934	1,480,729	1,427,298
Total generated	4,339,114	4,304,220	3,262,971	3,742,046	3,572,981
Purchased	1,870,901	2,085,550	2,516,702	2,440,246	2,373,282
Total generated and purchased	6,210,015	6,389,770	5,779,673	6,182,292	5,946,263
Interchange (net)	(1,298)	(1,716)	(568)	(436)	(940)
Total system output	6,208,717	6,388,054	5,779,105	6,181,856	5,945,323
Transmission by others losses[5]	(16,597)	(5,688)	—	—	—
Total system input	**6,192,120**	**6,382,366**	**5,779,105**	**6,181,856**	**5,945,323**
Maximum hourly system demand (Kw)	1,198,000	1,199,000	1,085,000	1,152,000	1,173,000
Owned capacity (end of period) (Kw)	1,392,000	1,409,000	1,257,000	1,255,000	1,255,000
Annual load factor (%)	52.0	53.17	55.38	54.29	53.39
Electric sales (000's of kWh):					
Residential	1,982,704	2,060,368	1,866,473	1,952,869	1,930,493
Commercial	1,576,342	1,644,917	1,579,832	1,622,048	1,610,814
Industrial	1,022,765	1,007,033	992,165	1,073,250	1,110,328
Public authorities[2]	126,724	124,554	121,816	122,375	115,109
Wholesale on-system	364,866	355,807	332,061	344,525	342,347
Total system	5,073,401	5,192,679	4,892,347	5,115,067	5,109,091
Wholesale off-system	740,009	798,084	515,899	688,203	459,665
Total Electric Sales	**5,813,410**	**5,990,763**	**5,408,246**	**5,803,270**	**5,568,756**
Company use (000's of kWh)[6]	9,371	9,598	9,088	9,209	9,369
kWh losses (000's of kWh)	369,339	382,005	361,771	369,377	367,198
Total System Input	**6,192,120**	**6,382,366**	**5,779,105**	**6,181,856**	**5,945,323**
Customers (average number):					
Residential	139,641	141,693	141,206	140,791	139,840
Commercial	24,155	24,505	24,412	24,532	24,330
Industrial	357	358	355	361	362
Public authorities[2]	2,021	2,003	1,995	1,935	1,927
Wholesale on-system	4	4	4	4	4
Total System	166,178	168,563	167,972	167,623	166,463
Wholesale off-system	25	22	19	22	20
Total	**166,203**	**168,585**	**167,991**	**167,645**	**166,483**
Average annual sales per residential customer (kWh)	14,199	14,541	13,218	13,871	13,805
Average annual revenue per residential customer	$ 1,588	$ 1,446	$ 1,278	$ 1,273	$ 1,248
Average residential revenue per kWh	11.18¢	9.94¢	9.67¢	9.18¢	9.04¢
Average commercial revenue per kWh	9.99¢	8.89¢	8.60¢	8.19¢	8.01¢
Average industrial revenue per kWh	7.72¢	6.92¢	6.65¢	6.28¢	6.10¢

(1) See Item 6, "Selected Financial Data" for additional financial information regarding Empire.

(2) Includes Public Street & Highway Lighting and Public Authorities.

(3) Includes transmission service revenues, late payment fees, renewable energy credit sales, rent, etc.

(4) Before intercompany eliminations.

(5) Energy provided in-kind to third party transmission providers to compensate for transmission losses associated with delivery of capacity and energy under their transmission tariffs.

(6) Includes kWh used by Company and Interdepartmental.

GAS OPERATING STATISTICS[1]

	2011	2010	2009	2008	2007
Gas Operating Revenues (000's):					
Residential	$28,999	$32,245	$36,176	$39,639	$39,205
Commercial	12,506	13,336	15,552	17,416	16,588
Industrial	682	812	2,066	5,069	752
Public authorities	324	342	365	416	373
Total retail sales revenues	42,511	46,735	54,159	62,540	56,918
Miscellaneous[2]	464	436	221	231	206
Transportation revenues	3,455	3,714	2,934	2,667	2,753
Total Gas Operating Revenues	**46,430**	**50,885**	**57,314**	**65,438**	**59,877**
Maximum Daily Flow (mcf)	**67,789**	**73,280**	**70,046**	**66,005**	**68,379**
Gas delivered to customers (000's of mcf sales)[3]					
Residential	2,560	2,675	2,687	2,949	2,835
Commercial	1,268	1,265	1,278	1,397	1,304
Industrial	102	108	218	553	76
Public authorities	33	33	30	35	30
Total retail sales	3,963	4,081	4,213	4,934	4,245
Transportation sales	4,528	4,829	4,330	4,059	4,300
Total gas operating and transportation sales	8,491	8,910	8,543	8,993	8,545
Company use[3]	4	4	3	4	2
Transportation sales (cash outs)	—	—	—	—	56
Mcf losses	(47)	70	36	140	8
Total system sales	**8,448**	**8,984**	**8,582**	**9,137**	**8,611**
Customers (average number):					
Residential	38,051	38,277	38,621	39,159	40,315
Commercial	4,951	4,968	5,038	5,119	5,208
Industrial	26	26	25	26	24
Public authorities	136	137	131	127	124
Total retail customers	43,164	43,408	43,815	44,431	45,671
Transportation customers	311	313	296	272	270
Total gas customers	**43,475**	**43,721**	**44,111**	**44,703**	**45,941**

(1) See Item 6, "Selected Financial Data" for additional financial information regarding Empire.

(2) Primarily includes miscellaneous service revenue and late fees.

(3) Includes mcf used by Company and Interdepartmental mcf.

Executive Officers and Other Officers of Empire

The names of our officers, their ages and years of service with Empire as of December 31, 2011, positions held during the past five years and effective dates of such positions are presented below. All of our officers have been employed by Empire for at least the last five years.

Name	Age at 12/31/11	Positions With the Company	With the Company Since	Officer Since
Bradley P. Beecher[(1)]	46	President and Chief Executive Officer (2011). Executive Vice President (2011), Executive Vice President and Chief Operating Officer — Electric (2010), Vice President and Chief Operating Officer — Electric (2006)	2001	2001
Laurie A. Delano[(2)]	56	Vice President — Finance and Chief Financial Officer, (2011), Controller, Assistant Secretary and Assistant Treasurer and Principal Accounting Officer (2005)	2002	2005
Ronald F. Gatz	61	Vice President and Chief Operating Officer — Gas (2006)	2001	2001
Blake Mertens[(3)]	34	Vice President — Energy Supply (2011), General Manager — Energy Supply (2010), Director of Strategic Projects, Safety and Environmental Services (2010), Associate Director of Strategic Projects (2009), Manager of Strategic Projects (2006)	2001	2011
Michael E. Palmer[(4)]	55	Vice President — Transmission Policy and Corporate Services (2011), Vice President — Commercial Operations (2001)	1986	2001
Martin O. Penning[(5)]	56	Vice President — Commercial Operations, (2011), Director of Commercial Operations (2006)	1980	2011
Kelly S. Walters[(6)]	46	Vice President and Chief Operating Officer — Electric (2011), Vice President — Regulatory and Services (2006)	2001	2006
Janet S. Watson	59	Secretary — Treasurer (1995)	1994	1995
Robert W. Sager[(7)]	37	Controller, Assistant Secretary and Assistant Treasurer and Principal Accounting Officer (2011), Director of Financial Services (2006)	2006	2011

(1) Bradley P. Beecher became President and Chief Executive Officer effective June 1, 2011. Effective February 4, 2011, Mr. Beecher was elected executive vice president.

(2) Laurie A. Delano was elected Vice President — Finance and Chief Financial Officer effective August 1, 2011.

(3) Blake Mertens was elected Vice President — Energy Supply effective May 1, 2011.

(4) Michael E. Palmer was elected Vice President — Transmission Policy and Corporate Services effective February 4, 2011.

(5) Martin O. Penning was elected Vice President — Commercial Operations effective February 4, 2011.

(6) Kelly S. Walters was elected Vice President and Chief Operating Officer — Electric effective February 4, 2011.

(7) Robert W. Sager was elected Controller, Assistant Secretary and Assistant Treasurer and Principal Accounting Officer effective August 1, 2011.

Regulation

Electric Segment

General. As a public utility, our electric segment operations are subject to the jurisdiction of the MPSC, the State Corporation Commission of the State of Kansas (KCC), the Corporation Commission of Oklahoma (OCC) and the Arkansas Public Service Commission (APSC) with respect to services and facilities, rates and charges, regulatory accounting, valuation of property, depreciation and various other matters. Each such Commission has jurisdiction over the creation of liens on property located in its state to secure bonds or other securities. The KCC also has jurisdiction over the issuance of all securities because we are a regulated utility incorporated in Kansas. Our transmission and sale at wholesale of electric energy in interstate commerce and our facilities are also subject to the jurisdiction of the FERC, under the Federal Power Act. FERC jurisdiction extends to, among other things, rates and charges in connection with such transmission and sale; the sale, lease or other disposition of such facilities and accounting matters. See discussion in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations — Competition."

During 2011, approximately 90.3% of our electric operating revenues was received from retail customers. Sales subject to FERC jurisdiction represented approximately 8.8% of our electric operating revenues during 2011 with the remaining 0.9% being from miscellaneous sources. The percentage of retail revenues derived from each state follows:

Missouri	88.8%
Kansas	5.3
Oklahoma	2.8
Arkansas	3.1

Rates. See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations — Rate Matters" for information concerning recent electric rate proceedings.

Fuel Adjustment Clauses. Typical fuel adjustment clauses permit the distribution to customers of changes in fuel costs, subject to routine regulatory review, without the need for a general rate proceeding. Fuel adjustment clauses are presently applicable to our retail electric sales in Missouri, Oklahoma and Kansas and system wholesale kilowatt-hour sales under FERC jurisdiction. We have an Energy Cost Recovery Rider in Arkansas that adjusts for changing fuel and purchased power costs on an annual basis.

Gas Segment

General. As a public utility, our gas segment operations are subject to the jurisdiction of the MPSC with respect to services and facilities, rates and charges, regulatory accounting, valuation of property, depreciation and various other matters. The MPSC also has jurisdiction over the creation of liens on property to secure bonds or other securities.

Purchased Gas Adjustment (PGA). The PGA clause allows EDG to recover from our customers, subject to routine regulatory review, the cost of purchased gas supplies, including costs associated with our use of natural gas financial instruments to hedge the purchase price of natural gas and related carrying costs. This PGA clause allows us to make rate changes periodically (up to four times) throughout the year in response to weather conditions and supply demands, rather than in one possibly extreme change per year.

Environmental Matters

See Note 11 to the consolidated financial statements for information regarding environmental matters.

Conditions Respecting Financing

Our EDE Indenture of Mortgage and Deed of Trust, dated as of September 1, 1944, as amended and supplemented (the EDE Mortgage), and our Restated Articles of Incorporation (Restated Articles), specify earnings coverage and other conditions which must be complied with in connection with the issuance of additional first mortgage bonds or cumulative preferred stock, or the incurrence of unsecured indebtedness. The principal amount of all series of first mortgage bonds outstanding at any one time under the EDE Mortgage is limited by terms of the mortgage to $1 billion. Substantially all of the property, plant and equipment of The Empire District Electric Company (but not its subsidiaries) is subject to the lien of the EDE Mortgage. Restrictions in the EDE mortgage bond indenture could affect our liquidity. The EDE Mortgage contains a requirement that for new first mortgage bonds to be issued, our net earnings (as defined in the EDE Mortgage) for any twelve consecutive months within the fifteen months preceding issuance must be two times the annual interest requirements (as defined in the EDE Mortgage) on all first mortgage bonds then outstanding and on the prospective issue of new first mortgage bonds. Our earnings for the year ended December 31, 2011, would permit us to issue approximately $511.0 million of new first mortgage bonds based on this test at an assumed interest rate of 6.0%. In addition to the interest coverage requirement, the EDE Mortgage provides that new bonds must be issued against, among other things, retired bonds or 60% of net property additions. At December 31, 2011, we had retired bonds and net property additions which would enable the issuance of at least $697.6 million principal amount of bonds if the annual interest requirements are met. As of December 31, 2011, we are in compliance with all restrictive covenants of the EDE Mortgage.

Under our Restated Articles, (a) cumulative preferred stock may be issued only if our net income available for interest and dividends (as defined in our Restated Articles) for a specified twelve-month period is at least 1½ times the sum of the annual interest requirements on all indebtedness and the annual dividend requirements on all cumulative preferred stock to be outstanding immediately after the issuance of such additional shares of cumulative preferred stock, and (b) so long as any preferred stock is outstanding, the amount of unsecured indebtedness outstanding may not exceed 20% of the sum of the outstanding secured indebtedness plus our capital and surplus. We have no outstanding preferred stock. Accordingly, the restriction in our Restated Articles does not currently restrict the amount of unsecured indebtedness that we may have outstanding.

The EDG Indenture of Mortgage and Deed of Trust, dated as of June 1, 2006, as amended and supplemented (the EDG Mortgage) contains a requirement that for new first mortgage bonds to be issued, the amount of such new first mortgage bonds shall not exceed 75% of the cost of property additions acquired after the date of the Missouri Gas acquisition. The principal amount of all series of first mortgage bonds outstanding at any one time under the EDG Mortgage is limited by terms of the mortgage to $300 million. Substantially all of the property, plant and equipment of The Empire District Gas Company is subject to the lien of the EDG Mortgage. The mortgage also contains a limitation on the issuance by EDG of debt (including first mortgage bonds, but excluding short-term debt incurred in the ordinary course under working capital facilities) unless, after giving effect to such issuance, EDG's ratio of EBITDA (defined as net income plus interest, taxes, depreciation, amortization and certain other non-cash charges) to interest charges for the most recent four fiscal quarters is at least 2.0 to 1. As of December 31, 2011, this test would allow us to issue approximately $10.7 million principal amount of new first mortgage bonds.

See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources."

Our Web Site

We maintain a web site at www.empiredistrict.com. Our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on form 8-K and related amendments are available free of charge through our web site as soon as reasonably practicable after such reports are filed with or furnished to the

SEC electronically. Our Corporate Governance Guidelines, our Code of Business Conduct and Ethics, our Code of Ethics for the Chief Executive Officer and Senior Financial Officer, the charters for our Audit Committee, Compensation Committee and Nominating/Corporate Governance Committee, our Procedures for Reporting Complaints on Accounting, Internal Accounting Controls and Auditing Matters, our Procedures for Communicating with Non-Management Directors and our Policy and Procedures with Respect to Related Person Transactions can also be found on our web site. All of these documents are available in print to any interested party who requests them. Our web site and the information contained in it and connected to it shall not be deemed incorporated by reference into this Form 10-K.

ITEM 1A. RISK FACTORS

Investors should review carefully the following risk factors and the other information contained in this Form 10-K. The risks we face are not limited to those in this section. There may be additional risks and uncertainties (either currently unknown or not currently believed to be material) that could adversely affect our financial position, results of operations and liquidity.

Readers are cautioned that the risks and uncertainties described in this Form 10-K are not the only ones facing Empire. Additional risks and uncertainties that we are not presently aware of, or that we currently consider immaterial, may also affect our business operations. Our business, financial condition or results of operations (including our ability to pay dividends on our common stock) could suffer if the concerns set forth below are realized.

We are exposed to increases in costs and reductions in revenue which we cannot control and which may adversely affect our business, financial condition and results of operations.

The primary drivers of our electric operating revenues in any period are: (1) rates we can charge our customers, (2) weather, (3) customer growth and (4) general economic conditions. Of the factors driving revenues, weather has the greatest short-term effect on the demand for electricity for our regulated business. Mild weather reduces demand and, as a result, our electric operating revenues. In addition, changes in customer demand due to downturns in the economy could reduce our revenues.

The primary drivers of our electric operating expenses in any period are: (1) fuel and purchased power expenses, (2) maintenance and repairs expense, including repairs following severe weather and plant outages, (3) taxes and (4) non-cash items such as depreciation and amortization expense. Although we generally recover these expenses through our rates, there can be no assurance that we will recover all, or any part of, such increased costs in future rate cases.

The primary drivers of our gas operating revenues in any period are: (1) rates we can charge our customers, (2) weather, (3) customer growth, (4) the cost of natural gas and interstate pipeline transportation charges and (5) general economic conditions. Because natural gas is heavily used for residential and commercial heating, the demand for this product depends heavily upon weather patterns throughout our natural gas service territory and a significant amount of our natural gas revenues are recognized in the first and fourth quarters related to the heating seasons. Accordingly, our natural gas operations have historically generated less revenues and income when weather conditions are warmer in the winter.

The primary driver of our gas operating expense in any period is the price of natural gas.

Significant increases in electric and gas operating expenses or reductions in electric and gas operating revenues may occur and result in a material adverse effect on our business, financial condition and results of operations.

We are exposed to factors that can increase our fuel and purchased power expenditures, including disruption in deliveries of coal or natural gas, decreased output from our power plants, failure of performance by purchased power counterparties and market risk in our fuel procurement strategy.

Fuel and purchased power costs are our largest expenditures. Increases in the price of coal, natural gas or the cost of purchased power will result in increased electric operating expenditures. Given we have a fuel cost recovery mechanism in all of our jurisdictions, our net income exposure to the impact of the risks discussed above is significantly reduced. However, cash flow could still be impacted by these increased expenditures. We are also subject to prudency reviews which could negatively impact our net income if a regulatory commission would conclude our costs were incurred imprudently.

We depend upon regular deliveries of coal as fuel for our Riverton, Asbury, Iatan and Plum Point plants. Substantially all of this coal comes from mines in the Powder River Basin of Wyoming and is delivered to the plants by train. Production problems in these mines, railroad transportation or congestion problems, or unavailability of trains could affect delivery cycle times required to maintain plant inventory levels, causing us to implement coal conservation and supply replacement measures to retain adequate reserve inventories at our facilities. These measures could include some or all of the following: reducing the output of our coal plants, increasing the utilization of our gas-fired generation facilities, purchasing power from other suppliers, adding additional leased trains to our supply system and purchasing locally mined coal which can be delivered without using the railroads. Such measures could result in increased fuel and purchased power expenditures.

We have also established a risk management practice of purchasing contracts for future fuel needs to meet underlying customer needs and manage cost and pricing uncertainty. Within this activity, we may incur losses from these contracts. By using physical and financial instruments, we are exposed to credit risk and market risk. Market risk is the exposure to a change in the value of commodities caused by fluctuations in market variables, such as price. The fair value of derivative financial instruments we hold is adjusted cumulatively on a monthly basis until prescribed determination periods. At the end of each determination period, which is the last day of each calendar month in the period, any realized gain or loss for that period related to the contract will be reclassified to fuel expense and recovered or refunded to the customer through our fuel adjustment mechanisms. Credit risk is the risk that the counterparty might fail to fulfill its obligations under contractual terms.

We may be unable to recover increases in the cost of natural gas from our natural gas utility customers, or may lose customers as a result of any price increases.

In our natural gas utility business, we are permitted to recover the cost of gas directly from our customers through the use of a purchased gas adjustment provision. Our purchased gas adjustment provision is regularly reviewed by the MPSC. In addition to reviewing our adjustments to customer rates, the MPSC reviews our costs for prudency as well. To the extent the MPSC may determine certain costs were not incurred prudently, it could adversely affect our gas segment earnings and cash flows. In addition, increases in natural gas costs affect total prices to our customers and, therefore, the competitive position of gas relative to electricity and other forms of energy. Increases in natural gas costs may also result in lower usage by customers unable to switch to alternate fuels. Such disallowed costs or customer losses could have a material adverse effect on our business, financial condition and results of operations.

We are subject to regulation in the jurisdictions in which we operate.

We are subject to comprehensive regulation by federal and state utility regulatory agencies, which significantly influences our operating environment and our ability to recover our costs from utility customers. The utility commissions in the states where we operate regulate many aspects of our utility operations, including the rates that we can charge customers, siting and construction of facilities, pipeline safety and compliance, customer service and our ability to recover costs we incur, including capital expenditures and fuel and purchased power costs.

The FERC has jurisdiction over wholesale rates for electric transmission service and electric energy sold in interstate commerce. Federal, state and local agencies also have jurisdiction over many of our other activities.

Information concerning recent filings requesting increases in rates and related matters is set forth under Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations — Rate Matters."

We are unable to predict the impact on our operating results from the regulatory activities of any of these agencies. Despite our requests, these regulatory commissions have sole discretion to leave rates unchanged, grant increases or order decreases in the base rates we charge our utility customers. They have similar authority with respect to our recovery of increases in our fuel and purchased power costs. If our costs increase and we are unable to recover increased costs through base rates or fuel adjustment clauses, or if we are unable to fully recover our investments in new facilities, our results of operations could be materially adversely affected. Changes in regulations or the imposition of additional regulations could also have a material adverse effect on our results of operations.

Operations risks may adversely affect our business and financial results.

The operation of our electric generation, and electric and gas transmission and distribution systems involves many risks, including breakdown or failure of expensive and sophisticated equipment, processes and personnel performance; operating limitations that may be imposed by equipment conditions, environmental or other regulatory requirements; fuel supply or fuel transportation reductions or interruptions; transmission scheduling constraints; and catastrophic events such as fires, explosions, severe weather or other similar occurrences. In addition, our information technology systems and network infrastructure may be vulnerable to internal or external cyber attack, unauthorized access, computer viruses or other attempts to harm our systems or misuse our confidential information.

We have implemented training and preventive maintenance programs and have security systems and related protective infrastructure in place, but there is no assurance that these programs will prevent or minimize future breakdowns, outages or failures of our generation facilities or related business processes. In those cases, we would need to either produce replacement power from our other facilities or purchase power from other suppliers at potentially volatile and higher cost in order to meet our sales obligations, or implement emergency back-up business system processing procedures .

These and other operating events may reduce our revenues, increase costs, or both, and may materially affect our results of operations, financial position and cash flows.

Any reduction in our credit ratings could materially and adversely affect our business, financial condition and results of operations.

Currently, our corporate credit ratings and the ratings for our securities are as follows:

	Fitch	Moody's	Standard & Poor's
Corporate Credit Rating	n/r*	Baa2	BBB−
EDE First Mortgage Bonds	BBB+	A3	BBB+
Senior Notes	BBB	Baa2	BBB−
Commercial Paper	F3	P-2	A-3
Outlook	Stable	Stable	Stable

* Not rated.

The ratings indicate the agencies' assessment of our ability to pay the interest and principal of these securities. A rating is not a recommendation to purchase, sell or hold securities and each rating should be evaluated independently of any other rating. The lower the rating, the higher the interest cost of the securities when they are sold. In addition, a downgrade in our senior unsecured long-term debt rating would result in an increase in our borrowing costs under our bank credit facility. If any of our ratings fall below investment grade (investment grade is defined as Baa3 or above for Moody's and BBB- or above for Standard & Poor's and Fitch), our ability to issue short-term debt, commercial paper or other securities or to market those securities would be impaired or made more difficult or expensive. Therefore, any such downgrades could have a material adverse effect on our business, financial condition and results of operations. In addition, any actual downgrade of our commercial paper rating from Moody's or Fitch, may make it difficult for us to issue commercial paper. To the extent we are unable to issue commercial paper, we will need to meet our short-term debt needs through borrowings under our revolving credit facilities, which may result in higher costs.

We cannot assure you that any of our current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances in the future so warrant.

We are subject to environmental laws and the incurrence of environmental liabilities which may adversely affect our business, financial condition and results of operations.

We are subject to extensive federal, state and local regulation with regard to air and other environmental matters. Failure to comply with these laws and regulations could have a material adverse effect on our results of operations and financial position. In addition, new environmental laws and regulations, and new interpretations of existing environmental laws and regulations, have been adopted and may in the future be adopted which may substantially increase our future environmental expenditures for both new facilities and our existing facilities. Compliance with current and future air emission standards (such as those limiting emission levels of sulfur dioxide (SO_2), emissions of mercury, other hazardous pollutants (HAPS), nitrogen oxide (NOx), and, potentially, carbon dioxide (CO_2)) has required, and may in the future require, significant environmental expenditures. Although we have historically recovered such costs through our rates, there can be no assurance that we will recover all, or any part of, such increased costs in future rate cases. The incurrence of additional material environmental costs which are not recovered in our rates may result in a material adverse effect on our business, financial condition and results of operations.

The cost and schedule of construction projects may materially change.

Our capital expenditure budget for the next three years is estimated to be $470.2 million. This includes expenditures for environmental upgrades to our existing facilities and additions to our transmission and distribution systems. There are risks that actual costs may exceed budget estimates, delays may occur in obtaining permits and materials, suppliers and contractors may not perform as required under their contracts, there may be inadequate availability, productivity or increased cost of qualified craft labor, start-up activities may take longer than planned, the scope and timing of projects may change, and other events beyond our control may occur that may materially affect the schedule, budget, cost and performance of projects. To the extent the completion of projects is delayed, we expect that the timing of receipt of increases in base rates reflecting our investment in such projects will be correspondingly delayed. Costs associated with these projects will also be subject to prudency review by regulators as part of future rate case filings and all costs may not be allowed recovery.

Financial market disruptions may increase financing costs, limit access to the credit markets or cause reductions in investment values in our pension plan assets.

We estimate our capital expenditures to be $147.2 million in 2012. Although we believe it is unlikely we will have difficulty accessing the markets for the capital needed to complete these projects (if such a need arises), financing costs could fluctuate. Our pension plan and Other Postretirement Benefits (OPEB) costs increased, resulting in an $8.8 million increase in our 2010 net pension and OPEB liability. During 2011, our net pension and OPEB liability increased $8.2 million. We expect to fund approximately $14.3 million in 2012 for pension and OPEB liabilities. Future market changes could result in increased pension and OPEB liabilities and funding obligations.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Electric Segment Facilities

At December 31, 2011, we owned generating facilities with an aggregate generating capacity of 1,392 megawatts.

Our principal electric baseload generating plant is the Asbury Plant with 207 megawatts of generating capacity. The plant, located near Asbury, Missouri, is a coal-fired generating station with two steam turbine generating units. The plant presently accounts for approximately 14% of our owned generating capacity and in 2011 accounted for approximately 27.0% of the energy generated by us. Routine plant maintenance, during which the entire plant is taken out of service, is scheduled annually, normally for approximately three to four weeks in the spring. Approximately every fifth year, the maintenance outage is scheduled to be extended to approximately six weeks to permit inspection of the Unit No. 1 turbine. The next such outage is scheduled to take place in the fall of 2013. The Unit No. 2 turbine is inspected approximately every 35,000 hours of operations and was last inspected in 2001. As of December 31, 2011, Unit No. 2 has operated approximately 3,341 hours since its last turbine inspection in 2001. When the Asbury Plant is out of service, we typically experience increased purchased power and fuel expenditures associated with replacement energy, which is now likely to be recovered through our fuel adjustment clauses.

Our generating plant located at Riverton, Kansas, has two steam-electric generating units (Units 7 and 8) with an aggregate generating capacity of 92 megawatts and four gas-fired combustion turbine units (Units 9, 10, 11 and 12) with an aggregate generating capacity of 187 megawatts. The steam-electric generating units burn coal as a primary fuel and have the capability of burning natural gas. We installed a Siemens V84.3A2 combustion turbine (Unit 12) at our Riverton plant in 2007. It began commercial operation on April 10, 2007.

We own a 12% undivided interest in the coal-fired Unit No. 1 and Unit No. 2 at the Iatan Generating Station located near Weston, Missouri, 35 miles northwest of Kansas City, Missouri, as well as a 3% interest in the site and a 12% interest in certain common facilities. Unit No. 2 entered commercial operation on December 31, 2010. We are entitled to 12% of the units' available capacity, currently 85 megawatts for Unit No. 1 and 102 megawatts for Unit No. 2, and are obligated to pay for that percentage of the operating costs of the units. KCP&L operates the units for the joint owners.

We own a 7.52% undivided interest in the coal-fired Plum Point Energy Station located near Osceola, Arkansas. We are entitled to 50 megawatts, or 7.52% of the unit's available capacity. The Plum Point Energy Station entered commercial operation on September 1, 2010.

Our State Line Power Plant, which is located west of Joplin, Missouri, consists of Unit No. 1, a combustion turbine unit with generating capacity of 94 megawatts and a Combined Cycle Unit with generating capacity of 495 megawatts of which we are entitled to 60%, or 295 megawatts. The Combined Cycle Unit consists of the combination of two combustion turbines, two heat recovery steam generators, a steam turbine and auxiliary equipment. The Combined Cycle Unit is jointly owned with Westar Generating Inc., a subsidiary of Westar Energy, Inc., which owns the remaining 40% of the unit. Westar reimburses us for a percentage of the operating costs per our joint ownership agreement. We are the operator of the Combined Cycle Unit. All units at our State Line Power Plant burn natural gas as a primary fuel with Unit No. 1 having the additional capability of burning oil.

We have four combustion turbine peaking units at the Empire Energy Center in Jasper County, Missouri, with an aggregate generating capacity of 262 megawatts. These peaking units operate on natural gas, as well as oil.

Our hydroelectric generating plant (FERC Project No. 2221), located on the White River at Ozark Beach, Missouri, has a generating capacity of 16 megawatts. We have a long-term license from FERC to operate this plant which forms Lake Taneycomo in southwestern Missouri. As part of the Energy and Water Development Appropriations Act of 2006 (the Appropriations Act), a new minimum flow pattern was established with the intent of increasing minimum flows on recreational streams in Arkansas. To accomplish this, the level of Bull Shoals Lake will be increased an average of 5 feet. The increase at Bull Shoals will decrease the net head waters available for generation at Ozark Beach by 5 feet and, thus, reduce our electrical output. We estimate the lost production to be up to 16% of our average annual energy production for this unit. The loss in this facility would require us to replace it with additional generation from our gas-fired and coal-fired units or with purchased power. The Appropriations Act required the Southwest Power Administration (SWPA), in coordination with us and our relevant public service commissions, to determine our economic detriment assuming a January 1, 2011 implementation date. On June 17, 2010, the SWPA posted a revised Final Determination that our customers' damages were $26.6 million. On September 16, 2010, we received a $26.6 million payment from the SWPA, which was deferred and recorded as a noncurrent liability. We originally increased our current tax liability by approximately $10.0 million recognizing that the $26.6 million payment might have been considered taxable income in 2010. During the first quarter of 2011, we submitted a pre-filing agreement with the Internal Revenue Service (IRS) requesting that a determination be made regarding whether or not the payment could be deferred under certain sections of the Internal Revenue code. The IRS accepted our position that the payment be deferred for tax purposes and recognized over the next twenty years. As such, we reduced the current tax liability in accordance with this deferral. The SWPA payment, net of taxes, is being used to reduce fuel expense for our customers in all our jurisdictions. In addition, it is our current understanding that the SWPA has delayed the implementation of the new minimum flows until 2016.

At December 31, 2011, our transmission system consisted of approximately 22 miles of 345 kV lines, 441 miles of 161 kV lines, 745 miles of 69 kV lines and 81 miles of 34.5 kV lines. Our distribution system consisted of approximately 6,842 miles of line at December 31, 2011 as compared to 6,923 miles of line at December 31, 2010. The decrease is due to distribution system lines destroyed during the May 22, 2011 tornado that have not yet been replaced.

Our electric generation stations, other than Plum Point Energy Station, are located on land owned in fee. We own a 3% undivided interest as tenant in common in the land for the Iatan Generating Station. We own a similar interest in 60% of the land used for the State Line Combined Cycle Unit. Substantially all of our electric transmission and distribution facilities are located either (1) on property leased or owned in fee; (2) over streets, alleys, highways and other public places, under franchises or other rights; or (3) over private property by virtue of easements obtained from the record holders of title. Substantially all of our electric segment property, plant and equipment are subject to the EDE Mortgage.

We also own and operate water pumping facilities and distribution systems consisting of a total of approximately 87 miles of water mains in three communities in Missouri.

Gas Segment Facilities

At December 31, 2011, our principal gas utility properties consisted of approximately 87 miles of transmission mains and approximately 1,130 miles of distribution mains.

Substantially all of our gas transmission and distribution facilities are located either (1) on property leased or owned in fee; (2) under streets, alleys, highways and other public places, under franchises or other rights; or (3) under private property by virtue of easements obtained from the record holders of title. Substantially all of our gas segment property, plant and equipment are subject to the EDG Mortgage.

Other Segment

Our other segment consists of our leasing of fiber optics cable and equipment (which we also use in our own utility operations).

ITEM 3. LEGAL PROCEEDINGS

See Note 11 of "Notes to Consolidated Financial Statements" under Item 8, which description is incorporated herein by reference.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

Our common stock is listed on the New York Stock Exchange. On February 3, 2012, there were 4,738 record holders and 28,680 individual participants in security position listings. The high and low sale prices for our common stock as reported by the New York Stock Exchange for composite transactions, and the amount per share of quarterly dividends declared and paid on the common stock for each quarter of 2011 and 2010 were as follows:

	Price of Common Stock				Dividends Paid Per Share	
	2011		2010			
	High	Low	High	Low	2011	2010
First Quarter	$22.40	$20.70	$19.30	$17.75	$0.32	$0.32
Second Quarter	23.26	18.01	20.00	17.57	0.32	0.32
Third Quarter	21.12	18.10	20.41	18.41	0.00	0.32
Fourth Quarter	21.40	18.41	22.50	20.06	0.00	0.32

Holders of our common stock are entitled to dividends, if, as, and when declared by the Board of Directors, out of funds legally available therefore subject to the prior rights of holders of any outstanding cumulative preferred stock and preference stock. Payment of dividends is determined by our Board of Directors after considering all relevant factors, including the amount of our retained earnings, which is essentially our accumulated net income less dividend payouts. In response to the expected loss of revenues resulting from the May 22, 2011 tornado, our level of retained earnings and other relevant factors, our Board of Directors suspended our quarterly dividend for the third and fourth quarters of 2011. On February 2, 2012, the Board of Directors re-established the dividend and declared a quarterly dividend of $0.25 per share on common stock payable on March 15, 2012 to holders of record as of March 1, 2012. As of December 31, 2011, our retained earnings balance was $33.7 million, compared to $5.5 million at December 31, 2010. A reduction of our dividend per share, partially or in whole, could have an adverse effect on our common stock price.

See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operation — Dividends"for information on limitations on our ability to pay dividends on our common stock.

During 2011, no purchases of our common stock were made by or on behalf of us.

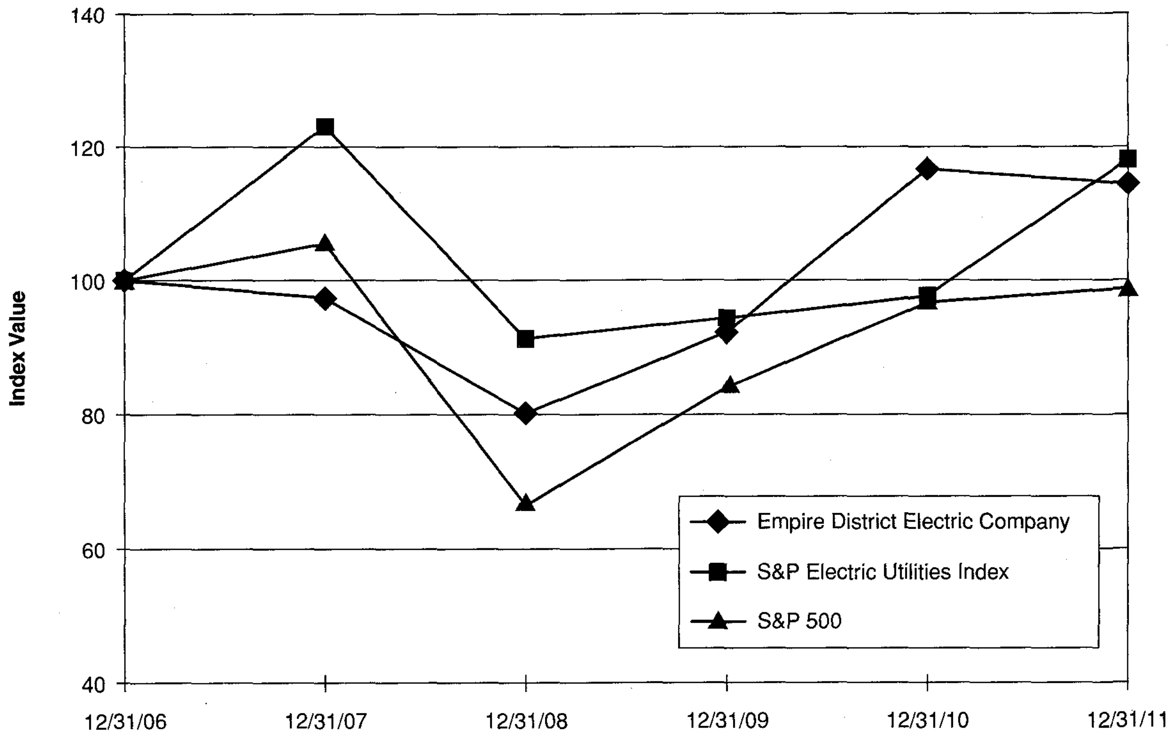
Participants in our Dividend Reinvestment and Stock Purchase Plan may acquire, at a 3% discount, newly issued common shares with reinvested dividends. Participants may also purchase, at an averaged market price, newly issued common shares with optional cash payments on a weekly basis, subject to certain restrictions. We also offer participants the option of safekeeping for their stock certificates.

Our shareholders rights plan, dated July 26, 2000, expired July 25, 2010, pursuant to its terms. See Note 5 of "Notes to Consolidated Financial Statements" under Item 8 for additional information. In addition, we have stock based compensation programs which are described in Note 4 of "Notes to Consolidated Financial Statements" under Item 8.

Our By-laws provide that K.S.A. Sections 17-1286 through 17-1298, the Kansas Control Share Acquisitions Act, will not apply to control share acquisitions of our capital stock.

See Note 4 of "Notes to Consolidated Financial Statements" under Item 8 for additional information regarding our common stock and equity compensation plans.

The following graph and table indicates the value at the end of the specified years of a $100 investment made on December 31, 2006, in our common stock and similar investments made in the securities of the companies in the Standard & Poor's 500 Composite Index (S&P 500 Index) and the Standard & Poor's Electric Utilities Index (S&P Electric Utility). The graph and table assume that dividends were reinvested when received.



Total Return Analysis	12/31/2006	12/31/2007	12/31/2008	12/31/2009	12/31/2010	12/31/2011
The Empire District Electric Company	**$100.00**	**$ 97.38**	**$80.21**	**$92.21**	**$116.73**	**$114.46**
S&P Electric Utilities Index	**$100.00**	**$123.13**	**$91.31**	**$94.39**	**$ 97.64**	**$118.11**
S&P 500 Index	**$100.00**	**$105.49**	**$66.46**	**$84.05**	**$ 96.71**	**$ 98.76**

ITEM 6. SELECTED FINANCIAL DATA

(in thousands, except per share amounts)

	2011	2010	2009	2008	2007
Operating revenues	**$ 576,870**	$ 541,276	$ 497,168	$ 518,163	$ 490,160
Operating income	**$ 96,934**	$ 80,495	$ 74,495	$ 71,012	$ 65,566
Total allowance for funds used during construction	**$ 512**	$ 10,174	$ 14,133	$ 12,518	$ 7,665
Income from continuing operations	**$ 54,971**	$ 47,396	$ 41,296	$ 39,722	$ 33,181
Income (loss) from discontinued operations, net of tax	**$ —**	$ —	$ —	$ —	$ 63
Net income	**$ 54,971**	$ 47,396	$ 41,296	$ 39,722	$ 33,244
Weighted average number of common shares outstanding — basic	**41,852**	40,545	34,924	33,821	30,587
Weighted average number of common shares outstanding — diluted	**41,887**	40,580	34,956	33,860	30,610
Earnings from continuing operations per weighted average share of common stock — basic and diluted	**$ 1.31**	$ 1.17	$ 1.18	$ 1.17	$ 1.09
Loss from discontinued operations per weighted average share of common stock — basic and diluted	**$ —**	$ —	$ —	$ —	$ 0.00
Total earnings per weighted average share of common stock — basic and diluted	**$ 1.31**	$ 1.17	$ 1.18	$ 1.17	$ 1.09
Cash dividends per share	**$ 0.64**	$ 1.28	$ 1.28	$ 1.28	$ 1.28
Common dividends paid as a percentage of net income	**48.6%**	109.7%	108.5%	109.0%	117.2%
Allowance for funds used during construction as a percentage of net income	**0.9%**	21.5%	34.2%	31.5%	23.1%
Book value per common share (actual) outstanding at end of year	**$ 16.53**	$ 15.82	$ 15.75	$ 15.56	$ 16.04
Capitalization:					
Common equity	**$ 693,989**	$ 657,624	$ 600,150	$ 528,872	$ 539,176
Long-term debt	**$ 692,259**	$ 693,072	$ 640,156	$ 611,567	$ 541,880
Ratio of earnings to fixed charges	**2.87x**	2.63x	2.15x	2.19x	2.08x
Total assets	**$2,021,835**	$1,921,311	$1,839,846	$1,713,846	$1,473,074
Plant in service at original cost	**$2,176,650**	$2,108,115	$1,718,584	$1,586,152	$1,506,234
Capital expenditures (including AFUDC)	**$ 101,177**	$ 108,157	$ 148,804	$ 206,405	$ 195,568

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

EXECUTIVE SUMMARY

We operate our businesses as three segments: electric, gas and other. The Empire District Electric Company (EDE) is an operating public utility engaged in the generation, purchase, transmission, distribution and sale of electricity in parts of Missouri, Kansas, Oklahoma and Arkansas. As part of our electric segment, we also provide water service to three towns in Missouri. The Empire District Gas Company (EDG) is our wholly owned subsidiary. It provides natural gas distribution to customers in 44 communities in northwest, north central and west central Missouri. Our other segment consists of our fiber optics business.

During the year ended December 31, 2011, our gross operating revenues were derived as follows:

Electric segment sales*	90.9%
Gas segment sales	8.0
Other segment sales	1.1

* Sales from our electric segment include 0.3% from the sale of water.

Electric Segment

The primary drivers of our electric operating revenues in any period are: (1) rates we can charge our customers, (2) weather, (3) customer growth and (4) general economic conditions. The utility commissions in the states in which we operate, as well as the Federal Energy Regulatory Commission (FERC), set the rates which we can charge our customers. In order to offset expenses, we depend on our ability to receive adequate and timely recovery of our costs (primarily fuel and purchased power) and/or rate relief. We assess the need for rate relief in all of the jurisdictions we serve and file for such relief when necessary. The effects of timing of rate relief are discussed in detail in Note 3 of "Notes to the Consolidated Financial Statements" under Item 8. Of the factors driving revenues, weather has the greatest short-term effect on the demand for electricity for our regulated business. Very hot summers and very cold winters increase electric demand, while mild weather reduces demand. Residential and commercial sales are impacted more by weather than industrial sales, which are mostly affected by business needs for electricity and by general economic conditions. Customer growth, which is the growth in the number of customers, contributes to the demand for electricity. Our annual customer growth is calculated by comparing the number of customers at the end of a year to the number of customers at the end of the prior year. Due to the devastating EF-5 tornado that hit the Joplin, Missouri area on May 22, 2011, damaging or destroying thousands of homes and businesses (discussed below), we ended 2011 with 1.5% fewer electric customers. As we continue to add customers back to our system, our customer growth expectations range from approximately 0.5% to 1.1% over the next several years. We define electric sales growth to be growth in kWh sales period over period excluding the impact of weather. The primary drivers of electric sales growth are customer growth and general economic conditions.

The primary drivers of our electric operating expenses in any period are: (1) fuel and purchased power expense, (2) operating maintenance and repairs expense, including repairs following severe weather and plant outages, (3) taxes and (4) non-cash items such as depreciation and amortization expense. Historically, fuel and purchased power costs were the expense items that had the most significant impact on our net income. However, with the addition of the Missouri fuel adjustment mechanism in 2008, we now have a fuel cost recovery mechanism in all of our jurisdictions, which significantly reduces the impact of fluctuating fuel and purchased power costs on our net income.

Gas Segment

The primary drivers of our gas operating revenues in any period are: (1) rates we can charge our customers, (2) weather, (3) customer growth, (4) the cost of natural gas and interstate pipeline transportation charges and (5) general economic conditions. The MPSC sets the rates which we can charge our customers. In order to offset expenses, we depend on our ability to receive adequate and timely recovery of our costs (primarily commodity natural gas) and/or rate relief. We assess the need for rate relief and file for such relief when necessary. A Purchased Gas Adjustment (PGA) clause is included in our gas rates, which allows us to recover our actual cost of natural gas from customers through rate changes, which are made periodically (up to four times) throughout the year in response to weather conditions, natural gas costs and supply demands. Weather affects the demand for natural gas. Very cold winters increase demand for gas, while mild weather reduces demand. Due to the seasonal nature of the gas business, revenues and earnings are typically concentrated in the November through March period, which generally corresponds with the heating season. Customer growth, which is the growth in the number of customers, contributes to the demand for gas. Our annual customer growth is calculated by comparing the number of customers at the end of a year to the number of customers at the end of the prior year. Our gas segment customer contraction for the year ended December 31, 2011 was 0.9%, which we believe was due to depressed economic conditions. We expect gas customer growth to be flat during the next several years. We define gas sales growth to be growth in mcf sales excluding the impact of weather. The primary drivers of gas sales growth are customer growth and general economic conditions.

The primary driver of our gas operating expense in any period is the price of natural gas. However, because gas purchase costs for our gas utility operations are normally recovered from our customers, any change in gas prices does not have a corresponding impact on income unless such costs are deemed imprudent or cause customers to reduce usage.

Earnings

For the year ended December 31, 2011, basic and diluted earnings per weighted average share of common stock were $1.31 on $54.9 million of net income compared to $1.17 on $47.4 million of net income for the year ended December 31, 2010. The primary positive driver for 2011 as compared to 2010 was increased electric revenues due primarily to rate increases. These increases were partially offset by a decrease in sales due to the loss of customers resulting from the May 22, 2011 tornado. Other negative drivers for 2011 as compared to 2010 were increased electric segment operation and maintenance expenses, increased depreciation and amortization amounts resulting from the completion of our construction program and changes in AFUDC amounts. A portion of the increase in depreciation and amortization expense reflects the effect of additional regulatory amortization collected in revenues in our Missouri rate case effective September 2010. The regulatory amortization expense ended effective June 15, 2011.

The table below sets forth a reconciliation of basic and diluted earnings per share between 2010 and 2011, which is a non-GAAP presentation. The economic substance behind our non-GAAP earnings per share (EPS) measure is to present the after tax impact of significant items and components of the statement of income on a per share basis before the impact of additional stock issuances.

We believe this presentation is useful to investors because the statement of income does not readily show the EPS impact of the various components, including the effect of new stock issuances. This could limit the readers' understanding of the reasons for the EPS change from previous years. This information is useful to management, and we believe this information is useful to investors, to better understand the reasons for the fluctuation in EPS between the prior and current years on a per share basis.

This reconciliation may not be comparable to other companies or more useful than the GAAP presentation included in the statements of income. We also note that this presentation does not purport to be an alternative to earnings per share determined in accordance with GAAP as a measure of operating performance or any other measure of financial performance presented in accordance with GAAP.

Management compensates for the limitations of using non-GAAP financial measures by using them to supplement GAAP results to provide a more complete understanding of the factors and trends affecting the business than GAAP results alone. The dilutive effect of additional shares issued included in the table reflects the estimated impact of all shares issued during the period.

Earnings Per Share — 2010	$ 1.17
Revenues	
Electric on-system	$ 0.62
Electric off-system and other	0.02
Gas	(0.07)
Other	0.01
Expenses	
Electric fuel and purchased power	(0.02)
Cost of natural gas sold and transported	0.06
Operating — electric segment	(0.12)
Operating — gas segment	0.02
Maintenance and repairs	(0.07)
Depreciation and amortization	(0.08)
Other taxes	(0.05)
Interest charges	0.01
AFUDC	(0.15)
Change in effective income tax rates	0.00
Dilutive effect of additional shares issued	(0.04)
Other income and deductions	0.00
Earnings Per Share — 2011	**$ 1.31**

Fourth Quarter Results

Earnings for the fourth quarter of 2011 were $8.7 million, or $0.21 per share, as compared to $8.5 million, or $0.20 per share, in the fourth quarter 2010. Electric segment revenues for the quarter ended December 31, 2011 increased $1.1 million compared to the same period in 2010 mainly due to rate increases in 2011. Other regulated operating expenses increased $2.8 million in the fourth quarter of 2011 primarily related to increased operating expenses due to new plant in service, increased pension and retiree healthcare expenses and a $0.7 million increase in maintenance expenses. These increases were partially offset by a $2.7 million decrease in depreciation primarily due to a decrease in the amount recorded for regulatory amortization.

2011 Activities

Tornado and Dividend Suspension

On May 22, 2011, a devastating EF-5 tornado hit the Joplin, Missouri area damaging or destroying thousands of homes and businesses. At the end of the second quarter of 2011, approximately 4,200 customers remained unable to return to service due to damaged or destroyed structures with that number being reduced to approximately 3,600 customers by the end of the third quarter. Approximately 600 temporary housing facilities were added to our system during the third quarter to shelter some local residents displaced by the tornado. Joplin's continuing tornado recovery efforts have resulted in approximately 2,300 customers still unable to return to service in the Joplin area at the end of 2011. As of December 31, 2011, our system-wide customer count is down by approximately 1,800 as compared to pre-tornado levels. We estimate that lost customers from the tornado will reduce kilowatt hour sales approximately less than 1% over the near term. Storm restoration costs were initially estimated to be in the $20 million to $30 million range. As of December 31, 2011, approximately $20.6 million in initial storm costs have been incurred as well as approximately $5.5 million in new service extensions to customers. The majority of these costs have been capitalized. We expect to spend an additional $6.5 million to rebuild our destroyed substation, but anticipate insurance proceeds will cover most of this cost. The ongoing loss of revenue associated with the tornado was mitigated in 2011 by increased usage due to storm recovery efforts, rate increases that became effective during 2010 and early 2011 and record hot weather during the month of July. We expect the loss of electric load and corresponding revenues to abate as customers rebuild. As we continue to add customers back to our system, our customer growth expectations range from approximately 0.5% to 1.1% over the next several years.

In response to this expected loss of revenues, our level of retained earnings and other relevant factors, our Board of Directors suspended our quarterly dividend for the third and fourth quarters of 2011. On February 2, 2012, the Board of Directors re-established the dividend and declared a quarterly dividend of $0.25 per share on common stock payable on March 15, 2012 to holders of record as of March 1, 2012.

On June 6, 2011, we filed an Accounting Authority Order with the MPSC requesting authorization to defer expenses associated with the tornado and to allow for recovery of the loss of the fixed cost component included in our rates resulting from the lost sales. On November 15, 2011, a joint settlement agreement was filed with the MPSC allowing us to defer actual incremental operating and maintenance expenses associated with the repair, restoration and rebuilding activities resulting from the tornado. The settlement does not include deferral of the loss of revenues associated with the fixed cost component included in our rates due to the reduction in customers served by us as a result of the tornado. The settlement was approved by the MPSC on November 30, 2011, effective December 7, 2011. For additional information, see "Rate Matters" below.

Environmental Compliance

In July 2011, the Environmental Protection Agency (EPA) finalized the Cross State Air Pollution Rule (CSAPR) requiring a reduction in NOx and SO_2 levels by 2014. The rule was scheduled to take effect January 1, 2012, but the District of Columbia Circuit Court of Appeals issued a last-minute stay in late December 2011. In the meantime, we are moving forward with our compliance plan, as detailed in Note 11 to the consolidated financial statements, to meet Mercury and Air Toxics Standards (MATS) Rules, which will assist in meeting final CSAPR requirements. See Note 11 of "Notes to Consolidated Financial Statements" under Item 8 for additional information.

New Union Agreement

At December 31, 2011, we had 746 full-time employees, including 51 employees of EDG. 336 of the EDE employees are members of Local 1474 of The International Brotherhood of Electrical Workers (IBEW). On October 17, 2011, the Local 1474 IBEW voted to ratify a new two-year agreement which will extend through October 31, 2013.

Iatan Coal Conservation related to Missouri River Flooding

The Iatan plant, located along the Missouri River north of Kansas City and operated by Kansas City Power & Light ("KCP&L"), was impacted by flooding in the Midwest during June and July of 2011. Beginning June 30, 2011 coal deliveries to Iatan were suspended. As a result, in early July it was decided to begin operating Iatan Units 1 and 2 at reduced loads in an effort to conserve coal. Additionally, we entered into a short term purchase of power for the month of August to address a portion of the lost generation from the Iatan units. We expect that additional fuel and purchased power costs incurred as a result of this event will be recovered in our rates through fuel recovery mechanisms. The Iatan plant returned to normal operations on October 13, 2011.

Amendment of EDE Mortgage

On June 9, 2011, we amended the Indenture of Mortgage and Deed of Trust of The Empire District Electric Company (EDE Mortgage) in order to provide us with additional flexibility to pay dividends to our shareholders by permitting the payment of any dividend or distribution on, or purchase of, shares of its common stock within 60 days after the related date of declaration or notice of such dividend, distribution or purchase if (i) on the date of declaration or notice, such dividend, distribution or purchase would have complied with the provisions of the indenture and (ii) as of the last day of the calendar month ended immediately preceding the date of such payment, our ratio of total indebtedness to total capitalization (after giving pro forma effect to the payment of such dividend, distribution, or purchase) was not more than 0.625 to 1. The amendment followed the successful completion of a solicitation of consents from the holders of our First Mortgage Bonds outstanding under the EDE Mortgage. We received consents from holders of 73.91% in aggregate principal amount of the outstanding bonds and paid consent fees of approximately $0.9 million. See "Dividends" below.

Financings

On January 28, 2011, we filed a $400 million shelf registration statement with the SEC covering our common stock, unsecured debt securities, preference stock, and first mortgage bonds. This shelf registration statement became effective on February 7, 2011. We have received regulatory approval for the issuance of securities under this shelf from all four states in our electric service territory, but we may only issue up to $250 million of such securities in the form of first mortgage bonds. We plan to use proceeds from offerings made pursuant to this shelf to fund capital expenditures, refinancings of existing debt or general corporate needs during the three-year effective period.

On January 17, 2012, we entered into the Third Amended and Restated Unsecured Credit Agreement which amended and restated our Second Amended and Restated Unsecured Credit Agreement dated January 26, 2010. This agreement extended the termination date of the revolving credit facility from January 26, 2013 to January 17, 2017 and reduced the pricing. The agreement also removes the letter of credit facility and includes a swingline loan facility with a $15 million swingline loan sublimit. The aggregate amount of the revolving credit commitments remains $150 million, inclusive of the $15 million swingline loan sublimit. See "Liquidity and Capital Resources" below for additional information.

Regulatory Matters

A settlement agreement among the parties to our Missouri rate case filed on September 28, 2010 was approved by the MPSC on June 1, 2011, reflecting an overall annual increase in rates of $18.7 million, or approximately 4.7%, effective June 15, 2011. Due to rate design changes, this rate increase, however, will primarily impact our winter season rates which generally run from October through May. Also as part of the settlement, regulatory amortization expense of $14.5 million annually and construction accounting terminated on June 15, 2011. The approved settlement included authorization of a tracker mechanism for the SWPA payment associated with the capacity restrictions to be implemented for our Ozark Beach hydro facility. We agreed to flow the SWPA payment, net of tax, back to our customers over a ten year period using a tracker mechanism resulting in an annual decrease to expenses of approximately $1.4 million. The settlement agreement also allowed for a tracker mechanism related to Plum Point, Iatan 2 and Iatan common plant operating expenses. We have recorded a regulatory asset for the difference between actual expenses (excluding fuel and fuel related expenses) and the amount of expense included in base rates.

On June 17, 2011, we filed an application with the Kansas Corporation Commission (KCC) seeking a rate increase of $1.5 million, or 6.39%. The rate increase was requested to recover the costs associated with our investment in the Iatan 1, Iatan 2 and Plum Point generating units and the depreciation and operation and maintenance costs deferred since the in-service dates of the units. The June 17, 2011 filing was made under the KCC's abbreviated rate case rules which the KCC authorized in our 2009 Kansas rate case. The case included a request to recover the Iatan and Plum Point cost deferrals over a 3-year period. A joint settlement agreement was filed on November 10, 2011 and approved by the KCC on December 21, 2011, resulting in an increase in annual revenues of $1.25 million, or approximately 5.2%. The new rates became effective on January 1, 2012.

On June 30, 2011, we filed a request with the Oklahoma Corporation Commission (OCC) for an annual increase in base rates for our Oklahoma electric customers in the amount of $0.6 million, or 4.1% over the base rate and Capital Reliability Rider (CRR) revenues that were currently in effect. A stipulation and agreement, reached by all parties participating in the case, was filed on November 17, 2011. This agreement, which was approved by the OCC on January 4, 2012, made rates previously collected under the CRR permanent and will result in a net overall increase of total annual revenues of $0.2 million, or approximately 1.66%. The agreement also removes fuel and purchase power costs from base rates. Fuel and purchase power costs will be listed as a separate line item, identified as the Fuel Adjustment Charge, on customers bills.

On February 2, 2011 we entered into a unanimous settlement agreement with the parties involved in our Arkansas rate case filed August 19, 2010. The settlement included a general rate increase of $2.1 million, or 19%. The APSC approved the settlement on April 12, 2011 with the new rates effective April 13, 2011.

On March 12, 2010, we filed Generation Formula Rate (GFR) tariffs with the FERC which we propose to be utilized for our wholesale customers. On May 28, 2010, the FERC issued an order that conditionally approved our GFR filing subject to refund effective June 1, 2010. On June 30, 2010, three of our on-system wholesale customers were granted intervention in the GFR rate case. On September 15, 2010, the parties agreed to a settlement in principle and on May 24, 2011, we, the Missouri Public Utility Alliance and the cities of Monett, Mt. Vernon and Lockwood, Missouri filed a Settlement Agreement and Offer of Settlement with the FERC which was approved on November 3, 2011. We refunded approximately $1.3 million, including interest, in November 2011 as a result of this settlement.

See Note 3 of "Notes to the Consolidated Financial Statements" under Item 8 for additional information regarding rate matters.

Litigation

A lawsuit has been filed in Jasper County Circuit Court against us by three of our residential customers, purporting to act on behalf of all Empire customers. These customers are seeking a refund of certain amounts paid for service provided by Empire between January 1, 2007, and December 13, 2007. We will vigorously defend against the claims made against us by these three residential customers. At all times, we charged the three plaintiffs, and all of our customers, the rates approved by and on file with the MPSC.

The rates charged by us during the time period at issue were approved by the MPSC in our 2006 rate case. The orders of the MPSC in that case were appealed by the OPC, acting on behalf of the public, and certain industrial customers. The Missouri Court of Appeals affirmed all decisions entered by the MPSC in our 2006 rate case.

RESULTS OF OPERATIONS

The following discussion analyzes significant changes in the results of operations for the years 2011, 2010 and 2009.

The following table represents our results of operations by operating segment for the applicable years ended December 31 (in millions):

	2011	2010	2009
Electric	$50.6	$43.2	$39.1
Gas	2.7	2.6	0.9
Other	1.6	1.6	1.3
Net income	**$54.9**	**$47.4**	**$41.3**

Electric Segment

Overview

Our electric segment income for 2011 was $50.6 million as compared to $43.2 million for 2010.

Electric operating revenues comprised approximately 90.6% of our total operating revenues during 2011. Electric operating revenues for 2011, 2010, and 2009 were comprised of the following:

	2011	2010	2009
Residential	42.4%	42.4%	41.6%
Commercial	30.1	30.3	31.4
Industrial	15.1	14.4	15.2
Wholesale on-system	3.7	4.0	4.2
Wholesale off-system	4.5	4.7	3.3
Miscellaneous sources*	2.6	2.6	2.7
Other electric revenues	1.6	1.6	1.6

* Primarily other public authorities

The amounts and percentage changes from the prior periods in kilowatt-hour ("kWh") sales and electric segment operating revenues by major customer class for on-system and off-system sales were as follows:

Customer Class	2011	2010	% Change(1)	2010	2009	% Change(1)
Residential	1,982.7	2,060.4	(3.8)%	2,060.4	1,866.5	10.4%
Commercial	1,576.3	1,644.9	(4.2)	1,644.9	1,579.8	4.1
Industrial	1,022.8	1,007.0	1.6	1,007.0	992.2	1.5
Wholesale on-system	364.9	355.8	2.5	355.8	332.0	7.2
Other(2)	128.7	126.5	1.8	126.5	123.4	2.5
Total on-system sales	5,075.4	5,194.6	(2.3)	5,194.6	4,893.9	6.1
Off-system	740.0	798.1	(7.3)	798.1	515.9	54.7
Total KWh Sales	5,815.4	5,992.7	(3.0)	5,992.7	5,409.8	10.8

(1) Percentage changes are based on actual kWh sales and may not agree to the rounded amounts shown above.

(2) Other kWh sales include street lighting, other public authorities and interdepartmental usage.

Customer Class	2011	2010	% Change[1]	2010	2009	% Change[1]
Residential	$221.7	$204.9	8.2%	$204.9	$180.4	13.6%
Commercial	157.4	146.3	7.6	146.3	135.8	7.7
Industrial	78.9	69.7	13.3	69.7	66.0	5.6
Wholesale on-system	19.1	19.2	(0.6)	19.2	18.2	5.8
Other[2]	13.9	12.3	12.7	12.3	11.6	6.1
Total on-system revenues	491.0	452.4	8.5	452.4	412.0	9.8
Off-system	23.3	22.9	1.7	22.9	14.3	59.6
Total revenues from KWh sales	514.3	475.3	8.2	475.3	426.3	11.5
Miscellaneous revenues[3]	8.2	7.6	8.2	7.6	6.8	11.1
Total electric operating revenues	$522.5	$482.9	8.2	$482.9	$433.1	11.5
Water revenues	1.8	1.8	(1.9)	1.8	1.8	2.3
Total Electric Segment Operating Revenues	$524.3	$484.7	8.2	$484.7	$434.9	11.5

(1) Percentage changes are based on actual revenues and may not agree to the rounded amounts shown above.

(2) Other operating revenues include street lighting, other public authorities and interdepartmental usage.

(3) Miscellaneous revenues include transmission service revenues, late payment fees, renewable energy credit sales, rent, etc.

We have a fuel cost recovery mechanism in all of our jurisdictions, which significantly reduces the impact of fluctuating fuel costs on our net income. For this reason, we believe electric gross margin, although a non-GAAP measurement, is useful for understanding and analyzing changes in our electric operating performance from one period to the next. We define electric gross margins as electric revenues less fuel and purchased power costs.

The table below represents our electric gross margins for the years ended December 31 (in millions), which is a non-GAAP presentation. We believe this presentation is useful to investors and have included the analysis below as a complement to the financial information we provide in accordance with GAAP. However, these margins may not be comparable to other companies' presentations or more useful than the GAAP information we provide elsewhere in this report.

	2011	2010	2009
Electric revenues	$522.5	$482.9	$433.1
Fuel and purchased power	200.3	199.3	182.0
Electric gross margins	$322.2	$283.6	$251.1
Margin as % of total electric revenues	61.7%	58.7%	58.0%

The electric gross margin increased during 2011 as compared to 2010 mainly due to the September 2010 Missouri rate increase, the July 2010 Kansas rate increase, the September 2010 and March 2011 Oklahoma rate increases and the April 2011 Arkansas rate increase. The electric gross margin increased during 2010 as compared to 2009 mainly due to the 2010 rate increases as well as favorable weather in 2010 as compared to 2009.

__2011 Compared to 2010__

On-System Operating Revenues and Kilowatt-Hour Sales

KWh sales for our on-system customers decreased approximately 2.3% during 2011 as compared to 2010 primarily due to the loss of customers due to damaged or destroyed structures resulting from the May 22, 2011 tornado, although some of the effect has been offset by temporary housing units. Revenues for our on-system customers increased approximately $38.6 million (8.5%). Rate changes, primarily the September 2010 Missouri rate increase, the July 2010 Kansas rate increase, the September 2010 and March 2011 Oklahoma rate increases and the April 2011 Arkansas rate increase, contributed an estimated $49.2 million to revenues. We estimate the impact of the tornado, after adjusting for weather, was an approximate 2% reduction in kilowatt hour sales for 2011. This reduction is reflected in a $7.7 million reduction in revenues, which includes customer growth in the first quarter of 2011, offset by negative sales growth (contraction) for the second, third and fourth quarters of 2011, resulting from the loss of customers due to the loss of residences and businesses. Weather and other related factors decreased revenues an estimated $2.9 million in 2011 as compared to 2010, primarily due to mild weather in the first and fourth quarters of 2011. Total cooling degree days (the cumulative number of degrees that the average temperature for each day during that period was above 65° F) for 2011 were 4.6% more than 2010 and 33.0% more than the 30-year average mainly due to unseasonably hot weather in June and July of 2011. Total heating degree days (the sum of the number of degrees that the daily average temperature for each day during that period was below 65° F) for 2011 were 2.6% less than 2010 and 0.3% less than the 30-year average.

Residential and commercial kWh sales decreased in 2011 primarily due to the loss of residences and businesses in the May 22, 2011 tornado. The related revenues increased during 2011 primarily due to the Missouri, Kansas, Oklahoma and Arkansas rate increases. Industrial kWh sales increased 1.6% in 2011 as compared to 2010 when there was a slowdown created by economic uncertainty. Industrial revenues increased 13.3% mainly due to the Missouri, Kansas, Oklahoma and Arkansas rate increases. On-system wholesale kWh sales increased during 2011 as compared to 2010 reflecting the warmer weather in the third quarter of 2011. Revenues associated with these sales decreased 0.6% primarily due to the portion of FERC revenues that were subject to refund while we were waiting on approval of the Settlement Agreement and Offer of Settlement filed with the FERC on May 24, 2011. We refunded approximately $1.3 million of these revenues, including interest, in November 2011 as a result of this settlement.

Off-System Electric Transactions

In addition to sales to our own customers, we also sell power to other utilities as available, including through the Southwest Power Pool (SPP) energy imbalance services (EIS) market. See "— Competition" below. The majority of our off-system sales margins are included as a component of the fuel adjustment clause in our Missouri, Kansas and Oklahoma jurisdictions and our transmission rider in our Arkansas jurisdiction and generally adjust the fuel and purchased power expense. As a result, nearly all of the off-system sales margin flows back to the customer and has little effect on net income.

Off-system sales decreased during 2011 as compared to 2010 primarily due to limited power available for sale during the third quarter of 2011 as the excessive heat required us to use our resources to serve our own load. Off-system revenues increased 1.7%. Total purchased power related expenses are included in our discussion of purchased power costs below.

Miscellaneous Revenues

Our miscellaneous revenues were $8.2 million during 2011 as compared to $7.6 million during 2010. These revenues are comprised mainly of transmission revenues, late payment fees and renewable energy credit sales.

Operating Revenue Deductions — Fuel and Purchased Power

During 2011, total fuel and purchased power expenses increased approximately $1.0 million (0.5%) as compared to 2010. The table below is a reconciliation of our actual fuel and purchased power expenditures (netted with the regulatory adjustments) to the fuel and purchased power expense shown on our statements of income for 2011 and 2010.

(in millions)	2011	2010
Actual fuel and purchased power expenditures	$196.5	$200.0
Missouri fuel adjustment recovery(1)	7.3	3.1
Missouri fuel adjustment deferral(2)	(2.7)	(4.5)
Kansas regulatory adjustments(2)	(0.6)	(0.1)
SWPA amortization(3)	(1.5)	—
Unrealized (gain)/loss on derivatives	1.3	0.8
Total fuel and purchased power expense per income statement	$200.3	$199.3

(1) Recovered from customers from prior deferral period.

(2) A negative amount indicates costs have been under recovered from customers and a positive amount indicates costs have been over recovered from customers. Missouri amount includes the deferral of additional costs due to construction accounting, which terminated as of June 15, 2011, the effective date of rates for our 2010 Missouri rate case.

(3) Missouri ten year amortization of the $26.6 million payment received from the SWPA in September, 2010.

Summarized in the table below are our 2011 estimated cost and volume changes in the components of fuel and purchased power expenses when compared to 2010. This table incorporates all the changes mentioned above. As shown below, the largest impact on fuel and purchased power costs was increased coal costs.

(in millions)	2011 vs. 2010
Natural gas generation volume	$(4.1)
Coal generation volume	3.0
Purchased power spot purchase volume	(4.0)
Coal (cost per mWh)	9.5
Natural gas (cost per mWh)	(7.9)
Purchased power (cost per mWh)	1.2
Other (primarily fuel adjustments)	3.3
TOTAL	$ 1.0

Operating Revenue Deductions — Other Than Fuel and Purchased Power

Regulated operating expenses increased approximately $7.4 million (10.5%) during 2011 as compared to 2010 primarily due to changes in the following accounts:

(in millions)	2011 vs. 2010
Employee pension expense	$ 3.1
Steam power other operating expense	2.7
Transmission and distribution expense	2.4
Regulatory commission expense	0.7
Employee health care expense	0.5
Injuries and damages expense	0.5
Property insurance	0.3
Other power supply expense	0.2
Customer assistance expense	0.2
Uncollectible accounts	0.2
General labor costs	(1.6)
Professional services	(1.2)
Other steam power expense(1)	(1.0)
Other miscellaneous accounts (netted)	0.4
TOTAL	7.4

(1) Related to Iatan 1 and Iatan 2 construction accounting in accordance with our agreement with the MPSC that allowed deferral of certain costs until the plant additions were included in customer rates. This deferral terminated as of June 15, 2011, the effective date of rates for our 2010 Missouri rate case.

Maintenance and repairs expense increased approximately $4.3 million (11.9%) during 2011 primarily due to changes in the following accounts:

(in millions)	2011 vs. 2010
Distribution maintenance expense	$ 2.0
Maintenance and repairs expense to SLCC(1)	1.8
Maintenance and repairs expense at the Iatan plant	1.5
Maintenance and repairs expense at the Plum Point plant	0.7
Maintenance and repairs expense at the Riverton plant — coal units	(1.2)
Maintenance and repairs expense at the Riverton plant — gas units	(0.3)
Iatan deferred maintenance expense	(0.3)
Other miscellaneous accounts (netted)	0.1
TOTAL	$ 4.3

(1) Mainly due to a transformer failure in December 2011.

Depreciation and amortization expense increased approximately $4.3 million (7.9%) during 2011 as compared to 2010. This reflects increased depreciation of $6.3 million due to increased plant in service during 2011 and the effect of ending deferred depreciation related to Iatan 2 as allowed in our regulatory agreements. This increase was partially offset by a decrease in regulatory amortization expense of $0.9 million due to the termination of construction accounting as of June 15, 2011, the effective date of rates for our 2010 Missouri rate case.

Other taxes increased approximately $3.0 million due to increased property tax reflecting our additions to plant in service and increased municipal franchise taxes.

2010 Compared to 2009

On-System Operating Revenues and Kilowatt-Hour Sales

KWh sales for our on-system customers increased approximately 6.1% during 2010 as compared to 2009 with the associated revenues increasing approximately $40.5 million (9.8%). Weather and other related factors increased revenues an estimated $24.1 million. Total cooling degree days (the cumulative number of degrees that the average temperature for each day during that period was above 65° F) for 2010 were 56.5% more than 2009 and 27.2% more than the 30-year average. Total heating degree days (the sum of the number of degrees that the daily average temperature for each day during that period was below 65° F) for 2010 were 2.9% more than 2009 and 2.3% more than the 30-year average. Rate changes, primarily the September 2010 Missouri rate increase and July 2010 Kansas rate increase (discussed below), contributed an estimated $14.0 million to revenues, while continued sales growth contributed an estimated $2.4 million.

Residential and commercial kWh sales increased in 2010 primarily due to favorable weather during the year. The related revenues increased during 2010 primarily due to the Missouri and Kansas rate increases, as well as continued sales growth. Industrial kWh sales increased 1.5% in 2010 as compared to 2009 when there was a slowdown created by economic uncertainty. Industrial revenues increased 5.6% mainly due to the 2010 Missouri and Kansas rate increases. On-system wholesale kWh sales and revenues increased reflecting the increased market demand resulting from the favorable weather.

Off-System Electric Transactions

Off-system revenues and related expenses were higher during 2010 as compared to 2009 primarily due to increased market demand resulting from the favorable weather discussed above. Total purchased power related expenses are included in our discussion of purchased power costs below.

Miscellaneous Revenues

Our miscellaneous revenues were $7.6 million during 2010 as compared to $6.8 million during 2009. These revenues are comprised mainly of transmission revenues, late payment fees and renewable energy credit sales.

Operating Revenue Deductions – Fuel and Purchased Power

During 2010, total fuel and purchased power expenses increased approximately $17.3 million (9.5%) as compared to 2009. The table below is a reconciliation of our actual fuel and purchased power expenditures (netted with the regulatory adjustments) to the fuel and purchased power expense shown on our statements of income for 2010 and 2009.

(in millions)	2010	2009
Actual fuel and purchased power expenditures	$200.0	$182.1
Missouri fuel adjustment recovery(1)	3.1	1.7
Missouri fuel adjustment deferral(2)	(4.5)	(2.0)
Kansas regulatory adjustments(2)	(0.1)	0.5
Unrealized (gain)/loss on derivatives	0.8	(0.3)
Total fuel and purchased power expense per income statement	$199.3	$182.0

(1) Recovered from customers from prior deferral period.

(2) A negative amount indicates costs have been under recovered from customers and a positive amount indicates costs have been over recovered from customers.

The overall fuel and purchased power increase primarily reflects the effect of increased market demand in 2010 resulting from favorable weather conditions.

Summarized in the table below are our 2010 estimated cost and volume changes in the components of fuel and purchased power expenses when compared to 2009. This table incorporates all the changes mentioned above. As shown below, the largest impact on fuel and purchased power costs was increased generation by our gas-fired units.

(in millions)	2010 vs 2009
Natural gas generation volume	$ 35.1
Coal generation volume	7.5
Purchased power spot purchase volume	(9.8)
Coal (cost per mWh)	(0.9)
Natural gas (cost per mWh)	(16.9)
Purchased power (cost per mWh)	3.4
Other (including fuel adjustments)	(1.1)
TOTAL	$ 17.3

Operating Revenue Deductions — Other Than Fuel and Purchased Power

Regulated operating expenses increased approximately $7.0 million (11.1%) during 2010 as compared to 2009 primarily due to changes in the following accounts:

(in millions)	2010 vs. 2009
Transmission and distribution expense(1)	$ 1.9
General labor costs	1.2
Employee pension expense	1.0
Employee health care expense	1.0
Customer accounts expense(2)	1.5
Steam power other operating expense	0.6
Property insurance	0.4
Injuries and damages expense	0.3
Customer assistance expense	0.3
General office expense	0.3
Other steam power expense(3)	(1.9)
Other miscellaneous accounts (netted)	0.4
TOTAL	$ 7.0

(1) Approximately $1.6 million of this total is for charges incurred for delivering the output from Plum Point to our system.

(2) Mainly increased banking fees and uncollectible accounts.

(3) Related to Iatan 1 and Iatan 2 operating costs that we were able to defer in accordance with our agreement with the MPSC that allowed deferral of certain costs until the plant additions were included in customer rates. Construction accounting terminated as of June 15, 2011, the effective date of rates for our 2010 Missouri rate case.

Maintenance and repairs expense increased approximately $3.8 million (11.8%) during 2010 primarily due to changes in the following accounts:

(in millions)	2010 vs. 2009
Distribution maintenance expense[(1)]	$ 1.3
Transmission maintenance expense	0.7
Maintenance and repairs expense at the Riverton plant — coal units[(2)]	0.9
Maintenance and repairs expense at the Iatan plant	0.7
Maintenance and repairs expense at the Plum Point plant	0.4
Maintenance and repairs expense at the Asbury plant	0.3
Maintenance and repairs expense at the Riverton plant — gas units	0.4
Maintenance and repairs expense to SLCC[(3)]	(1.1)
Other miscellaneous accounts (netted)	0.2
TOTAL	$ 3.8

(1) Mainly due to continued implementation of our system reliability plan.

(2) Mainly due to the 2010 five-year maintenance outage.

(3) Decrease mainly due to maintenance outage in 2009.

Depreciation and amortization expense increased approximately $5.9 million (12.4%) during 2010 reflecting our additions to plant in service and to additional regulatory amortization of $3.1 million. The remainder is increased plant in service in 2010, partially offset by the effect of deferred depreciation related to Iatan 2 as allowed in our regulatory agreements pertaining to our Kansas and Missouri jurisdictions. This is net of the construction accounting effect of deferring $2.0 million of Iatan 1 and Iatan 2 depreciation expense in 2010 as compared to $0.8 million of Iatan 1 depreciation expense in 2009. Other taxes increased approximately $2.0 million due to increased property tax reflecting our additions to plant in service and increased municipal franchise taxes.

Gas Segment

Gas Operating Revenues and Sales

The following tables detail our natural gas sales and revenues for the years ended December 31:

	Total Gas Delivered to Customers					
(bcf sales)	2011	2010	% Change	2010	2009	% Change
Residential	2.56	2.68	(4.3)%	2.68	2.69	(0.4)%
Commercial	1.27	1.26	0.3	1.26	1.27	(1.0)
Industrial[(1)]	0.10	0.11	(5.9)	0.11	0.22	(50.5)
Other[(2)]	0.03	0.03	(0.9)	0.03	0.03	11.6
Total retail sales	3.96	4.08	(2.9)	4.08	4.21	(3.1)
Transportation sales[(1)]	4.53	4.83	(6.2)	4.83	4.33	11.5
Total gas operating sales	8.49	8.91	(4.7)	8.91	8.54	4.3

($ in millions)	Operating Revenues and Cost of Gas Sold					
	2011	2010	% Change	2010	2009	% Change
Residential	$29.0	$32.3	(10.1)%	$32.3	$36.2	(10.9)%
Commercial	12.5	13.3	(6.2)	13.3	15.5	(14.2)
Industrial[1]	0.7	0.8	(16.0)	0.8	2.1	(60.7)
Other[2]	0.3	0.4	(5.5)	0.4	0.4	(6.0)
Total retail revenues	$42.5	$46.8	(9.0)	$46.8	$54.2	(13.7)
Other revenues	0.4	0.4	7.3	0.4	0.2	107.3
Transportation revenues[1]	3.5	3.7	(7.0)	3.7	2.9	26.6
Total gas operating revenues	$46.4	$50.9	(8.8)	$50.9	$57.3	(11.2)
Cost of gas sold	22.8	26.6	(14.5)	26.6	35.6	(25.2)
Gas operating revenues over cost of gas in rates	$23.6	$24.3	(2.5)	$24.3	$21.7	11.8

(1) Percentage change reflects three industrial customers switching to transportation during 2011.

(2) Other includes other public authorities and interdepartmental usage.

2011 Compared to 2010

Operating Revenues and bcf Sales

Gas retail sales decreased 2.9% during 2011 as compared to 2010 reflecting both customer contraction of 0.9% and customers switching from sales service retail to transportation. We expect gas customer growth to be flat during the next several years. Residential sales decreased during 2011 despite heating degree days being 1.8% higher in 2011 than 2010. Heating degree days were 0.4% lower in 2011, however, than the 30-year average. Commercial sales increased slightly during 2011. Industrial sales decreased 5.9% during 2011 due to customer contraction and the transfer of the customers between classes mentioned above.

During 2011, gas segment revenues were approximately $46.4 million as compared to $50.9 million in 2010, a decrease of 8.8%. This decrease was largely driven by a decrease in the PGA that went into effect November 2, 2010. During 2011, our PGA revenue (which represents the cost of gas recovered from our customers) was approximately $22.8 million as compared to $26.6 million in 2010, a decrease of approximately $3.8 million (14.5%), representing a decrease in the cost of gas. Our margin (defined as gas operating revenues less cost of gas in rates) was $0.7 million less in 2011 as compared to 2010.

Our PGA clause allows us to recover from our customers, subject to routine regulatory review, the cost of purchased gas supplies, transportation and storage, including costs associated with the use of financial instruments to hedge the purchase price of natural gas. Pursuant to the provisions of the PGA clause, the difference between actual costs incurred and costs recovered through the application of the PGA are reflected as a regulatory asset or regulatory liability until the balance is recovered from or credited to customers.

As of December 31, 2011, we had unrecovered purchased gas costs of $0.2 million recorded as a current regulatory asset and $1.3 million recorded as a non-current regulatory asset.

Operating Revenue Deductions

Total other operating expenses were $8.3 million during 2011 as compared to $9.5 million in 2010, primarily due to a $0.6 million decrease in customer accounts expense (mainly uncollectible accounts), a $0.3 million decrease in rent expense, a $0.2 million decrease in employee pension expense and a $0.2 million decrease in general labor costs.

Depreciation and amortization expense increased approximately $0.5 million (15.2%) during 2011 due to increased depreciation rates resulting from our 2010 Missouri gas rate case.

Our gas segment had net income of $2.7 million in 2011 as compared to $2.6 million in 2010.

2010 Compared to 2009

Operating Revenues and bcf Sales

Gas retail sales decreased 3.1% during 2010 as compared to 2009 reflecting customer contraction of 0.9%. We believe this contraction was due to depressed economic conditions. Residential and commercial sales decreased slightly during 2010 despite heating degree days being 1.8% higher in 2010 than 2009. Heating degree days were 2.2% lower in 2010, however, than the 30-year average. Industrial sales decreased during 2010 due to customer contraction and the transfer of the customer between classes mentioned above.

During 2010, gas segment revenues were approximately $50.9 million as compared to $57.3 million in 2009, a decrease of 11.2%. This decrease was largely driven by lower PGAs that went into effect November 13, 2009 and November 2, 2010. During 2010, our PGA revenue was approximately $26.6 million as compared to $35.6 million in 2009, a decrease of approximately $9.0 million (25.2%), representing a decrease in the cost of gas. The cost of natural gas was lower for 2010 compared to 2009 as we experienced more than a 20% decrease in the annual price. The overall impact resulted in an improved margin of approximately $2.6 million primarily due to an increase in base rates for our Missouri gas customers that was effective April 1, 2010.

As of December 31, 2010, we had unrecovered purchased gas costs of $0.4 million recorded as a non-current regulatory asset and over recovered purchased gas costs of $1.2 million recorded as a current regulatory liability.

Operating Revenue Deductions

Total other operating expenses were $9.5 million during 2010 as compared to $10.3 million in 2009, primarily due to a $0.7 million decrease in employee pension expense and a $0.2 million decrease in customer accounts expense (mainly uncollectible accounts) partially offset by a $0.1 million increase in regulatory commission expense.

Depreciation and amortization expense increased approximately $1.0 million (50.5%) during 2010 due to increased depreciation rates resulting from our 2010 Missouri gas rate case.

Our gas segment had net income of $2.6 million in 2010 as compared to $0.9 million in 2009.

Consolidated Company

Income Taxes

The following table shows the changes in our consolidated provision for income taxes (in millions) and our consolidated effective federal and state income tax rates for the applicable years ended December 31:

	2011	2010	2009
Consolidated provision for income taxes	$ 3.6	$10.9	$ 0.4
Consolidated effective federal and state income tax rates	38.4%	39.2%	32.5%

The effective tax rate for 2011 is lower than 2010 primarily due to an adjustment made in 2010 as a result of the Patient Protection and Affordable Care Act, which became law on March 23, 2010. This legislation included a provision that removed the non-taxable status, for income tax purposes, of Medicare D subsidies received. Although the elimination of this tax benefit does not take effect until 2013, this change required us to recognize the full accounting impact in our financial statements in the period in which the legislation was enacted. As a result, in the first quarter of 2010, we recorded a one-time non-cash charge of approximately $2.1 million to income taxes to reflect the impact of this change, which increased our effective tax rate in 2010 and our 2010 provision for income taxes. The effective tax rate for 2010 is higher than 2009 primarily due to the new health care legislation.

As part of an agreement reached in our 2009 Missouri electric rate case, effective September 10, 2010, we also agreed to commence an eighteen year amortization of a regulatory asset related to the tax benefits of cost of removal. These tax benefits were flowed through to customers from 1981-2008 and totaled approximately $11.1 million. We had recorded the regulatory asset expecting to recover these benefits from customers in future periods. Based on the agreement, we estimated the portion of the amortization period where rate recovery would no longer be probable for this item and wrote off approximately $1.2 million in the first quarter of 2010. Amortization of the remaining regulatory tax asset began during the third quarter of 2011.

We received $26.6 million in 2010 from the SWPA which was deferred for book purposes and recorded as a noncurrent liability. We originally increased our current tax liability by approximately $10.0 million recognizing that the $26.6 million payment may be considered taxable income in 2010. During the first quarter of 2011, we submitted a pre-filing agreement with the Internal Revenue Service (IRS) requesting that a determination be made regarding whether or not the payment could be deferred under certain sections of the Internal Revenue code. The IRS accepted our position that the payment be deferred for tax purposes and recognized over the next twenty years. As such, we reduced the current tax liability in accordance with this deferral. The SWPA payment, net of taxes, is being used to reduce fuel expense for our customers in all our jurisdictions.

We do not expect any significant changes to our unrecognized tax benefits over the next twelve months. The reserve balance related to unrecognized tax benefits as of December 31, 2010 was $359,000. With the running of the statute of limitations on these unrecognized tax benefits on September 15, 2011, there are no unrecognized tax benefits at December 31, 2011. See Note 9 of "Notes to Consolidated Financial Statements" under Item 8 for additional information regarding income taxes.

Nonoperating Items

The following table shows the total allowance for funds used during construction (AFUDC) for the applicable periods ended December 31. AFUDC decreased in 2011 as compared to 2010 and in 2010 as compared to 2009, reflecting the completion of Iatan 2 and the Plum Point Energy Station in 2010. See Note 1 of "Notes to Consolidated Financial Statements" under Item 8.

($ in millions)	2011	2010	2009
Allowance for equity funds used during construction	$0.3	$ 4.5	$ 6.2
Allowance for borrowed funds used during construction	0.2	5.7	7.9
Total AFUDC	$0.5	$10.2	$14.1

Total interest charges on long-term and short-term debt for 2011, 2010 and 2009 are shown below. The changes in long-term debt interest for 2011 and 2010 reflect the redemption of $48.3 million aggregate principal amount of our Senior Notes, 7.05% Series due 2022, which were redeemed on August 27, 2010, and replaced by $50 million principal amount 5.20% first mortgage bonds issued August 25, 2010. The changes also reflect the redemption of 6.5% first mortgage bonds on April 1, 2010 and the redemption of our 8.5% trust preferred securities on June 28, 2010, which were replaced by 4.65% first mortgage bonds issued May 28, 2010. The decreases in short-term debt interest for all periods presented primarily reflect lower levels of borrowing.

	Interest Charges ($ in millions)					
	2011	2010	Change	2010	2009	Change
Long-term debt interest	$42.6	$41.9	1.5%	$41.9	$42.1	(0.3)%
Short-term debt interest	0.1	0.6	(86.3)	0.6	1.1	(43.9)
Trust preferred securities interest	—	2.1	(100.0)	2.1	4.3	(50.8)
Iatan 1 and 2 carrying charges*	(2.1)	(3.2)	31.8	(3.2)	(1.3)	136.9
Other interest	0.9	0.9	19.6	0.9	0.6	28.2
Total interest charges	$41.5	$42.3	(2.0)	$42.3	$46.8	(9.5)

* Beginning in the second quarter of 2009, we deferred Iatan 1 carrying charges to reflect construction accounting in accordance with our agreement with the MPSC that allowed deferral of certain costs until the environmental upgrades to Iatan 1 were included in our rate base. We began deferring Iatan 2 carrying charges in the third quarter of 2010. Deferral ended when the plant was placed in rates. Iatan 1 was placed in rates in September 2010. Iatan 2 was placed in rates June 15, 2011. See Note 3 of "Notes to Consolidated Financial Statements" under Item 8 for information regarding carrying charges.

RATE MATTERS

We continually assess the need for rate relief in all of the jurisdictions we serve and file for such relief when necessary.

Our rates for retail electric and natural gas services (other than specially negotiated retail rates for industrial or large commercial customers, which are subject to regulatory review and approval) are determined on a "cost of service" basis. Rates are designed to provide, after recovery of allowable operating expenses, an opportunity for us to earn a reasonable return on "rate base." "Rate base" is generally determined by reference to the original cost (net of accumulated depreciation and amortization) of utility plant in service, subject to various adjustments for deferred taxes and other items. Over time, rate base is increased by additions to utility plant in service and reduced by depreciation, amortization and retirement of utility plant or write-off's as ordered by the utility commissions. In general, a request of new rates is made on the basis of a "rate base" as of a date prior to the date of the request and allowable operating expenses for a 12-month test period ended prior to the date of the request. Although the current rate making process provides recovery of some future changes in rate base and operating costs, it does not reflect all changes in costs for the period in which new retail rates will be in place. This results in a lag (commonly referred to as "regulatory lag") between the time we incur costs and the time when we can start recovering the costs through rates.

The following table sets forth information regarding electric and water rate increases since January 1, 2009:

Jurisdiction	Date Requested	Annual Increase Granted	Percent Increase Granted	Date Effective
Missouri — Electric	September 28, 2010	$18,700,000	4.70%	June 15, 2011
Missouri — Electric	October 29, 2009	$46,800,000	13.40%	September 10, 2010
Kansas — Electric	June 17, 2011	$ 1,250,000	5.20%	January 1, 2012
Kansas — Electric	November 4, 2009	$ 2,800,000	12.40%	July 1, 2010
Oklahoma — Electric	June 30, 2011	$ 240,000	1.66%	January 6, 2012
Oklahoma — Electric	January 28, 2011	$ 1,063,100	9.32%	March 1, 2011
Oklahoma — Electric	March 25, 2010	$ 1,456,979	15.70%	September 1, 2010
Arkansas — Electric	August 19, 2010	$ 2,104,321	19.00%	April 13, 2011
Missouri — Gas	June 5, 2009	$ 2,600,000	4.37%	April 1, 2010

See Note 3 of "Notes to Consolidated Financial Statements" under Item 8 for additional information regarding rate matters.

COMPETITION

Electric Segment

SPP-RTO

Energy Imbalance Services: The Southwest Power Pool (SPP) regional transmission organization (RTO) energy imbalance services market (EIS) provides real time energy for most participating members within the SPP regional footprint. Imbalance energy prices are based on market bids and status/availability of dispatchable generation and transmission within the SPP market footprint. In addition to energy imbalance service, the SPP RTO performs a real time security-constrained economic dispatch of all generation voluntarily offered into the EIS market to the market participants to also serve the native load.

Day Ahead Market: The SPP RTO will implement a Day-Ahead Market, with unit commitment and co-optimized ancillary services market, in March 2014. As part of the Day-Ahead Market, the SPP RTO will create, prior to implementation of such market, a single NERC approved balancing authority to take over balancing authority responsibilities for its members, including Empire, which is expected to provide operational and economic benefits for our customers. The Day-Ahead Market would replace the existing EIS market described above.

SPP Regional Transmission Development: On June 17, 2010, the FERC approved the new highway/byway cost allocation method. This is a new transmission cost allocation method to replace the existing FERC accepted cost allocation method for new transmission facilities needed to continue to reliably and economically serve SPP customers, including ours, well into the future. Prior to FERC approval, we and other SPP members had filed a joint protest at the FERC based on our disagreement with the SPP on the allocation percentages and various other issues. Following the approval, we and other SPP members requested a rehearing. On October 20, 2011, the FERC issued its Order on Rehearing denying our request. In mid December 2011, we, along with the other SPP member joint protestors, filed a Petition for Review and Motion for Stay of Procedures with the U. S. Court of Appeals for the Eight Circuit. We believe we are aggrieved by the FERC's orders because the orders authorize the SPP to allocate to us the costs of transmission projects from which we would receive either no benefits or benefits that are not roughly commensurate with the allocated costs. Our request for a stay of procedures directly relates to the SPP's efforts to adopt a method satisfactory to us for analyzing the reasonableness of the highway/byway cost allocation approach and an effective remediation process for imbalanced cost allocations. On December 16, 2011, the Eighth Circuit U.S. Court of Appeals granted our petition and stay request. We are required to make an update filing to the Court regarding the SPP Board's actions and progress of the regional allocation review process by May 2012. To date, the SPP's BOD has approved $1.4 billion in highway/byway projects to be constructed by 2017 with an additional $1.5 billion in transmission projects expected to receive approval during the first quarter of 2012. As these projects are constructed, we will be allocated a share of the costs of the projects pursuant to the FERC accepted highway/byway regional cost allocation method. We expect that these operating costs will be material, but that they will be recoverable in future rates.

Other FERC Activity

On July 21, 2011, the FERC issued Order No. 1000 (Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities). Order 1000 requires all public utility transmission providers to (among other things) facilitate non-incumbent transmission developer participation in regional transmission planning by removing from FERC-approved tariffs and agreements any language creating a federal right of first refusal (ROFR) for an incumbent transmission provider to construct transmission facilities selected in a regional transmission plan for cost allocation. As a transmission owning member of the SPP RTO, this could directly affect our rights to build transmission facilities within our service territory. A second key element of Order 1000 directed transmission providers to develop policy and procedures for interregional transmission coordination and interregional cost allocation. Since we are on the southeastern seam of the SPP, this policy will most likely have a direct impact on our customers, primarily through a potential reduction to our production costs as a result of greater access to lower cost power from within the SPP, and across this seam and the possible reduction because of the cost sharing for new transmission projects. We will continue to participate in the SPP stakeholder processes to understand the impact of Order 1000 on our ability to construct new facilities within our service territory as well as its influence on promoting construction of transmission projects on/near our borders with our neighbors. Compliance filings by the SPP to address the ROFR requirements are currently scheduled to be due October 11, 2012 and April 13, 2013 for interregional/seams planning and cost allocation.

See Note 3 of "Notes to Consolidated Financial Statements" under Item 8 for additional information regarding competition.

LIQUIDITY AND CAPITAL RESOURCES

Overview. Our primary sources of liquidity are cash provided by operating activities, short-term borrowings under our commercial paper program (which is supported by our credit facilities) and borrowings from our unsecured revolving credit facility. As needed, we raise funds from the debt and equity capital markets to fund our liquidity and capital resource needs.

Our issuance of various securities, including equity, long-term and short-term debt, is subject to customary approval or authorization by state and federal regulatory bodies including state public service commissions and the SEC. We estimate that internally generated funds (funds provided by operating activities less dividends paid) will provide the majority of the funds required in 2012 for our budgeted capital expenditures (as discussed in "Capital Requirements and Investing Activities" below). We believe the amounts available to us under our credit facilities and the issuance of debt and equity securities, together with this cash provided by operating activities, will allow us to meet our needs for working capital, pension contributions, our continuing construction expenditures, anticipated debt redemptions, interest payments on debt obligations, dividend payments and other cash needs through the next several years.

We will continue to evaluate our need to increase available liquidity based on our view of working capital requirements, including the timing of our construction programs, impacts of the 2011 tornado and other factors. See Item 1A, "Risk Factors" for additional information on items that could impact our liquidity and capital resource requirements. The following table provides a summary of our operating, investing and financing activities for the last three years.

Summary of Cash Flows

(in millions)	Fiscal Year 2011	2010	2009
Cash provided by/(used in):			
Operating activities	$ 134.6	$ 135.9	$ 129.6
Investing activities	(105.1)	(111.0)	(154.7)
Financing activities	(34.6)	(20.0)	28.0
Net change in cash and cash equivalents	$ (5.1)	$ 4.9	$ 2.9

Cash flow from Operating Activities

We prepare our statement of cash flows using the indirect method. Under this method, we reconcile net income to cash flows from operating activities by adjusting net income for those items that impact net income but may not result in actual cash receipts or payments during the period. These reconciling items include depreciation and amortization, pension costs, deferred income taxes, equity AFUDC, changes in commodity risk management assets and liabilities and changes in the consolidated balance sheet for working capital from the beginning to the end of the period.

Year-over-year changes in our operating cash flows are attributable primarily to working capital changes resulting from the impact of weather, the timing of customer collections, payments for natural gas and coal purchases and the effects of deferred fuel recoveries. The increase or decrease in natural gas prices directly impacts the cost of gas stored in inventory.

2011 compared to 2010. In 2011, our net cash flows provided from operating activities was $134.6 million, a decrease of $1.3 million or 1.0% from 2010. This increase was primarily a result of:

- Changes in net income — $7.6 million.
- Changes in depreciation and amortization, reflecting increased plant in service and fuel deferral amortization — $8.7 million
- Increased deferrals for income taxes, reflecting positive impacts for accelerated tax depreciation and deferring taxability of the 2010 SWPA payment — $18.2 million.
- Lower equity AFUDC — $4.2 million
- Changes in receivables due to lower unbilled revenues, receipt of transmission credits and income tax refunds collected — $21.6 million.
- Changes in accounts payable partially due to lower prices for fuel purchases — $5.9 million.
- Changes in pension and other post retirement benefit costs due to the result of $20.2 million in additional pension contributions compared to 2010 — $(16.7) million.
- Increased natural gas purchases and supplies for new and existing generation plants — $(15.1) million.
- Changes in prepaid expenses and deferred charges mostly reflecting certain regulatory treatment of fuel charges and carrying costs — ($3.6) million.
- Changes reflecting the receipt of SWPA minimum flows payment in 2010 — $(26.6) million.

2010 compared to 2009. In 2010, our net cash flows provided from operating activities was $138.1 million, an increase of $8.5 million or 6.6% from 2009. This increase was primarily a result of:

- Changes in net income — $6.1 million.
- One-time payment from SWPA for future minimum flow decreases at Ozark Beach hydro plant (see Note 1 — Other Noncurrent Liabilities of "Notes to Consolidated Financial Statements" under Item 8) — $26.6 million
- Changes in investment tax credits, including the granting of $17.7 million of advanced coal investment tax credits resulting from a revised MOU from the IRS, offset by changes in deferred income taxes — $11.6 million
- Draw down of the commodity risk management margin accounts through settlement of hedged positions in 2009 — $(8.5) million.
- Changes in seasonal levels of inventory, including the effect of building coal inventories at Plum Point and Iatan 2 — $(6.2) million.
- Changes in pension and other post retirement benefit costs primarily due to the result of increased pension contributions of $7.2 million — $(7.8) million.
- Changes in receivables due to seasonal levels of trade accounts receivable, unbilled revenues and income taxes receivable, offset by insurance proceeds received from the 2009 State Line generator failure — $(14.2) million.
- Changes in prepaid expenses and deferred charges primarily related to changes in deferred fuel costs and non-cash construction accounting (See Note 3 of "Notes to Consolidated Financial Statements" under Item 8) — $(9.9) million.

Capital Requirements and Investing Activities

Our net cash flows used in investing activities decreased $5.9 million from 2010 to 2011. The decrease was primarily the result of a decrease in new generation construction in 2011.

Our net cash flows used in investing activities decreased $45.5 million from 2009 to 2010. The decrease was primarily the result of a decrease in electric plant additions and replacements, including new generation construction in 2010.

Our capital expenditures totaled approximately $101.1 million, $108.2 million, and $148.8 million in 2011, 2010 and 2009, respectively.

A breakdown of these capital expenditures for 2011, 2010 and 2009 is as follows:

	Capital Expenditures		
(in millions)	2011	2010	2009
Distribution and transmission system additions	$ 46.5	$ 38.8	$ 33.7
New generation — Plum Point Energy Station	—	6.9	16.3
New generation — Iatan 2	4.5	42.7	66.2
Storms	15.9	0.1	6.4
Additions and replacements — electric plant	13.4	7.2	22.8
Gas segment additions and replacements	3.9	5.0	2.1
Transportation	3.9	1.3	1.4
Other (including retirements and salvage — net)(1)	9.2	3.4	(1.4)
Subtotal	$ 97.3	$105.4	$147.5
Non-regulated capital expenditures (primarily fiber optics)	3.8	2.8	1.3
Subtotal capital expenditures incurred(2)	$101.1	$108.2	$148.8
Adjusted for capital expenditures payable(3)	1.4	3.8	3.8
Insurance proceeds receivable	—	(0.1)	5.6
Capital lease, primarily Plum Point unit train	—	(2.7)	(2.9)
Total cash outlay	$102.5	$109.2	$155.3

(1) Other includes equity AFUDC of $(0.3) million, $(4.5) million and $(6.2) million for 2011, 2010 and 2009, respectively. 2009 also includes proceeds from sale of property of $0.5 million.

(2) Expenditures incurred represent the total cost for work completed for the projects during the year. Discussion of capital expenditures throughout this 10-K is presented on this basis. These capital expenditures include AFUDC, capital expenditures to retire assets and benefits from salvage.

(3) The amount of expenditures paid/(unpaid) at the end of the year to adjust to actual cash outlay reflected in the Investing Activities section of the Statement of Cash Flows.

Approximately 100%, 75% and 55% of our cash requirements for capital expenditures for 2011, 2010 and 2009, respectively, were satisfied internally from operations (funds provided by operating activities less dividends paid). The remaining amounts of such requirements were satisfied from short-term borrowings and proceeds from our sales of common stock and debt securities discussed below.

Our estimated capital expenditures (excluding AFUDC) for 2012, 2013 and 2014 are detailed below. See Item 1, "Business — Construction Program." We anticipate that we will spend the following amounts over the next three years for the following projects:

Project	2012	2013	2014	Total
Electric distribution system additions	$ 63.7	$ 52.1	$ 39.3	$155.1
Asbury environmental upgrades	30.1	50.4	35.4	115.9
Electric transmission facilities	15.0	13.3	26.2	54.5
Other	38.4	42.9	63.4	144.7
Total	$147.2	$158.7	$164.3	$470.2

Our estimated total capital expenditures (excluding AFUDC) for 2015 and 2016 are $286.5 million and $138.4 million, respectively.

We estimate that internally generated funds will provide approximately 76% of the funds required in 2012 for our budgeted capital expenditures. We intend to utilize a combination of short-term debt, the proceeds of sales of long-term debt and/or common stock (including common stock sold under our

Employee Stock Purchase Plan, our Dividend Reinvestment and Stock Purchase Plan, our 401(k) Plan and our ESOP) if needed to finance additional amounts needed beyond those provided by operating activities for such capital expenditures. We will continue to utilize short-term debt as needed to support normal operations or other temporary requirements. The estimates herein may be changed because of changes we make in our construction program, unforeseen construction costs, our ability to obtain financing, regulation and for other reasons. See further discussion under "Financing Activities" below.

Financing Activities

Our net cash flows used in financing activities increased $14.6 million to $34.6 million during 2011 as compared to $20.0 million in 2010, primarily due to a decrease in proceeds (net of repayments of long-term debt) received from new issuances of long term debt and equity in 2011 as compared to 2010 and a $25.3 million reduction in dividend payments.

Our net cash flows provided by financing activities decreased $48.0 million to ($20.0) million during 2010 as compared to $28.0 million in 2009, primarily due to a decrease in proceeds (net of repayments of long-term debt) received from new issuances of long-term debt and equity as described below.

On August 25, 2010, we issued $50 million principal amount of 5.20% first mortgage bonds due September 1, 2040. The net proceeds (after payment of expenses) of approximately $49.1 million were used to redeem $48.3 million aggregate principal amount of our Senior Notes, 7.05% Series due 2022 on August 27, 2010.

On May 28, 2010, we issued $100 million principal amount of 4.65% first mortgage bonds due June 1, 2020. The net proceeds (after payment of expenses) of approximately $98.8 million, were used to redeem all 2 million outstanding shares of our 8.5% trust preferred securities, totaling $50 million, on June 28, 2010, and to repay short-term debt which was incurred, in part, to fund the repayment, at maturity, of our 6.5% first mortgage bonds due 2010.

On March 27, 2009, we issued $75 million principal amount of 7% first mortgage bonds due April 1, 2024. The net proceeds (after payment of expenses) of approximately $72.6 million were used to repay short-term debt incurred, in part, to fund our current construction program.

On February 25, 2009, we entered into an equity distribution agreement with UBS Securities LLC (UBS). Under the terms of the agreement, as amended, we could offer and sell shares of our common stock, par value $1.00 per share, having an aggregate offering amount of up to $120 million from time to time through UBS, as sales agent. We successfully completed our equity distribution program during the second quarter of 2010 and used the net proceeds to repay short-term debt and for general corporate purposes, including the funding of our construction program. During 2010, we issued and sold 2,870,985 shares of our common stock pursuant to this equity distribution program, at an average price per share of $18.41, resulting in net proceeds to us of approximately $51.3 million. Since inception of the program, in the aggregate, we issued and sold 6,535,216 shares pursuant to the program, at an average price per share of $18.36, resulting in net proceeds to us of approximately $116.0 million.

On January 28, 2011, we filed a $400 million shelf registration statement with the SEC covering our common stock, unsecured debt securities, preference stock, and first mortgage bonds. This shelf registration statement became effective on February 7, 2011. We have received regulatory approval for the issuance of securities under this shelf from all four states in our electric service territory, but we may only issue up to $250 million of such securities in the form of first mortgage bonds. We plan to use proceeds from offerings made pursuant to this shelf to fund capital expenditures, refinancings of existing debt or general corporate needs during the three-year effective period.

On January 17, 2012, we entered into the Third Amended and Restated Unsecured Credit Agreement which amended and restated our Second Amended and Restated Unsecured Credit Agreement dated January 26, 2010. This agreement extended the termination date of the revolving credit facility from

January 26, 2013 to January 17, 2017. The agreement also removes the letter of credit facility and includes a swingline loan facility with a $15 million swingline loan sublimit. The aggregate amount of the revolving credit commitments remains $150 million, inclusive of the $15 million swingline loan sublimit. In addition, the pricing and fees under the facility were amended. Interest on borrowings under the facility accrues at a rate equal to, at our option, (i) the highest of (A) the bank's prime commercial rate, (B) the federal funds effective rate plus 0.5% or (C) one month LIBOR plus 1.0%, plus a margin or (ii) one month, two month or three month LIBOR, in each case, plus a margin. Each margin is based on our current credit ratings and the pricing schedule in the facility. As of the date hereof, and based on our current credit ratings, the LIBOR margin under the facility decreased from 2.70% to 1.25%. A facility fee is payable quarterly on the full amount of the commitments under the facility based on our current credit ratings, which fee is currently 0.25%. In addition, upon entering into the amended and restated facility, we paid an upfront fee to the revolving credit banks of $262,500 in the aggregate. There were no other material changes to the terms of the facility.

The facility is used for working capital, general corporate purposes and to back-up our use of commercial paper. This facility requires our total indebtedness to be less than 62.5% of our total capitalization at the end of each fiscal quarter and our EBITDA (defined as net income plus interest, taxes, depreciation and amortization) to be at least two times our interest charges for the trailing four fiscal quarters at the end of each fiscal quarter. Failure to maintain these ratios will result in an event of default under the credit facility and will prohibit us from borrowing funds thereunder. As of December 31, 2011, we are in compliance with these ratios. Our total indebtedness is 50.4% of our total capitalization as of December 31, 2011 and our EBITDA is 5.0 times our interest charges. This credit facility is also subject to cross-default if we default on in excess of $10 million in the aggregate on our other indebtedness. This arrangement does not serve to legally restrict the use of our cash in the normal course of operations. There were no outstanding borrowings under this agreement at December 31, 2011. However, $12.0 million was used to back up our outstanding commercial paper.

The principal amount of all series of first mortgage bonds outstanding at any one time under the EDE Mortgage is limited by terms of the mortgage to $1 billion. Substantially all of the property, plant and equipment of The Empire District Electric Company (but not its subsidiaries) is subject to the lien of the EDE Mortgage. Restrictions in the EDE mortgage bond indenture could affect our liquidity. The EDE Mortgage contains a requirement that for new first mortgage bonds to be issued, our net earnings (as defined in the EDE Mortgage) for any twelve consecutive months within the fifteen months preceding issuance must be two times the annual interest requirements (as defined in the EDE Mortgage) on all first mortgage bonds then outstanding and on the prospective issue of new first mortgage bonds. Our earnings for the year ended December 31, 2011 would permit us to issue approximately $511.0 million of new first mortgage bonds based on this test with an assumed interest rate of 6.0%. In addition to the interest coverage requirement, the EDE Mortgage provides that new bonds must be issued against, among other things, retired bonds or 60% of net property additions. At December 31, 2011, we had retired bonds and net property additions which would enable the issuance of at least $697.6 million principal amount of bonds if the annual interest requirements are met. As of December 31, 2011, we are in compliance with all restrictive covenants of the EDE Mortgage.

The principal amount of all series of first mortgage bonds outstanding at any one time under the EDG Mortgage is limited by terms of the mortgage to $300 million. Substantially all of the property, plant and equipment of The Empire District Gas Company is subject to the lien of the EDG Mortgage. The EDG Mortgage contains a requirement that for new first mortgage bonds to be issued, the amount of such new first mortgage bonds shall not exceed 75% of the cost of property additions acquired after the date of the Missouri Gas acquisition. The mortgage also contains a limitation on the issuance by EDG of debt (including first mortgage bonds, but excluding short-term debt incurred in the ordinary course under working capital facilities) unless, after giving effect to such issuance, EDG's ratio of EBITDA (defined as net income plus interest, taxes, depreciation, amortization and certain other non-cash charges) to interest charges for the most recent four fiscal quarters is at least 2.0 to 1. As of December 31, 2011, this test would allow us to issue approximately $10.7 million principal amount of new first mortgage bonds.

Currently, our corporate credit ratings and the ratings for our securities are as follows:

	Fitch	Moody's	Standard & Poor's
Corporate Credit Rating	n/r*	Baa2	BBB-
First Mortgage Bonds	BBB+	A3	BBB+
Senior Notes	BBB	Baa2	BBB-
Commercial Paper	F3	P-2	A-3
Outlook	Stable	Stable	Stable

* Not rated.

On March 10, 2011, Standard & Poor's revised its outlook on us from stable to positive and affirmed the corporate credit rating at BBB-, citing greater-than-expected improvement in our financial condition from the winding down of our heavy construction program, sale of $120 million of common stock in 2010, rate increases and enhanced cost recovery via new rate riders. On May 27, 2011 Standard & Poor's revised our rating outlook to stable from positive after the May 22, 2011 tornado. On April 14, 2011, and again on May 26, 2011 after the May 22, 2011 tornado, Moody's reaffirmed all of our other ratings. On March 24, 2011, Fitch revised our commercial paper rating from F2 to F3 and reaffirmed our other ratings. The rating action was not based on a specific action or event on our part, but reflected their traditional linkage of long-term and short-term Issuer Default Ratings.

A security rating is not a recommendation to buy, sell or hold securities. Each rating is subject to revision or withdrawal at any time by the assigning rating organization. Each security rating agency has its own methodology for assigning ratings, and, accordingly, each rating should be considered independently of all other ratings.

CONTRACTUAL OBLIGATIONS

Set forth below is information summarizing our contractual obligations as of December 31, 2011. Other pension and postretirement benefit plans are funded on an ongoing basis to match their corresponding costs, per regulatory requirements and have been estimated for 2012-2016 as noted below.

	Payments Due By Period (in millions)				
Contractual Obligations[1]	**Total**	**Less Than 1 Year**	**1-3 Years**	**3-5 Years**	**More Than 5 Years**
Long-term debt (w/o discount)	$ 689.0	$ 0.6	$111.6	$ 25.0	$ 551.8
Interest on long-term debt	586.5	40.1	72.5	69.8	404.1
Short-term debt	12.0	12.0	—	—	—
Capital lease obligations	7.4	0.6	1.1	1.1	4.6
Operating lease obligations[2]	5.6	0.9	1.5	1.4	1.8
Electric purchase obligations[3]	272.6	69.4	99.8	55.7	47.7
Gas purchase obligations[4]	42.1	8.3	13.9	10.9	9.0
Open purchase orders	56.1	19.5	36.5	0.1	—
Postretirement benefit obligation funding	17.7	5.0	6.8	5.9	—
Pension benefit funding	57.6	11.1	27.0	19.5	—
Other long-term liabilities[5]	3.4	0.1	0.3	0.3	2.7
TOTAL CONTRACTUAL OBLIGATIONS	$1,750.0	$167.6	$371.0	$189.7	$1,021.7

(1) Some of our contractual obligations have price escalations based on economic indices, but we do not anticipate these escalations to be significant.

(2) Excludes payments under our Elk River Wind Farm, LLC and Cloud County Wind Farm, LLC agreements, as payments are contingent upon output of the facilities. Payments under the Elk River Wind Farm, LLC agreement can run from zero up to a maximum of approximately $16.9 million per year based on a 20 year average cost and an annual output of 550,000 megawatt hours. Payments under the Meridian Way Wind Farm agreement can range from zero to a maximum of approximately $14.6 million per year based on a 20-year average cost.

(3) Includes a water usage contract for our SLCC facility, fuel and purchased power contracts and associated transportation costs, as well as purchased power for 2012 through 2015 for Plum Point.

(4) Represents fuel contracts and associated transportation costs of our gas segment.

(5) Other long-term liabilities primarily represent electric facilities charges paid to City Utilities of Springfield, Missouri of $11,000 per month over 30 years.

DIVIDENDS

Holders of our common stock are entitled to dividends if, as, and when declared by the Board of Directors, out of funds legally available therefore, subject to the prior rights of holders of any outstanding cumulative preferred stock and preference stock. Payment of dividends is determined by our Board of Directors after considering all relevant factors, including the amount of our retained earnings (which is essentially our accumulated net income less dividend payouts). A reduction of our dividend per share, partially or in whole, could have an adverse effect on our common stock price.

In response to the expected loss of revenues resulting from the May 22, 2011 tornado, our level of retained earnings and other relevant factors, our Board of Directors suspended our quarterly dividend for the third and fourth quarters of 2011. On February 2, 2012, the Board of Directors re-established the dividend and declared a quarterly dividend of $0.25 per share on common stock payable on March 15, 2012 to holders of record as of March 1, 2012. As of December 31, 2011, our retained earnings balance was $33.7 million (compared to $5.5 million at December 31, 2010) after paying out $26.7 million in dividends during 2011.

Our diluted earnings per share were $1.31 for the year ended December 31, 2011 and were $1.17 and $1.18 for the years ended December 31, 2010 and 2009, respectively. Dividends paid per share were $0.64 for the year ended December 31, 2011 and $1.28 for each of the years ended December 31, 2010 and 2009.

Under Kansas corporate law, our Board of Directors may only declare and pay dividends out of our surplus or, if there is no surplus, out of our net profits for the fiscal year in which the dividend is declared or the preceding fiscal year, or both. Our surplus, under Kansas law, is equal to our retained earnings plus accumulated other comprehensive income/(loss), net of income tax. However, Kansas law does permit, under certain circumstances, our Board of Directors to transfer amounts from capital in excess of par value to surplus. In addition, Section 305(a) of the Federal Power Act (FPA) prohibits the payment by a utility of dividends from any funds "properly included in capital account". There are no additional rules or regulations issued by the FERC under the FPA clarifying the meaning of this limitation. However, several decisions by the FERC on specific dividend proposals suggest that any determination would be based on a fact-intensive analysis of the specific facts and circumstances surrounding the utility and the dividend in question, with particular focus on the impact of the proposed dividend on the liquidity and financial condition of the utility.

In addition, the EDE Mortgage and our Restated Articles contain certain dividend restrictions. The most restrictive of these is contained in the EDE Mortgage, which provides that we may not declare or pay any dividends (other than dividends payable in shares of our common stock) or make any other distribution on, or purchase (other than with the proceeds of additional common stock financing) any shares of, our common stock if the cumulative aggregate amount thereof after August 31, 1944 (exclusive of the first quarterly dividend of $98,000 paid after said date) would exceed the sum of $10.75 million and the earned surplus (as defined in the EDE Mortgage) accumulated subsequent to August 31, 1944, or the date of succession in the event that another corporation succeeds to our rights and liabilities by a merger or consolidation. On June 9, 2011, we amended the EDE Mortgage in order to provide us with additional flexibility to pay dividends to our shareholders by permitting the payment of any dividend or distribution on, or purchase of, shares of its common stock within 60 days after the related date of declaration or notice of such dividend, distribution or purchase if (i) on the date of declaration or notice, such dividend, distribution or purchase would have complied with the provisions of the EDE Mortgage and (ii) as of the last day of the calendar month ended immediately preceding the date of such payment, our ratio of total indebtedness to total capitalization (after giving pro forma effect to the payment of such dividend, distribution, or purchase) was not more than 0.625 to 1.

OFF-BALANCE SHEET ARRANGEMENTS

We have no off-balance sheet arrangements that have or are reasonably likely to have a current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources, other than operating leases entered into in the normal course of business.

CRITICAL ACCOUNTING POLICIES

Set forth below are certain accounting policies that are considered by management to be critical and that typically require difficult, subjective or complex judgments, often as a result of the need to make estimates about the effect of matters that are inherently uncertain (other accounting policies may also require assumptions that could cause actual results to be different than anticipated results). A change in assumptions or judgments applied in determining the following matters, among others, could have a material impact on future financial results.

Pensions and Other Postretirement Benefits (OPEB). We recognize expense related to pension and other postretirement benefits as earned during the employee's period of service. Related assets and liabilities are established based upon the funded status of the plan compared to the accumulated benefit obligation. Our pension and OPEB expense or benefit includes amortization of previously unrecognized net gains or losses. Additional income or expense may be recognized when our unrecognized gains or losses as of the most recent measurement date exceed 10% of our postretirement benefit obligation or fair value of plan assets, whichever is greater. For pension benefits and OPEB benefits, unrecognized net gains or losses as of the measurement date are amortized into actuarial expense over ten years.

We have electric rate orders in Missouri, Kansas and Oklahoma that allow us to recover pension costs consistent with our GAAP policy noted above. In accordance with the rate orders, we prospectively calculate the value of plan assets using a market related value method as allowed by the Accounting Standard Codification (ASC) guidance on defined benefit plans disclosure. In addition, our rate orders allow us to defer any pension cost that is different from those allowed recovery in rate cases.

In our agreement with the MPSC regarding the purchase of Missouri Gas by EDG, we were allowed to adopt this pension cost recovery methodology for EDG, as well. Also, it was agreed that the effects of purchase accounting entries related to pension and other post-retirement benefits would be recoverable in future rate proceedings. Thus the fair value adjustment acquisition entries have been recorded as regulatory assets, as we believe these amounts are probable of recovery in future rates. The regulatory asset is reduced by an amount equal to the difference between the regulatory costs and the estimated GAAP costs. The difference between this total and the costs being recovered from customers is deferred as a regulatory asset or liability in accordance with the ASC guidance on regulated operations, and recovered over a period of 5 years.

We expect future pension expense or benefits are probable of full recovery in our rates, thus lowering our sensitivity to accounting risks and uncertainties.

We have rate orders in Missouri, Kansas and Oklahoma that allow us to defer any OPEB cost that is different from those allowed recovery in rate cases. This treatment is similar to treatment afforded pension costs. This includes the use of a market-related value of assets, the amortization of unrecognized gains or losses into expense over ten years and the recognition of regulatory assets and liabilities as described in the immediately preceding paragraph.

Based on the regulatory treatment of pension and OPEB recovery afforded in our jurisdictions, we record the amount of unfunded defined benefit pension and postretirement plan obligation as regulatory assets on our balance sheet rather than as reductions of equity through comprehensive income.

Our funding policy is to contribute annually an amount at least equal to the actuarial cost of postretirement benefits. The actual minimum pension funding requirements will be determined based on the results of the actuarial valuations and the performance of our pension assets during the current year. See Note 8 of "Notes to Consolidated Financial Statements" under Item 8.

Risks and uncertainties affecting the application of our pension accounting policy include: future rate of return on plan assets, interest rates used in valuing benefit obligations (i.e. discount rates), demographic assumptions (i.e. mortality and retirement rates) and employee compensation trend rates. Factors that could result in additional pension expense and/or funding include: a lower discount rate than estimated, higher compensation rate increases, lower return on plan assets, and longer retirement periods.

Risks and uncertainties affecting the application of our OPEB accounting policy and related funding include: future rate of return on plan assets, interest rates used in valuing benefit obligations (i.e. discount rates), healthcare cost trend rates, Medicare prescription drug costs and demographic assumptions (i.e. mortality and retirement rates). See Note 1 and Note 8 of "Notes to Consolidated Financial Statements" under Item 8 for further information.

Hedging Activities. We engage in hedging activities in an effort to minimize our risk from volatile natural gas prices. We enter into both physical and financial contracts with counterparties relating to our future natural gas requirements that lock in prices (with respect to a range of predetermined percentages of our expected future natural gas needs) in an attempt to lessen the volatility in our fuel expenditures and gain predictability. We recognize that if risk is not timely and adequately balanced or if counterparties fail to perform contractual obligations, actual results could differ materially from intended results.

All derivative instruments are recognized at fair value on the balance sheet with the unrealized losses or gains from derivatives used to hedge our fuel costs in our electric segment recorded in regulatory assets or liabilities. All gains and losses from derivatives related to the gas segment are also recorded in regulatory assets or liabilities. This is in accordance with the ASC guidance on regulated operations, given that those regulatory assets and liabilities are probable of recovery through our fuel adjustment mechanisms.

Risks and uncertainties affecting the determination of fair value include: market conditions in the energy industry, especially the effects of price volatility, regulatory and global political environments and requirements, fair value estimations on longer term contracts, the effectiveness of the derivative instrument in hedging the change in fair value of the hedged item, estimating underlying fuel demand and counterparty ability to perform. If we estimate that we have overhedged forecasted demand, the gain or loss on the overhedged portion will be recognized immediately as fuel and purchased power expense in our Consolidated Statement of Income and subject to our fuel adjustment clause. See Note 14 of "Notes to Consolidated Financial Statements" under Item 8 for detailed information regarding our hedging information.

Regulatory Assets and Liabilities. In accordance with the ASC accounting guidance for regulated activities, our financial statements reflect ratemaking policies prescribed by the regulatory commissions having jurisdiction over us (Missouri, Kansas, Arkansas, Oklahoma and FERC).

In accordance with accounting guidance for regulated activities, we record a regulatory asset for all or part of an incurred cost that would otherwise be charged to expense in accordance with the accounting guidance, which requires that an asset be recorded if it is probable that future revenue in an amount at least equal to the capitalized cost will be allowable for costs for rate making purposes and the current available evidence indicates that future revenue will be provided to permit recovery of the cost. Additionally, we follow the accounting guidance for regulated activities which says that a liability should be recorded when a regulator has provided current recovery for a cost that is expected to be incurred in the future. We follow this guidance for incurred costs or credits that are subject to future recovery from or refund to our customers in accordance with the orders of our regulators.

Historically, all costs of this nature, which are determined by our regulators to have been prudently incurred, have been recoverable through rates in the course of normal ratemaking procedures. Regulatory assets and liabilities are ratably eliminated through a charge or credit, respectively, to earnings while being recovered in revenues and fully recognized if and when it is no longer probable that such amounts will be recovered through future revenues. We continually assess the recoverability of our regulatory assets. Although we believe it unlikely, should retail electric competition legislation be passed in the states we serve, we may determine that we no longer meet the criteria set forth in the ASC accounting guidance for regulated activities with respect to continued recognition of some or all of the regulatory assets and liabilities. Any regulatory changes that would require us to discontinue application of ASC accounting guidance for regulated activities based upon competitive or other events may also impact the valuation of certain utility plant investments. Impairment of regulatory assets or utility plant investments could have a material adverse effect on our financial condition and results of operations.

As of December 31, 2011, we have recorded $239.6 million in regulatory assets and $128.4 million as regulatory liabilities. See Note 3 of "Notes to Consolidated Financial Statements" under Item 8 for detailed information regarding our regulatory assets and liabilities.

Risks and uncertainties affecting the application of this accounting policy include: regulatory environment, external regulatory decisions and requirements, anticipated future regulatory decisions and their impact of deregulation and competition on ratemaking process, unexpected disallowances, possible changes in accounting standards (including as a result of adoption of IFRS) and the ability to recover costs.

Fuel Adjustment Clause. Typical fuel adjustment clauses permit the distribution to customers of changes in fuel costs, subject to routine regulatory review, without the need for a general rate proceeding. Fuel adjustment clauses are presently applicable to our retail electric sales in Missouri, Oklahoma and Kansas and system wholesale kilowatt-hour sales under FERC jurisdiction. We have an Energy Cost Recovery Rider in Arkansas that adjusts for changing fuel and purchased power costs on an annual basis.

The MPSC authorized a fuel adjustment clause for our Missouri customers effective September 1, 2008. The MPSC established a base cost for the recovery of fuel and purchased power expenses used to supply energy. The fuel adjustment clause permits the distribution to customers of 95% of the changes in fuel and purchased power costs prudently incurred above or below the base cost. Off-system sales margins are also part of the recovery of fuel and purchased power costs. As a result, nearly all of the off-system sales margin flows back to the customer.

Unbilled Revenue. At the end of each period we estimate, based on expected usage, the amount of revenue to record for energy and natural gas that has been provided to customers but not billed. Risks and uncertainties affecting the application of this accounting policy include: projecting customer energy usage, estimating the impact of weather and other factors that affect usage (such as line losses) for the unbilled period and estimating loss of energy during transmission and delivery.

Contingent Liabilities. We are a party to various claims and legal proceedings arising in the ordinary course of our business, which are primarily related to workers' compensation and public liability. We regularly assess our insurance deductibles, analyze litigation information with our attorneys and evaluate our loss experience. Based on our evaluation as of the end of 2011, we believe that we have accrued liabilities in accordance with ASC accounting guidance sufficient to meet potential liabilities that could result from these claims. This liability at December 31, 2011 and 2010 was $4.5 million and $3.4 million, respectively.

Risks and uncertainties affecting these assumptions include: changes in estimates on potential outcomes of litigation and potential litigation yet unidentified in which we might be named as a defendant.

Goodwill. As of December 31, 2011, the consolidated balance sheet included $39.5 million of goodwill. All of this goodwill was derived from our gas acquisition and recorded in our gas segment, which is also the reporting unit for goodwill testing purposes. Accounting guidance requires us to test goodwill for impairment on an annual basis or whenever events or circumstances indicate possible impairment. Absent an indication of fair value from a potential buyer or a similar specific transaction, a combination of the market and income approaches is used to estimate the fair value of goodwill.

We use the market approach which estimates fair value of the gas reporting unit by comparing certain financial metrics to comparable companies. Comparable companies whose securities are actively traded in the public market are judgmentally selected by management based on operational and economic similarities. We utilize EBITDA (earnings before interest, taxes, depreciation, and amortization) multiples of the comparable companies in relation to the EBITDA results of the gas reporting unit to determine an estimate of fair value.

We also utilize a valuation technique under the income approach which estimates the discounted future cash flows of operations. Our procedures include developing a baseline test and performing sensitivity analysis to calculate a reasonable valuation range. The sensitivities are derived from altering those assumptions which are subjective in nature and inherent to a discounted cash flows calculation. Other qualitative factors and comparisons to industry peers are also used to further support the assumptions and ultimately the overall evaluation. A key qualitative assumption considered in our evaluation is the impact of regulation, including rate regulation and cost recovery for the gas reporting unit. Some of the key quantitative assumptions included in our tests involve: regulatory rate design and results; the discount rate; the growth rate; capital spending rates and terminal value calculations. If negative changes occurred to one or more key assumptions, an impairment charge could result. With the exception of the capital spending rate, the key assumptions noted are significantly determined by market factors and significant changes in market factors that impact the gas reporting unit would likely be mitigated by our current and future regulatory rate design to some extent. Other risks and uncertainties affecting these assumptions include: management's identification of impairment indicators, changes in business, industry, laws, technology and economic conditions. Actual results for the gas reporting unit indicate a recent decline in gas customer growth and demand, but this was anticipated in our assumptions for purposes of the discounted cash flow calculation. Our forecasts anticipate the customer contraction will minimize in the near future and return to positive customer growth within the next few years.

We weight the results of the two approaches discussed above in order to estimate the fair value of the gas reporting unit. Our annual test performed as of October 31, 2011 indicated the estimated fair market value of the gas reporting unit to be $5 million to $8 million higher than its carrying value at that time. While we believe the assumptions utilized in our analysis were reasonable, adverse developments in future periods could negatively impact goodwill impairment considerations, which could adversely impact earnings. Specifically, the quantitative assumptions noted previously, such as an increase to the discount rate or decline in the terminal value calculation could lead to an impairment charge in the future.

Use of Management's Estimates. The preparation of our consolidated financial statements in conformity with generally accepted accounting principles (GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. We evaluate our estimates on an on-going basis, including those related to unbilled utility revenues, collectibility of accounts receivable, depreciable lives, asset impairment and goodwill evaluations, employee benefit obligations, contingent liabilities, asset retirement obligations, the fair value of stock based compensation and tax provisions. Actual amounts could differ from those estimates.

RECENTLY ISSUED ACCOUNTING STANDARDS

See Note 1 of "Notes to Consolidated Financial Statements" under Item 8 for further information regarding Recently Issued and Proposed Accounting Standards.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our fuel procurement activities involve primary market risk exposures, including commodity price risk and credit risk. Commodity price risk is the potential adverse price impact related to the fuel procurement for our generating units. Credit risk is the potential adverse financial impact resulting from non-performance by a counterparty of its contractual obligations. Additionally, we are exposed to interest rate risk which is the potential adverse financial impact related to changes in interest rates.

Market Risk and Hedging Activities. Prices in the wholesale power markets can be extremely volatile. This volatility impacts our cost of power purchased and our participation in energy trades. If we were unable to generate an adequate supply of electricity for our customers, we would attempt to purchase power from others. Such supplies are not always available. In addition, congestion on the transmission system can limit our ability to make purchases from (or sell into) the wholesale markets.

We engage in physical and financial trading activities with the goals of reducing risk from market fluctuations. In accordance with our established Energy Risk Management Policy, which typically includes entering into various derivative transactions, we attempt to mitigate our commodity market risk. Derivatives are utilized to manage our gas commodity market risk and to help manage our exposure resulting from purchasing most of our natural gas on the volatile spot market for the generation of power for our native-load customers. See Note 14 of "Notes to Consolidated Financial Statements" under Item 8 for further information.

Commodity Price Risk. We are exposed to the impact of market fluctuations in the price and transportation costs of coal, natural gas, and electricity and employ established policies and procedures to manage the risks associated with these market fluctuations, including utilizing derivatives.

We satisfied 65.0% of our 2011 generation fuel supply need through coal. Approximately 94% of our 2011 coal supply was Western coal. We have contracts and binding proposals to supply a portion of the fuel for our coal plants through 2014. These contracts satisfy approximately 87% of our anticipated fuel requirements for 2012, 61% for 2013 and 43% for our 2014 requirements for our Asbury and Riverton coal plants. In order to manage our exposure to fuel prices, future coal supplies will be acquired using a combination of short-term and long-term contracts.

We are exposed to changes in market prices for natural gas we must purchase to run our combustion turbine generators. Our natural gas procurement program is designed to manage our costs to avoid volatile natural gas prices. We enter into physical forward and financial derivative contracts with counterparties relating to our future natural gas requirements that lock in prices (with respect to predetermined percentages of our expected future natural gas needs) in an attempt to lessen the volatility in our fuel expenditures and improve predictability. As of December 31, 2011, 61%, or 3.9 million Dths's, of our anticipated volume of natural gas usage for our electric operations for 2012 is hedged. See Note 14 of "Notes to Consolidated Financial Statements" under Item 8 for further information.

Based on our expected natural gas purchases for our electric operations for 2012, if average natural gas prices should increase 10% more in 2012 than the price at December 31, 2011, our natural gas expenditures would increase by approximately $0.7 million based on our December 31, 2011 total hedged positions for the next twelve months. However, such an increase would be probable of recovery through fuel adjustment mechanisms in all of our jurisdictions, which significantly reduces the impact of fluctuating fuel costs.

We attempt to mitigate a portion of our natural gas price risk associated with our gas segment using physical forward purchase agreements, storage and derivative contracts. As of December 31, 2011, we have 1.5 million Dths in storage on the three pipelines that serve our customers. This represents 76% of our storage capacity. We have an additional 1.4 million Dths hedged through financial derivatives and physical contracts.

The following table sets forth our long-term hedge strategy of mitigating price volatility for our customers by hedging a minimum of expected gas usage for the current winter season and the next two winter seasons by the beginning of the Actual Cost Adjustment (ACA) year at September 1 and illustrates our hedged position as of December 31, 2011 (in thousands). However, due to purchased natural gas cost recovery mechanisms for our retail customers, fluctuations in the cost of natural gas have little effect on income.

Season	Minimum % Hedged	Dth Hedged Financial	Dth Hedged Physical	Dth in Storage	Actual % Hedged
Current	**50%**	420	310	1,436	**98%**
Second	Up to 50%	700	—	—	16%
Third	Up to 20%	—	—	—	
Total		1,120	310	1,436	

Credit Risk. In order to minimize overall credit risk, we maintain credit policies, including the evaluation of counterparty financial condition and the use of standardized agreements that facilitate the netting of cash flows associated with a single counterparty. See Note 14 of "Notes to Consolidated Financial Statements (Unaudited)" regarding agreements containing credit risk contingent features. In addition, certain counterparties make available collateral in the form of cash held as margin deposits as a result of exceeding agreed-upon credit exposure thresholds or may be required to prepay the transaction. Conversely, we are required to post collateral with counterparties at certain thresholds, which is typically the result of changes in commodity prices. Amounts reported as margin deposit liabilities represent counterparty funds we hold that result from various trading counterparties exceeding agreed-upon credit exposure thresholds. Amounts reported as margin deposit assets represent our funds held on deposit for our NYMEX contracts with our broker and other financial contracts with other counterparties that resulted from us exceeding agreed-upon credit limits established by the counterparties. The following table depicts our margin deposit assets at December 31, 2011 and December 31, 2010. There were no margin deposit liabilities at these dates.

(in millions)	2011	2010
Margin deposit assets	$5.8	$3.9

Our exposure to credit risk is concentrated primarily within our fuel procurement process, as we transact with a smaller, less diverse group of counterparties and transactions may involve large notional volumes and potentially volatile commodity prices. Below is a table showing our net credit exposure at December 31, 2011, reflecting that our counterparties are exposed to Empire for the net unrealized mark-to-market losses for physical forward and financial natural gas contracts carried at fair value.

(in millions)	
Net unrealized mark-to-market losses for physical forward natural gas contracts	$13.9
Net unrealized mark-to-market losses for financial natural gas contracts	9.8
Net credit exposure	$23.7

The $9.8 million net unrealized mark-to-market loss for financial natural gas contracts is comprised entirely of $9.8 million of exposure to counterparties of Empire for unrealized losses. We are holding no collateral from any counterparty since we are below the $10 million mark-to-market collateral threshold in our agreements. As noted above, as of December 31, 2011, we have $5.8 million on deposit for NYMEX contract exposure to Empire, of which $5.8 million represents our collateral requirement. If NYMEX gas prices decreased 25% from their December 31, 2011 levels, our collateral requirement would increase $2.5 million. If these prices increased 25%, our collateral requirement would decrease $2.4 million. Our other counterparties would not be required to post collateral with Empire.

We sell electricity and gas and provide distribution and transmission services to a diverse group of customers, including residential, commercial and industrial customers. Credit risk associated with trade accounts receivable from energy customers is limited due to the large number of customers. In addition, we enter into contracts with various companies in the energy industry for purchases of energy-related commodities, including natural gas in our fuel procurement process.

Interest Rate Risk. We are exposed to changes in interest rates as a result of financing through our issuance of commercial paper and other short-term debt. We manage our interest rate exposure by limiting our variable-rate exposure (applicable to commercial paper and borrowings under our unsecured credit agreement) to a certain percentage of total capitalization, as set by policy, and by monitoring the effects of market changes in interest rates. See Notes 6 and 7 of "Notes to Consolidated Financial Statements" under Item 8 for further information.

If market interest rates average 1% more in 2012 than in 2011, our interest expense would increase, and income before taxes would decrease by less than $0.2 million. This amount has been determined by considering the impact of the hypothetical interest rates on our highest month-end commercial paper balance for 2011. These analyses do not consider the effects of the reduced level of overall economic activity that could exist in such an environment. In the event of a significant change in interest rates, management would likely take actions to further mitigate its exposure to the change. However, due to the uncertainty of the specific actions that would be taken and their possible effects, the sensitivity analysis assumes no changes in our financial structure.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders
of the Empire District Electric Company:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15 present fairly, in all material respects, the financial position of The Empire District Electric Company and its subsidiaries at December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15 presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP
St. Louis, Missouri
February 23, 2012

THE EMPIRE DISTRICT ELECTRIC COMPANY
CONSOLIDATED BALANCE SHEETS

	December 31, 2011	December 31, 2010
	($-000's)	
Assets		
Plant and property, at original cost:		
Electric	$2,063,208	$2,001,142
Natural gas	66,918	63,581
Water	11,540	11,128
Other	34,984	32,264
Construction work in progress	24,141	9,337
	2,200,791	2,117,452
Accumulated depreciation and amortization	637,139	598,363
	1,563,652	1,519,089
Current assets:		
Cash and cash equivalents	5,408	10,525
Restricted cash	4,357	1,771
Accounts receivable — trade, net of allowance of $1,138 and $865, respectively	42,296	41,380
Accrued unbilled revenues	20,326	23,595
Accounts receivable — other	16,269	25,445
Fuel, materials and supplies	62,239	45,557
Prepaid expenses and other	14,629	7,891
Regulatory assets	7,724	4,974
	173,248	161,138
Noncurrent assets and deferred charges:		
Regulatory assets	231,922	189,404
Goodwill	39,492	39,492
Unamortized debt issuance costs	9,331	9,257
Other	4,190	2,931
	284,935	241,084
Total assets	$2,021,835	$1,921,311

(Continued)

The accompanying notes are an integral part of these consolidated financial statements.

THE EMPIRE DISTRICT ELECTRIC COMPANY

CONSOLIDATED BALANCE SHEETS (Continued)

	December 31, 2011	December 31, 2010
	($-000's)	
Capitalization and liabilities		
Common stock, $1 par value, 100,000,000 shares authorized, 41,977,725 and 41,576,869 shares issued and outstanding, respectively	$ 41,978	$ 41,577
Capital in excess of par value	618,304	610,579
Retained earnings	33,707	5,468
Total common stockholders' equity	693,989	657,624
Long-term debt (net of current portion)		
Obligations under capital lease	4,739	4,995
First mortgage bonds and secured debt	487,948	488,577
Unsecured debt	199,572	199,500
Total long-term debt	692,259	693,072
Total long-term debt and common stockholders' equity	1,386,248	1,350,696
Current liabilities:		
Accounts payable and accrued liabilities	59,307	58,820
Current maturities of long-term debt	933	881
Short-term debt	12,000	24,000
Customer deposits	11,428	11,061
Interest accrued	5,958	6,004
Other current liabilities	—	578
Unrealized loss in fair value of derivative contracts	4,769	760
Taxes accrued	2,634	3,935
Regulatory liabilities	—	1,243
	97,029	107,282
Commitments and contingencies (Note 11)		
Noncurrent liabilities and deferred credits:		
Regulatory liabilities	128,440	87,579
Deferred income taxes	263,933	212,003
Unamortized investment tax credits	19,226	19,597
Pension and other postretirement benefit obligations	103,371	93,405
Unrealized loss in fair value of derivative contracts	5,081	3,564
Other	18,507	47,185
	538,558	463,333
Total capitalization and liabilities	$2,021,835	$1,921,311

The accompanying notes are an integral part of these consolidated financial statements.

THE EMPIRE DISTRICT ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
	2011	2010	2009
	(000's, except per share amounts)		
Operating revenues:			
Electric	$522,506	$482,910	$433,133
Gas	46,430	50,885	57,314
Water	1,769	1,805	1,764
Other	6,165	5,676	4,957
	576,870	541,276	497,168
Operating revenue deductions:			
Fuel and purchased power	200,256	199,299	182,028
Cost of natural gas sold and transported	22,760	26,614	35,601
Regulated operating expenses	85,442	79,292	73,086
Other operating expenses	2,098	1,950	1,801
Maintenance and repairs	41,041	36,771	33,012
Loss on plant disallowance	150	—	—
Depreciation and amortization	63,537	58,656	51,494
Provision for income taxes	34,071	30,470	19,571
Other taxes	30,581	27,729	26,080
	479,936	460,781	422,673
Operating income	96,934	80,495	74,495
Other income and (deductions):			
Allowance for equity funds used during construction	294	4,538	6,209
Interest income	555	176	217
Provision for other income taxes	(227)	(63)	(311)
Other — non-operating expense, net	(1,283)	(1,039)	(460)
	(661)	3,612	5,655
Interest charges:			
Long-term debt	42,581	41,959	42,084
Trust preferred securities	—	2,090	4,250
Short-term debt	86	631	1,125
Allowance for borrowed funds used during construction	(218)	(5,636)	(7,924)
Other	(1,147)	(2,333)	(681)
	41,302	36,711	38,854
Net income	$ 54,971	$ 47,396	$ 41,296
Weighted average number of common shares outstanding — basic	41,852	40,545	34,924
Weighted average number of common shares outstanding — diluted	41,887	40,580	34,956
Total earnings per weighted average share of common stock — basic and diluted	$ 1.31	$ 1.17	$ 1.18
Dividends declared per share of common stock	$ 0.64	$ 1.28	$ 1.28

The accompanying notes are an integral part of these consolidated financial statements.

THE EMPIRE DISTRICT ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended December 31,		
	2011	2010	2009
		($-000's)	
Net income	$ 54,971	$47,396	$41,296
Reclassification adjustments for loss included in net income or reclassified to regulatory asset or liability	—	5,814	13,568
Net change in fair market value of open derivative contracts for period	—	(6,362)	(9,576)
Income taxes	—	209	(1,521)
Comprehensive income	$ 54,971	$47,057	$43,767

The accompanying notes are an integral part of these consolidated financial statements.

THE EMPIRE DISTRICT ELECTRIC COMPANY

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY

	Common Stock	Capital in excess of Par	Retained earnings	Accumulated comprehensive income/(loss)	Total
			($-000's)		
Balance at December 31, 2008	$ 33,982	$483,443	$ 13,579	$ (2,132)	$528,872
Net income			41,296		41,296
Stock/stock units issued through:					
Public offering	3,664	60,825			64,489
Stock purchase and reinvestment plans	466	7,363			7,829
Dividends declared			(44,807)		(44,807)
Reclassification adjustment for gains included in net income				13,568	13,568
Change in fair value of open derivative contracts for period				(9,576)	(9,576)
Income taxes				(1,521)	(1,521)
Balance at December 31, 2009	38,112	551,631	10,068	339	600,150
Net income			47,396		47,396
Stock/stock units issued through:					
Public offering	2,871	48,325			51,196
Stock purchase and reinvestment plans	594	10,623			11,217
Dividends declared			(51,996)		(51,996)
Reclassification adjustment for losses included in net income				5,814	5,814
Change in fair value of open derivative contracts for period				(6,362)	(6,362)
Income taxes				209	209
Balance at December 31, 2010	41,577	610,579	5,468	—	657,624
Net income			54,971		54,971
Stock/stock units issued through:					
Public offering					
Stock purchase and reinvestment plans	401	7,725			8,126
Dividends declared			(26,732)		(26,732)
Balance at December 31, 2011	$ 41,978	$618,304	$ 33,707	$ —	$693,989

The accompanying notes are an integral part of these consolidated financial statements.

THE EMPIRE DISTRICT ELECTRIC COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2011	2010	2009
		($-000's)	
Operating activities:			
Net income	$ 54,971	$ 47,396	$ 41,296
Adjustments to reconcile net income to cash flows from operating activities:			
Depreciation and amortization including regulatory items	79,751	71,076	62,247
Pension and other postretirement benefit costs, net of contributions	(20,379)	(3,683)	4,096
Deferred income taxes and unamortized investment tax credit, net	45,051	26,880	15,324
Allowance for equity funds used during construction	(294)	(4,538)	(6,209)
Stock compensation expense	2,147	3,478	2,616
Non cash loss on derivatives	1,187	1,853	10,350
Other	381	—	(457)
Cash flows impacted by changes in:			
Accounts receivable and accrued unbilled revenues	10,342	(11,211)	2,989
Fuel, materials and supplies	(16,682)	(1,585)	4,635
Prepaid expenses, other current assets and deferred charges	(23,163)	(19,606)	(7,464)
Accounts payable and accrued liabilities	(318)	(6,179)	(1,305)
Interest, taxes accrued and customer deposits	(980)	1,522	806
Other liabilities and other deferred credits	3,172	3,954	699
SWPA minimum flows payment	—	26,564	—
Accumulated provision — rate refunds	(578)	—	—
Net cash provided by operating activities	134,608	135,921	129,623

(Continued)

The accompanying notes are an integral part of these consolidated financial statements.

THE EMPIRE DISTRICT ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS (Continued)

	Year Ended December 31,		
	2011	2010	2009
		($-000's)	
Investing activities:			
Capital expenditures — regulated	$ (99,162)	$(106,388)	$(154,016)
Capital expenditures and other investments — non-regulated	(3,375)	(2,817)	(1,239)
Proceeds from the sale of property, plant and equipment	—	—	544
Restricted cash	(2,586)	(1,771)	—
Total net cash used in investing activities	(105,123)	(110,976)	(154,711)
Financing activities:			
Proceeds from first mortgage bonds, net	—	149,635	75,000
Proceeds from issuance of notes payable	—	—	2,470
Long-term debt issuance costs	—	(1,758)	(2,397)
Proceeds from issuance of common stock, net of issuance costs	5,884	60,239	70,271
Repayment of first mortgage bonds	—	(50,000)	(20,025)
Redemption of trust preferred securities	—	(50,000)	—
Redemption of senior notes	—	(48,304)	
Net short-term repayments	(12,000)	(26,500)	(51,500)
Dividends	(26,732)	(51,996)	(44,807)
Other	(1,754)	(1,356)	(1,058)
Net cash provided by (used in) financing activities	(34,602)	(20,040)	27,954
Net increase (decrease) in cash and cash equivalents	(5,117)	4,905	2,866
Cash and cash equivalents, beginning of year	10,525	5,620	2,754
Cash and cash equivalents, end of year	$ 5,408	$ 10,525	$ 5,620

	2011	2010	2009
Supplemental cash flow information:			
Interest paid	$ 41,088	$ 43,044	$ 45,730
Income taxes (refunded) paid, net of refund	(14,300)	11,264	3,246
Supplementary non-cash investing activities:			
Change in accrued additions to property, plant and equipment not reported above	$ (1,387)	$ (3,846)	$ (3,833)
Capital lease obligations for purchase of new equipment	29	2,696	2,946

The accompanying notes are an integral part of these consolidated financial statements.

THE EMPIRE DISTRICT ELECTRIC COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

General

We operate our businesses as three segments: electric, gas and other. The Empire District Electric Company (EDE), a Kansas corporation organized in 1909, is an operating public utility engaged in the generation, purchase, transmission, distribution and sale of electricity in parts of Missouri, Kansas, Oklahoma and Arkansas. As part of our electric segment, we also provide water service to three towns in Missouri. The Empire District Gas Company (EDG) is our wholly owned subsidiary engaged in the distribution of natural gas in Missouri. Our other segment consists of our fiber optics business. See Note 12. Our gross operating revenues in 2011 were derived as follows:

Electric segment sales*	90.9%
Gas segment sales	8.0%
Other segment sales	1.1%

* Sales from our electric segment include 0.3% from the sale of water.

The utility portions of our business are subject to regulation by the Missouri Public Service Commission (MPSC), the State Corporation Commission of the State of Kansas (KCC), the Corporation Commission of Oklahoma (OCC), the Arkansas Public Service Commission (APSC) and the Federal Energy Regulatory Commission (FERC). Our accounting policies are in accordance with the ratemaking practices of the regulatory authorities and conform to generally accepted accounting principles as applied to regulated public utilities.

Our electric operations serve approximately 166,000 customers as of December 31, 2011, and the 2011 electric operating revenues were derived as follows:

Customer	% of revenue
Residential	42.4%
Commercial	30.1%
Industrial	15.1%
Wholesale on-system	3.7%
Wholesale off-system	4.5%
Miscellaneous sources, primarily public authorities	2.6%
Other electric revenues	1.6%

Our retail electric revenues for 2011 by jurisdiction were as follows:

Jurisdiction	% of revenue
Missouri	88.8%
Kansas	5.3%
Arkansas	2.8%
Oklahoma	3.1%

Our gas operations serve approximately 44,000 customers as of December 31, 2011, and the 2011 gas operating revenues were derived as follows:

Customer	% of revenue
Residential	62.5%
Commercial	26.9%
Industrial	1.5%
Other	9.1%

Basis of Presentation

The consolidated financial statements include the accounts of EDE, EDG, and our other subsidiaries. The consolidated entity is referred to throughout as "we" or the "Company". All intercompany balances and transactions have been eliminated in consolidation. See Note 12 for additional information regarding our three segments. Certain immaterial reclassifications have been made to prior year information to conform to the current year presentation.

Accounting for the Effects of Regulation

In accordance with the Accounting Standard Codification (ASC) guidance for regulated operations, our financial statements reflect ratemaking policies prescribed by the regulatory commissions having jurisdiction over our regulated generation and other utility operations (the MPSC, the KCC, the OCC, the APSC and the FERC).

We record a regulatory asset for all or part of an incurred cost that would otherwise be charged to expense in accordance with the ASC guidance for regulated operations which say that an asset should be recorded if it is probable that future revenue in an amount at least equal to the capitalized cost will be allowable for costs for rate making purposes and the current available evidence indicates that future revenue will be provided to permit recovery of the cost. This guidance also says that a liability should be recorded when a regulator has provided current recovery for a cost that is expected to be incurred in the future. We follow this guidance for incurred costs or credits that are subject to future recovery from or refund to our customers in accordance with the orders of our regulators.

Historically, all costs of this nature, which are determined by our regulators to have been prudently incurred, have been recoverable through rates in the course of normal ratemaking procedures. Regulatory assets and liabilities are ratably amortized through a charge or credit, respectively, to earnings while being recovered in revenues and fully recognized if and when it is no longer probable that such amounts will be recovered through future revenues. We continually assess the recoverability of our regulatory assets. Although we believe it unlikely, should retail electric competition legislation be passed in the states we serve, we may determine that we no longer meet the criteria set forth in the ASC guidance for regulated operations with respect to continued recognition of some or all of the regulatory assets and liabilities. Any regulatory changes that would require us to discontinue application of this guidance based upon competitive or other events may also impact the valuation of certain utility plant investments. Impairment of regulatory assets or utility plant investments could have a material adverse effect on our financial condition and results of operations. (See Note 3 for further discussion of regulatory assets and liabilities).

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles (GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements. Estimates also affect the reported amounts of revenues and expenses during the period. Areas in the financial statements significantly affected by estimates and assumptions include unbilled utility revenues, collectibility of accounts receivable, depreciable lives, asset impairment and goodwill impairment evaluations, employee benefit obligations, contingent liabilities, asset retirement obligations, the fair value of stock based compensation, tax provisions and derivatives. Actual amounts could differ from those estimates.

Revenue Recognition

For our utility operations, we use cycle billing and accrue estimated, but unbilled, revenue for services provided between the last bill date and the period end date. Unbilled revenues represent the estimate of receivables for energy and natural gas services delivered, but not yet billed to customers. The accuracy of our unbilled revenue estimate is affected by factors including fluctuations in energy demands, weather, line losses and changes in the composition of customer classes.

Municipal Franchise Taxes

Municipal franchise taxes are collected for and remitted to their respective entities and are included in operating revenues and other taxes in the Consolidated Statements of Income. Municipal franchise taxes of $11.0 million, $10.6 million and $10.2 million were recorded for each of the years ended December 31, 2011, 2010 and 2009, respectively.

Accounts Receivable

Accounts receivable are recorded at the tariffed rates for customer usage, including applicable taxes and fees and do not bear interest. We review the outstanding accounts receivable monthly, as well as the bad debt write-offs experienced in the past, and establish an allowance for doubtful accounts. Account balances are charged off against the allowance when management determines it is probable the receivable will not be recovered.

Property, Plant & Equipment

The costs of additions to utility property and replacements for retired property units are capitalized. Costs include labor, material, an allocation of general and administrative costs, and an allowance for funds used during construction (AFUDC). The original cost of units retired or disposed of and the costs of removal are charged to accumulated depreciation, unless the removed property constitutes an operating unit or system. In this case a gain or loss is recognized upon the disposal of the asset. Maintenance expenditures and the removal of minor property items are charged to income as incurred. A liability is created for any additions to electric or gas utility property that are paid for by advances from developers. For a period of five years the Company refunds, to the developer, a pro rata amount of the original cost of the extension for each new customer added to the extension. Nonrefundable payments at the end of the five year period are applied as a reduction to the cost of the plant in service. The liability as of December 31, 2011 and 2010 was $6.6 million and $8.3 million, respectively.

As of December 31, 2011 and 2010, we had recorded accrued cost of removal of $68.6 million and $58.8 million, respectively, for our electric operating segment. This represents an estimated cost of dismantling and removing plant from service upon retirement, accrued as part of our depreciation rates. Pursuant to our 2005 Missouri rate order, we accrue cost of removal in depreciation rates for mass property (including transmission, distribution and general plant assets). These accruals are not considered an asset retirement obligation under the guidance provided on asset retirement obligations within the ASC. We reclassify the accrued cost of dismantling and removing plant from service upon retirement from accumulated depreciation to a regulatory liability. We have a similar cost of removal regulatory liability for our gas operating segment. This amount at December 31, 2011 and 2010 was $5.0 million and $3.9 million, respectively. These amounts are net of our actual cost of removal expenditures.

Asset Retirement Obligation

We record the estimated fair value of legal obligations associated with the retirement of tangible long-lived assets in the period in which the liabilities are incurred and capitalize a corresponding amount as part of the book value of the related long-lived asset. In subsequent periods, we are required to adjust asset retirement obligations based on changes in estimated fair value, and the corresponding increases in asset book values are depreciated over the useful life of the related asset. Uncertainties as to the probability, timing or cash flows associated with an asset retirement obligation affect our estimate of fair value.

We have identified asset retirement obligations associated with the future removal of certain river water intake structures and equipment at the Iatan Power Plant, in which we have a 12% ownership. We also have a liability for future containment of an ash landfill at the Riverton Power Plant, a liability for a solid waste land fill at the Plum Point Energy Station, and asset retirement obligations associated with the removal of asbestos located at the Riverton and Asbury Plants. In addition, we have a liability for the removal and disposal of Polychlorinated Biphenyls (PCB) contaminants associated with our transformers and substation equipment. These liabilities have been estimated based upon either third party costs or historical review of expenditures for the removal of similar past liabilities. The potential costs of these future expenditures are based on engineering estimates of third party costs to remove the assets in satisfaction of the associated obligations. This liability will be accreted over the period up to the estimated settlement date.

All of our recorded asset retirement obligations have been estimated as of the expected retirement date, or settlement date, and have been discounted using a credit adjusted risk-free rate ranging from 4.5% to 5.52% depending on the settlement date. Revisions to these liabilities could occur due to changes in the cost estimates, anticipated timing of settlement or federal or state regulatory requirements.

The balances at the end of 2010 and 2011 are shown below.

(000's)	Liability Balance 12/31/10	Liabilities Recognized	Liabilities Settled	Accretion	Cash Flow Revisions	Liability Balance at 12/31/11
Asset Retirement Obligation	$3,757	$ —	$ —	$187	$ —	$3,944

(000's)	Liability Balance 12/31/09	Liabilities Recognized	Liabilities Settled	Accretion	Cash Flow Revisions	Liability Balance at 12/31/10
Asset Retirement Obligation	$3,607	$ —	$ —	$150	$ —	$3,757

Upon adoption of the standards on the retirement of long lived assets and conditional asset retirement obligations, we recorded a liability and regulatory asset because we expect to recover these costs of removal in electric and gas rates either through depreciation accruals or direct expenses. We also defer the liability accretion and depreciation expense as a regulatory asset. At December 31, 2011 and 2010, our regulatory assets relating to asset retirement obligations totaled $3.6 million and $3.4 million, respectively.

Also as noted previously under property, plant and equipment, we reclassify the accrued cost of dismantling and removing plant from service upon retirement, which is not considered an asset retirement obligation under this guidance, from accumulated depreciation to a regulatory liability. This balance sheet reclassification has no impact on results of operations.

Depreciation

Provisions for depreciation are computed at straight-line rates in accordance with GAAP consistent with rates approved by regulatory authorities. These rates are applied to the various classes of utility assets on a composite basis. Provisions for depreciation for our other segment are computed at straight-line rates over the estimated useful life of the properties (See Note 2 for additional details regarding depreciation rates).

In accordance with our previous rate orders, we recorded approximately $6.6 million, $7.5 million, and $4.5 million of regulatory amortization during 2011, 2010, and 2009, respectively. This amortization included in our rates was granted in the Experimental Regulatory Plan approved by the MPSC on August 2, 2005 and terminated on June 15, 2011, as a result of our 2010 Missouri rate case. It provided additional cash flow to enhance the financial support for our generation expansion plan and was related to our investment in Iatan 2 as well as our Riverton V84.3A2 combustion turbine (Riverton Unit 12) and environmental improvement and upgrades at Asbury and Iatan 1. This amortization was included in depreciation and amortization expense and in accumulated depreciation and amortization on the consolidated balance sheet.

Allowance for Funds Used During Construction

As provided in the FERC regulatory Uniform System of Accounts, utility plant is recorded at original cost, including an allowance for funds used during construction (AFUDC) when first placed in service. The AFUDC is a utility industry accounting practice whereby the cost of borrowed funds and the cost of equity funds applicable to our construction program are capitalized as a cost of construction. This accounting practice offsets the effect on earnings of the cost of financing current construction, and treats such financing costs in the same manner as construction charges for labor and materials.

AFUDC does not represent current cash income. Recognition of this item as a cost of utility plant is in accordance with regulatory rate practice under which such plant costs are permitted as a component of rate base and the provision for depreciation.

In accordance with the methodology prescribed by the FERC, we utilized aggregate rates (on a before-tax basis) of 5.2% for 2011, 7.5% for 2010 and 7.0% for 2009, compounded semiannually, in determining AFUDC for all of our projects except Iatan 2. The specific Iatan 2 AFUDC rate was a result of our Experimental Regulatory Plan approved by the MPSC on August 2, 2005, and it terminated on June 15, 2011. In this agreement, we were allowed to receive the regulatory amortization discussed above, in rates prior to the completion of Iatan 2. As a result, the equity portion of our AFUDC rate for the Iatan 2 project was reduced by 2.5 percentage points (See Note 3 for additional discussion of our regulatory plan).

Asset Impairments (excluding goodwill)

We review long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. To the extent that certain assets may be impaired, analysis is performed based on undiscounted forecasted cash flows to determine the impairment amount. None of our assets were impaired as of December 31, 2011 and 2010.

Goodwill

As of December 31, 2011, the consolidated balance sheet included $39.5 million of goodwill. All of this goodwill was derived from our gas acquisition and recorded in our gas segment, which is also the reporting unit for goodwill testing purposes. Accounting guidance requires us to test goodwill for impairment on an annual basis or whenever events or circumstances indicate possible impairment. Absent an indication of fair value from a potential buyer or a similar specific transaction, a combination of the market and income approaches is used to estimate the fair value of goodwill.

We use the market approach which estimates fair value of the gas reporting unit by comparing certain financial metrics to comparable companies. Comparable companies whose securities are actively traded in the public market are judgmentally selected by management based on operational and economic similarities. We utilize EBITDA (earnings before interest, taxes, depreciation, and amortization) multiples of the comparable companies in relation to the EBITDA results of the gas reporting unit to determine an estimate of fair value.

We also utilize a valuation technique under the income approach which estimates the discounted future cash flows of operations. Our procedures include developing a baseline test and performing sensitivity analysis to calculate a reasonable valuation range. The sensitivities are derived from altering those assumptions which are subjective in nature and inherent to a discounted cash flows calculation. Other qualitative factors and comparisons to industry peers are also used to further support the assumptions and ultimately the overall evaluation. A key qualitative assumption considered in our evaluation is the impact of regulation, including rate regulation and cost recovery for the gas reporting unit. Some of the key quantitative assumptions included in our tests involve: regulatory rate design and results; the discount rate; the growth rate; capital spending rates and terminal value calculations. If negative changes occurred to one or more key assumptions, an impairment charge could result. With the exception of the capital spending rate, the key assumptions noted are significantly determined by market factors and significant changes in market factors that impact the gas reporting unit would likely be mitigated by our current and future regulatory rate design to some extent. Other risks and uncertainties affecting these assumptions include: management's identification of impairment indicators, changes in business, industry, laws, technology and economic conditions. Actual results for the gas reporting unit indicate a recent decline in gas customer growth and demand, but this was anticipated in our assumptions for purposes of the discounted cash flow calculation. Our forecasts anticipate the customer contraction will minimize in the near future and return to positive customer growth within the next few years.

We weight the results of the two approaches discussed above in order to estimate the fair value of the gas reporting unit. Our annual test performed as of October 31, 2011 indicated the estimated fair market value of the gas reporting unit to be $5-$8 million higher than its carrying value at that time. While we believe the assumptions utilized in our analysis were reasonable, adverse developments in future periods could negatively impact goodwill impairment considerations, which could adversely impact earnings. Specifically, the quantitative assumptions noted previously, such as an increase to the discount rate or decline in the terminal value calculation could lead to an impairment charge in the future.

Fuel and Purchased Power

Electric Segment

Fuel and purchased power costs are recorded at the time the fuel is used, or the power purchased. This amount is adjusted to reflect regulatory treatment for our Missouri and Kansas fuel adjustment mechanisms discussed below.

The MPSC authorized a fuel adjustment clause (FAC) for our Missouri customers effective September 1, 2008. The MPSC established a base cost for the recovery of fuel and purchased power expenses used to supply energy. The FAC permits the distribution to customers of 95% of the changes in fuel and purchased power costs prudently incurred above or below the base cost. Off-system sales margins are also part of the recovery of fuel and purchased power costs. As a result, nearly all of the off-system sales margin flows back to the customer. Rates related to the fuel adjustment clause are modified twice a year subject to the review and approval by the MPSC. In accordance with the ASC guidance for regulated operations, 95% of the difference between the actual costs of fuel and purchased power and the base cost of fuel and purchased power recovered from our customers is recorded as an adjustment to fuel and purchased power expense with a corresponding regulatory asset or regulatory liability. If the actual fuel and purchased power costs are higher or lower than the base fuel and purchased power costs billed to customers, 95% of these amounts will be recovered or refunded to our customers when the fuel adjustment clause is modified.

In our Kansas jurisdiction, the costs of fuel are recovered from customers through a fuel adjustment clause, based upon estimated fuel costs and purchased power. The adjustments are subject to audit and final determination by regulators. The difference between the costs of fuel used and the cost of fuel recovered from our Kansas customers is recorded as a regulatory asset or a regulatory liability if the actual costs are higher or lower than the costs billed to customers, in accordance with the ASC guidance for regulated operations. Similar fuel recovery mechanisms are in place for our Oklahoma, Arkansas and the FERC jurisdictions.

At December 31, 2011, our Missouri and Kansas fuel and purchased power costs were under-recovered by $6.0 million, which is reflected as a regulatory asset.

We receive the renewable attributes associated with the power purchased through our purchased power agreements with Elk River Windfarm LLC and Cloud County Windfarm, LLC. These renewable attributes are converted into renewable energy credits, which are considered inventory, and recorded at zero cost (See Note 11).

We have a Stipulation and Agreement with the MPSC granting us authority to manage our SO_2 allowance inventory in accordance with our SO_2 Allowance Management Policy (SAMP). The SAMP allows us to exchange banked allowances for future vintage allowances and/or monetary value and, in extreme market conditions, to sell SO_2 allowances outright for monetary value. We have not yet exchanged or sold any allowances. We classify our allowances as inventory and they are recorded at cost. We had not needed to purchase SO_2 allowances until the addition of the Plum Point plant in 2010, which is not allocated allowances from the EPA. The allocated allowances are recorded at zero cost. The allowances are removed from inventory on a FIFO basis. We consider used allowances to be a part of fuel expense (See Note 11).

Gas Segment

Fuel expense for our gas segment is recognized when the natural gas is delivered to our customers, based on the current cost recovery allowed in rates. A Purchased Gas Adjustment (PGA) clause allows EDG to recover from our customers, subject to audit and final determination by regulators, the cost of purchased gas supplies and related carrying costs associated with the Company's use of natural gas financial instruments to hedge the purchase price of natural gas. This PGA clause allows us to make rate changes periodically (up to four times) throughout the year in response to weather conditions and supply demands, rather than in one possibly extreme change per year.

We calculate the PGA factor based on our best estimate of our annual gas costs and volumes purchased for resale. The calculated factor is reviewed by the MPSC staff and approved by the MPSC. PGA factor elements considered include cost of gas supply, storage costs, hedging contracts, revenue and refunds, prior period adjustments and transportation costs.

Pursuant to the provisions of the PGA clause, the difference between actual costs incurred and costs recovered through the application of the PGA (including costs, cost reductions and carrying costs associated with the use of financial instruments), are reflected as a regulatory asset or liability. The balance is amortized as amounts are reflected in customer billings.

Derivatives

We utilize derivatives to help manage our natural gas commodity market risk resulting from purchasing natural gas, to be used as fuel in our electric business or sold in our natural gas business, on the volatile spot market and to manage certain interest rate exposure.

Electric Segment

Pursuant to the ASC guidance on accounting for derivative instruments and hedging activities, derivatives are required to be recognized on the balance sheet at their fair value. On the date a derivative contract is entered into, the derivative is designated as (1) a hedge of a forecasted transaction or of the variability of cash flows to be received or paid related to a recognized asset or liability ("cash-flow" hedge); or (2) an instrument that is held for non-hedging purposes (a "non-hedging" instrument). We record the mark-to-market gains or losses on derivatives used to hedge our fuel costs as regulatory assets or liabilities. This is in accordance with the ASC guidance on regulated operations, given that those regulatory assets and liabilities are probable of recovery through our fuel adjustment mechanism. Unrealized gains and losses from cash flow hedges existing prior to the implementation of our fuel adjustment clause were recorded through comprehensive income through September 30, 2010. At December 31, 2010 the remaining hedges, that were entered into prior to the fuel adjustment clause, were de-designated. Given that upon settlement, the realized gain or loss would be recorded as fuel expense and be subject to the fuel adjustment clause, we reclassified the unrealized loss on these hedges from comprehensive income to a regulatory asset.

We also enter into fixed-price forward physical contracts for the purchase of natural gas, coal and purchased power. These contracts, if they meet the definition of a derivative, are not subject to derivative accounting because they are considered to be normal purchase normal sales (NPNS) transactions. If these transactions don't qualify for NPNS treatment, they would be marked to market for each reporting period through regulatory assets or liabilities.

Gas Segment

Financial hedges for our natural gas business are recorded at fair value on our balance sheet. Because we have a commission approved natural gas cost recovery mechanism (PGA), we record the mark-to-market gain/loss on natural gas financial hedges each reporting period to a regulatory asset/liability account. The regulatory asset/liability account tracks the difference between revenues billed to customers for natural gas costs and actual natural gas expense which is trued up at the end of August each year and included in the Actual Cost Adjustment (ACA) factor to be billed to customers during the next year. This is consistent with the ASC guidance on regulated operations, in that we will be recovering our costs after the annual true up period (subject to a prudency review by the MPSC).

Cash flows from hedges for both electric and gas segments are classified within cash flows from operations.

Pension and Other Postretirement Benefits

We recognize expense related to pension and other postretirement benefits as earned during the employee's period of service. Related assets and liabilities are established based upon the funded status of the plan compared to the projected benefit obligation. Our pension and OPEB expense or benefit includes amortization of previously unrecognized net gains or losses. Additional income or expense may be recognized when our unrecognized gains or losses as of the most recent measurement date exceed 10% of our postretirement benefit obligation or fair value of plan assets, whichever is greater. For pension benefits and OPEB benefits, unrecognized net gains or losses as of the measurement date are amortized into actuarial expense over ten years.

Pensions

We have rate orders with Missouri, Kansas and Oklahoma that allow us to recover pension costs consistent with our GAAP policy noted above. In accordance with the rate orders, we prospectively calculated the value of plan assets using a market-related value method as allowed by the ASC guidance on pension benefits. As a result, we are allowed to record the Missouri, Kansas and Oklahoma portion of any costs above or below the amount included in rates as a regulatory asset or liability, respectively.

In the Company's agreement with the MPSC regarding the purchase of Missouri Gas by EDG, the Company was allowed to adopt this pension cost recovery methodology for EDG as well. Also, it was agreed that the effects of purchase accounting entries related to pension and other postretirement benefits would be recoverable in future rate proceedings. Thus the fair value adjustment acquisition entries have been recorded as regulatory assets, as these amounts are probable of recovery in future rates. The regulatory asset is reduced by an amount equal to the difference between the regulatory costs and the estimated GAAP costs. The difference between this total and the costs being recovered from customers is deferred as a regulatory asset or liability in accordance with the ASC guidance on regulated operations, and recovered over a period of five years.

Other Postretirement Benefits (OPEB)

In our 2006 Missouri rate case, the MPSC approved regulatory treatment for our OPEB costs similar to the treatment described above for pension costs. In our 2010 Kansas rate case, the KCC also approved regulatory treatment for our OPEB costs. This includes the use of a market-related value of assets, the amortization of unrecognized gains or losses into actuarial expense over ten years and the recognition of regulatory assets and liabilities as described above.

In accordance with the guidance provided in the ASC on the Medicare Prescription Drug, Improvement and Modernization Act of 2003, the accumulated postretirement benefit obligation (APBO) and net cost recognized for OPEB reflects the effects of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act). The Act provides for a federal subsidy, beginning in 2006, of 28% of prescription drug costs between $250 and $5,000 for each Medicare-eligible retiree who does not join Medicare Part D, to companies whose plans provide prescription drug benefits to their retirees that are "actuarially equivalent" to the prescription drug benefits provided under Medicare. Equivalency must be certified annually by the Federal Government. Our plan provides prescription drug benefits that are "actuarially equivalent" to the prescription drug benefits provided under Medicare and have been certified as such.

Additional guidance in the ASC on employers' accounting for defined benefit pension and other postretirement plans requires an employer to recognize the over funded or under funded status of a defined benefit postretirement plan (other than a multiemployer plan) as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through comprehensive income of a business entity. The guidance also requires an employer to measure the funded status of a plan as of the date of its year-end statement of financial position, with limited exceptions. Pension and other postretirement employee benefits tracking mechanisms are utilized to allow for future rate recovery of the obligations. We record these as regulatory assets on the balance sheet rather than as reductions of equity through comprehensive income (See Note 8).

Unamortized Debt Discount, Premium and Expense

Discount, premium and expense associated with long-term debt are amortized over the lives of the related issues. Costs, including gains and losses, related to refunded long-term debt are amortized over the lives of the related new debt issues, in accordance with regulatory rate practices.

Liability Insurance

We are primarily self-insured for workers' compensation claims, general liabilities, benefits paid under employee healthcare programs and long-term disability benefits. Accruals are primarily based on the estimated undiscounted cost of claims. We self-insure up to certain limits that vary by segment and type of risk. Periodically, we evaluate the level of insurance coverage over the self insured limits and adjust insurance levels based on risk tolerance and premium expense. We carry excess liability insurance for workers' compensation and public liability claims for our electric segment. In order to provide for the cost of losses not covered by insurance, an allowance for injuries and damages is maintained based on our loss experience. Our gas segment is covered by excess liability insurance for public liability claims, and workers' compensation claims are covered by a guaranteed cost policy (See Note 11).

Other Noncurrent Liabilities

Other noncurrent liabilities are comprised of accruals and other accounting estimates not sufficiently large enough to merit individual disclosure. At December 31, 2011, the balance of other noncurrent liabilities is primarily comprised of accruals for self insurance, customer advances for construction and asset retirement obligations.

Cash & Cash Equivalents

Cash and cash equivalents include cash on hand and temporary investments purchased with an initial maturity of three months or less. It also includes checks and electronic funds transfers that have been issued but have not cleared the bank, which are also reflected in current accrued liabilities and were $16.6 million and $14.5 million at December 31, 2011 and 2010, respectively.

Restricted Cash

As part of our Plum Point ownership agreement, we are required to have funds available in an escrow account which guarantees payment of certain operating and construction costs. The cash is held at a financial institution and restricted as to withdrawal or use. We expect the restrictions on these funds related to construction costs, approximately $2.5 million and $0 at December 31, 2011 and 2010, respectively, to expire during 2012. The amounts restricted for operating costs, $1.8 million at December 31, 2011 and 2010, may increase or decrease based on an annual review.

Fuel, Materials and Supplies

Fuel, materials and supplies consist primarily of coal, natural gas in storage and materials and supplies, which are reported at average cost. These balances are as follows (in thousands):

	2011	2010
Electric fuel inventory	$27,431	$17,648
Natural gas inventory	6,346	4,470
Materials and supplies	28,462	23,439
TOTAL	$62,239	$45,557

Income Taxes

Deferred tax assets and liabilities are recognized for the tax consequences of transactions that have been treated differently for financial reporting and tax return purposes, measured using statutory tax rates (See Note 9).

Investment tax credits utilized in prior years were deferred and are being amortized over the useful lives of the properties to which they relate. Remaining unamortized investment tax credits are being amortized over their lives of up to approximately 52 years.

A December 2009 award from an arbitration panel ordered KCP&L to renegotiate with the IRS a previous $125 million advanced coal investment tax credit granted to our Iatan 2 plant. The IRS executed a revised memorandum of understanding (MOU) on September 7, 2010, which granted us our share, $17.7 million, of advanced coal investment tax credits in accordance with the arbitration panel's order. We utilized less than $0.2 million of these credits when preparing our 2010 tax return as utilization of the credits was limited by alternative minimum tax rules. We expect to use the remaining credits over the 2012 and 2013 tax years. The tax credit will have no significant income statement impact as the credits will flow to our customers as we amortize the tax credits over the life of the plant.

Accounting for Uncertainty in Income Taxes

In 2006, the FASB issued guidance which clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with the ASC guidance on accounting for income taxes. We file consolidated income tax returns in the U.S. federal and state jurisdictions. With few exceptions, we are no longer subject to U.S. federal, state and local income tax examinations by tax authorities for years before 2007. At December 31, 2011 and 2010, our balance sheet included approximately zero and $0.4 million, respectively, of unrecognized tax benefits which would affect our effective tax rate if recognized. We do not expect any material changes to unrecognized tax benefits within the next twelve months. We recognize interest accrued and penalties related to unrecognized tax benefits in other expenses.

Computations of Earnings Per Share

The ASC guidance on earnings per share requires dual presentation of basic and diluted earnings per share. Basic earnings per share does not include potentially dilutive securities and is computed by dividing net income by the weighted average number of common shares outstanding. Diluted earnings per share assumes the issuance of common shares pursuant to the Company's stock-based compensation plans at the beginning of each respective period, or at the date of grant or award if later. Shares attributable to stock options and performance-based restricted stock are excluded from the calculation of diluted earnings per share if the effect would be antidilutive.

	2011	2010	2009
Weighted Average Number Of Shares			
Basic	41,851,759	40,544,802	34,923,526
Dilutive Securities:			
Performance-based restricted stock awards	18,222	14,991	20,513
Dividend equivalents	9,585	12,558	12,122
Employee stock purchase plan	3,815	7,170	103
Stock options	3,240	—	—
Time-based restricted stock awards	807	—	—
Total dilutive securities	35,669	34,719	32,738
Diluted weighted average number of shares	41,887,428	40,579,521	34,956,264
Antidilutive Shares	**—**	**74,800**	**117,178**

Potentially dilutive shares are not expected to have a material impact unless significant appreciation of the Company's stock price occurs.

Stock-Based Compensation

We have several stock-based compensation plans, which are described in more detail in Note 4. In accordance with the ASC guidance on stock-based compensation, we recognize compensation expense over the requisite service period of all stock-based compensation awards based upon the fair-value of the award as of the date of issuance (See Note 4).

Reclassifications

The Company has revised its previously reported 2010 cash and cash equivalents numbers in its balance sheet from $14.5 million to $10.5 million to correct for certain immaterial errors arising from an incorrect classification of certain other assets as cash. Accordingly, certain amounts (Operating Cash flows revised from $138.1 million to $135.9 million and investing cash flows revised from [$109.2] million to [$111.0] million) in the statement of cash flows that were affected by the immaterial classification errors have been revised. Such revisions, in the opinion of management, are not material to the prior period financial statements.

Recently Issued and Proposed Accounting Standards

Fair Value: In May 2011, the Financial Accounting Standards Board (FASB) amended the guidance governing fair value measurements and disclosure requirements. The revised guidance is intended to result in common fair value measurement and disclosure requirements in U.S. Generally Accepted Accounting Principles (GAAP) and International Financial Reporting Standards. The revised guidance changes the wording used to describe some of the requirements in U.S. GAAP. Additionally, some of the revisions clarify the FASB's intent for the application of the guidance. The revised guidance will be applicable for interim and annual periods beginning after December 15, 2011. The application of this standard will not have a material impact on our results of operations, financial position or liquidity.

Other Comprehensive Income: In June 2011, the FASB amended the guidance governing the presentation of other comprehensive income. Under the revised guidance, items of net income and other comprehensive income may be presented in one single statement, or in two separate, but consecutive, statements. The statements are required to be presented with equal prominence as the other primary financial statements. In December 2011, the FASB amended this guidance to defer provisions of the guidance that required the presentation of reclassification adjustments by component in both the statement where net income is presented and the statement where other comprehensive income is presented. The deferral has been made to allow the FASB to redeliberate this requirement. All other requirements of the revised guidance will be applicable for interim and annual periods beginning after December 15, 2011. The application of this standard will not have a material impact on our results of operations, financial position or liquidity.

Goodwill Impairment: In September 2011, the FASB amended the guidance governing goodwill impairment testing. Under the revised guidance an entity will be permitted to complete a qualitative analysis to determine if further impairment testing is necessary. The standard is effective for interim and annual goodwill impairment tests performed for fiscal years beginning after December 15, 2011. Early adoption is permitted. The application of this standard will not have a material impact on our results of operations, financial position or liquidity.

Balance Sheet Offsetting: In December 2011, the FASB amended the guidance governing the offsetting, or netting, of assets and liabilities on the balance sheet. Under the revised guidance, an entity would be required to disclose both the gross and net information about instruments and transactions that are eligible for offset on the balance sheet, as well as instruments or transactions subject to a master netting agreement. This standard is effective for annual periods beginning after January 1, 2013. The application of this standard will not have a material impact on our results of operations, financial position or liquidity.

2. Property, Plant and Equipment

Our total property, plant and equipment are summarized below (in thousands).

	December 31, 2011	December 31, 2010
Electric plant		
Production	$1,023,154	$1,015,040
Transmission	232,390	220,514
Distribution	719,731	682,175
General(1)	87,933	83,413
Electric plant	2,063,208	2,001,142
Less accumulated depreciation and amortization(2)	610,084	575,061
Electric plant net of depreciation and amortization	1,453,124	1,426,081
Construction work in progress	23,494	9,214
Net electric plant	1,476,618	1,435,295
Gas plant	66,918	63,581
Less accumulated depreciation and amortization	10,851	8,994
Gas plant net of accumulated depreciation	56,067	54,587
Construction work in progress	79	6
Net gas plant	56,146	54,593
Water plant	11,540	11,128
Less accumulated depreciation and amortization	4,158	3,855
Water plant net of depreciation and amortization	7,382	7,273
Construction work in progress	126	40
Net water plant	7,508	7,313
Other		
Fiber	34,984	32,264
Less accumulated depreciation and amortization	12,046	10,453
Non-regulated net of depreciation and amortization	22,938	21,811
Construction work in progress	442	77
Net non-regulated property	23,380	21,888
TOTAL NET PLANT AND PROPERTY	$1,563,652	$1,519,089

(1) Includes intangible property of $22.1 and $20.1 million as of December 31, 2011 and 2010, respectively, primarily related to capitalized software and investments in facility upgrades owned by other utilities. Accumulated amortization related to this property in 2011 and 2010 was $9.9 and $9.2 million respectively.

(2) Includes regulatory amortization of $37.3 million and $30.7 million as of December 30, 2011 and 2010, respectively, resulting from our regulatory plan (See Note 3 for additional discussion of our regulatory plan).

The table below summarizes the total provision for depreciation and the depreciation rates for continuing operations, both capitalized and expensed, for the years ended December 31 (in thousands):

	2011	2010	2009
Provision for depreciation			
Regulated — Electric and Water	$54,628	$49,254	$44,973
Regulated — Gas	3,485	3,046	2,072
Non-Regulated	1,807	1,641	1,443
TOTAL	59,920	53,941	48,488
Amortization(1)	7,445	8,347	5,159
TOTAL	$67,365	$62,288	$53,647

(1) Includes $6.6 million, $7.5 million, and $4.5 million of regulatory amortization for 2011, 2010 and 2009, respectively. This was granted by the MPSC effective January 1, 2007 and updated August 23, 2008, and September 10, 2010. This regulatory amortization terminated as of June 15, 2011 as a result or our 2010 Missouri rate case.

	2011	2010	2009
Annual depreciation rates			
Electric and water	2.7%	2.8%	2.9%
Gas	5.5%	5.1%	3.7%
Non-Regulated	5.4%	5.3%	5.0%
TOTAL COMPANY	2.9%	2.9%	3.0%

The table below sets forth the average depreciation rate for each class of assets for each period presented:

	2011	2010	2009
Annual Weighted Average Depreciation Rate			
Electric fixed assets:			
Production plant	2.1%	2.0%	2.2%
Transmission plant	2.3%	2.4%	2.4%
Distribution plant	3.6%	3.6%	3.6%
General plant	6.1%	6.2%	6.1%
Water	2.7%	2.7%	2.7%
Gas	5.5%	5.1%	3.7%
Non-regulated	5.4%	5.3%	5.0%

3. Regulatory Matters

Regulatory Assets and Liabilities and Other Deferred Credits

The Missouri Public Service Commission (MPSC) approved a joint settlement agreement allowing us to defer actual incremental operating and maintenance expenses associated with the repair, restoration and rebuilding activities resulting from the tornado which hit our service territory on May 22, 2011. In addition, depreciation related to the capital expenditures will be deferred and a carrying charge will be accrued. These amounts, which were approximately $1.6 million as of December 31, 2011, have been recorded as a regulatory asset.

Construction accounting, as approved by the MPSC in our 2005 regulatory plan, permitted the deferral of charges for depreciation, operations and maintenance and carrying costs related to the operation of Iatan 1 and Iatan 2 until they were ultimately included in our rates. Construction accounting was also applied to Plum Point construction costs incurred subsequent to February 28, 2010. All of these deferrals began at the plants' respective in-service dates, and ended when recovery began in rates. All of these deferrals are being amortized over the life of the plants beginning on June 15, 2011, the effective date of rates for our recently completed Missouri rate case. As of December 31, 2011 these deferrals totaled $17.1 million and were recorded as regulatory assets. The regulatory plan also required us to continue to defer the fuel and purchased power expense impacts of Iatan 2, which were approximately $8.3 million as of December 31, 2011 and are recorded in Non-Current Regulatory Liabilities. Through December 31, 2011, $6.6 million in regulatory plan amortization had been recognized.

As part of a stipulated agreement in our 2009 Kansas rate case, approved by the KCC on June 25, 2010, we also defered depreciation and operating and maintenance expense on both Plum Point and Iatan 2 from their respective in-service dates until the effective date for rates from the next Kansas case, which was January 1, 2012. These deferrals will be recovered over a 4 year period.

Changes to regulatory assets and liabilities regarding their rate base inclusion or amortizable lives since December 31, 2010 are as follows: As a result of our recently completed Missouri rate case, a tracking mechanism has been created to flow the 2010 SWPA payment, net of associated taxes, back to our customers (see Note 9). The Missouri, Kansas and Oklahoma jurisdictional portions of the payment will be amortized over ten years and reflected as a reduction to fuel expense, while the Arkansas jurisdictional portion of the 2010 SWPA payment will be amortized on a straight-line basis over a 50 year period. A tracking mechanism was also created by Missouri related to the Plum Point, Iatan 2 and Iatan common plant operating expenses. The Missouri tracker is to exclude consumables and SO_2 allowances which are recovered through the fuel adjustment clause. A regulatory asset or liability will be recorded for the difference between the Missouri jurisdictional portion of actual expenses and the annual recovery allowance with a corresponding charge or credit to regulated operating expense.

The following table sets forth the components of our regulatory assets and regulatory liabilities on our consolidated balance sheet (in thousands).

	December 31, 2011	December 31, 2010
Regulatory Assets:		
Under recovered purchased gas costs — gas segment — current	$ 211	$ —
Under recovered electric fuel and purchased power costs — current	7,513	4,974
Regulatory assets, current[1]	7,724	4,974
Pension and other postretirement benefits[2]	121,058	92,192
Income taxes	49,631	50,188
Deferred construction accounting costs[3]	17,095	10,521
Unamortized loss on reacquired debt	11,610	13,099
Unsettled derivative losses — electric segment	7,839	3,166
System reliability — vegetation management	6,569	3,338
Storm costs[4]	5,303	7,733
Asset retirement obligation	3,571	3,412
Customer programs	3,408	2,119
Unamortized loss on interest rate derivative	1,462	1,776
Other	1,420	473
Under recovered purchased gas costs — gas segment	1,281	439
Deferred operating and maintenance expense	952	—
Asbury five-year maintenance	492	948
Under recovered electric fuel and purchased power costs	231	—
Regulatory assets, long-term	231,922	189,404
TOTAL REGULATORY ASSETS	$239,646	$194,378
Regulatory Liabilities		
Over recovered purchased gas costs — gas segment — current	$ —	$ 1,243
Regulatory liabilities, current[1]	—	1,243
Costs of removal	73,562	62,756
SWPA payment for Ozark Beach lost generation	25,074	—
Income taxes	12,337	12,715
Deferred construction accounting costs — fuel	8,304	3,126
Unamortized gain on interest rate derivative	3,711	3,881
Pension and other postretirement benefits[5]	2,939	4,604
Over recovered electric fuel and purchased power costs	2,513	409
Other	—	88
Regulatory liabilities, long-term	128,440	87,579
TOTAL REGULATORY LIABILITIES	$128,440	$ 88,822

(1) Reflects over and under recovered costs expected to be returned or recovered as applicable, within the next 12 months in Missouri rates.

(2) Primarily reflects regulatory assets resulting from the unfunded portion of our pension and OPEB liabilities and regulatory accounting for EDG acquisition costs. Approximately $0.5 million in pension and other postretirement benefit costs have been recognized since January 1, 2011 to reflect the amortization of the regulatory assets that were recorded at the time of the EDG acquisition of the Aquila, Inc. gas properties.

(3)

Balances as of December 31, 2011	Deferred Carrying Charges	Deferred O&M	Depreciation	Total
Iatan 1	$2,728	1,363	1,652	$ 5,743
Iatan 2	$3,891	4,271	2,728	$10,890
Plum Point	$ 65	239	158	$ 462
Total				$17,095

Balances as of December 31, 2011	Deferred Carrying Charges	Deferred O&M	Depreciation	Total
Iatan 1	$2,779	1,388	1,682	$ 5,849
Iatan 2	$1,770	1,643	1,111	$ 4,524
Plum Point	$ 33	70	45	$ 148
Total				$10,521

(4) Reflects ice storm costs incurred in 2007 and costs incurred as a result of the May 2011 tornado.

(5) Includes the effect of costs incurred that are more or less than those allowed in rates for the Missouri (EDE and EDG) and Kansas (EDE) portion of pension and other postretirement benefit costs. Since January 1, 2011, regulatory liabilities and corresponding expenses have been reduced by approximately $0.5 million as a result of ratemaking treatment.

Unamortized losses on debt and losses on interest rate derivatives are not included in rate base, but are included in our capital structure for rate base purposes. The remainder of our regulatory assets are not included in rate base, generally because they are not cash items or they are earning carrying costs. However, as of December 31, 2011, the costs of all of our regulatory assets are currently being recovered except for approximately $113.8 million of pension and other postretirement costs primarily related to the unfunded liabilities for future pension and OPEB costs. The amount and timing of recovery of this item will be based on the changing funded status of the pension and OPEB plans in future periods.

The regulatory income tax assets and liabilities are generally amortized over the average depreciable life of the related assets. The loss on reacquired debt and the loss and gain on interest rate derivatives are amortized over the life of the related new debt issue, which currently ranges from 2 to 30 years. The unrecovered fuel costs are generally recovered within a year following their recognition. Severe storm costs and the Asbury five-year maintenance costs are recovered over five years. Pension and other postretirement benefit tracking mechanisms are recovered over a five year period. The cost of removal regulatory liability is amortized as removal costs are incurred.

RATE MATTERS

We continually assess the need for rate relief in all of the jurisdictions we serve and file for such relief when necessary.

Our rates for retail electric and natural gas services (other than specially negotiated retail rates for industrial or large commercial customers, which are subject to regulatory review and approval) are determined on a "cost of service" basis. Rates are designed to provide, after recovery of allowable operating expenses, an opportunity for us to earn a reasonable return on "rate base." "Rate base" is generally determined by reference to the original cost (net of accumulated depreciation and amortization) of utility plant in service, subject to various adjustments for deferred taxes and other items. Over time, rate base is increased by additions to utility plant in service and reduced by depreciation, amortization and retirement of utility plant or write-off's as ordered by the utility commissions. In general, a request of new rates is made on the basis of a "rate base" as of a date prior to the date of the request and allowable operating expenses for a 12-month test period ended prior to the date of the request. Although the current rate making process provides recovery of some future changes in rate base and operating costs, it does not reflect all changes in costs for the period in which new retail rates will be in place. This results in a lag (commonly referred to as "regulatory lag") between the time we incur costs and the time when we can start recovering the costs through rates.

The following table sets forth information regarding electric and water rate increases since January 1, 2009:

Jurisdiction	Date Requested	Annual Increase Granted	Percent Increase Granted	Date Effective
Missouri — Electric	September 28, 2010	$18,700,000	4.70%	June 15, 2011
Missouri — Electric	October 29, 2009	$46,800,000	13.40%	September 10, 2010
Kansas — Electric	June 17, 2011	$ 1,250,000	5.20%	January 1, 2012
Kansas — Electric	November 4, 2009	$ 2,800,000	12.40%	July 1, 2010
Oklahoma — Electric	June 30, 2011	$ 240,722	1.66%	January 4, 2012
Oklahoma — Electric	January 28, 2011	$ 1,063,100	9.32%	March 1, 2011
Oklahoma — Electric	March 25, 2010	$ 1,456,979	15.70%	September 1, 2010
Arkansas — Electric	August 19, 2010	$ 2,104,321	19.00%	April 13, 2011
Missouri — Gas	June 5, 2009	$ 2,600,000	4.37%	April 1, 2010

Electric Segment

Missouri

2010 Rate Case

On September 28, 2010, we filed a rate increase request with the MPSC for an annual increase in base rates for our Missouri electric customers in the amount of $36.5 million, or 9.2% to recover the Iatan 2 costs and other cost of service items not included in our 2009 Missouri rate case, effective September 10, 2010. A settlement agreement among the parties to the case was reached and filed with the MPSC on May 27, 2011 reflecting an overall annual increase in rates of $18.7 million, or approximately 4.7% effective on June 15, 2011. Due to rate design changes, this rate increase, however, primarily impacts our winter season rates which generally run from October through May. Also as part of the settlement, regulatory amortization expense of $14.5 million annually and construction accounting terminated as of June 15, 2011. The MPSC approved the settlement agreement on June 1, 2011 and the new rates were effective on June 15, 2011. The approved settlement included authorization of a tracker mechanism for the SWPA payment associated with the capacity restrictions to be implemented for our Ozark Beach hydro facility. We agreed to flow the SWPA payment, net of tax, back to our customers over a ten year period using a tracker mechanism resulting in an annual decrease to expenses of approximately $1.4 million. The settlement agreement also allowed for a tracker mechanism related to Plum Point, Iatan 2 and Iatan common plant operating expenses. We will record a regulatory asset or liability for the difference between actual expenses (excluding fuel and fuel related expenses) and the amount of expense included in base rates.

2009 Rate Case

On October 29, 2009, we filed a request with the MPSC for an annual increase in base rates for our Missouri electric customers in the amount of $68.2 million, or 19.6%. This request was primarily designed to allow us to recover capital expenditures associated with environmental upgrades at Iatan 1 and our investment in new generating units at Iatan 2 and the Plum Point Generating Station. As a result of the delay in the Iatan 2 project, however, we agreed to not seek a permanent increase in this rate case for any costs associated with the Iatan 2 unit with the exception of that portion of the Iatan common plant needed to operate Iatan 1.

A stipulated agreement was filed on May 12, 2010, calling for an annual increase of $46.8 million, provided the Plum Point Generating Station met its in-service criteria by August 15, 2010. If the in-service criteria were not met by such date, a base rate increase of $33.1 million was stipulated. The Plum Point Generating Station completed its in-service criteria testing on August 12, 2010, with an in-service date of August 13, 2010, thus new rates, providing for the full increase of $46.8 million, were effective September 10, 2010. The $46.8 million authorized increase in annual revenues includes $36.8 million in base rate revenue and $10 million in regulatory amortization. The regulatory amortization, which is treated as additional book depreciation for rate-making purposes and is reflected in the financial statements, was granted to provide additional cash flow through rates. This regulatory amortization is related to our investments in facilities and environmental upgrades completed during the recent construction cycle. As agreed in our regulatory plan, we used construction accounting for our Iatan 2 project. As noted above, regulatory amortization expense of $14.5 million annually and construction accounting terminated as of June 15, 2011 as a result of our 2010 rate case (See Note 3 and Note 11). We also agreed to commence an eighteen year amortization of a deferred asset related to the tax benefits of cost of removal. These tax benefits were flowed through to customers from 1981 to 2008 and totaled approximately $11.1 million. We had previously recorded a regulatory asset expecting to recover these benefits from customers in future periods. We estimated the portion of the amortization period where rate recovery would no longer be probable for this item and wrote off approximately $1.2 million in the first quarter of 2010. Amortization of the remaining regulatory tax asset began during the third quarter of 2011 (See Note 9).

2007 Rate Case

The MPSC issued an order on July 30, 2008 in response to a request filed with the MPSC on October 1, 2007 for an annual increase in base rates for our Missouri electric customers. This order granted an annual increase in revenues for our Missouri electric customers in the amount of $22.0 million, or 6.7%, based on a 10.8% return on equity. The new rates went into effect August 23, 2008.

The MPSC also authorized a fuel adjustment clause for our Missouri customers effective September 1, 2008. The MPSC established a base cost for the recovery of fuel and purchased power expenses used to supply energy. The clause permits the distribution to customers of 95% of the changes in fuel and purchased power costs above or below the base cost. Off-system sales margins are also part of the recovery of fuel and purchased power costs. As a result, the off-system sales margin flows back to the customer. Rates related to the recovery of fuel and purchased power costs will be modified twice a year subject to the review and approval by the MPSC. In accordance with accounting guidance for regulated activities, 95% of the difference between the actual cost of fuel and purchased power and the base cost of fuel and purchased power recovered from our customers is recorded as an adjustment to fuel and purchased power expense with a corresponding regulatory asset or a regulatory liability. If the actual fuel and purchased power costs are higher or lower than the base fuel and purchased power costs billed to customers, 95% of these amounts will be recovered or refunded to our customers when the fuel adjustment clause is modified.

The MPSC issued its Report and Order on July 30, 2008, effective August 9, 2008. The OPC and intervenors Praxair, Inc. and Explorer Pipeline Company filed applications for rehearing with the MPSC regarding this order. On August 12, 2008, the MPSC issued its Order Granting Expedited Treatment and Approving Compliance Tariff Sheets, effective August 23, 2008, in which the MPSC approved our tariff sheets containing our base rates for service rendered on and after August 23, 2008, and approved our fuel adjustment clause tariff sheets effective September 1, 2008. On September 3, 2008, the MPSC denied all pending applications for rehearing.

On October 2, 2008, the OPC and intervenors Praxair, Inc. and Explorer Pipeline Company filed Petitions for Writ of Review with the Cole County Circuit Court. These actions were consolidated into one proceeding, briefs were filed and the Cole County Circuit Court heard oral arguments on September 29, 2009. The Cole County Circuit Court issued a ruling on December 31, 2009, affirming the Commission's Report and Order. OPC, Praxair and Explorer Pipeline filed appeals with the Western District Court of Appeals. On August 2, 2011, the Western District Court of Appeals issued a ruling affirming the Commission's Report and Order.

Tornado Recovery

On June 6, 2011, we filed an Accounting Authority Order with the MPSC requesting authorization to defer expenses associated with the tornado and to allow for recovery of the loss of the fixed cost component included in our rates resulting from the lost sales. On June 23, 2011, Praxair, Inc. and Explorer Pipeline Company filed as intervenors with the MPSC, who granted their request on July 6, 2011. On November 15, 2011, following extensive negotiations, the parties filed a joint settlement agreement with the MPSC allowing us to defer actual incremental operating and maintenance expenses associated with the repair, restoration and rebuilding activities resulting from the tornado. In addition, depreciation related to the capital expenditures will be deferred and a carrying charge will be accrued. In the event that an electric rate request is filed in Missouri by June 1, 2013, a ten-year amortization of the deferral will begin. The settlement does not include deferral of the fixed cost component associated with the reduction in customers served by us as a result of the tornado. On November 30, 2011, the MPSC issued an order approving the settlement agreement, effective December 7, 2011. Approximately $1.6 million has been deferred under this agreement.

Kansas

2011 Rate Case

On June 17, 2011, we filed an application with the KCC seeking a rate increase of $1.5 million, or 6.39%. The rate increase was requested to recover the costs associated with our investment in the Iatan 1, Iatan 2 and Plum Point generating units and the depreciation and operation and maintenance costs deferred since the in-service dates of the units. The June 17, 2011 filing was made under the KCC's abbreviated rate case rules which the KCC authorized in our 2009 Kansas rate case. The case included a request to recover the Iatan and Plum Point cost deferrals over a 3-year period. A joint settlement agreement was filed on November 10, 2011 and approved by the KCC on December 21, 2011, resulting in an increase in annual revenues of $1.25 million, or approximately 5.2%. The new rates became effective on January 1, 2012.

2009 Rate Case

On November 4, 2009, we filed a request with the KCC for an annual increase in base rates for our Kansas electric customers in the amount of $5.2 million, or 24.6%. This request was primarily to allow us to recover capital expenditures associated with environmental upgrades at Iatan 1 completed in 2009 and at our Asbury plant completed in 2008 and our investment in new generating units at Iatan 2, the Plum Point Generating Station and our Riverton 12 unit that went on line in 2007. A stipulated agreement was filed on May 4, 2010, and approved by the KCC on June 25, 2010, calling for a $2.8 million, or 12.4%, increase in base rates effective July 1, 2010. We agreed to defer depreciation and operating and maintenance expense on both Plum Point and Iatan 2 from their respective in-service dates until the effective date of the rates from the next Kansas case, which was filed on June 17, 2011. We recorded AFUDC on all Plum Point and Iatan 2 capital expenditures incurred after January 31, 2010.

Oklahoma

On March 25, 2010, we requested a capital cost recovery rider (CCRR) at the OCC. The rider was designed to recover the carrying costs on our capital investment for generation, transmission and distribution assets that have been added to the system since our last Oklahoma general rate case (May 2003), as well as investments made on an ongoing basis. As requested, the operation of the CCRR would have increased our operating revenue by approximately $3 million, or approximately 33%, in Oklahoma in a series of three steps to be followed with a general rate case in 2011. On August 30, 2010, we were granted a two-phase Capital Reliability Rider (CRR) by the OCC. The first phase of the rider was put into place for Oklahoma customers for usage on and after September 1, 2010, and resulted in an overall annual base revenue increase of approximately $1.5 million, or 15.7%. In total, the CRR revenue has been specifically limited by the OCC to an overall annual revenue increase of $2.6 million, or 27.67% increase. On January 28, 2011 we requested the approval by the OCC of the phase 2 rates of the CRR. We requested an additional $1.1 million, which brought the total annual revenue under the OCC to approximately $2.5 million. On June 30, 2011, we filed a request with the OCC for an annual increase in base rates for our Oklahoma electric customers in the amount of $0.6 million, or 4.1% over the base rate and CRR revenues that were currently in effect. A stipulation and agreement, reached by all parties participating in the case, was filed on November 16, 2011. This agreement, which was approved by the OCC on January 4, 2012, made rates previously collected under the CRR permanent, and will result in a net overall increase of total annual revenues of $0.2 million, or approximately 1.66%. The agreement also removes fuel and purchase power costs from base rates. Fuel and purchase power costs will be listed as a separate line item, identified as the Fuel Adjustment Charge, on customer bills.

Arkansas

On August 19, 2010, we filed a rate increase request with the Arkansas Public Service Commission (APSC) for an annual increase in base rates for our Arkansas electric customers in the amount of $3.2 million, or 27.3%. On February 2, 2011 we entered into a unanimous settlement agreement with the parties involved. The settlement included a general rate increase of $2.1 million, or 19%, and called for the implementation of a new tariff, the Transmission Cost Recovery Rider (TCR) designed to track changes in the cost of transmission charges from the Southwest Power Pool, Inc. The existing Energy Cost Recovery Rider was also modified to include the recovery of the costs associated with certain air quality control materials. The APSC approved the settlement on April 12, 2011 with the new rates effective April 13, 2011.

FERC

On March 12, 2010, we filed GFR tariffs with the FERC which we propose to be utilized for our wholesale customers. On May 28, 2010, the FERC issued an order that conditionally approved our GFR filing subject to refund effective June 1, 2010. As of December 31, 2010, we had collected $0.6 million in rates subject to refund. On June 30, 2010, three of our on-system wholesale customers were granted intervention in the GFR rate case. Also on May 28, 2010, we filed a notice with the FERC requesting termination of the current bundled service agreements for our wholesale customers effective July 31, 2010. On July 28, 2010, the FERC issued an order accepting and suspending the proposed terminations for a nominal period to become effective July 31, 2010, subject to refund. The FERC's order also consolidated the GFR and termination proceedings. On September 15, 2010, the parties agreed to a settlement in principle and on May 24, 2011, we, the Missouri Public Utility Alliance and the cities of Monett, Mt. Vernon and Lockwood, Missouri filed a Settlement Agreement and Offer of Settlement with the FERC. We refunded approximately $1.3 million, including interest, in November 2011 as a result of this settlement.

Gas Segment

On June 5, 2009, we filed a request with the MPSC for an annual increase in base rates for our Missouri gas customers in the amount of $2.9 million, or 4.9%. In this filing, we requested recovery of the ongoing cost of operating and maintaining our 1,200-mile gas distribution system and a return on equity of 11.3%. On February 24, 2010, the MPSC unanimously approved an agreement among the Office of the Public Counsel (OPC), the MPSC staff and Empire for an increase of $2.6 million. Pursuant to the Agreement, new rates went into effect on April 1, 2010.

COMPETITION

Electric Segment

SPP-RTO

Energy Imbalance Services: The Southwest Power Pool (SPP) regional transmission organization (RTO) energy imbalance services market (EIS) provides real time energy for most participating members within the SPP regional footprint. Imbalance energy prices are based on market bids and status/availability of dispatchable generation and transmission within the SPP market footprint. In addition to energy imbalance service, the SPP RTO performs a real time security-constrained economic dispatch of all generation voluntarily offered into the EIS market to the market participants to also serve the native load.

Day Ahead Market: On April 28, 2009, the SPP Regional State Committee (SPP RSC), whose members include state commissioners from our four state commissions, and the SPP Board of Directors (SPP BOD) endorsed a cost benefit report that recommended the SPP RTO move forward with the development of a day-ahead market with unit commitment and co-optimized ancillary services market (Day-Ahead Market). Implementation of the SPP's Day-Ahead Market is scheduled for March 2014. As part of the Day-Ahead Market, the SPP RTO will create, prior to implementation of such market, a single NERC approved balancing authority to take over balancing authority responsibilities for its members, including Empire, which is expected to provide operational and economic benefits for our customers. The implementation of the Day-Ahead Market will replace the existing EIS market described above.

SPP Regional Transmission Development: On October 27, 2009, the SPP BOD endorsed a new transmission cost allocation method to replace the existing FERC accepted cost allocation method for new transmission facilities needed to continue to reliably and economically serve SPP customers, including ours, well into the future. On April 19, 2010, SPP filed revisions to its open access transmission pro forma tariff (OATT) to adopt a new highway/byway cost allocation methodology which require SPP BOD approved transmission projects of 300 kV or larger to be funded by the region at 100%, transmission projects between 100 kV and 300 kV to receive 33% regional funding with individual constructing zones to pay 67% of those projects built within the zone. For projects under 100kV, the constructing zones would pay 100% of the cost. On May 17, 2010, we filed a joint protest at the FERC with other SPP members based on our disagreement with the SPP on the allocation percentages and various other issues. On June 17, 2010, the FERC unconditionally approved the new highway/byway cost allocation method. We and other members of the SPP filed a Request for Rehearing on July 19, 2010. On October 20, 2011, the FERC issued its Order on Rehearing denying our request to review various aspects of its June 17, 2010 order. In mid December 2011, we, along with the other SPP member joint protestors, filed a Petition for Review and Motion for Stay of Procedures with the U. S. Court of Appeals for the Eight Circuit. We believe we are aggrieved by the FERC's orders because the orders authorize the SPP to allocate to us the costs of transmission projects from which we would receive either no benefits or benefits that are not roughly commensurate with the allocated costs. Our request for a stay of procedures directly relates to the SPP's efforts to adopt a method satisfactory to us for analyzing the reasonableness of the highway/byway cost allocation approach and an effective remediation process for imbalanced cost allocations. On December 16, 2011, the Eighth Circuit U.S. Court of Appeals granted our petition and stay request. We are required to make an update filing to the Court regarding the SPP Board's actions and progress of the regional allocation review process by May 2012. To date, the SPP's BOD has approved \$1.4 billion in highway/byway projects to be constructed by 2017 with an additional \$1.5 billion in transmission projects expected to receive approval during the first quarter of 2012. As these projects are constructed, we will be allocated a share of the costs of the projects pursuant to the FERC accepted highway/byway regional cost allocation method. We expect that these operating costs will be material, but that they will be recoverable in future rates.

Other FERC Activity

On June 17, 2010, FERC issued a Notice of Proposed Rulemaking (NOPR) proposing to amend the transmission planning and cost allocation requirements established in Order No. 890 to ensure that FERC-jurisdictional services are provided on a basis that is just, reasonable and not unduly discriminatory or preferential. With respect to transmission planning, FERC said that the proposed rule would: (1) provide that local and regional transmission planning processes account for transmission needs driven by public policy requirements established by state or federal laws or regulations; (2) improve coordination between neighboring transmission planning regions with respect to interregional facilities; and (3) remove from FERC-approved tariffs or agreements a right of first refusal (ROFR) created by those documents that provides an incumbent transmission provider with an undue advantage over a non-incumbent transmission developer. Neither incumbent nor non-incumbent transmission facility developers should, as a result of a FERC-approved tariff or agreement, receive different treatment in a regional transmission planning process, FERC contended. Further, both should share similar benefits and obligations commensurate with that participation, including the right, consistent with state or local laws or regulations, to construct and own a facility that it sponsors in a regional transmission planning process and that is selected for inclusion in the regional transmission plan. With respect to cost allocation, the proposed rule would establish a closer link between transmission planning processes and cost allocation and would require cost allocation methods for intraregional and interregional transmission facilities to satisfy newly established cost allocation principles.

On July 21, 2011, the FERC issued Order No. 1000 (Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities). Order 1000 requires all public utility transmission providers to (among other things) facilitate non-incumbent transmission developer participation in regional transmission planning by removing from FERC-approved tariffs and agreements any language creating a federal ROFR for an incumbent transmission provider to construct transmission facilities selected in a regional transmission plan for cost allocation. As a transmission owning member of the SPP RTO, this could directly affect our rights to build transmission facilities within our service territory. A second key element of Order 1000 directed transmission providers to develop policy and procedures for interregional transmission coordination and interregional cost allocation. Since we are on the southeastern seam of the SPP, this policy will most likely have a direct impact on our customers, primarily through a potential reduction to our production costs as a result of greater access to lower cost power from within the SPP, and across this seam and the possible reduction because of the cost sharing for new transmission projects. We will continue to participate in the SPP stakeholder processes to understand the impact of Order 1000 on our ability to construct new facilities within our service territory as well as its influence on promoting construction of transmission projects on/near our borders with our neighbors. Compliance filings by the SPP to address the ROFR requirements are currently scheduled to be due October 11, 2012 and April 13, 2013 for interregional/seams planning and cost allocation.

Gas Segment

Non-residential gas customers whose annual usage exceeds certain amounts may purchase natural gas from a source other than EDG. EDG does not have a non-regulated energy marketing service that sells natural gas in competition with outside sources. EDG continues to receive non-gas related revenues for distribution and other services if natural gas is purchased from another source by our eligible customers.

Other — Rate Matters

In accordance with ASC guidance on regulated operations, we currently have deferred approximately $2.0 million of expense related to rate cases under other non-current assets and deferred charges. These amounts will be amortized over varying periods based upon the completion of the specific cases. Based on past history, we expect all these expenses to be recovered in rates.

4. Common Stock

Recent Issues

We successfully completed an equity distribution program during the second quarter of 2010 and used the net proceeds to repay short-term debt and for general corporate purposes, including the funding of our construction program. During 2010, we issued and sold 2,870,985 shares of our common stock pursuant to this equity distribution program, at an average price per share of $18.41, resulting in net proceeds to us of approximately $51.3 million. Since inception of the program on February 25, 2009, in the aggregate, we issued and sold 6,535,216 shares pursuant to the program, at an average price per share of $18.36, resulting in net proceeds to us of approximately $116.0 million. Sales of the shares pursuant to the equity distribution agreement were made at market prices or as otherwise agreed with UBS, our sales agent.

Stock Based Compensation

We have several stock-based awards and programs, which are described below. Performance-based restricted stock awards, time-vested restricted stock, stock options and their related dividend equivalents are valued as liability awards, in accordance with fair value guidelines. We allow employees to elect to have taxes in excess of the minimum statutory requirements withheld from their awards and, therefore, the awards are classified as liability instruments under the ASC guidance on share based payment. Awards treated as liability instruments must be revalued each period until settled, and cost is accrued over the requisite service period and adjusted to fair value at each reporting period until settlement or expiration of the award.

We recognized the following amounts in compensation expense and tax benefits for all of our stock-based awards and programs for the applicable years ended December 31 (in thousands):

	2011	2010	2009
Compensation expense	$1,765	$3,193	$2,292
Tax benefit recognized	614	1,160	819

Stock Incentive Plans

Our 2006 Stock Incentive Plan (the 2006 Incentive Plan) was adopted by shareholders at the annual meeting on April 28, 2005 and provides for grants of up to 650,000 shares of common stock through January 2016. The 2006 Stock Incentive Plan permits grants of stock options and restricted stock to qualified employees and permits Directors and, if approved by the Compensation Committee of the Board of Directors, qualified employees to receive common stock in lieu of cash. Certain executive officers and other senior managers applied to receive annual incentive awards related to 2009, 2010 and 2011 performance in the form of Empire common stock rather than cash. These requests were granted by the Compensation Committee of the Board of Directors under the terms of our 2006 Stock Incentive Plan. The terms and conditions of any option or stock grant are determined by the Board of Directors Compensation Committee, within the provisions of these Stock Incentive Plans.

Time-Vested Restricted Stock Awards

Beginning in 2011, time-vested restricted stock awards were granted to qualified individuals that vest after a three-year period. No dividend rights accumulate during the vesting period. Time-vested restricted stock is valued at an amount equal to the fair market value of our common stock on the date of grant. If employment terminates during the vesting period because of death, retirement, or disability, the participant is entitled to a pro-rata portion of the time-vested restricted stock awards such participant would otherwise have earned, which is distributed six months following the date of termination. If employment is terminated during the vesting period for reasons other than those listed above, the time-vested restricted stock awards will be forfeited on the date of the termination, unless the Board of Directors Compensation Committee determines, in its sole discretion, that the participant is entitled to a pro-rata portion of the award.

A summary of time-vested restricted stock activity under the plan for 2011 is presented in the table below:

	2011	
	Number of shares	Weighted Average Fair Market Value
Outstanding at January 1,	—	$ —
Granted	10,200	$21.84
Vested	794	$19.32
Distributed	661	$21.02
Forfeited	6,106	
Vested but not distributed	133	$20.13
Outstanding at December 31,	3,433	$21.84

Performance-Based Restricted Stock Awards

Performance-based restricted stock awards are granted to qualified individuals consisting of the right to receive a number of shares of common stock at the end of the restricted period assuming performance criteria are met. The performance measure for the award is the total return to our shareholders over a three-year period compared with an investor-owned utility peer group. The threshold level of performance under the 2009, 2010 and 2011 grants was set at the 20th percentile level of the peer group, target at the 50th percentile level, and the maximum at the 80th percentile level. Shares would be earned at the end of the three-year performance period as follows: 100% of the target number of shares if the target level of performance is reached, 50% if the threshold is reached, and 200% if the percentile ranking is at or above the maximum, with the number of shares interpolated between these levels. However, no shares would be payable if the threshold level is not reached. As noted previously, all performance-based restricted stock awards are classified as liability instruments, which must be revalued each period until settled. The fair value of the outstanding restricted stock awards was estimated as of December 31, 2011, 2010 and 2009 using a Monte Carlo option valuation model. The assumptions used in the model for each grant year are noted in the following table:

	Fair Value of Grants Outstanding at December 31,		
	2011	2010	2009
Risk-free interest rate	0.12% to 0.23%	0.30% to 0.62%	0.47% to 1.08%
Expected volatility of Empire stock	23.8%	26.9%	28.8%
Expected volatility of peer group stock	15.7% to 57.4%	21.7% to 82.7%	22.1% to 80.9%
Expected dividend yield on Empire stock	4.7%	6.5%	7.6%
Expected forfeiture rates	3%	3%	3%
Plan cycle	3 years	3 years	3 years
Fair value percentage	51.0% to 75.0%	138.0% to 193.7%	87.0% to 132.0%
Weighted average fair value per share	$13.67	$37.17	$21.00

Non-vested restricted stock awards (based on target number) as of December 31, 2011, 2010 and 2009 and changes during the year ended December 31, 2011, 2010 and 2009 were as follows:

	2011		2010		2009	
	Number of Shares	Weighted Average Grant Date Fair Value	Number of Shares	Weighted Average Grant Date Fair Value	Number Of Shares	Weighted Average Grant Date Fair Value
Outstanding at January 1,	47,500	$19.86	52,200	$21.57	52,300	$22.64
Granted	10,900	$21.84	13,000	$18.36	13,500	$18.12
Awarded	(39,621)	$21.92	(15,104)	$23.81	(12,394)	$22.23
Awarded in excess of target	18,621	$21.92				
Not awarded	—	$ —	(2,596)	$ —	(1,206)	$ —
Nonvested at December 31,	37,400	$19.28	47,500	$19.86	52,200	$21.57

At December 31, 2011 and 2010, unrecognized compensation expense related to estimated outstanding awards was $0.1 million and $0.4 million, respectively.

Stock Options

Beginning in 2011, we began issuing time-vested restricted stock in lieu of stock options and dividend equivalents. Stock options were issued with an exercise price equal to the fair market value of the shares on the date of grant, become exercisable after three years and expire ten years after the date granted. Participants' options that are not vested become forfeited when participants leave Empire except for terminations of employment under certain specified circumstances. Dividend equivalent awards were also issued to the recipients of the stock options under which dividend equivalents will be accumulated for the three-year period until the option becomes exercisable. Dividend equivalents cease to be accumulated on the date that a participant leaves Empire, and the accumulated dividend equivalents are forfeited when a participant leaves the Company, except for terminations of employment under certain specified circumstances. There were no stock options or dividend equivalents granted in 2011. The fair value per dividend equivalent grants for 2009, 2010 and outstanding at December 31, 2011, were $3.20 and $2.92, respectively.

The dividend equivalents are accumulated for the three-year period and are converted to shares of common stock based on the fair market value of the shares on the date converted. As per Section 409A of the Internal Revenue Code, added by the American Jobs Creation Act of 2004, the dividend equivalent awards vest and are payable in fully vested shares of our common stock on the third anniversary of the grant date (conversion date) or at a change in control and not dependent upon the exercise of the related option.

As noted previously, all outstanding stock option awards are classified as liability instruments, which must be revalued each period until settled. Stock option grants vest upon satisfaction of service conditions. The cost of the awards is generally recognized over the requisite (explicit) service period. The fair value of the outstanding options was estimated as of December 31, 2011, 2010 and 2009, under a Black-Scholes methodology. The assumptions used in the valuations are shown below:

	Fair Value of Grants Outstanding at December 31,		
	2011	2010	2009
Risk-free interest rate	0.12% to 0.72%	0.45% to 2.34%	1.11% to 2.98%
Dividend yield	4.7%	6.5%	7.6%
Expected volatility	25.0%	23.0%	24.0%
Expected life in months	78	78	78
Market value	$21.09	$22.20	$18.73
Weighted average fair value per option	$2.08	$2.02	$0.97

A summary of option activity under the plan during the years ended December 31, 2011, 2010 and 2009 is presented below:

	2011		2010		2009	
	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price
Outstanding at January 1,	267,400	$21.69	232,600	$22.19	205,600	$22.73
Granted	0	$ —	34,800	$18.36	27,000	$18.12
Exercised	77,100	$22.02	—	$ —	—	$ —
Outstanding at December 31,	190,300	$21.56	267,400	$21.69	232,600	$22.19
Exercisable, end of year	128,500	$23.15	149,200	$23.04	85,000	$22.46

The intrinsic value of the unexercised options is the difference between the Company's closing stock price on the last day of the period and the exercise price multiplied by the number of in-the-money options, had all option holders exercised their options on the last day of the period. The intrinsic value is zero if such closing price is less than the exercise price. The table below shows the aggregate intrinsic values at December 31, 2011, 2010 and 2009:

	2011	2010	2009
Aggregate intrinsic value (in millions)	$0.2	$0.3	$0.0
Weighted-average remaining contractual life of outstanding options	5.1 years	6.6 years	6.6 years
Range of exercise prices	$18.12 to $23.81	$18.12 to $23.81	$18.12 to $23.81
Total unrecognized compensation expense (in millions) related to non-vested options and related dividend equivalents granted under the plan	$0.1	$0.2	$0.2
Recognition period	1 year	1 to 3 years	

Employee Stock Purchase Plan

Our Employee Stock Purchase Plan (ESPP) permits the grant to eligible employees of options to purchase common stock at 90% of the lower of market value at date of grant or at date of exercise. The lookback feature of this plan is valued at 90% of the Black-Scholes methodology plus 10% of the maximum subscription price. As of December 31, 2011, there were 261,792 shares available for issuance in this plan.

	2011	2010	2009
Subscriptions outstanding at December 31,	70,756	71,326	68,591
Maximum subscription price	$ 17.27(1)	$ 16.06	$ 14.62
Shares of stock issued	69,229	66,723	44,265
Stock issuance price	$ 16.06	$ 14.62	$ 14.10

(1) Stock will be issued on the closing date of the purchase period, which runs from June 1, 2011 to May 31, 2012.

Assumptions for valuation of these shares are shown in the table below.

	2011	2010	2009
Weighted average fair value of grants	$ 3.17	$ 2.28	$ 3.26
Risk-free interest rate	0.18%	0.35%	0.48%
Dividend yield	2.60%	7.20%	7.90%
Expected volatility(1)	22.00%	17.00%	40.00%
Expected life in months	12	12	12
Grant date	6/1/11	6/1/10	6/1/09

(1) One-year historic volatility

Stock Unit Plan for Directors

Our Stock Unit Plan for directors (Stock Unit Plan) provides a stock-based compensation program for directors. This plan enhances our ability to attract and retain competent and experienced directors and allows the directors the opportunity to accumulate compensation in the form of common stock units. The

Stock Unit Plan also provides directors the opportunity to convert previously earned cash retirement benefits to common stock units. All eligible directors who had benefits under the prior cash retirement plan converted their cash retirement benefits to common stock units.

A total of 400,000 shares are authorized under this plan. Each common stock unit earns dividends in the form of common stock units and can be redeemed for shares of common stock. The number of units granted annually is computed by dividing an annual credit (determined by the Compensation Committee) by the fair market value of our common stock on January 1 of the year the units are granted. Common stock unit dividends are computed based on the fair market value of our stock on the dividend's record date. We record the related compensation expense at the time we make the accrual for the directors' benefits as the directors provide services. Shares accrued to directors' accounts and shares available for issuance under this plan at December 31 are shown in the table below:

	2011	2010
Shares accrued to directors' accounts	133,956	139,912
Shares available for issuance	280,282	311,523

Units accrued for service and dividends as well as units redeemed for common stock at December 31 are shown in the table below:

	2011	2010	2009
Units accrued for service and dividends	25,287	33,364	33,024
Units redeemed for common stock	31,243	6,347	34,853

401(k) Plan and ESOP

Our Employee 401(k) Plan and ESOP (the 401(k) Plan) allows participating employees to defer up to 25% of their annual compensation up to an Internal Revenue Service specified limit. We match 50% of each employee's deferrals by contributing shares of our common stock, with such matching contributions not to exceed 3% of the employee's eligible compensation. We record the compensation expense at the time the quarterly matching contributions are made to the plan. At December 31, 2011 and 2010, there were 36,038 and 104,601 shares available to be issued, respectively.

	2011	2010	2009
Shares contributed	68,523	64,830	73,408

Dividends

Holders of our common stock are entitled to dividends if, as, and when declared by the Board of Directors, out of funds legally available therefore, subject to the prior rights of holders of any outstanding cumulative preferred stock and preference stock. Payment of dividends is determined by our Board of Directors after considering all relevant factors, including the amount of our retained earnings (which is essentially our accumulated net income less dividend payouts). A reduction of our dividend per share, partially or in whole, could have an adverse effect on our common stock price. In response to the expected loss of revenues resulting from the May 22, 2011 tornado, our current level of retained earnings and other relevant factors, our Board of Directors suspended our quarterly dividend for the third and fourth quarters of 2011. On February 2, 1012, the Board of Directors re-established the dividend and declared a quarterly dividend of $0.25 per share on common stock payable on March 15, 2012 to holders of record as of

March 1, 2012. As of December 31, 2011, our retained earnings balance was $33.7 million (compared to $5.5 million at December 31, 2010) after paying out $26.7 million in dividends during 2011.

Under Kansas corporate law, our Board of Directors may only declare and pay dividends out of our surplus or, if there is no surplus, out of our net profits for the fiscal year in which the dividend is declared or the preceding fiscal year, or both. Our surplus, under Kansas law, is equal to our retained earnings plus accumulated other comprehensive income/(loss), net of income tax. However, Kansas law does permit, under certain circumstances, our Board of Directors to transfer amounts from capital in excess of par value to surplus. In addition, Section 305(a) of the Federal Power Act (FPA) prohibits the payment by a utility of dividends from any funds "properly included in capital account". There are no additional rules or regulations issued by the FERC under the FPA clarifying the meaning of this limitation. However, several decisions by the FERC on specific dividend proposals suggest that any determination would be based on a fact-intensive analysis of the specific facts and circumstances surrounding the utility and the dividend in question, with particular focus on the impact of the proposed dividend on the liquidity and financial condition of the utility.

In addition, the EDE Mortgage and our Restated Articles contain certain dividend restrictions. The most restrictive of these is contained in the EDE Mortgage, which provides that we may not declare or pay any dividends (other than dividends payable in shares of our common stock) or make any other distribution on, or purchase (other than with the proceeds of additional common stock financing) any shares of, our common stock if the cumulative aggregate amount thereof after August 31, 1944 (exclusive of the first quarterly dividend of $98,000 paid after said date) would exceed the sum of $10.75 million and the earned surplus (as defined in the EDE Mortgage) accumulated subsequent to August 31, 1944, or the date of succession in the event that another corporation succeeds to our rights and liabilities by a merger or consolidation. On June 9, 2011, we amended the EDE Mortgage in order to provide us with additional flexibility to pay dividends to our shareholders by permitting the payment of any dividend or distribution on, or purchase of, shares of its common stock within 60 days after the related date of declaration or notice of such dividend, distribution or purchase if (i) on the date of declaration or notice, such dividend, distribution or purchase would have complied with the provisions of the EDE Mortgage and (ii) as of the last day of the calendar month ended immediately preceding the date of such payment, our ratio of total indebtedness to total capitalization (after giving pro forma effect to the payment of such dividend, distribution, or purchase) was not more than 0.625 to 1.

5. Preferred and Preference Stock

We have 2.5 million shares of preference stock authorized, including 0.5 million shares of Series A Participating Preference Stock, none of which have been issued. We have 5 million shares of $10.00 par value cumulative preferred stock authorized. There was no preferred stock issued and outstanding at December 31, 2011 or 2010.

Preference Stock Purchase Rights

Our shareholder rights plan provided each of the common stockholders one Preference Stock Purchase Right (Right) for each share of common stock owned. The shareholder rights plan, dated as of July 26, 2000, expired on July 25, 2010, pursuant to its terms. As a result of the expiration, no rights were outstanding at December 31, 2011 or 2010.

6. Long-Term Debt

At December 31, 2011 and 2010, the balance of long-term debt outstanding was as follows (in thousands):

	2011	2010
First mortgage bonds (EDE):		
7.20% Series due 2016	$ 25,000	$ 25,000
5.3% Pollution Control Series due 2013(1)	8,000	8,000
5.2% Pollution Control Series due 2013(1)	5,200	5,200
5.875% Series due 2037(2)	80,000	80,000
6.375% Series due 2018(2)	90,000	90,000
4.65% Series due 2020(2)	100,000	100,000
5.20% Series due 2040(2)	50,000	50,000
7.0% Series due 2024(3)	74,829	74,854
First mortgage bonds (EDG):		
6.82% Series due 2036(2)	55,000	55,000
	488,029	488,054
Senior Notes, 4.50% Series due 2013(2)	98,000	98,000
Senior Notes, 6.70% Series due 2033(2)	62,000	62,000
Senior Notes, 5.80% Series due 2035(2)	40,000	40,000
Other	6,087	6,932
Less unamortized net discount	(924)	(1,033)
	693,192	693,953
Less current obligations of long-term debt	(641)	(614)
Less current obligations under capital lease	(292)	(267)
Total long-term debt	$692,259	$693,072

(1) We may redeem some or all of the notes at any time at 100% of their principal amount, plus accrued and unpaid interest to the redemption date.

(2) We may redeem some or all of the notes at any time at 100% of their principal amount, plus a make-whole premium, plus accrued and unpaid interest to the redemption date.

(3) We may redeem some or all of the bonds at any time on or after April 1, 2012, at 100% of the principal amount of the bonds plus accrued and unpaid interest to the redemption date.

Debt Financing Activities

On August 25, 2010, we issued $50 million principal amount of 5.20% first mortgage bonds due September 1, 2040. The net proceeds (after payment of expenses) of approximately $49.1 million were used to redeem $48.3 million aggregate principal amount of our Senior Notes, 7.05% Series due 2022 on August 27, 2010.

On May 28, 2010, we issued $100 million principal amount of 4.65% first mortgage bonds due June 1, 2020. The net proceeds (after payment of expenses) of approximately $98.8 million, were used to redeem all 2 million outstanding shares of our 8.5% trust preferred securities, totaling $50 million, on June 28, 2010, and to repay short-term debt which was incurred, in part, to fund the repayment, at maturity, of our 6.5% first mortgage bonds due 2010.

On January 28, 2011, we filed a $400 million shelf registration statement with the SEC covering our common stock, unsecured debt securities, preference stock, and first mortgage bonds. This shelf registration statement became effective on February 7, 2011. We have received regulatory approval for the issuance of securities under this shelf from all four states in our electric service territory, but we may only issue up to $250 million of such securities in the form of first mortgage bonds. We plan to use proceeds from offerings made pursuant to this shelf to fund capital expenditures, refinancings of existing debt or general corporate needs during the three-year effective period.

The principal amount of all series of first mortgage bonds outstanding at any one time under the EDE Mortgage is limited by terms of the mortgage to $1 billion. Substantially all of the property, plant and equipment of The Empire District Electric Company (but not its subsidiaries) is subject to the lien of the EDE Mortgage. Restrictions in the EDE mortgage bond indenture could affect our liquidity. The EDE Mortgage contains a requirement that for new first mortgage bonds to be issued, our net earnings (as defined in the EDE Mortgage) for any twelve consecutive months within the fifteen months preceding issuance must be two times the annual interest requirements (as defined in the EDE Mortgage) on all first mortgage bonds then outstanding and on the prospective issue of new first mortgage bonds. Our earnings for the year ended December 31, 2011 would permit us to issue approximately $511.0 million of new first mortgage bonds based on this test with an assumed interest rate of 6.0%. In addition to the interest coverage requirement, the EDE Mortgage provides that new bonds must be issued against, among other things, retired bonds or 60% of net property additions. At December 31, 2011, we had retired bonds and net property additions which would enable the issuance of at least $697.6 million principal amount of bonds if the annual interest requirements are met. As of December 31, 2011, we are in compliance with all restrictive covenants of the EDE Mortgage.

The principal amount of all series of first mortgage bonds outstanding at any one time under the EDG Mortgage is limited by terms of the mortgage to $300 million. Substantially all of the property, plant and equipment of The Empire District Gas Company is subject to the lien of the EDG Mortgage. The EDG Mortgage contains a requirement that for new first mortgage bonds to be issued, the amount of such new first mortgage bonds shall not exceed 75% of the cost of property additions acquired after the date of the Missouri Gas acquisition. The mortgage also contains a limitation on the issuance by EDG of debt (including first mortgage bonds, but excluding short-term debt incurred in the ordinary course under working capital facilities) unless, after giving effect to such issuance, EDG's ratio of EBITDA (defined as net income plus interest, taxes, depreciation, amortization and certain other non-cash charges) to interest charges for the most recent four fiscal quarters is at least 2.0 to 1. As of December 31, 2011, this test would allow us to issue approximately $10.7 million principal amount of new first mortgage bonds.

The carrying amount of our total debt exclusive of capital leases at December 31, 2011 was $688 million compared to a fair market value of approximately $752 million. The carrying amount of our total debt exclusive of capital leases as of December 31, 2010 was $689 million, compared to a fair value of approximately $697 million. These estimates were based on the quoted market prices for the same or similar issues or on the current rates offered to us for debt of the same remaining maturities. The estimated fair market value may not represent the actual value that could have been realized as of year-end or that will be realizable in the future.

Long-Term Debt Payout Schedule (Excluding Unamortized Discount (in thousands)	Payments Due By Period Total	Regulated Entity Debt Obligations	Capital Lease Obligations
2012	$ 933	$ 641	$ 292
2013	111,913	111,615	298
2014	274	—	274
2015	292	—	292
2016	25,307	25,000	307
Thereafter	555,397	551,829	3,568
Total long-term debt obligations	694,116	$689,085	$5,031
Less current obligations and unamortized discount	1,857		
Total long-term debt	$692,259		

7. Short-term Borrowings

At December 31, 2011, total short-term borrowings consisted of $12.0 million in commercial paper and no borrowings from our line of credit. Short-term borrowings outstanding averaged $8.8 million and $36.3 million daily during 2011 and 2010, respectively, with the highest month-end balances being $18.5 million and $74.0 million, respectively. The weighted average interest rates during 2011 and 2010 were 0.98% and 1.74% in each period. The weighted average interest rate of borrowings outstanding at December 31, 2011 and 2010 was 0.85% and 1.15%, respectively.

On January 17, 2012, we entered into the Third Amended and Restated Unsecured Credit Agreement which amended and restated our Second Amended and Restated Unsecured Credit Agreement dated January 26, 2010. This agreement extended the termination date of the revolving credit facility from January 26, 2013 to January 17, 2017. The agreement also removes the letter of credit facility and includes a swingline loan facility with a $15 million swingline loan sublimit. The aggregate amount of the revolving credit commitments remains $150 million, inclusive of the $15 million swingline loan sublimit. In addition, the pricing and fees under the facility were amended. Interest on borrowings under the facility accrues at a rate equal to, at our option, (i) the highest of (A) the bank's prime commercial rate, (B) the federal funds effective rate plus 0.5% or (C) one month LIBOR plus 1.0%, plus a margin or (ii) one month, two month or three month LIBOR, in each case, plus a margin. Each margin is based on our current credit ratings and the pricing schedule in the facility. As of the date hereof, and based on our current credit ratings, the LIBOR margin under the facility decreased from 2.70% to 1.25%. A facility fee is payable quarterly on the full amount of the commitments under the facility based on our current credit ratings (the fee is currently 0.25%). In addition, upon entering into the amended and restated facility, we paid an upfront fee to the revolving credit banks of $262,500 in the aggregate. There were no other material changes to the terms of the facility.

The facility is used for working capital, general corporate purposes and to back-up our use of commercial paper. This facility requires our total indebtedness to be less than 62.5% of our total capitalization at the end of each fiscal quarter and our EBITDA (defined as net income plus interest, taxes, depreciation and amortization) to be at least two times our interest charges for the trailing four fiscal quarters at the end of each fiscal quarter. Failure to maintain these ratios will result in an event of default under the credit facility and will prohibit us from borrowing funds thereunder. As of December 31, 2011, we are in compliance with these ratios. Our total indebtedness is 50.4% of our total capitalization as of December 31, 2011 and our EBITDA is 5.0 times our interest charges. This credit facility is also subject to cross-default if we default on in excess of $10 million in the aggregate on our other indebtedness. This arrangement does not serve to legally restrict the use of our cash in the normal course of operations. There were no outstanding borrowings under this agreement at December 31, 2011. However, $12.0 million was used to back up our outstanding commercial paper.

8. Retirement Benefits

We record retirement benefits in accordance with the ASC guidance on accounting for pension and other postretirement benefits, and have recorded the appropriate liabilities to reflect the unfunded status of our benefit plans, with offsetting entries to a regulatory asset, because we believe it is probable the unfunded amount of these plans will be afforded rate recovery. The tax effects of these entries are reflected as deferred tax assets and liabilities and regulatory liabilities.

Annually we evaluate the discount rate, retirement age, compensation rate increases, expected return on plan assets and healthcare cost trend rate assumptions related to pension benefit and post-retirement medical plan. We utilize an interest rate yield curve to determine an appropriate discount rate. The yield curve is constructed based on the yields on over 500 high-quality, non-callable corporate bonds with maturities between zero and thirty years. A theoretical spot rate curve constructed from this yield curve is then used to discount the annual benefit cash flows of the Empire pension plan and develop a single point discount rate matching the plan's payout structure. In evaluating these assumptions, many factors are considered, including, current market conditions, asset allocations, changes in demographics and the views of leading financial advisors and economists. In evaluating the expected retirement age assumption, we consider the retirement ages of past employees eligible for pension and medical benefits together with expectations of future retirement ages. It is reasonably possible that changes in these assumptions will occur in the near term and, due to the uncertainties inherent in setting assumptions, the effect of such changes could be material to the Company's consolidated financial statements. A roll forward technique is used to value the year ending pension obligations. The roll forward technique values the year-end obligation by rolling forward the beginning-of-year obligation using the demographic assumptions shown below. The economic assumptions are updated as of the end of the year. All of the benefit plans have been measured as of December 31, 2011, consistent with previous years. See Note 1.

Pensions

Our noncontributory defined benefit pension plan includes all employees meeting minimum age and service requirements. The benefits are based on years of service and the employee's average annual basic earnings. Annual contributions to the plan are at least equal to the greater of either minimum funding requirements of ERISA or the accrued cost of the Plan, as required by the Missouri Public Service Commission. We also have a supplemental retirement program ("SERP") for designated officers of the Company, which we fund from Company funds as the benefits are paid.

Our net pension liability increased $7.6 million and $4.5 million in 2011 and 2010, respectively. This increase was recorded as an increase in regulatory assets as we believe it is probable of recovery through customer rates based on rate orders received in our jurisdictions. Our contribution is estimated to be approximately $11.1 million for 2012. We expect future pension funding commitments to continue at least at the level of our accrued cost, as required by our regulator. The actual minimum funding requirements will be determined based on the results of the actuarial valuations and, in the case of 2013, the performance of our pension assets during 2012.

Expected benefit payments are as follows (in millions):

Year	Payments from Trust	Payments from Company Funds
2012	$ 8.4	$0.3
2013	9.0	0.3
2014	9.7	0.3
2015	10.4	0.3
2016	11.1	0.3
2017 – 2021	$65.9	$1.9

Other Postretirement Benefits (OPEB)

We provide certain healthcare and life insurance benefits to eligible retired employees, their dependents and survivors through trusts we have established. Participants generally become eligible for retiree healthcare benefits after reaching age 55 with 5 years of service.

Our net liability increased $0.6 million and $4.3 million in 2011 and 2010, respectively. The increase was recorded as an increase in regulatory assets as we believe it is probable of recovery through customer rates based on rate orders received in our jurisdictions. Our funding policy is to contribute annually an amount at least equal to the actuarial cost of postretirement benefits. We expect to be required to fund approximately $3.2 million in 2012.

Estimated benefit payments are as follows (in millions):

Year	Payments from Trust	Expected Federal Subsidy	Payments from Company Funds
2012	$ 2.3	$0.3	$0.1
2013	2.6	0.3	0.1
2014	2.9	0.4	0.1
2015	3.1	0.4	0.1
2016	3.5	0.5	0.2
2017 – 2021	$21.3	$3.1	$0.9

The following tables set forth the Company's benefit plans' projected benefit obligations, the fair value of the plans' assets and the funded status (in thousands).

Reconciliation of Projected Benefit Obligations:

	Pension		SERP		OPEB	
	2011	2010	2011	2010	2011	2010
Benefit obligation at beginning of year	$186,840	$169,055	$2,895	$2,575	$80,938	$69,911
Service cost	5,596	4,887	93	70	2,266	2,138
Interest cost	10,405	10,115	183	153	4,383	4,329
Net actuarial (gain)/loss	20,869	10,946	1,883	160	(2,136)	6,454
Plan participant's contribution	—	—	—	—	863	949
Benefits and expenses paid	(8,622)	(8,163)	(191)	(63)	(3,261)	(2,966)
Federal subsidy	—	—	—	—	173	123
Benefit obligation at end of year	$215,088	$186,840	$4,863	$2,895	$83,226	$80,938

Reconciliation of Fair Value of Plan Assets:

	Pension		SERP		OPEB	
	2011	2010	2011	2010	2011	2010
Fair value of plan assets at beginning of year	$120,353	$107,076	$ —	$ —	$56,730	$50,036
Actual return on plan assets — gain/(loss)	(625)	11,740	—	—	279	4,825
Employer contribution	29,869	9,700	—	—	3,544	3,681
Benefits paid	(8,622)	(8,163)	—	—	(3,160)	(2,845)
Plan participant's contribution	—	—	—	—	826	917
Federal subsidy	—	—	—	—	165	116
Fair value of plan assets at end of year	$140,975	$120,353	$ —	$ —	$58,384	$56,730

Reconciliation of Funded Status:

	Pension		SERP		OPEB	
	2011	2010	2011	2010	2011	2010
Fair value of plan assets	$ 140,975	$ 120,353	$ —	$ —	$ 58,384	$ 56,730
Projected benefit obligations	(215,088)	(186,840)	(4,863)	(2,895)	(83,226)	(80,938)
Funded status	$ (74,113)	$ (66,487)	$(4,863)	$(2,895)	$(24,842)	$(24,208)

The employee pension plan accumulated benefit obligation at December 31, 2011 and 2010 is presented in the following table (in thousands):

	Pension Benefits		SERP	
	2011	2010	2011	2010
Accumulated benefit obligation	$191,295	$164,340	$4,670	$2,431

Amounts recognized in the balance sheet consist of (in thousands):

	Pension		SERP		OPEB	
	2011	2010	2011	2010	2011	2010
Accounts Payable and Accrued Liabilities	$ —	$ —	$ 311	$ 64	$ 136	$ 121
Pension and other postretirement benefit obligation	$74,113	$66,487	$4,552	$2,831	$24,706	$24,087

Net periodic benefit pension cost for 2011, 2010 and 2009, some of which is capitalized as a component of labor cost and some of which is deferred as a regulatory asset (see Note 3), is comprised of the following components (in thousands):

Net Periodic Pension Benefit Cost:

	Pension			OPEB		
	2011	2010	2009	2011	2010	2009
Service cost	$ 5,596	$ 4,887	$ 4,612	$ 2,266	$ 2,138	$ 1,830
Interest cost	10,405	10,115	9,876	4,383	4,329	3,907
Expected return on plan assets	(11,139)	(9,847)	(10,379)	(4,157)	(3,844)	(3,843)
Amortization of prior service cost[(1)]	532	531	604	(1,011)	(1,011)	(1,011)
Amortization of actuarial loss[(1)]	5,494	3,996	3,182	1,762	1,499	869
Net periodic benefit cost	$ 10,888	$ 9,682	$ 7,895	$ 3,243	$ 3,111	$ 1,752

Net Periodic Pension Benefit Cost:

	SERP		
	2011	2010	2009
Service cost	$ 93	$ 70	$ 61
Interest cost	183	153	148
Expected return on plan assets	—	—	—
Amortization of prior service cost(1)	(8)	(8)	(8)
Amortization of actuarial loss(1)	171	96	103
Net periodic benefit cost	$439	$311	$304

(1) Amounts are amortized from our regulatory asset originally recorded upon recognizing our net pension liability on the balance sheet.

The tables below present the activity in the regulatory asset accounts for the year (in thousands).

		Amount Recognized			
Regulatory Assets	Beginning Balance 12/31/10	Current Year Actuarial Loss	Amortization of Actuarial Loss	Amortization of Prior Service (Cost)/ Credit	Ending Balance 12/31/11
Pension	$67,050	32,632	(5,494)	(532)	$93,656
SERP	$ 1,291	1,884	(171)	8	$ 3,012
OPEB	$16,031	1,740	(1,762)	1,011	$17,020

The following table presents the amount of net actuarial gains / losses, transition obligations / assets and prior period service costs in regulatory assets not yet recognized as a component of net periodic benefit cost. It also shows the amounts expected to be recognized in the subsequent year. The following table presents those items for the employee pension plan and other benefits plan at December 31, 2011, and the subsequent twelve-month period (in thousands):

	Pension Benefits		SERP		OPEB	
	2011	Subsequent Period	2011	Subsequent Period	2011	Subsequent Period
Net actuarial loss	$91,144	$7,799	$3,051	$305	$22,637	$ 1,871
Prior service cost (benefit)	2,512	532	(39)	(8)	(5,617)	(1,011)
Total	$93,656	$8,331	$3,012	$297	$17,020	$ 860

The measurement date used to determine the pension and other postretirement benefits is December 31. The assumptions used to determine the benefit obligation and the periodic costs are as follows:

Weighted-average assumptions used to determine the benefit obligation as of December 31:

	Pension Benefits		OPEB	
	2011	2010	2011	2010
Discount rate	4.70%	5.50%	4.90%	5.50%
Rate of compensation increase	3.50%	4.50%	3.50%	4.50%

Weighted-average assumptions used to determine the net benefit cost (income) as of January 1:

	Pension Benefits			OPEB		
	2011	2010	2009	2011	2010	2009
Discount rate	5.50%	6.00%	6.30%	5.50%	6.00%	6.30%
Expected return on plan assets	8.00%	8.00%	8.50%	7.00%	7.00%	7.45%
Rate of compensation increase	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%

The expected long-term rate of return assumption was based on historical return and adjusted to estimate the potential range of returns for the current asset allocation.

The assumed 2011 cost trend rate used to measure the expected cost of healthcare benefits and benefit obligation is 8.0%. Each trend rate decreases 0.50% through 2018 to an ultimate rate of 5.0% in 2018 and subsequent years.

The healthcare cost trend rate affects projected benefit obligations. A 1% change in assumed healthcare cost growth rates would have the following effects (in thousands):

	1% Increase	1% Decrease
Effect on total of service and interest cost	$ 1,258	$ (990)
Effect on post-retirement benefit obligation	$12,663	$(10,235)

Fair value measurements of plan assets

See Note 15 for a discussion of fair value measurements. The Company believes that it is appropriate for the pension fund to assume a moderate degree of investment risk with diversification of fund assets among different classes (or types) of investments, as appropriate, as a means of reducing risk. Although the pension fund can and will tolerate some variability in market value and rates of return in order to achieve a greater long-term rate of return, primary emphasis is placed on preserving the pension fund's principal. Full discretion is delegated to the investment managers to carry out investment policy within stated guidelines. The guidelines and performance of the managers are monitored by the Company's Investment Committee.

Pension

We utilize fair value in determining the market-related values for the different classes of our pension plan assets. The market-related value is determined based on smoothing actual asset returns in excess of (or less than) expected return on assets over a 5-year period.

The Company's primary investment goals for pension fund assets are based around four basic elements:

1. Preserve capital,
2. Maintain a minimum level of return equal to the actuarial interest rate assumption,
3. Maintain a high degree of flexibility and a low degree of volatility, and
4. Maximize the rate of return while operating within the confines of prudence and safety.

The target allocations for plan assets are 60%-80% equity securities, 20%-40% debt securities, and 0%-15% in all other types of investments.

The following fair value hierarchy table presents information about the pension fund assets measured at fair value as of December 31, 2011 (in thousands):

	Fair Value Measurements as of December 31, 2011				
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total	Percentage of Plan Assets
Short term investments	$ —	$ 1,787	$ —	$ 1,787	1.2%
Equity securities					
U.S. equity	57,228	—	—	57,228	40.6%
International equity	19,151	—	—	19,151	13.6%
Fixed income					
Common collective trust	—	22,904	—	22,904	16.3%
U.S. corporate debt	—	11,692	—	11,692	8.3%
U.S. government debt	794	—	—	794	0.6%
Other types of investments					
Equity long/short hedge funds	—	—	27,419	27,419	19.4%
	$77,173	$36,383	$27,419	$140,975	100.0%

	Fair Value Measurements as of December 31, 2010				
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total	Percentage of Plan Assets
Short term investments	$ —	$ 1,387	$ —	$ 1,387	1.1%
Equity securities					
U.S. equity	47,797	—	—	47,797	39.7%
International equity	15,876	—	—	15,876	13.2%
Fixed income					
Common collective trust	—	32,955	—	32,955	27.4%
Other types of investments					
Equity long/short hedge funds	—	—	22,338	22,338	18.6%
	$63,673	$34,342	$22,338	$120,353	100.0%

Fair Value Measurements Using Significant Unobservable Inputs (Level 3) — December 31,

	2011 Equity long/short hedge funds	2010 Equity long/short hedge funds
Beginning Balance, January 1,	$22,338	$23,515
Actual return on plan assets:		
Relating to assets still held at the reporting date	(669)	1,423
Relating to assets sold during the period	—	—
Purchases	5,750	—
Sales	—	(2,600)
Settlements		—
Transfers into and (out of) Level 3	—	—
Ending Balance, December 31,	$27,419	$22,338

Permissible Investments

Listed below are the investment vehicles specifically permitted:

Permissible Investments

Equity Oriented

- Common Stocks
- Preferred Stocks
- Convertible Preferred Stocks
- Convertible Bonds
- Covered Options
- Hedged Equity Funds of Funds protection

Fixed Income Oriented and Real Estate

- Bonds
- GICs, BICs
- Corporate Bonds (minimum quality rating of Baa or BBB)
- Cash-Equivalent Securities (e.g., U.S. T-Bills, Commercial Paper, etc.)
- Certificates of Deposit in institutions with FDIC/FSLIC
- Money Market Funds / Bank STIF Funds
- Real Estate — Publicly Traded

The above assets can be held in commingled (mutual) funds as well as privately managed separate accounts.

Those investments prohibited by the Investment Committee without prior approval are:

Prohibited Investments Requiring Pre-approval

- Privately Placed Securities
- Commodities Futures
- Securities of Empire District
- Derivatives
- Warrants
- Short Sales
- Index Options

OPEB

The Company's primary investment goals for the component of the OPEB fund used to pay current benefits are liquidity and safety. The primary investment goals for the component of the OPEB fund used to accumulate funds to provide for payment of benefits after the retirement of plan participants are preservation of the fund with a reasonable rate of return. The target allocations for plan assets are 0% – 10% cash and cash equivalents, 40% – 60% fixed income securities and 40% – 60% in equity. The following fair value hierarchy table presents information about the OPEB fund assets measured at fair value as of December 31, 2011:

	Fair Value Measurements as of December 31, 2011				
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total	Percentage of Plan Assets
Cash and cash equivalents	$ 1,536	$ —	$—	$ 1,536	2.6%
Fixed income					
U.S. government debt	—	1,839	—	1,839	3.1%
U.S. corporate debt	—	17,232	—	17,232	29.5%
Foreign debt	—	1,460	—	1,460	2.5%
Mutual funds — fixed income	2,107	—	—	2,107	3.6%
Equity securities					
U.S. equity	21,080	—	—	21,080	36.1%
International equity	1,784	—	—	1,784	3.1%
Mutual funds — equity	11,075	—	—	11,075	19.0%
	37,582	20,531	—	58,113	
Accrued interest & dividends				271	0.5%
				$58,384	100%

	Fair Value Measurements as of December 31, 2010				
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total	Percentage of Plan Assets
Cash and cash equivalents	$ 3,897	$ —	$—	$ 3,897	7.0%
Fixed income					
U.S. government debt	—	4,091	—	4,091	7.2%
U.S. corporate debt	—	15,156	—	15,156	26.7%
Foreign debt	—	420	—	420	0.7%
Mutual funds — fixed income	1,496	—	—	1,496	2.6%
Equity securities					
U.S. equity	17,592	—	—	17,592	31.0%
International equity	1,274	—	—	1,274	2.2%
Mutual funds — equity	12,556	—	—	12,556	22.1%
	36,815	19,667	—	56,482	
Accrued interest & dividends				248	0.5%
				$56,730	100%

The Company's guideline in the management of this fund is to endorse a long-term approach, but not expose the fund to levels of volatility that might adversely affect the value of the assets. Full discretion is delegated to the investment managers to carry out investment policy within stated guidelines. The guidelines and performance of the managers are monitored by the Company's Investment Committee.

Permissible Investments

Listed below are the investment vehicles specifically permitted:

Permissible Investments

Equity

- Common Stocks
- Preferred Stocks

Fixed Income

- Cash-Equivalent Securities with a maturity of one-year or less
- Bonds
- Money Market Funds / Bank STIF Funds
- Certificates of Deposit in institutions with FDIC protection
- Corporate Bonds (minimum quality rating of A)

The above assets can be held in commingled (mutual) funds as well as privately managed separate accounts.

Listed below are those investments prohibited by the Investment Committee:

Prohibited Investments

- Privately Placed Securities
- Commodities Futures
- Securities of Empire District
- Derivatives
- Instrumentalities in violation of the Prohibited Transactions Standards of ERISA
- Margin Transactions
- Short Sales
- Index Options
- Real Estate and Real Property
- Restricted Stock

9. Income Taxes

Income tax expense components for the years ended December 31 are as follows (in thousands):

	2011	2010	2009
Current income taxes:			
Federal	$ (8,604)	$ 7,713	$ 3,987
State	(2,120)	1,057	572
TOTAL	(10,724)	8,770	4,559
Deferred income taxes:			
Federal	39,096	17,942	13,854
State	6,297	4,349	1,973
TOTAL	45,393	22,291	15,827
Investment tax credit amortization	(371)	(528)	(504)
TOTAL INCOME TAX EXPENSE	$ 34,298	$30,533	$19,882

Deferred Income Taxes

Deferred tax assets and liabilities are reflected on our consolidated balance sheet as follows (in thousands):

Deferred Income Taxes	December 31, 2011	December 31, 2010
Current deferred tax assets, net[1]	$ 6,688	$ —
Non-current deferred tax liabilities, net	263,933	212,003
NET DEFERRED TAX LIABILITIES	$257,245	$212,003

(1) Current deferred tax assets are included in prepaid expenses and other on the face of the balance sheet.

Temporary differences related to deferred tax assets and deferred tax liabilities are summarized as follows (in thousands):

Temporary Differences	December 31, 2011	December 31, 2010
Deferred tax assets:		
Net operating loss	$ 6,688	$ —
Disallowed plant costs	1,097	1,127
Alternative minimum tax	261	—
Gains on hedging transactions	1,454	1,518
Plant related basis differences	21,044	21,105
Regulated liabilities related to income taxes	13,318	13,702
Pensions and other post-retirement benefits	—	1,588
Carry forward of income tax credit	16,304	12,596
Income received — deferred	598	10,044
Other	32	2,262
Total deferred tax assets	$ 60,796	$ 63,942
Deferred tax liabilities:		
Depreciation, amortization and other plant related differences	$253,743	$216,685
Regulated assets related to income	40,555	41,107
Loss on reacquired debt	4,288	3,996
Pensions and other post-retirement benefits	673	—
Deferred ice storm expenses	1,413	2,957
Deferred fuel costs	2,662	1,965
Amortization of intangibles	5,929	4,850
Other	8,778	4,385
Total deferred tax liabilities	318,041	275,945
NET DEFERRED TAX LIABILITIES	$257,245	$212,003

The Company generated approximately $25.1 million of tax net operating losses during 2011, mainly due to bonus depreciation. These losses may be carried back two years and are also available to offset future taxable income until 2031.

Effective Income Tax Rates

The difference between income taxes and amounts calculated by applying the federal legal rate to income tax expense for continuing operations were as follows:

Effective Income Tax Rates	2011	2010	2009
Federal statutory income tax rate	35.0%	35.0%	35.0%
Increase in income tax rate resulting from:			
State income tax (net of federal benefit)	3.1	3.1	3.1
Investment tax credit amortization	(0.4)	(0.7)	(0.8)
Effect of ratemaking on property related differences	0.2	(0.8)	(3.6)
Effect of Medicare part D changes	—	2.7	
Other	0.5	(0.1)	(1.2)
Effective income tax rate	38.4%	39.2%	32.5%

Unrecognized Tax Benefits	2011	2010	2009
Unrecognized tax benefits — January 1,	$ 359,000	$ 906,000	$ 2,176,000
The gross amounts of increases in unrecognized tax benefits taken during prior periods	—	—	—
The gross amounts of decreases in unrecognized tax benefits taken during the period relating to positions accepted by taxing authorities	—	—	—
Reductions to unrecognized tax benefits as a result of a lapse of the applicable statute of limitations	(359,000)	(547,000)	(1,270,000)
Unrecognized tax benefits — December 31,	$ —	$ 359,000	$ 906,000

The Company does not have any unrecognized tax benefits as of December 31, 2011. The Company recognized interest or penalties of $0.0 million, $0.1 million and $(0.0) million during 2011, 2010 and 2009, respectively, related to unrecognized tax benefits in other expenses and on the balance sheet. The Company does not expect any significant changes to our unrecognized tax benefits over the next twelve months.

A December 2009 award from an arbitration panel ordered KCP&L to renegotiate with the IRS a previous $125 million advanced coal investment tax credit granted to our Iatan 2 plant. The IRS executed a revised memorandum of understanding (MOU) on September 7, 2010, which granted us our share, $17.7 million, of advanced coal investment tax credits in accordance with the arbitration panel's order. We utilized less than $0.2 million of these credits when preparing our 2010 tax return as utilization of the credits was limited by alternative minimum tax rules. We expect to use the remaining credits over the 2012 and 2013 tax years. The tax credit will have no significant income statement impact as the credits will flow to our customers as we amortize the tax credits over the life of the plant.

We received a $26.6 million payment received from the SWPA during 2010 which was deferred and treated as a noncurrent liability for book purposes. We increased our current tax liability by $10.0 million during 2010 in recognition that the $26.6 million payment may be considered taxable income in 2010. An agreement was reached with the IRS in 2011 that allowed us to defer recognition for tax purposes of approximately $26.1 million utilizing "like-kind exchange" rules within the Code. Accordingly, we reduced our current tax liability based on the agreement and will recognize the $26.1 million for tax purposes over more than 50 years.

On March 23, 2010, the Patient Protection and Affordable Care Act was enacted. This legislation included a provision that reduced the deductibility, for income tax purposes, of retiree healthcare costs to the extent an employer receives federal subsidies. Companies receive the subsidy when they provide retiree prescription benefits at least equivalent to Medicare Part D coverage in their postretirement healthcare plan. Although the elimination of this tax benefit does not take effect until 2013, this change required us to recognize the full accounting impact in our financial statements in the period in which the legislation was enacted. As a result, in the first quarter of 2010, we recorded a one-time non-cash charge of approximately $2.1 million to provision for income taxes to reflect the impact of this change. Our 2010 effective tax rate increased as noted in the statutory rate reconciliation above based on the change.

10. Commonly Owned Facilities

We own a 12% undivided interest in the coal-fired Units No. 1 and No. 2 at the Iatan Generating Station located near Weston, Missouri, 35 miles northwest of Kansas City, Missouri, as well as a 3% interest in the site and a 12% interest in certain common facilities. At December 31, 2011 and 2010, our property, plant and equipment accounts included the amounts in the following chart (in millions):

Iatan	2011	2010
Cost of ownership in plant in service	$362.6	$353.9
Accumulated Depreciation	$ 39.6	$ 34.1
Expenditures(1)	$ 31.3	$ 18.2

(1) Operating, maintenance, and fuel expenditures excluding depreciation expense.

We are entitled to 12% of each unit's available capacity and are obligated to pay for that percentage of the operating costs of the units. KCP&L and KCP&L Greater Missouri Operations Co. own 70% and 18% respectively, of Unit 1, and 54% and 18%, respectively, of Unit 2. KCP&L operates the units for the joint owners. Iatan 2 met its in-service criteria on August 26, 2010, and entered commercial operation on December 31, 2010. During 2010 we added $212.2 million to plant in service associated with Iatan 2 and placed in service approximately $2.9 million of common property expenditures associated with this construction project.

We and Westar Generating, Inc, ("WGI"), a subsidiary of Westar Energy, Inc., share joint ownership of a 500-megawatt combined cycle unit at the State Line Power Plant (the "State Line Combined Cycle Unit"). We are responsible for the operation and maintenance of the State Line Combined Cycle Unit, and are entitled to 60% of the available capacity and are responsible for approximately 60% of its costs. At December 31, 2011 and 2010, our property, plant and equipment accounts include the amounts in the following chart (in millions):

State Line Combined Cycle Unit	2011	2010
Cost of ownership in plant in service	$162.1	$164.1
Accumulated Depreciation	$ 49.4	$ 44.9
Expenditures(1)	$ 57.0	$ 59.6

(1) Operating, maintenance, and fuel expenditures excluding depreciation expense.

We own a 7.52% undivided interest in the coal-fired Plum Point Energy Station located near Osceola, Arkansas. We are entitled to 7.52% of the station's capacity, and are obligated to pay for that percentage of the station's operating costs. The Plum Point Energy Station met its in-service criteria on August 13, 2010 and entered commercial operation on September 1, 2010. At December 31, 2011 and 2010, our property, plant and equipment accounts included the amounts in the following chart (in millions):

Plum Point Energy Station	2011	2010
Cost of ownership in plant in service	$110.1	$110.2
Accumulated Depreciation	$ 2.7	$ 0.7
Expenditures[(1)]	$ 8.5	$ 3.4

(1) Operating, maintenance and fuel expenditures excluding depreciation expense.

All of the dollar amounts listed above represent our ownership share of costs.

11. Commitments and Contingencies

We are a party to various claims and legal proceedings arising out of the normal course of our business. Management regularly analyzes this information, and has provided accruals for any liabilities, in accordance with the guidelines presented in the ASC on accounting for contingencies. In the opinion of management, it is not probable, given the company's defenses, that the ultimate outcome of these claims and lawsuits, individually or in the aggregate, will have a material adverse effect upon our financial condition, or results of operations or cash flows.

On May 22, 2009, a suit was filed in the Circuit Court of Platte County Missouri by several individuals and Class Representatives alleging damages to land, structures, equipment and devastation of crops due to inappropriate management of the levee system around the Iatan Generating Station, of which we are a 12% owner. This matter was set for trial beginning November 7, 2011, but has now been rescheduled for March 14, 2012. We are unable to predict the outcome of the law suit or estimate the amount of damages, if any.

A lawsuit has been filed in Jasper County Circuit Court against us by three of our residential customers, purporting to act on behalf of all Empire customers. These customers are seeking a refund of certain amounts paid for service provided by Empire between January 1, 2007, and December 13, 2007. We will vigorously defend against the claims made against us by these three residential customers. At all times, we charged the three plaintiffs, and all of our customers, the rates approved by and on file with the MPSC.

The rates charged by us during the time period at issue were approved by the MPSC in our 2006 rate case. The orders of the MPSC in that case were appealed by the OPC, acting on behalf of the public, and certain industrial customers. The Missouri Court of Appeals affirmed all decisions entered by the MPSC in our 2006 rate case.

Coal, Natural Gas and Transportation Contracts

	Firm physical gas and transportation contracts	Coal and coal transportation contracts
	(in millions)	
January 1, 2012 through December 31, 2012	$30.9	$35.3
January 1, 2013 through December 31, 2014	43.5	46.7
January 1, 2015 through December 31, 2016	24.5	31.3
January 1, 2017 and beyond	17.8	—

In addition to the above, we have an agreement with Southern Star Central Pipeline, Inc. to purchase one million Dths of firm gas storage service capacity for our electric business for a period of five years, which began in April 2011. The reservation charge for this storage capacity is approximately $1.1 million annually.

We have entered into long and short-term agreements to purchase coal and natural gas for our energy supply and natural gas operations. Under these contracts, the natural gas supplies are divided into firm physical commitments and derivatives that are used to hedge future purchases. In the event that this gas cannot be used at our plants, the gas would be liquidated at market price. The firm physical gas and transportation commitments are detailed in the table above.

We have coal supply agreements and transportation contracts in place to provide for the delivery of coal to the plants. These contracts are written with Force Majeure clauses that enable us to reduce tonnages or cease shipments under certain circumstances or events. These include mechanical or electrical maintenance items, acts of God, war or insurrection, strikes, weather and other disrupting events. This reduces the risk we have for not taking the minimum requirements of fuel under the contracts. We entered into a contract in the second quarter of 2010 to transport coal beginning June 30, 2010, which replaced a contract that expired June 29, 2010. The contract term is for six and one-half years and includes minimum payments totaling approximately $91.9 million. The minimum requirements for our coal and coal transportation contracts are detailed in the table above.

Purchased Power

We currently supplement our on-system generating capacity with purchases of capacity and energy from other entities in order to meet the demands of our customers and the capacity margins applicable to us under current pooling agreements and National Electric Reliability Council (NERC) rules.

We have a long term (30 year) agreement for the purchase of capacity from the Plum Point Energy Station, a 665-megawatt, coal-fired generating facility near Osceola, Arkansas. We began receiving purchased power on September 1, 2010. We have the option to purchase an undivided ownership interest in the 50 megawatts covered by the purchased power agreement in 2015. Commitments under this contract total approximately $35.0 million through August 30, 2015.

We have a 20-year purchased power agreement, which began on December 15, 2008, with Cloud County Windfarm, LLC, owned by EDP Renewables North America LLC (formerly Horizon Wind Energy), Houston, Texas to purchase the energy generated at the approximately 105-megawatt Phase 1 Meridian Way Wind Farm located in Cloud County, Kansas. We do not own any portion of the windfarm. Annual payments are contingent upon output of the facility and can range from zero to a maximum of approximately $14.6 million based on a 20-year average cost.

We also have a 20-year contract, which began on December 15, 2005, with Elk River Windfarm, LLC, owned by IBERDROLA RENEWABLES, Inc., to purchase the energy generated at the 150-megawatt Elk River Windfarm located in Butler County, Kansas. We do not own any portion of the windfarm. Annual payments are contingent upon output of the facility and can range from zero to a maximum of approximately $16.9 million based on a 20-year average cost.

Payments for these agreements are recorded as purchased power expenses, and, because of the contingent nature of these payments, are not included in the operating lease obligations shown below.

New Construction

We own a 50 megawatt, 7.52%, undivided interest in the Plum Point Energy Station described above. Our share of the Plum Point initial construction costs through December 31, 2011 was $86.8 million plus AFUDC of $16.5 million. The Plum Point Energy Station entered commercial operation on September 1, 2010.

We also own an undivided ownership interest in the coal-fired Iatan 2 generating facility operated by Kansas City Power & Light Company (KCP&L) and located at the site of the existing Iatan Generating Station (Iatan 1) near Weston, Missouri. We own 12%, or approximately 102 megawatts, of the 850-megawatt unit, which entered commercial operation on December 31, 2010. Our share of the initial construction costs through December 31, 2011 was $233.3 million plus AFUDC of $19.1 million.

The recovery of these construction costs has been sought through rate cases filed with the regulators in each of our jurisdictions. These construction costs, as well as other construction costs, are subject to prudency reviews by our regulators. The prudency of the construction costs for Iatan 1, Iatan 2 and Plum Point was not addressed in our most recent Missouri rate case, but may be considered in a future rate proceeding. See Rate Matters in Note 3 for the details of each case.

Leases

We have purchased power agreements with Cloud County Windfarm, LLC and Elk River Windfarm, LLC, which are considered operating leases for GAAP purposes. Details of these agreements are disclosed in the Purchased Power section of this note.

We also currently have short-term operating leases for two unit trains to meet coal delivery demands, for garage and office facilities for our electric segment and for one office facility related to our gas segment. In addition, we have capital leases for certain office equipment and 108 railcars to provide coal delivery for our ownership and purchased power agreement shares of the Plum Point generating facility.

The gross amount of assets recorded under capital leases total $5.5 million at December 31, 2011.

Our lease obligations over the next five years are as follows (in thousands):

Capital Leases	Capital Leases	Operating Leases
2012	$ 618	$ 939
2013	595	758
2014	553	720
2015	553	720
2016	549	720
Thereafter	4,646	1,813
Total minimum payments	7,514	5,670
Less amount representing interest	2,483	—
Present value of net minimum lease payments	$5,031	$5,670

Expenses incurred related to operating leases were $1.0 million, $0.8 million and $1.4 million for 2011, 2010, and 2009, respectively, excluding payments for wind generated purchased power agreements. The accumulated amount of amortization for our capital leases was $1.0 million and $0.6 million at December 31, 2011 and 2010, respectively.

Environmental Matters

We are subject to various federal, state, and local laws and regulations with respect to air and water quality and with respect to hazardous and toxic materials and hazardous and other wastes, including their identification, transportation, disposal, record-keeping and reporting, as well as remediation of contaminated sites and other environmental matters. We believe that our operations are in material compliance with present environmental laws and regulations. Environmental requirements have changed frequently and become more stringent over time. We expect this trend to continue. While we are not in a position to accurately estimate compliance costs for any new requirements, we expect any such costs to be material, although recoverable in rates.

Electric Segment

Air

The Federal Clean Air Act (CAA) and comparable state laws regulate air emissions from stationary sources such as electric power plants through permitting and/or emission control and related requirements. These requirements include maximum emission limits on our facilities for sulfur dioxide (SO_2), particulate matter, and nitrogen oxides (NOx). In the future they are also likely to include limits on emissions of mercury, other hazardous pollutants (HAPs) and so-called greenhouse gases (GHG) such as carbon dioxide (CO_2) and methane.

Permits

Under the CAA we have obtained, and renewed as necessary, site operating permits, which are valid for five years, for each of our plants.

Compliance Plan

In order to comply with forthcoming environmental regulations, Empire is taking actions to implement its compliance plan and strategy (Compliance Plan). While the Cross State Air Pollution Rule

(CSAPR) that was set to take effect on January 1, 2012 was stayed at the last minute in late December 2011 by the District of Columbia Circuit Court of Appeals, the Mercury and Air Toxics Standards (MATS) Rules were signed by the Environmental Protection Agency (EPA) Administrator on December 16, 2011. MATS is set to become effective and will require compliance within a three year timeframe (with flexibility for extensions for reliability reasons). This Compliance Plan largely follows the preferred plan presented in our most recent Integrated Resource Plan. The Compliance Plan calls for the installation of a scrubber, fabric filter, and powder activated carbon injection system at our Asbury plant by early 2015 at a cost ranging from \$112 million to \$130 million. The addition of this air quality control equipment will require the retirement of Asbury Unit 2, an 18 megawatt steam turbine that is currently used for peaking purposes. The Compliance Plan also calls for the transition of our Riverton Units 7 and 8 from operation on coal to full operation on natural gas after the summer of 2013. Riverton Units 7 and 8, along with Riverton Unit 9, a small combustion turbine that requires steam from Unit 7 for start-up, will be retired upon the conversion of Riverton Unit 12, a recently installed simple cycle combustion turbine, to a combined cycle unit. This conversion is currently scheduled for the 2016 timeframe.

SO_2 Emissions

The CAA regulates the amount of SO_2 an affected unit can emit. Currently SO_2 emissions are regulated by the Title IV Acid Rain Program and the Clean Air Interstate Rule (CAIR). On January 1, 2012, CAIR was to have been replaced by the Cross-State Air Pollution Rule (CSAPR- formerly the Clean Air Transport Rule). But, on December 30, 2011 the District of Columbia Circuit Court of Appeals issued a stay of the CSAPR. CAIR will remain in effect while the case is reviewed. The Title IV Acid Rain Program will still remain in effect.

The Mercury Air Toxics Standards (MATS), discussed below, was signed on December 16, 2011, and will affect SO_2 emission rates at our facilities. In addition, the compliance date for the revised SO_2 National Ambient Air Quality Standards (NAAQS) is August of 2017; this will also affect SO_2 emissions from our facilities. The SO_2 NAAQS is discussed in more detail below.

Title IV Acid Rain Program:

Under the Title IV Acid Rain Program, each existing affected unit has been allocated a specific number of emission allowances by the U.S. Environmental Protection Agency (EPA). Each allowance entitles the holder to emit one ton of SO_2. Covered utilities, such as Empire, must have emission allowances equal to the number of tons of SO_2 emitted during a given year by each of their affected units. Allowances in excess of the annual emissions are banked for future use. In 2010, our SO_2 emissions exceeded the annual allocations. This deficit was covered by our banked allowances. When our Title IV Acid Rain Program SO_2 allowance bank is exhausted, currently estimated to be late 2012, we will need to purchase additional SO_2 allowances, blend more low sulfur coal at our facilities or transition our coal-fired Riverton Units 7 and 8 to natural gas or a combination of the above. Long-term compliance with this program will be met by the Compliance Plan detailed above along with possible procurement of additional $S0_2$ allowances. We expect the cost of compliance to be fully recoverable in our rates.

CAIR:

In 2005, the EPA promulgated CAIR under the CAA. CAIR generally calls for fossil-fueled power plants greater than 25 megawatts to reduce emission levels of SO_2 and/or NOx in 28 eastern states and the District of Columbia, including Missouri, where our Asbury, Energy Center, State Line and Iatan Units No. 1 and No. 2 are located. Kansas was not included in CAIR and our Riverton Plant was not affected. Arkansas, where our Plum Point Plant is located, was included for ozone season NOx but not for SO_2.

In 2008, the U.S. Court of Appeals for the District of Columbia vacated CAIR and remanded it back to EPA for further consideration, but also stayed its vacatur. As a result, CAIR became effective for NOx on January 1, 2009 and for SO_2 on January 1, 2010 and required covered states to develop State Implementation Plans (SIPs) to comply with specific SO_2 state-wide annual budgets.

SO_2 allowance allocations under the Title IV Acid Rain Program are used for compliance in the CAIR SO_2 Program. Beginning in 2010, SO_2 allowances were utilized at a 2:1 ratio for our Missouri units. As a result, based on current SO_2 allowance usage projections, we expected to have sufficient allowances to take us into the latter part of 2012.

In order to meet CAIR requirements for SO_2 and NOx emissions (NOx is discussed below in more detail) and as a requirement for the air permit for Iatan 2, a Selective Catalytic Reduction system (SCR), a FGD scrubber system and baghouse were installed at our jointly-owned Iatan 1 plant and a SCR was installed at our Asbury plant in 2008. Our jointly-owned Iatan 2 and Plum Point plants were originally constructed with the above technology.

CSAPR- formerly the Clean Air Transport Rule:

On July 6, 2010, the EPA published a proposed CAIR replacement rule entitled the Clean Air Transport Rule (CATR). As proposed and supplemented, the CATR included Missouri and Kansas under both the annual and ozone season for NOx as well as the SO_2 program while Arkansas remained in the ozone season NOx program only. The final CATR was released on July 7, 2011 under the name of the CSAPR, and was set to become effective January 1, 2012. However, as mentioned above, the District of Columbia Circuit Court of Appeals stayed the rule and as of January 1, 2012, the CAIR will be in effect while the court reviews the case. When it was published, the final CSAPR required a 73% reduction in SO_2 from 2005 levels by 2014. The SO_2 allowances allocated under the EPA's Title IV Acid Rain Program cannot be used for compliance with CSAPR but would continue to be used for compliance with the Title IV Acid Rain Program. Therefore, new SO_2 allowances would be allocated under CSAPR and retired at one allowance per ton of SO_2 emissions emitted. We would receive fewer SO_2 allowances than we currently emit. Long-term compliance with this Rule will be met by the Compliance Plan detailed above along with possible procurement of additional SO_2 allowances. A number of states, including Kansas, electric utilities and industrial organizations commenced litigation with the District of Columbia Court of Appeals challenging the CSAPR being stayed. The court has ordered that the parties submit briefs for an April 2012 hearing. We expect compliance costs to be recoverable in our rates.

Mercury Air Toxics Standard

Proposed by the EPA on March 16, 2011 and signed on December 16, 2011, the MATS regulation does not include allowance mechanisms, but would establish alternative standards for certain pollutants, including SO_2 (as a surrogate for hydrogen chloride (HCl)), which must be met to show compliance with hazardous air pollutant limits (see additional discussion in the MATS section below).

SO_2 National Ambient Air Quality Standard (NAAQS):

In June 2010, the EPA finalized a new 1-hour SO_2 NAAQS which, for areas with no SO_2 monitor, will require modeling to determine attainment and non-attainment areas within each state. This modeling of emission sources is to be completed by June 2013 with compliance with the SO_2 NAAQS required by August 2017. Draft guidance for 1-hour SO_2 NAAQS has been published by the EPA to assist states as they prepare their SIP submissions. The EPA is also planning a rulemaking to address some of the 1-hour SO_2 NAAQS implementation program elements. It is likely coal-fired generating units will need scrubbers to be capable of meeting the new 1-hour SO_2 NAAQS. In addition, units will be required to include SO_2

emissions limits in their Title V permits or execute consent decrees to assure attainment and future compliance.

NOx Emissions

The CAA regulates the amount of NOx an affected unit can emit. As currently operated, each of our affected units is in compliance with the applicable NOx limits. Currently, revised NOx emissions are limited by the CAIR (subject to the outcome of the CSAPR proceedings) and by ozone NAAQS rules (discussed below) which were established in 1997 and in 2008.

CAIR:

In 2005, the EPA promulgated CAIR under the CAA. CAIR generally calls for fossil-fueled power plants greater than 25 megawatts to reduce emission levels of NOx in 28 states, including Missouri, where our Asbury, Energy Center, State Line and Iatan Units No. 1 and No. 2 are located and Arkansas where the Plum Point Energy Station is located. Kansas was not included in CAIR and our Riverton Plant was not affected.

The CAIR required covered states to develop SIPs to comply with specific annual NOx state-wide allowance allocation budgets. Based on existing SIPs, we had excess NOx allowances during 2010 which were banked for future use and will be sufficient for compliance at least through the end of 2012. The CAIR NOx program also was to have been replaced by the CSAPR program January 1, 2012 but because of the court stay will remain in effect while the case is reviewed.

CSAPR:

As published, the final rule requires a 54% reduction in NOx from 2005 levels by 2014. The NOx annual and ozone season allowances that were allocated and banked under CAIR cannot be used for compliance under CSAPR. New allowances will be issued under CSAPR.

To address NOx annual and NOx ozone season compliance, our options range from increasing the level of control with the Asbury SCR, the transition of our Riverton Plant coal-fired units to natural gas, or purchasing emission allowances. We expect the cost of compliance to be fully recoverable in our rates.

Ozone NAAQS:

Ozone, also called ground level smog, is formed by the mixing of NOx and Volatile Organic Compounds (VOCs) in the presence of sunlight. On January 6, 2010, the EPA proposed to lower the primary NAAQS for ozone designed to protect public health to a range between 60 and 70 ppb and to set a separate secondary NAAQS for ozone designed to protect sensitive vegetation and ecosystems.

On September 2, 2011, President Obama ordered the EPA to withdraw proposed air quality standards lowering the 2008 ozone standard pending the CAA 2013 scheduled reconsideration of the ozone NAAQS (the normal 5 year reconsideration period). States will move forward with area designations based on the 2008 75 ppb standard using 2008-2010 quality assured monitoring data. Our service territory will be designated as attainment, meaning it will be in compliance with the standard. In the interim, the 1997 ozone NAAQS will remain in effect.

Mercury Air Toxics Standard (MATS)

In 2005, the EPA issued the Clean Air Mercury Rule (CAMR) under the CAA. It set limits on mercury emissions by power plants and created a market-based cap and trade system expected to reduce nationwide mercury emissions in two phases. New mercury emission limits for Phase 1 were to go into effect January 1, 2010. On February 8, 2008, the U.S. Court of Appeals for the District of Columbia vacated CAMR. This decision was appealed to the U.S. Supreme Court which denied the appeal on February 23, 2009.

The EPA issued an Information Collection Request (ICR) for determining the National Emission Standards for Hazardous Air Pollutants (NESHAP), including mercury, for coal and oil-fired electric steam generating units on December 24, 2009. This ICR included our Iatan, Asbury and Riverton plants. All ICRs were submitted as required. The EPA ICR was intended for use in developing regulations under Section 112(r) of the CAA maximum achievable emission standards for the control of the emission of hazardous air pollutants (HAPs), including mercury. The EPA proposed the first ever national mercury and air toxics standards (MATS) in March 2011. It was signed by EPA Administrator on December 16, 2011 and establishes numerical emission limits to reduce emissions of heavy metals, including mercury (Hg), arsenic, chromium, and nickel, and acid gases, including HCl and hydrogen fluoride (HF). For all existing and new coal-fired electric utility steam generating units (EGUs), the proposed standard will be phased in over three years, and allows states the ability to give facilities a fourth year to comply.

The MATS regulation of HAPs in combination with CSAPR is the driving regulation behind our Compliance Plan and its implementation schedule. We expect compliance costs to be recoverable in our rates.

Greenhouse Gases

Our coal and gas plants, vehicles and other facilities, including EDG (our gas segment), emit CO2 and/or other Greenhouse Gases (GHGs) which are measured in Carbon Dioxide Equivalents (CO2e).

On September 22, 2009, the EPA issued the final Mandatory Reporting of Greenhouse Gases Rule under the CAA which requires power generating and certain other facilities that equal or exceed an emission threshold of 25,000 metric tons of CO2e to report GHGs to the EPA annually commencing in September 2011. GHG emissions have been reported as required to the EPA in 2011 for EDE and EDG. On January 11, 2012 EPA released the greenhouse gas data reported from large facilities and suppliers across the U.S. economy for the year 2010.

On December 7, 2009, responding to a 2007 U.S. Supreme Court decision that determined that GHGs constitute "air pollutants" under the CAA, the EPA issued its final finding that GHGs threaten both the public health and the public welfare. This "endangerment" finding does not itself trigger any EPA regulations, but is a necessary predicate for the EPA to proceed with regulations to control GHGs. On May 13, 2010, the EPA issued under the CAA its final Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule (Tailoring Rule) to address GHG emissions from stationary sources, which became effective January 2, 2011. The rule sets thresholds for GHG emissions that determine when permits will be required under the New Source Review Prevention of Significant Deterioration (PSD) and title V Operating Permit programs applicable to new and existing power plants and other covered sources. Under the PSD program, required controls for GHG emissions would be determined based on Best Available Control Technology (BACT). EPA issued a BACT permitting guidance document on November 11, 2010. Missouri and Kansas have been delegated GHG permitting authority by EPA. Several parties have filed petitions with the EPA and lawsuits have been filed challenging the EPA's Endangerment Finding and the Tailoring Rule.

In addition, on December 23, 2010 the EPA entered into an agreement with a number of state and environmental petitioners to settle litigation pending in the U.S. Court of Appeals for the District of Columbia Circuit that requires EPA to propose New Source Performance Standards (NSPS) for GHGs for fossil-fuel fired steam generating units by September 30, 2011 and to issue final GHG NSPS standards by May 26, 2012. The EPA has not to date issued a proposed GHG emissions rule for stationary sources.

A variety of proposals have been and are likely to continue to be considered by Congress to reduce GHGs. Proposals are also being considered in the House and Senate that would delay, limit or eliminate EPA's authority to regulate GHGs. At this time, it is not possible to predict what legislation, if any, will ultimately emerge from Congress regarding control of GHGs.

Certain states have taken steps to develop cap and trade programs and/or other regulatory systems which may be more stringent than federal requirements. For example, Kansas is a participating member of the Midwestern Greenhouse Gas Reduction Accord (MGGRA), one purpose of which is to develop a market-based cap and trade mechanism to reduce GHG emissions. The MGGRA has announced, however, that it will not issue a CO2e regulatory system pending federal legislative developments. Missouri is not a participant in the MGGRA.

The ultimate cost of any GHG regulations cannot be determined at this time. However, we would expect the cost of complying with any such regulations to be recoverable in our rates.

Water Discharges

We operate under the Kansas and Missouri Water Pollution Plans that were implemented in response to the Federal Clean Water Act (CWA). Our plants are in material compliance with applicable regulations and have received necessary discharge permits.

The Riverton Units 7 and 8 and Iatan Unit 1, which utilize once-through cooling water, were affected by regulations for Cooling Water Intake Structures issued by the EPA under the CWA Section 316(b) Phase II. The regulations became final on February 16, 2004. In accordance with these regulations, we submitted sampling and summary reports to the Kansas Department of Health and Environment (KDHE) which indicate that the effect of the cooling water intake structure on Empire Lake's aquatic life is insignificant. KCP&L, who operates Iatan Unit 1, submitted the appropriate sampling and summary reports to the Missouri Department of Natural Resources (MDNR). In 2007 the United States Court of Appeals for the Second Circuit remanded key sections of these CWA regulations to the EPA. As a result, the EPA suspended the regulations and revised and signed a pre-publication proposed regulation on March 28, 2011 and is obligated to finalize the rule by July 27, 2012.

We will not know the full impact of these rules until they are finalized. If adopted in their present form, we expect regulations of Cooling Water Intake Structures issued by the EPA under the CWA Section 316(b) to have an impact at Riverton ranging from minor improvements to the cooling water intake structure to retirement of units 7 and 8. Impacts at Iatan 1 could range from flow velocity reductions or traveling screen modifications for fish handling to installation of a closed cycle cooling tower retrofit. Our new Iatan Unit 2 and Plum Point Unit 1 are covered by the proposed regulation but were constructed with cooling towers, the proposed Best Technology Available. We expect them to be unaffected or minimally impacted by the final rule.

Surface Impoundments

We own and maintain coal ash impoundments located at our Riverton and Asbury Power Plants. Additionally, we own a 12 percent interest in a coal ash impoundment at the Iatan Generating Station and a 7.52% interest in a coal ash impoundment at Plum Point. The EPA has announced its intention to revise its wastewater effluent limitation guidelines under the CWA for coal-fired power plants sometime in 2012. Once the new guidelines are issued, the EPA and states would incorporate the new standards into wastewater discharge permits, including permits for coal ash impoundments. We do not have sufficient information at this time to estimate additional costs that might result from any new standards. All of the coal ash impoundments are compliant with existing state and federal regulations.

On June 21, 2010, the EPA proposed a new regulation pursuant to the Federal Resource Conservation and Recovery Act (RCRA) governing the management and storage of Coal Combustion Residuals (CCR). In the proposal, the EPA presents two options: (1) regulation of CCR under RCRA subtitle C as a hazardous waste and (2) regulation of CCR under RCRA subtitle D as a non-hazardous waste. The public comment period closed in November 2010. It is anticipated that the final regulation will be published in mid to late 2012. We expect compliance with either option as proposed to result in the need to construct a new landfill and the conversion of existing ash handling from a wet to a dry system(s) at a potential cost of up to $15 million at our Asbury and Riverton Power Plants. This preliminary estimate will likely change based on the final CCR rule and its requirements. We expect resulting costs to be recoverable in our rates.

On September 23, 2010 and on November 4, 2010 representatives from GEI Consultants, on behalf of the EPA, conducted on-site inspections of our Riverton and Asbury coal ash impoundments, respectively. The consultants performed a visual inspection of the impoundments to assess the structural integrity of the berms surrounding the impoundments, requested documentation related to construction of the impoundments, and reviewed recently completed engineering evaluations of the impoundments and their structural integrity. In response to the inspection comments, a qualified engineering firm has been selected to complete the recommended geotechnical studies and install new flow monitoring devices and settlement monuments at both coal ash impoundments. The project is expected to be completed by December 2012. The project will comply with all corrective measures and recommendations made by the EPA in its site assessment reports.

Renewable Energy

We have a 20-year purchased power agreement, which began on December 15, 2008, with Cloud County Windfarm, LLC, owned by EDP Renewables North America LLC (formerly Horizon Wind Energy), Houston, Texas to purchase the energy generated at the approximately 105-megawatt Phase 1 Meridian Way Wind Farm located in Cloud County, Kansas. We also have a 20-year contract, which began on December 15, 2005, with Elk River Windfarm, LLC, owned by IBERDROLA RENEWABLES, Inc., to purchase the energy generated at the 150-megawatt Elk River Windfarm located in Butler County, Kansas. We do not own any portion of either windfarm. More than 15% of the energy we put into the grid comes from these long-term Purchased Power Agreements (PPAs). Through these PPAs, we generate about 900,000 renewable energy certificates (RECs) each year. A REC represents one megawatt-hour of renewable energy that has been delivered into the bulk power grid and "unbundles" the renewable attributes from the associated energy. This unbundling is important because it cannot be determined where the renewable energy is ultimately delivered once it enters the bulk power grid. As a result, RECs provide an avenue for renewable energy tracking and compliance purposes.

On November 4, 2008, Missouri voters approved the Clean Energy Initiative (Proposition C). This initiative requires us and other investor-owned utilities in Missouri to generate or purchase electricity from renewable energy sources, such as solar, wind, biomass and hydro power, or purchase RECs, at the rate of at least 2% of retail sales by 2011, increasing to at least 15% by 2021. Two percent of this amount must be solar. We believe we are exempted from the solar requirement. A challenge to our exemption, brought by two of our customers and Power Source Solar, Inc., was dismissed on May 31, 2011 by the Missouri

Western District Court of Appeals. The plaintiffs filed in the Missouri Supreme Court for transfer of the case from the Missouri Western District to the Missouri Supreme Court. The transfer was denied.

Renewable energy standard compliance rules were published by the MPSC on July 7, 2010. Missouri investor-owned utilities and others initiated litigation to challenge these rules. On June 30, 2011, a Cole County Circuit Court judge ruled that portions of the MPSC rules were unlawful and unreasonable, in conflict with Missouri statute and in violation of the Missouri Constitution. Subsequent to that decision, a portion of the appeal was dropped and the entire order was stayed. On December 27, 2011 the judge issued another order identical to the one that was stayed except that the rulings with regard to the constitutionality issue had been omitted. We have satisfied the current compliance requirements of the rule requiring us and other investor-owned utilities in Missouri to generate or purchase electricity from renewable energy sources at the rate of at least 2% of retail sales by 2011, increasing to at least 15% by 2021.

Kansas established a renewable portfolio standard (RPS), effective November 19, 2010. It requires 10% of our Kansas retail customer peak capacity requirements to be sourced from renewables by 2011, 15% by 2016, and 20% by 2020. In addition, there are several proposals currently before the U.S. Congress to adopt a nationwide RPS.

We have been selling the majority of our RECs and plan to continue to sell all or a portion of them moving forward. As a result of these REC sales, we cannot claim the underlying energy is renewable. Once a REC has been claimed or retired, it cannot be used for any other purpose. At the end of 2011, sufficient RECs, including hydro, were retired to comply with the Missouri and Kansas requirements through the end of November 2011. Additional RECs will be retired in January of 2012 to complete the process for 2011. In the future, we will continue to retain a sufficient amount of RECs to meet any current or future RPS.

Gas Segment

The acquisition of our natural gas distribution assets in June 2006 involved the potential future remediation of two former manufactured gas plant (FMGP) sites. FMGP Site #1 in Chillicothe, Missouri is listed in the MDNR Registry of Confirmed Abandoned or Uncontrolled Hazardous Waste Disposal Sites in Missouri. No remediation of this site is expected to be required in the near term. We have received a letter stating no further action is required from the MDNR with respect to FMPG Site #2 in Marshall, Missouri. We have incurred $0.2 million in remediation costs and estimate further remediation costs at these two sites to be minimal.

12. Segment Information

We operate our business as three segments: electric, gas and other. As part of our electric segment, we also provide water service to three towns in Missouri. The Empire District Gas Company is our wholly owned subsidiary formed to provide gas distribution service in Missouri. The other segment consists of our non-regulated businesses subsidiary for our fiber optics business.

The tables below present statement of income information, balance sheet information and capital expenditures of our business segments.

	For the year ended December 31,				
	2011				
	Electric	Gas	Other	Eliminations	Total
Statement of Income Information:					
Revenues	$524,276	$46,430	$6,756	$(592)	$576,870
Depreciation and amortization	58,236	3,494	1,807	—	63,537
Federal and state income taxes	31,643	1,676	979	—	34,298
Operating income	88,590	6,514	1,830	—	96,934
Interest income	554	259	—	(258)	555
Interest expense	37,860	3,910	8	(258)	41,520
Income from AFUDC (debt and equity)	509	3	—	—	512
Income from continuing operations	$ 50,670	$ 2,709	$1,592	$ —	$ 54,971
Capital Expenditures	$ 93,499	$ 4,122	$3,556	$ —	$101,177

	2010				
	Electric	Gas	Other	Eliminations	Total
Statement of Income Information:					
Revenues	$484,715	$50,885	$6,268	$(592)	$541,276
Depreciation and amortization	53,983	3,032	1,641	—	58,656
Federal and state income taxes	27,925	1,620	988	—	30,533
Operating income	72,528	6,327	1,640	—	80,495
Interest income	198	403	—	(425)	176
Interest expense	38,798	3,941	33	(425)	42,347
Income from AFUDC (debt and equity)	10,155	19	—	—	10,174
Income from continuing operations	$ 43,187	$ 2,602	$1,607	$ —	$ 47,396
Capital Expenditures	$100,146	$ 5,242	$2,769	$ —	$108,157

	2009				
	Electric	Gas	Other	Eliminations	Total
Statement of Income Information:					
Revenues	$434,897	$57,314	$5,562	$(605)	$497,168
Depreciation and amortization	48,036	2,015	1,443	—	51,494
Federal and state income taxes	18,484	572	826	—	19,882
Operating income	68,414	4,634	1,447	—	74,495
Interest income	225	403	—	(411)	217
Interest expense	43,173	3,959	57	(411)	46,778
Income from AFUDC (debt and equity)	14,131	2	—	—	14,133
Income from continuing operations	$ 39,078	$ 874	$1,344	$ —	$ 41,296
Capital Expenditures	$145,287	$ 2,256	$1,261	$ —	$148,804

	December 31, 2011				
	Electric	Gas(1)	Other	Eliminations	Total
Balance Sheet Information:					
Total assets	$1,931,320	$145,897	$26,038	$(81,420)	$2,021,835

	December 31, 2010				
	Electric	Gas(1)	Other	Eliminations	Total
Balance Sheet Information:					
Total assets	$1,837,910	$139,532	$23,163	$(79,294)	$1,921,311

(1) Includes goodwill of $39,492 at December 31, 2011 and 2010.

13. Selected Quarterly Information (Unaudited)

The following is a summary of quarterly results for 2011 and 2010 (dollars in thousands except per share amounts):

	Quarters			
Quarterly Results for 2011	First	Second	Third	Fourth
Operating revenues	$150,728	$129,093	$164,284	$132,765
Operating income	$ 21,848	$ 19,134	$ 36,450	$ 19,502
Net Income	$ 11,922	$ 9,175	$ 25,184	$ 8,690
Basic Earning Per Share	$ 0.29	$ 0.22	$ 0.60	$ 0.21
Diluted Earnings Per Share	$ 0.29	$ 0.22	$ 0.60	$ 0.21

	Quarters			
Quarterly Results for 2010	First	Second	Third	Fourth
Operating revenues	$139,893	$114,482	$154,086	$132,815
Operating income	$ 16,078	$ 14,279	$ 31,873	$ 18,265
Net Income	$ 8,586	$ 7,369	$ 22,981	$ 8,460
Basic Earning Per Share	$ 0.22	$ 0.18	$ 0.56	$ 0.20
Diluted Earnings Per Share	$ 0.22	$ 0.18	$ 0.55	$ 0.20

The sum of the quarterly earnings per share of common stock may not equal the earnings per share of common stock as computed on an annual basis due to rounding.

Earnings for the fourth quarter of 2011 were $8.7 million, or $0.21 per share, as compared to $8.5 million, or $0.20 per share, in the fourth quarter 2010.

14. Risk Management and Derivative Financial Instruments

We engage in hedging activities in an effort to minimize our risk from volatile natural gas prices. We enter into both physical and financial contracts with counterparties relating to our future natural gas requirements that lock in prices (with respect to a range of predetermined percentages of our expected future natural gas needs) in an attempt to lessen the volatility in our fuel expenditures and gain predictability. We recognize that if risk is not timely and adequately balanced or if counterparties fail to perform contractual obligations, actual results could differ materially from intended results.

All derivative instruments are recognized at fair value on the balance sheet with the unrealized losses or gains from derivatives used to hedge our fuel costs in our electric segment recorded in regulatory assets or liabilities. All gains and losses from derivatives related to the gas segment are also recorded in regulatory assets or liabilities. This is in accordance with the ASC guidance on regulated operations, given that those regulatory assets and liabilities are probable of recovery through our fuel adjustment mechanism.

Risks and uncertainties affecting the determination of fair value include: market conditions in the energy industry, especially the effects of price volatility, regulatory and global political environments and requirements, fair value estimations on longer term contracts, the effectiveness of the derivative instrument in hedging the change in fair value of the hedged item, estimating underlying fuel demand and counterparty ability to perform. If we estimate that we have overhedged forecasted demand, the gain or loss on the overhedged portion will be recognized immediately as fuel and purchased power expense in our Consolidated Statement of Income and subject to our fuel adjustment clause.

As of December 31, 2011 and 2010, we have recorded the following assets and liabilities representing the fair value of derivative financial instruments held as of December 31, (in thousands):

ASSET DERIVATIVES

Non-designated hedging instruments due to regulatory accounting	Balance Sheet Classification	2011 Fair Value	2010 Fair Value
Natural gas contracts, gas segment	Current assets — Prepaid expenses and other	—	39
	Non-current assets and deferred charges — Other	2	117
Natural gas contracts, electric segment	Current assets — Prepaid expenses and other	—	—
	Non-current assets and deferred charges — Other		77
Total derivatives assets		$2	$233

LIABILITY DERIVATIVES

Derivatives designated as hedging instruments	Balance Sheet Classification	2011 Fair Value	2010 Fair Value
Natural gas contracts, electric segment	Current liabilities	$ —	$ —
	Non-current liabilities and deferred credits	—	—
Non-designated as hedging instruments due to regulatory accounting			
Natural gas contracts, gas segment	Current liabilities	967	252
	Non-current liabilities and deferred credits	86	2
Natural gas contracts, electric segment	Current liabilities	3,802	508
	Non-current liabilities and deferred credits	4,995	3,562
Total derivatives liabilities		$9,850	$4,324

Electric

At December 31, 2011, approximately $3.8 million of unrealized losses are applicable to financial instruments which will settle within the next twelve months. Effective September 1, 2008, in conjunction with the implementation of the Missouri fuel adjustment clause in the July 2008 MPSC rate order, new hedges are non-designated and the unrealized losses or gains are recorded in regulatory assets or liabilities. This is in accordance with ASC guidance on accounting for regulated operations, given that those regulatory assets and liabilities are probable of recovery through our fuel adjustment mechanism. Effective December 2010 all remaining cash flow hedges entered into prior to September 1, 2008 were de-designated and the unrealized loss of $1.0 million was transferred from OCI to a regulatory asset. Unrealized gains and losses are now recorded in regulatory assets or liabilities in accordance with the ASC guidance mentioned.

The following tables set forth the actual pre-tax gains/(losses) and the mark to market effect of unsettled positions from the qualified portion of our hedging activities for settled contracts for the electric segment for each of the years ended December 31, (in thousands):

Derivatives in Cash Flow Hedging Relationships — Electric Segment

	Income Statement Classification of Loss on Derivative	Amount of Loss Reclassed from OCI into Income (Effective Portion) 2011	2010
Commodity contracts	Fuel and purchased power expense	$ —	$(5,814)
Total Effective — Electric Segment		$ —	$(5,814)

Derivatives in Cash Flow Hedging Relationships — Electric Segment

	Statement of Comprehensive Income	Amount of Loss Recognized in OCI on Derivative (Effective Portion) 2011	2010
Commodity contracts	Fuel and purchased power expense . . .	$ —	$(6,362)
Total Effective — Electric Segment . . .		$ —	$(6,362)

There were no "mark-to-market" pre-tax gains/(losses) from ineffective portions of our hedging activities for the electric segment for the years ended December 31, 2011 and 2010, respectively.

The following tables set forth "mark-to-market" pre-tax gains/ (losses) from non-designated derivative instruments for the electric segment for each of the years ended December 31, (in thousands):

Non-Designated Hedging Instruments — Due to Regulatory Accounting Electric Segment

	Balance Sheet Classification of Loss on Derivative	Amount of Loss Recognized on Balance Sheet 2011	2010
Commodity contracts — electric segment	Regulatory assets . . .	$(6,965)	$(2,669)
Total — Electric Segment . . .		$(6,965)	$(2,669)

Non-Designated Hedging Instruments — Due to Regulatory Accounting Electric Segment

	Statement of Operations Classification of Loss on Derivative	Amount of Loss Recognized in Income on Derivative 2011	2010
Commodity contracts	Fuel and purchased power expense . . .	$(2,231)	$(752)
Total — Electric Segment . . .		$(2,231)	$(752)

We also enter into fixed-price forward physical contracts for the purchase of natural gas, coal and purchased power. These contracts are not subject to fair value accounting because they qualify for the normal purchase normal sale exemption. We have a process in place to determine if any future executed contracts that otherwise qualify for the normal purchase normal sale exception contain a price adjustment feature and will account for these contracts accordingly.

At December 31, 2011, the following volumes and percentages of our anticipated volume of natural gas usage for our electric operations for 2012 and the next four years are hedged at the following average prices per Dekatherm (Dth):

Year	% Hedged	Dth Hedged Physical	Dth Hedged Financial	Average Price
2012	61%	2,511,000	1,420,000	$6.459
2013	44%	2,020,000	1,440,000	$6.079
2014	20%	460,000	1,240,000	$5.514
2015	11%	—	1,010,000	$5.439
2016	0%	—	—	$ —

We utilize the following procurement guidelines for our electric segment, allowing the flexibility to hedge up to 100% of the current year's and 80% of any future year's expected requirements while being cognizant of volume risk. The 80% guideline is an annual target and volumes up to 100% can be hedged in any given month. For years beyond year four, additional factors of long term uncertainty (including with respect to required volumes and counterparty credit) are also considered.

Year	End of Year Minimum % Hedged
Current	Up to 100%
First	60%
Second	40%
Third	20%
Fourth	10%

Gas

We attempt to mitigate our natural gas price risk for our gas segment by a combination of (1) injecting natural gas into storage during the off-heating season months, (2) purchasing physical forward contracts and (3) purchasing financial derivative contracts. We target to have 95% of our storage capacity full by November 1 for the upcoming winter heating season. As the winter progresses, gas is withdrawn from storage to serve our customers. As of December 31, 2011 we had 1.5 million Dths in storage on the three pipelines that serve our customers. This represents 76% of our storage capacity.

The following table sets forth our long-term hedge strategy of mitigating price volatility for our customers by hedging a minimum of expected gas usage for the current winter season and the next two winter seasons by the beginning of the ACA year at September 1 and illustrates our hedged position as of December 31, 2011 (Dth in thousands).

Season	Minimum % Hedged	Dth Hedged Financial	Dth Hedged Physical	Dth in Storage	Actual % Hedged
Current	50%	420	310	1,436	98%
Second	Up to 50%	700	—	—	16%
Third	Up to 20%	—	—	—	
Total		1,120	310	1,436	

A Purchased Gas Adjustment (PGA) clause is included in our rates for our gas segment operations, therefore, we mark to market any unrealized gains or losses and any realized gains or losses relating to financial derivative contracts to a regulatory asset or regulatory liability account on our balance sheet.

The following table sets forth "mark-to-market" pre-tax gains / (losses) from derivatives not designated as hedging instruments for the gas segment for the years ended December 31, (in thousands):

Non-Designated Hedging Instruments Due to Regulatory Accounting — Gas Segment

	Balance Sheet Classification of Loss on Derivative	Amount of Loss Recognized on Balance Sheet	
		2011	2010
Commodity contracts	Regulatory assets	$(1,916)	$(626)
Total — Gas Segment		$(1,916)	$(626)

Contingent Features

Certain of our derivative instruments contain provisions that require our senior unsecured debt to maintain an investment grade credit rating with any relevant credit rating agency. If our debt were to fall below investment grade, it would be in violation of these provisions, and the counterparties to the derivative instruments could request increased collateralization on derivative instruments in net liability positions. The aggregate fair value of all derivative instruments with the credit-risk-related contingent features that are in a liability position on December 31, 2011 is $2.4 million for which we have posted no collateral in the normal course of business. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2011, we would have been required to post $2.4 million of collateral with one of our counterparties. On December 31, 2011, we had no collateral posted with this counterparty.

15. Fair Value Measurements

The accounting guidance on fair value measurements establishes a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value. These tiers include: (i) Level 1, defined as quoted prices in active markets for identical instruments; (ii) Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and (iii) Level 3, defined as unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions. Our Level 2 fair value measurements consist of both quoted price inputs and inputs that are derived principally from or corroborated by observable market data. Our Level 3 fair value measurements consist of both quoted price inputs and unobservable quoted inputs.

The guidance also requires that the fair value measurement of assets and liabilities reflect the nonperformance risk of counterparties and the reporting entity, as applicable. Therefore, using credit default spreads, we factored the impact of our own credit standing and the credit standing of our counterparties, as well as any potential credit enhancements (e.g. collateral) into the consideration of nonperformance risk for both derivative assets and liabilities. The results of this analysis were not material to the financial statements.

The following fair value hierarchy table presents information about our commodity contracts measured at fair value using the market value approach on a recurring basis as of December 31, 2011:

Fair Value Measurements at Reporting Date Using

($ in 000's) Description	Assets/(Liabilities) at Fair Value	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
December 31, 2011				
Net derivative liabilities*	$ (9,848)	$(9,848)	—	—
December 31, 2010				
Net derivative liabilities*	$ (4,091)	$(4,091)	—	—

* The only recurring measurements are derivative related and assets and liabilities are netted together in the table above.

The following tables present the change in net fair value of our Level 3 assets/liabilities during the twelve months ended December 31, 2011 and 2010 (in thousands):

Fair Value Measurements Using Significant Unobservable Inputs (Level 3)

($ in 000's)	2011 Net Derivatives(1)	2010 Net Derivatives(1)	2009 Net Derivatives(1)
Beginning Balance, January 1,	$ —	$ —	$ 6,208
Total gains or losses (realized/unrealized)			
Included in earnings (or changes in net assets)	—	—	—
Included in comprehensive income	—	—	(1,738)
Purchases	—	—	—
Issuances	—	—	—
Settlements	—	—	—
Transfers in and/or out of Level 3	—	—	(4,470)
Ending Balance, December 31,	$ —	$ —	$ —
Changes in unrealized gains relating to assets still held at reporting date	$ —	$ —	$ 1,738

(1) Net derivatives at December 31, 2011, 2010 and 2009 included no derivative assets or derivative liabilities.

16. Accounts Receivable — Other

The following table sets forth the major components comprising "accounts receivable — other" on our consolidated balance sheet (in thousands):

	December 31,	
	2011	2010
Accounts receivable for plant reimbursements, line extensions, highway projects, etc.	$ 811	$ 5,322
Taxes receivable — overpayment of estimated income taxes[1]	5,516	10,807
Accounts receivable for energy trading margin deposit[2]	5,818	3,878
Accounts receivable for true-up on maintenance contracts[3]	1,323	1,512
Accounts receivable for insurance proceeds for SLCC generator failure[4]	—	2,596
Accounts receivable from Westar Generating, Inc., for commonly-owned facility	1,642	636
Accounts receivable for gas segment	19	27
Accounts receivable for non-regulated subsidiary companies	1,037	602
Other	103	65
Total Accounts Receivable — Other	$16,269	$25,445

(1) Primarily due to the effects of Investment Tax Credits, and bonus depreciation, net of the payment received from SWPA. See note 9 for further detail.

(2) The accounts receivable for energy trading margin deposit represents the balance in our brokerage account. NYMEX futures contracts are used in our hedging program of natural gas which require posting of margin.

(3) Represents quarterly estimated credits due from Siemens Westinghouse related to our maintenance contract for State Line Combined Cycle Unit (SLCC). Forty percent of this credit belongs to Westar Generating, Inc., the owner of 40% of the SLCC, and has been recorded in accounts payable.

(4) Represents the insurance proceeds for the failure of the State Line Combined Cycle Unit 2-1 generator. Forty percent of these proceeds belonged to Westar Generating, Inc., and were recorded in accounts payable.

17. Regulated Operating Expense

The following table sets forth the major components comprising "regulated operating expenses" under "Operating Revenue Deductions" on our consolidated statements of income for the years ended (in thousands):

	December 31,		
	2011	*2010*	*2009*
Power operation expense (other than fuel)	$13,277	$11,356	$12,315
Electric transmission and distribution expense	15,361	12,996	11,063
Natural gas transmission and distribution expense	2,385	2,194	2,161
Customer accounts & assistance expense	10,210	11,618	10,597
Employee pension expense(1)	8,805	5,899	5,557
Employee healthcare plan(1)	7,439	6,930	5,908
General office supplies and expense	10,158	11,584	10,070
Administrative and general expense	14,295	12,896	12,211
Bad debt expense	3,425	3,651	3,125
Miscellaneous expense	87	168	79
Total	$85,442	$79,292	$73,086

(1) Does not include the capitalized portion of actuarially calculated costs, but reflects the GAAP expensed portion of these costs plus or minus costs deferred to a regulatory asset or recognized as a regulatory liability for Missouri and Kansas jurisdictions.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, an evaluation was carried out, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as such term is defined in Rule 13a-15(e) of the Securities Exchange Act of 1934). Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2011.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in the Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, our management concluded that our internal control over financial reporting was effective as of December 31, 2011.

Audit of Internal Control Over Financial Reporting

The effectiveness of our internal control over financial reporting as of December 31, 2011, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

Changes in Internal Control Over Financial Reporting

There have been no changes in our internal control over financial reporting that occurred during the fourth quarter of 2011 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Except as set forth below, the information required by this Item may be found in our proxy statement for our Annual Meeting of Stockholders to be held April 26, 2012, which is incorporated herein by reference.

Pursuant to instruction 3 of paragraph (b) of Item 401 of Regulation S-K, the information required by this Item with respect to executive officers is set forth in Item 1 of Part I of this Form 10-K under "Executive Officers and Other Officers of Empire."

We have adopted a Code of Ethics for the Chief Executive Officer and Senior Financial Officers. A copy of the code is available on our website at www.empiredistrict.com. Any future amendments or waivers to the code will be posted on our website at www.empiredistrict.com.

ITEM 11. EXECUTIVE COMPENSATION

Information required by this item may be found in our proxy statement for our Annual Meeting of Stockholders to be held April 26, 2012, which is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Except as set forth below, information required by this item may be found in our proxy statement for our Annual Meeting of Stockholders to be held April 26, 2012, which is incorporated herein by reference.

There are no arrangements the operation of which may at a subsequent date result in a change in control of Empire.

Securities Authorized For Issuance Under Equity Compensation Plans

We have four equity compensation plans, all of which have been approved by shareholders, the 1996 Stock Incentive Plan, the 2006 Stock Incentive Plan, the Employee Stock Purchase Plan (ESPP) and the Stock Unit Plan for Directors.

The following table summarizes information about our equity compensation plans as of December 31, 2011:

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights.	(b) Weighted-average exercise price of outstanding options, warrants and rights(1)	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders . . .	473,245	$20.40	1,123,374
Equity compensation plans not approved by security holders . . .	—	—	—
TOTAL	473,245	$20.40	1,123,374

(1) The weighted average exercise price of $20.40 relates to 39,100 and 4,200 options granted to executive officers in 2005 and 2004, respectively, under the 1996 Stock Incentive Plan, 34,800, 27,000, 5,400, 64,200 and 15,600 options granted to executive officers in 2010, 2009, 2008, 2007 and 2006, respectively, under the 2006 Stock Incentive Plan and 70,756 subscriptions outstanding for our ESPP. The two stock incentive plans had a weighted average exercise price of $21.56 and the ESPP had an exercise price of $17.27. There is no exercise price for 74,800 performance-based stock awards and 3,433 time-vested restricted stock awards awarded under the 2006 Stock Incentive Plans or for 133,956 units awarded under the Stock Unit Plan for Directors.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by this Item may be found in our proxy statement for our Annual Meeting of Stockholders to be held April 26, 2012 which is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this Item may be found in our proxy statement for our Annual Meeting of Stockholders to be held April 26, 2012 which is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

Index to Financial Statements and Financial Statement Schedule Covered by Report of Independent Registered Public Accounting Firm

All other schedules are omitted as the required information is either not present, is not present in sufficient amounts, or the information required therein is included in the financial statements or notes thereto.

List of Exhibits

(3)(a) The Restated Articles of Incorporation of Empire (Incorporated by reference to Exhibit 4(a) to Registration Statement No. 33-54539 on Form S-3).

(b) By-laws of Empire as amended October 31, 2002 (Incorporated by reference to Exhibit 4(b) to Annual Report on Form 10-K for year ended December 31, 2002, File No. 1-3368).

(4)(a) Indenture of Mortgage and Deed of Trust dated as of September 1, 1944 and First Supplemental Indenture thereto among Empire, The Bank of New York Mellon Trust Company, N.A. and UMB Bank, N.A., (Incorporated by reference to Exhibits B(1) and B(2) to Form 10, File No. 1-3368).

(b) Third Supplemental Indenture to Indenture of Mortgage and Deed of Trust (Incorporated by reference to Exhibit 2(c) to Form S-7, File No. 2-59924).

(c) Sixth through Eighth Supplemental Indentures to Indenture of Mortgage and Deed of Trust (Incorporated by reference to Exhibit 2(c) to Form S-7, File No. 2-59924).

(d) Fourteenth Supplemental Indenture to Indenture of Mortgage and Deed of Trust (Incorporated by reference to Exhibit 4(f) to Registration Statement No. 33-56635 on Form S-3).

(e) Twenty-Second Supplemental Indenture dated as of November 1, 1993 to Indenture of Mortgage and Deed of Trust (Incorporated by reference to Exhibit 4(k) to Annual Report on Form 10-K for the year ended December 31, 1993, File No. 1-3368).

(f) Twenty-Third Supplemental Indenture dated as of November 1, 1993 to Indenture of Mortgage and Deed of Trust (Incorporated by reference to Exhibit 4(l) to Annual Report on Form 10-K for the year ended December 31, 1993, File No. 1-3368).

(g) Twenty-Fourth Supplemental Indenture dated as of March 1, 1994 to Indenture of Mortgage and Deed of Trust (Incorporated by reference to Exhibit 4(m) to Annual Report on Form 10-K for the year ended December 31, 1993, File No. 1-3368).

(h) Twenty-Eighth Supplemental Indenture dated as of December 1, 1996 to Indenture of Mortgage and Deed of Trust (Incorporated by reference to Exhibit 4 to Annual Report on Form 10-K for the year ended December 31, 1996, File No. 1-3368).

(i) Thirty-First Supplemental Indenture dated as of March 26, 2007 to Indenture of Mortgage and Deed of Trust (Incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K dated March 26, 2007 and filed March 28, 2007, File No. 1-3368).

(j) Thirty-Second Supplemental Indenture dated as of March 11, 2008 to Indenture of Mortgage and Deed of Trust (Incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K dated March 11, 2008 and filed March 12, 2008, File No. 1-3368).

(k) Thirty-Third Supplemental Indenture dated as of May 16, 2008 to Indenture of Mortgage and Deed of Trust (Incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K dated May 16, 2008 and filed May 16, 2008, File No. 1-3368).

(l) Thirty-Fourth Supplemental Indenture, dated as of March 27, 2009, to Indenture of Mortgage and Deed of Trust (Incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K dated March 27, 2009 and filed March 30, 2009, File No. 1-3368).

(m) Thirty-Fifth Supplemental Indenture, dated as of May 28, 2010, to Indenture of Mortgage and Deed of Trust (Incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K dated May 28, 2010 and filed May 28, 2010, File No. 1-3368).

(n) Thirty-Sixth Supplemental Indenture, dated as of August 25, 2010, to Indenture of Mortgage and Deed of Trust (Incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K dated August 25, 2010 and filed August 26, 2010, File No. 1-3368).

(o) Thirty-Seventh Supplemental Indenture, dated as of June 9, 2011, to Indenture of Mortgage and Deed of Trust (Incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K dated June 9, 2011 and filed June 10, 2011, File No. 1-3368).

(p) Indenture for Unsecured Debt Securities, dated as of September 10, 1999 between Empire and Wells Fargo Bank, National Association (Incorporated by reference to Exhibit 4(v) to Registration Statement No. 333-87015 on Form S-3).

(q) Securities Resolution No. 4, dated as of June 10, 2003, of Empire under the Indenture for Unsecured Debt Securities (Incorporated by reference to Exhibit 4 to Current Report on Form 8-K dated June 10, 2003 and filed July 29, 2003, File No. 1-3368).

(r) Securities Resolution No. 5, dated as of October 29, 2003, of Empire under the Indenture for Unsecured Debt Securities (Incorporated by reference to Exhibit 4 to Quarterly Report on Form 10-Q for quarter ended September 30, 2003), File No. 1-3368).

(s) Securities Resolution No. 6, dated as of June 27, 2005, of Empire under the Indenture for Unsecured Debt Securities (Incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K dated June 27, 2005 and filed June 28, 2005, File No. 1-3368).

(t) Bond Purchase Agreement dated June 1, 2006 among The Empire District Gas Company and the purchasers party thereto (Incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K dated June 1, 2006 and filed June 6, 2006, File No. 1-3368).

(u) Indenture of Mortgage and Deed of Trust dated as of June 1, 2006 by The Empire District Gas Company, as Grantor, to Spencer R. Thomson, Deed of Trust Trustee for the Benefit of The Bank of New York Trust Company, N.A., Bond Trustee, as Grantee (Incorporated by reference to Exhibit 4.2 to Current Report on Form 8-K dated June 1, 2006 and filed June 6, 2006, File No. 1-3368).

(v) First Supplemental Indenture of Mortgage and Deed of Trust dated as of June 1, 2006 by The Empire District Gas Company, as Grantor, to Spencer R. Thomson, Deed of Trust Trustee for the Benefit of The Bank of New York Trust Company, N.A., Bond Trustee, as Grantee (Incorporated by reference to Exhibit 4.3 to Current Report on Form 8-K dated June 1, 2006 and filed June 6, 2006, File No. 1-3368).

(10)(a) 1996 Stock Incentive Plan (Incorporated by reference to Exhibit 4.1 to Form S-8, File No. 33-64639).†

(b) First Amendment to 1996 Stock Incentive Plan. (Incorporated by reference to Exhibit 10(b) to Annual Report on Form 10-K for the year ended December 31, 2007, File No. 1-3368).†

(c) 2006 Stock Incentive Plan (Incorporated by reference to Exhibit 4(u) to Form S-8, File No. 333-130075).†

(d) First Amendment to 2006 Stock Incentive Plan. (Incorporated by reference to Exhibit 10(d) to Annual Report on Form 10-K for the year ended December 31, 2007, File No. 1-3368).†

(e) Second Amendment to 2006 Stock Incentive Plan (Incorporated by reference to Exhibit 10(e) to Annual Report on Form 10-K for the year ended December 31, 2008, File No. 1-3368).†

(f) Deferred Compensation Plan for Directors as amended and restated effective January 1, 2008. (Incorporated by reference to Exhibit 10(e) to Annual Report on Form 10-K for the year ended December 31, 2007).†

(g) The Empire District Electric Company Change in Control Severance Pay Plan as amended and restated effective January 1, 2008. (Incorporated by reference to Exhibit 10(f) to Annual Report on Form 10-K for the year ended December 31, 2007, File No. 1-3368).†

(h) Form of Severance Pay Agreement under The Empire District Electric Company Change in Control Severance Pay Plan. (Incorporated by reference to Exhibit 10(g) to Annual Report on Form 10-K for the year ended December 31, 2007, File No. 1-3368).†

(i) The Empire District Electric Company Supplemental Executive Retirement Plan as amended and restated effective January 1, 2008. (Incorporated by reference to Exhibit 10(h) to Annual Report on Form 10-K for the year ended December 31, 2007, File No. 1-3368).†

(j) Retirement Plan for Directors as amended August 1, 1998 (Incorporated by reference to Exhibit 10(a) to Form 10-Q for the quarter ended September 30, 1998, File No. 1-3368).†

(k) Stock Unit Plan for Directors of The Empire District Electric Company (Incorporated by reference to Exhibit 10(i) to Annual Report on Form 10-K for the year ended December 31, 2005, File No. 1-3368).†

(l) First Amendment to Stock Unit Plan for Directors. (Incorporated by reference to Exhibit 10(k) to Annual Report on Form 10-K for the year ended December 31, 2007, File No. 1-3368).†

(m) Summary of Annual Incentive Plan. (Incorporated by reference to Exhibit 10(l) to Annual Report on Form 10-K for the year ended December 31, 2007, File No. 1-3368).†

(n) Form of Notice of Award of Dividend Equivalents. (Incorporated by reference to Exhibit 10(n) to Annual Report on Form 10-K for the year ended December 31, 2008, File No. 1-3368)†

(o) Form of Notice of Award of Non-Qualified Stock Options. (Incorporated by reference to Exhibit 10(o) to Annual Report on Form 10-K for the year ended December 31, 2008, File No. 1-3368).†

(p) Form of Notice of Award of Performance-Based Restricted Stock. (Incorporated by reference to Exhibit 10(p) to Annual Report on Form 10-K for the year ended December 31, 2008, File No. 1-3368).†

(q) Form of Notice of Award of Time-Based Restricted Stock.*†

(r) Summary of Compensation of Non-Employee Directors. (Incorporated by reference to Exhibit 10(q) to Annual Report on Form 10-K for the year ended December 31, 2008, File No. 1-3368).†

(s) Form of Indemnity Agreement (Incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K dated February 5, 2009 and filed February 10, 2009, File No. 1-3368).†

(t) Second Amended and Restated Unsecured Credit Agreement dated as of January 26, 2010, among The Empire District Electric Company, UMB Bank, N.A. as administrative agent, Bank of America, N.A., as syndication agent, Wells Fargo Bank, N.A., as documentation agent, and the lenders named therein (Incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K dated January 26, 2010 and filed January 27, 2010, File No. 1-3368).

(u) Third Amended and Restated Unsecured Credit Agreement dated as of January 17, 2012, among The Empire District Electric Company, UMB Bank, N.A. as administrative agent, Bank of America, N.A., as syndication agent, Wells Fargo Bank, N.A., as documentation agent, and the lenders named therein (Incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K dated January 17, 2012 and filed January 19, 2012, File No. 1-3368).

(12) Computation of Ratios of Earnings to Fixed Charges.*

(21) Subsidiaries of Empire.*

(23) Consent of PricewaterhouseCoopers LLP.*

(24) Powers of Attorney.*

(31)(a) Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.*

(31)(b) Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.*

(32)(a) Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.*~

(32)(b) Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.*~

(101) The following financial information from The Empire District Electric Company's Annual Report on Form 10-K for the period ended December 31, 2011, filed with the SEC on February 23, 2012, formatted in Extensible Business Reporting Language (XBRL): (i) the Consolidated Statements of Income for 2011, 2010 and 2009, (ii) the Consolidated Balance Sheets at December 31, 2011 and December 31, 2010, (iii) the Consolidated Statements of Cash Flows for 2011, 2010 and 2009, and (iv) Notes to Consolidated Financial Statements.**

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† This exhibit is a compensatory plan or arrangement as contemplated by Item 15(a)(3) of Form 10-K.

* Filed herewith.

** Pursuant to Rule 406T of Regulation S-T, the XBRL related information in Exhibit 101 to this Annual Report on Form 10-K shall not be deemed to be filed by the Company for purposes of Section 18 or any other provision of the Exchange Act of 1934, as amended.

~ This certification accompanies this Report pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 and shall not be deemed filed by the Company for purposes of Section 18 or any other provision of the Securities Exchange Act of 1934, as amended.

SCHEDULE II

Valuation and Qualifying Accounts

Years ended December 31, 2011, 2010 and 2009:

	Balance At Beginning Of Period	Additions: Charged To Income	Additions: Charged to Other Accounts: Description	Additions: Charged to Other Accounts: Amount	Deductions From Reserve: Description	Deductions From Reserve: Amount	Balance At Close of Period
Year ended **December 31, 2011:**							
Reserve deducted from assets: accumulated provision for uncollectible accounts.	$ 865,236	$3,737,630	Recovery of amounts previously written off	$1,847,527	Accounts written off	$5,312,749	$1,137,644
Year ended **December 31, 2010**:							
Reserve deducted from assets: accumulated provision for uncollectible accounts.	$1,086,853	$3,607,066	Recovery of amounts previously written off	$ 833,113	Accounts written off	$4,661,796	$ 865,236
Year ended **December 31, 2009**:							
Reserve deducted from assets: accumulated provision for uncollectible accounts.	$1,265,421	$3,109,679	Recovery of amounts previously written off	$1,531,820	Accounts written off	$4,820,067	$1,086,853

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

THE EMPIRE DISTRICT ELECTRIC COMPANY

Date: February 23, 2012

By /s/ BRADLEY P. BEECHER

Bradley P. Beecher, President and
Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated.

Date: February 23, 2012

/s/ BRADLEY P. BEECHER

Bradley P. Beecher, President,
Chief Executive Officer, Director
(Principal Executive Officer)

/s/ LAURIE A. DELANO

Laurie A. Delano, Vice President-Finance
(Principal Financial Officer)

/s/ ROBERT W. SAGER

Robert W. Sager, Controller, Assistant
Secretary and Assistant Treasurer
(Principal Accounting Officer)

/s/ D. RANDY LANEY*

D. Randy Laney, Director

/s/ KENNETH R. ALLEN*

Kenneth R. Allen, Director

/s/ PAUL R. PORTNEY*

Paul R. Portney, Director

/s/ ROSS C. HARTLEY*

Ross C. Hartley, Director

/s/ HERBERT J. SCHMIDT*

Herbert J. Schmidt, Director

/s/ THOMAS OHLMACHER*

Thomas Ohlmacher, Director

/s/ B. THOMAS MUELLER*

B. Thomas Mueller, Director

/s/ C. JAMES SULLIVAN*

C. James Sullivan, Director

/s/ BONNIE C. LIND*

Bonnie C. Lind, Director

/s/ LAURIE A. DELANO

*By (Laurie A. Delano, as attorney in fact for
each of the persons indicated)

EXHIBIT (12)

Computation of Ratios of Earnings to Fixed Charges

	Year ended December 31,				
	2011	**2010**	**2009**	**2008**	**2007**
Income before provision for income taxes and fixed charges (Note A)	**$136,980,092**	$125,706,453	$114,457,760	$108,185,260	$91,690,922
Fixed Charges:					
Interest on long-term debt	**$ 42,580,987**	$ 41,958,541	$ 42,084,023	$ 36,040,957	$31,120,122
Interest on short-term debt	**86,406**	630,913	1,124,883	1,853,682	2,940,317
Interest on trust preferred securities	**—**	2,089,583	4,250,000	4,250,000	4,250,000
Other interest	**(1,147,472)**	(2,332,530)	(680,863)	1,152,588	1,069,206
Rental expense representative of an interest factor (Note B)	**6,190,709**	5,430,863	6,501,484	6,040,062	4,686,748
Total fixed charges	**$ 47,710,630**	$ 47,777,370	$ 53,279,527	$ 49,337,289	$44,066,393
Ratio of earnings to fixed charges	**2.87**	2.63	2.15	2.19	2.08

NOTE A: For the purpose of determining earnings in the calculation of the ratio, net income has been increased by the provision for income taxes, non-operating income taxes and by the sum of fixed charges as shown above.

NOTE B: One-third of rental expense (which approximates the interest factor).

EXHIBIT (31)(a)

CERTIFICATION OF CHIEF EXECUTIVE OFFICER PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Bradley P. Beecher, certify that:

1. I have reviewed this annual report on Form 10-K of The Empire District Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:

   a. designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 23, 2012

By: /s/ Bradley P. Beecher

Name: Bradley P. Beecher
Title: President and Chief Executive Officer

EXHIBIT (31)(b)

CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002

I, Laurie A. Delano, certify that:

1. I have reviewed this annual report on Form 10-K of The Empire District Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:

   a. designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 23, 2012

By: /s/ Laurie A. Delano

Name: Laurie A. Delano
Title: Vice President — Finance and Chief Financial Officer

EXHIBIT (32)(a)

Certification of Chief Executive Officer Pursuant to 18 U.S.C. Section 1350, As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 *

In connection with the Annual Report of The Empire District Electric Company (the "Company") on Form 10-K for the period ending December 31, 2011 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Bradley P. Beecher, as Chief Executive Officer of the Company, certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

By: /s/ Bradley P. Beecher

Name: Bradley P. Beecher
Title: President and Chief Executive Officer

Date: February 23, 2012

A signed original of this written statement required by Section 906 or other document authenticating, acknowledging or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to The Empire District Electric Company and will be retained by The Empire District Electric Company and furnished to the Securities and Exchange Commission or its staff upon request.

EXHIBIT (32)(b)

Certification of Chief Financial Officer Pursuant to 18 U.S.C. Section 1350,
As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 *

In connection with the Annual Report of The Empire District Electric Company (the "Company") on Form 10-K for the period ending December 31, 2011 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Laurie A. Delano, as Chief Financial Officer of the Company, certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

By: /s/ Laurie A. Delano

Name: Laurie A. Delano
Title: Vice President — Finance and Chief Financial Officer

Date: February 23, 2012

A signed original of this written statement required by Section 906 or other document authenticating, acknowledging or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to The Empire District Electric Company and will be retained by The Empire District Electric Company and furnished to the Securities and Exchange Commission or its staff upon request.

Annual Meeting
The annual meeting of shareholders will be held Thursday, April 26, 2012, at 10:30 a.m., CDT, at the Holiday Inn, 3615 South Range Line, Joplin, Missouri.

Company Headquarters
The Empire District Electric Company
602 S. Joplin Avenue
P.O. Box 127
Joplin, Missouri 64802-0127
Telephone (417) 625-5100

Independent Registered Public Accounting Firm
PricewaterhouseCoopers LLP
St. Louis, Missouri

Registrar, Transfer Agent, and Dividend Agent
Wells Fargo Bank, N.A.
Shareowner Services
P.O. Box 64854
St. Paul, Minnesota 55164-0854
(800) 468-9716 (toll free in the United States)
(651) 450-4144 (for the hearing impaired) (TDD)
(651) 450-4064 (outside the United States)
www.shareowneronline.com (for registered shareholders & general inquiries)

Stock Trading
As of December 31, 2011, there were 4,775 common shareholders of record. Empire common stock is listed on the New York Stock Exchange under the ticker symbol EDE.

Stock Prices and Dividends

2011	Quarter	High	Low	Dividend Paid
	First	$22.40	$20.70	$0.32
	Second	$23.26	$18.01	$0.32
	Third	$21.12	$18.10	$0.00
	Fourth	$21.40	$18.41	$0.00

2010	Quarter	High	Low	Dividend Paid
	First	$19.30	$17.75	$0.32
	Second	$20.00	$17.57	$0.32
	Third	$20.41	$18.41	$0.32
	Fourth	$22.50	$20.06	$0.32

Credit Ratings

	Standard & Poor's	Moody's	Fitch
Corporate Credit Rating	BBB-	Baa2	N/R*
First Mortgage Bonds	BBB+	A3	BBB+
Commercial Paper	A-3	P-2	F3
Senior Notes	BBB-	Baa2	BBB
Outlook	Stable	Stable	Stable

*Not Rated

Direct Registration
Empire is a participant in the Direct Registration System ("DRS"). This system allows us to issue shares to our registered shareholders in a book-entry form called Direct Registration. All transfers or issuances of shares will be issued in Direct Registration unless a stock certificate is specifically requested.

Dividend Reinvestment and Stock Purchase Plan
The Dividend Reinvestment and Stock Purchase Plan offers a variety of convenient, low-cost services for current shareholders. It is designed for long-term investors who wish to invest and build their share ownership over time. All registered holders of Empire common stock can participate in the Plan. If you are a beneficial owner of shares in a brokerage account and wish to reinvest your dividends, you can request that your shares become registered or make arrangements with your broker or nominee to participate on your behalf. The Plan offers a 3 percent discount on the purchase of shares with reinvested dividends. Optional features (applicable to registered holders only) include:

- Additional cash purchases, as often as weekly, with $50 minimum per transaction up to $125,000 per year;
- Automatic deduction from your bank account for additional cash purchases;
- Safekeeping of your certificates;
- Participation in the Plan with full, partial, or no reinvestment of dividends; and
- Sale of shares through the Plan.

The Plan Administrator may be contacted as follows to request a prospectus describing the Plan, an enrollment form, or to make an optional cash investment:

Wells Fargo Bank, N.A.
Shareowner Services
P.O. Box 64856
St. Paul, Minnesota 55164-0856
(800) 468-9716 (toll free in the United States)
(651) 450-4144 (for the hearing impaired) (TDD)
(651) 450-4064 (outside the United States)
www.shareowneronline.com (for registered shareholders & general inquiries)

Financial Report – Form 10-K
Copies of this report which includes the Annual Report on Form 10-K including financial statements, as filed with the Securities and Exchange Commission, are available without charge upon written request to Janet S. Watson, The Empire District Electric Company, P.O. Box 127, Joplin, Missouri 64802-0127. This report may also be accessed via our Web site, **www.empiredistrict.com**. This report is not intended to induce any securities' sale or purchase.

Sarbanes-Oxley Certifications
Empire filed the CEO and CFO certifications required by Section 302 of the Sarbanes-Oxley Act as exhibits to its Annual Report on Form 10-K for the year ended December 31, 2011.

Inquiries
Investor and shareholder inquiries can be directed to:

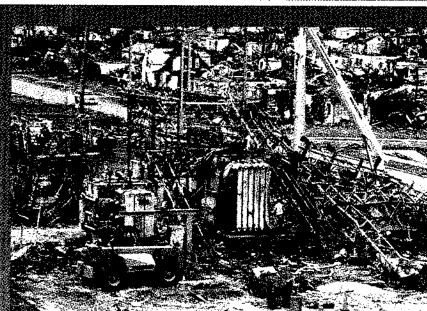
The Empire District Electric Company
Janet S. Watson, Secretary-Treasurer
P.O. Box 127
Joplin, Missouri 64802-0127
Telephone (417) 625-5108
investor.relations@empiredistrict.com

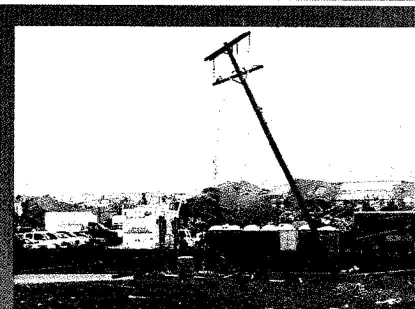
Internet
We invite you to learn more about our Company by connecting with us at: **www.empiredistrict.com**.

On the back cover: Walgreens, Empire's substation at 26th Street and Pearl Avenue, and Home Depot, following the May 22 tornado.

EMPIRE

SERVICES YOU COUNT ON





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