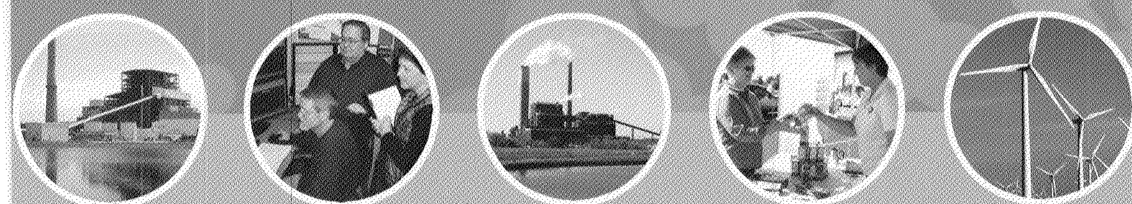
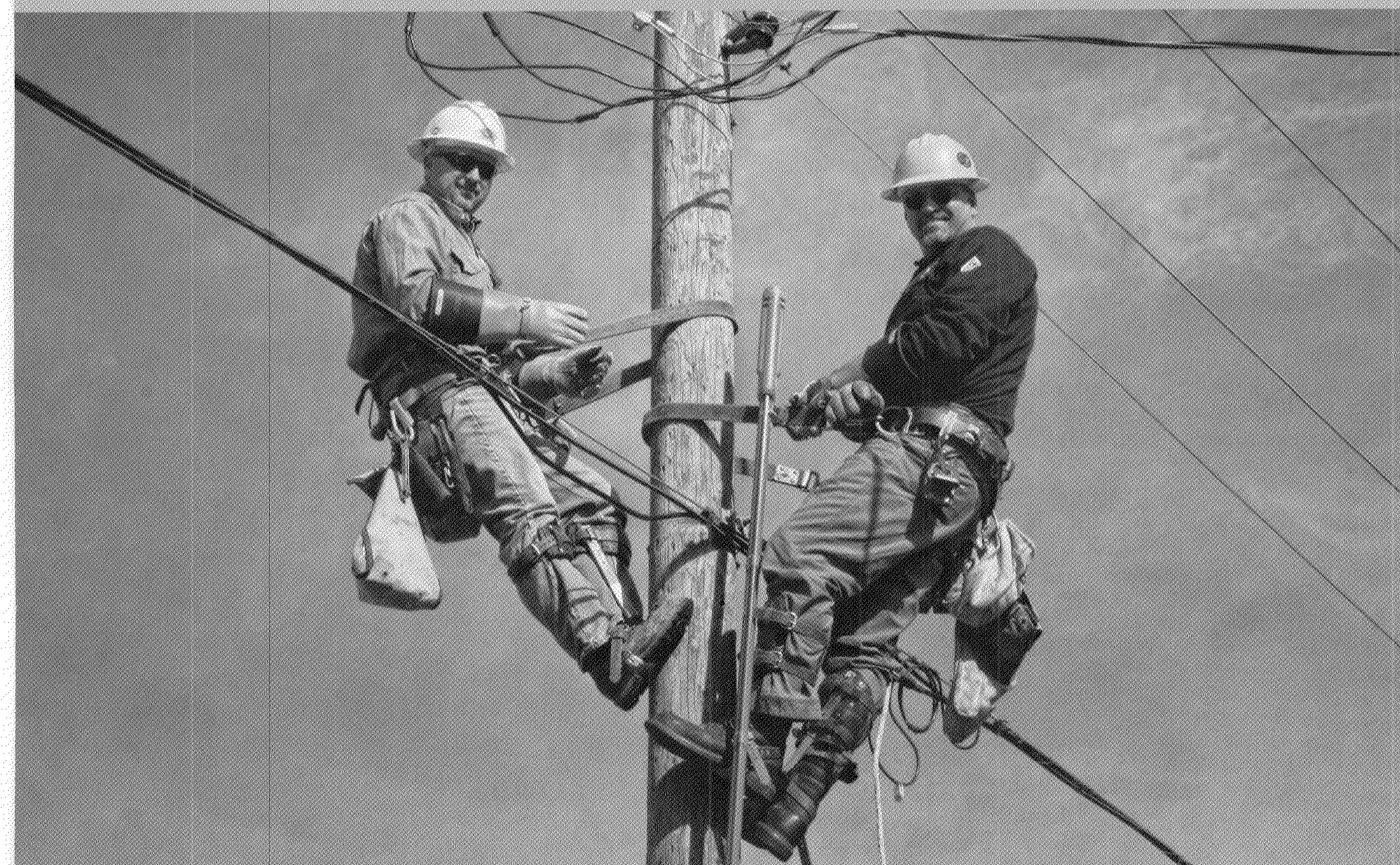
The Empire District Electric Company

2010 Annual Report





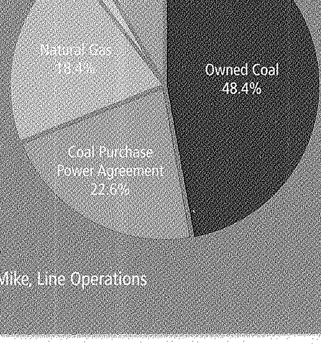
EMPIRE

SERVICES YOU COUNT ON

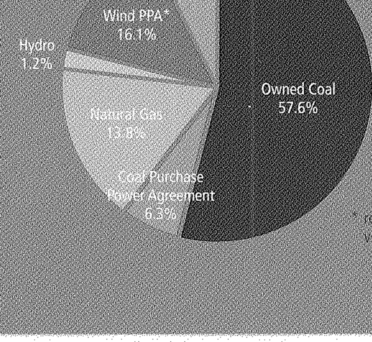
Financial *Highlights*

DECEMBER 31,	2010	2009	Percentage Change
Operating Revenues (000)	$541,276	$497,168	8.9%
Operating Income (000)	$80,495	$74,495	8.1%
Net Income (000)	$47,396	$41,296	14.8%
Earnings Per Weighted Average Common Share (Basic And Diluted)	$1.17	$1.18	-0.8%
Dividends Paid Per Share	$1.28	$1.28	0.0%
Return On Common Equity (End Of Period)	7.2%	6.9%	4.3%
Book Value Per Share Of Common Stock	$15.82	$15.75	0.4%
Common Shares Outstanding (Year End) (000)	41,577	38,112	9.1%
Weighted Average Common Shares Outstanding (Basic) (000)	40,545	34,924	16.1%
Capital Expenditures (Including AFUDC) (000)	$108,157	$148,804	-27.3%
Net Plant (000)	$1,519,089	$1,459,010	4.1%
On-System Electric Sales (MWh)	5,192,679	4,892,347	6.1%
On-System Gas Sales (000) (Mcf)	8,910	8,543	4.3%
Electric Customers (Year End)	169,047	168,706	0.2%
Gas Customers (Year End)	44,487	44,899	-0.9%
Owned System Capability (Net MW)	1,409	1,257	12.1%
System Electric Peak Demand (Net MW)	1,199	1,085	10.5%
System Gas Peak Demand (Mcf)	73,280	70,046	4.6%
Employees	750	730	2.7%

Net System Input Generation Mix (2004 Actual)
Prior to Current Construction Cycle



Net System Input Generation Mix (2011 Projected)
Following Current Construction Cycle



* renewable attributes may be sold via renewable energy credits

Cover Photo: Mike and Mike, Line Operations

Fellow Investors,

Five years ago, we embarked on a plan to add enough generation to replace an expiring long-term purchase power agreement that ended mid 2010 and provide for customer growth. The plan also provided for the upgrade of the environmental controls at two of our existing coal-fired plants.

This year we saw that plan come to fruition as the clean coal generating units at Plum Point Generating Station and Iatan 2 came online. It has been the largest construction cycle in the 100-year history of The Empire District Electric Company and has resulted in the nearly doubling of our investment in plant from $860 million in 2004 to $1.5 billion in 2010. For complete details on this plan, please read our summary on page 5.

During the five-year construction process, we raised capital to fund the projects by selling equity and issuing bonds. In order to recover the costs for this building project, we have implemented about $100 million in new annual rates and have filed for additional new annual rates of approximately $40 million.

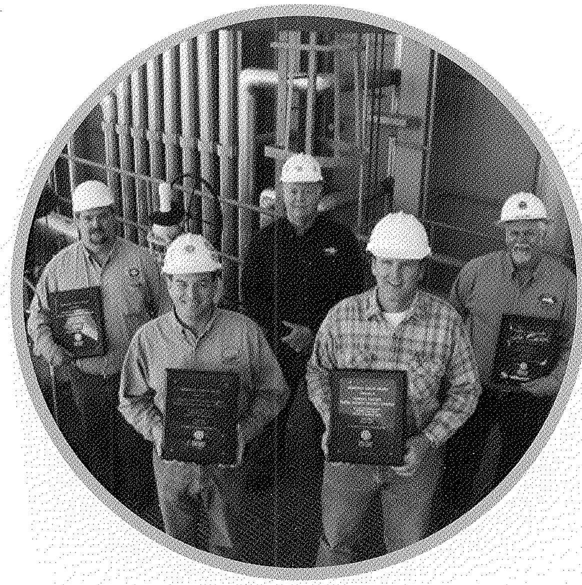
Our electric segment customer growth has slowed, but we have not seen any customer contraction. The unemployment rate for our service areas has remained lower than the national average. As 2010 came to a close, we began to see a recovery in our industrial kilowatt-hour and gas sales.

We continue to focus on providing a safe work environment and, during 2010, we reached significant safety milestones: State Line Combined Cycle and the Energy Center workgroups each achieved 600,000 work-hours lost-time injury free. Riverton and Asbury workgroups each reached 500,000 work-hours injury free. In an industry as challenging as ours, these records indicate our employees' commitment to safety.

On April 28, 2011, Bill Helton will retire from the board of directors having reached the board's mandatory retirement age. He has served on the board since 2004 and his vast experience in the utility industry has been a tremendous asset. We thank Bill for his counsel and service.

Tom Ohlmacher has been nominated to fill the vacancy and will stand for election at the Company's annual meeting of shareholders in April 2011. Also nominated to stand for election to the board in April is Brad Beecher, executive vice president. With his election, the size of the board will increase to eleven members.

Tom has been president and COO of Black Hills Corporation's Non-Regulated Energy Group since 2001. He began his employment with Black Hills Power in 1974. During his career, he has held positions as plant chemist, and in water management, and generation maintenance and management. As director of electric operations and



Safety remains a priority. Four energy supply workgroups reached significant milestones in 2010. State Line Combined Cycle and the Energy Center workgroups each achieved 600,000 work-hours without a lost time injury. Riverton and Asbury workgroups each reached 500,000 work-hours without a lost time injury. *Ray, Riverton Energy Supply; Richard, Asbury Energy Supply; Wayne, Safety; Dale, Energy Center Energy Supply; Stuart, State Line Combined Cycle Energy Supply.*

When the Quapaw Tribe of Oklahoma began to plan for their multi-million dollar casino and resort complex, they realized they needed to partner with a utility that was sizable enough to invest in the infrastructure necessary to bring electricity to their site and provide the reliable power they would need for their establishment. "It was important to have confidence in our electric carrier," explains Steven Drewes, general manager. "Empire District was the best choice."

Since opening in 2008, Downstream has welcomed over two million visitors annually and consistently has a 90 percent room occupancy rate in its 220-room hotel.

"Empire has been responsive in helping us meet the challenges of operating at peak efficiencies and to overcome a variety of obstacles that are to be expected in a 24/7 operation," says Drewes. "We are glad to be able to develop a solid partnership that will continue to grow."

Empire employees joined forces to complete a mission of clearing a lot of overgrown brush, neglected trees, weeds, and trash in preparation for Joplin Habitat for Humanity's 31st home. ***Empire volunteers along with volunteers from ACRT, Inc., Mid-Central Contractors, Wright Tree Service, and Habitat.***

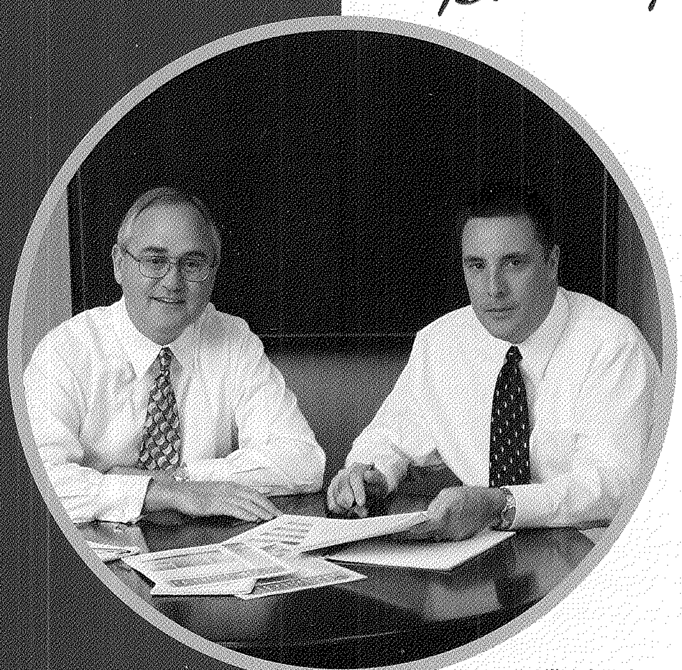
power resources, he managed transmission planning, environmental compliance, and development of energy marketing. As vice president of generation, beginning in 1995, in addition to his current role as president of Black Hills' Non-Regulated Holdings, Tom has been involved in the construction planning and commercial development of 1,700 megawatts of generation including natural gas-fired, coal-fired, and renewable power generation. Tom received a Bachelor of Science in Chemistry from South Dakota School of Mines and Technology in 1974.

Brad joined Empire in 1988 as a staff engineer at the Riverton Power Plant. He held various positions including director of production planning and administration and director of strategic planning. From August 1999 to February 2001, Brad worked for Black & Veatch, an engineering and construction firm in Kansas City. He returned to Empire in February 2001, was elected vice president – energy supply in April 2001, vice president and COO – electric in June 2006, executive vice president and COO – electric in February 2010, and executive vice president in February 2011. Brad graduated from Kansas State University with a Bachelor of Science degree in Chemical Engineering. He is a registered professional engineer in the State of Kansas.

On May 31, 2011, I will retire as president and CEO of Empire, but will stand for re-election to the board in April. On June 1, 2011, Brad will move into the role of president and CEO.

I have been fortunate to have a wonderful 30-year career with Empire and believe the Company is positioned for a great future. Brad leads a talented senior management team and a bright and capable workforce ready to take your Company to the next level.

Bill Gipson



Bill and Brad.

To Our Shareholders, Customers, and Employees,

As I prepare to lead your Company, I consider myself fortunate to have worked closely the past ten years with Bill Gipson. During that time, I have witnessed leadership at its finest.

Bill took the reins at Empire during one of the most exciting times in our Company's history. During Bill's tenure, we undertook a construction cycle so large in scale that it effectively doubled the asset size of the Company.

Bill set his focus on success and never waivered, no matter the challenge. Be it tight financial markets, multiple ice storms, unexpected equipment problems, or vastly fluctuating fuel prices, Bill simply led with a relentless will to succeed.

Finally, I personally thank Bill for being a great friend and mentor. We will miss having Bill in the office on a daily basis, but are pleased he will stand for re-election to the board of directors. We wish him the best in his retirement.

During the past several years, a major focus of your Company has been to provide customers an adequate, reliable source of power from a balanced mix of resources. We have also been working on ensuring reliability.

We have adopted a reliability initiative, dubbed "Operation Toughen Up," that targets $10 million per year for ten years, beginning in 2012, to improve and strengthen our delivery system. In connection with this, we continue to implement our aging workforce plan and have launched an in-house lineman training program to prepare the next generation of linemen.

We have filed an integrated resource plan with the Missouri Public Service Commission that puts us on a course to evaluate the environmental regulation impact on Asbury and possible mitigation strategies. It also addresses the possibility of converting Riverton Unit 12 to a combined cycle unit.

We are working to remain in compliance with standards established by the North American Electric Reliability Corporation regarding cyber security. We are also actively involved with the Southwest Power Pool to ensure adequate transmission resources are available and that the proper cost allocation is utilized to protect our customers.

In the gas operations area, we continue to ensure safe, reliable service as we work to grow that segment of your Company. To that end, we have continued with our gas line replacement program in the Brookfield, Missouri, community, and this year extended service to Camp Clark in the Nevada, Missouri, area.

An opportunity to expand the gas operation came this year. We extended service to 56 facilities at Camp Clark, Nevada, Missouri. Camp Clark is a Missouri Army National Guard Training Site. ***Deanna and Ron, Gas Operations.***

During this past year, work continued on our information technology disaster recovery site at The Mountain Complex in Branson, Missouri. All mission critical data is housed there to allow continuation of essential operations within a few hours should a disaster render the Joplin facility unworkable. Helping to make this possible are the diverse fiber optic paths provided to the complex by Empire's Fiber subsidiary. ***Aaron, Fiber, and Ivan, Information Technology.***

We will continue to evaluate and refine the key business strategies that guide us to ensure we remain focused on our goals to provide increasing value to our shareholders while effectively meeting our customers' expectations.

At its meeting in February, your Board put in motion changes to ensure a smooth transition in the senior management team. In addition to my election as president and CEO effective June 1, 2011, following Bill's retirement, the board also elected Kelly Walters, vice president and chief operating officer – electric, with continued responsibility for regulatory affairs; Mike Palmer, vice president – transmission policy and corporate services; and Martin Penning, vice president – commercial operations. These changes were made on February 4, 2011. The board also elected Blake Mertens, vice president – energy supply, effective May 1, 2011, to fill the vacancy created by Harold Colgin's retirement on April 30, 2011.

Your management team looks forward to the opportunities and challenges ahead of us at The Empire District Electric Company.

Brad Beecher

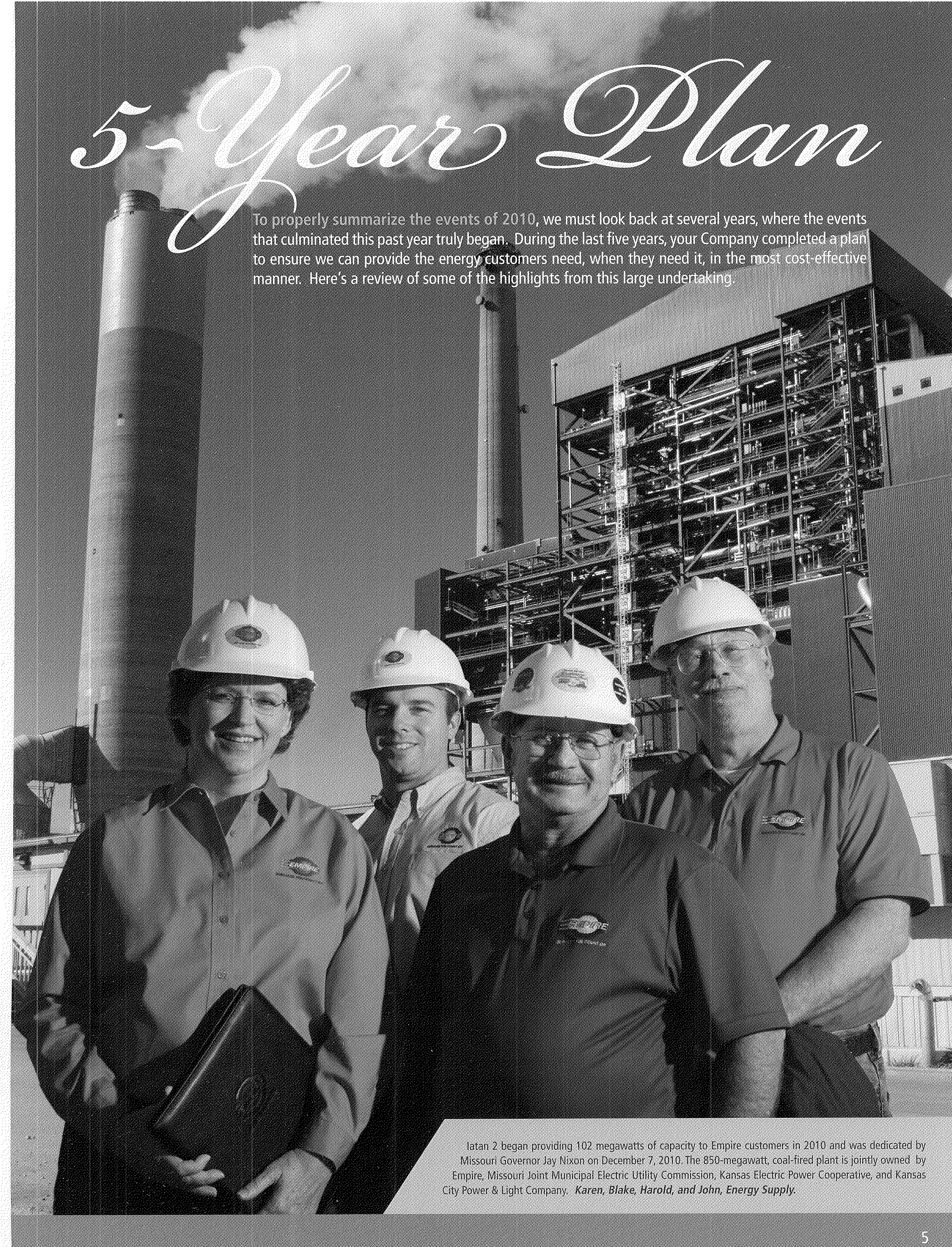
An additional portable substation, designed and engineered to fit Empire's specific needs, was acquired and readied for service this past year. Basically a complete substation on wheels, it can keep the lights on for customers during routine maintenance or an unexpected outage. ***David, Substation Maintenance, and Sam, Engineering and Line Services.***

Preparing the next generation of linemen to replace our aging workforce is the focus of our lineman training program. The program provides an opportunity to prepare linemen for the important career on which they are embarking by evaluating if the position is a good fit for the employee. ***Rick, Training Operations.***

New hybrid vehicles were added to the Empire fleet including this Ford Escape Hybrid that is used for mail delivery in the Joplin area. The Escape uses no fuel when stopped in traffic or at drive speeds below 44 mph thanks to the regenerative braking system that recharges the nickel-metal-hydride battery each time the brakes are applied. ***Nate, Building Services.***

5-Year Plan

To properly summarize the events of 2010, we must look back at several years, where the events that culminated this past year truly began. During the last five years, your Company completed a plan to ensure we can provide the energy customers need, when they need it, in the most cost-effective manner. Here's a review of some of the highlights from this large undertaking.



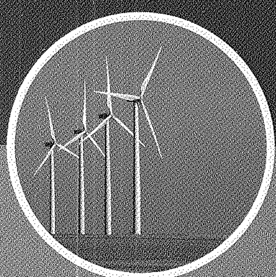
Iatan 2 began providing 102 megawatts of capacity to Empire customers in 2010 and was dedicated by Missouri Governor Jay Nixon on December 7, 2010. The 850-megawatt, coal-fired plant is jointly owned by Empire, Missouri Joint Municipal Electric Utility Commission, Kansas Electric Power Cooperative, and Kansas City Power & Light Company. ***Karen, Blake, Harold, and John, Energy Supply.***

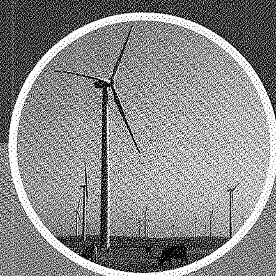
Charting Future Energy Course

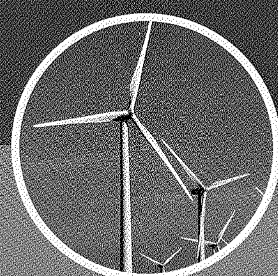
In 2004, we began to map out the next five years and decades beyond. Working with the staff of the Missouri Public Service Commission (MPSC), the Office of Public Counsel (Missouri's consumer advocate), the Missouri Department of Natural Resources, and representatives from industrial customers, we developed a blueprint to meet customers' future needs for electric power service. This included a replacement for a long-term energy purchase from another utility which was ending in 2010, new resources to meet customer growth, and environmental retrofits to make our coal plants cleaner.

In August 2005, we filed, and the MPSC approved, a five-year plan that stressed a balanced mix of least-cost resources. The plan included the construction of a unit at our Riverton plant, a jointly-owned coal-fired plant, Iatan 2, and upgrades to two existing coal-fired facilities, Iatan 1 and Asbury power plants, to meet new environmental regulations.

Earlier in 2005, we had announced the Riverton 12 addition, a 150-megawatt, gas-fired combustion turbine. Construction began in 2005 and the unit went into service in 2007, at a cost of about $39.5 million.







Rounding Out Resource Mix

Between 2004 and 2007, we secured two long-term contracts with wind-generation developers. The first purchases the output at the 150-megawatt Elk River Windfarm, and the second secures 105 megawatts from the Meridian Way Wind Farm. These projects provide price stability, reduce exposure to more cost-volatile natural gas, and provide diversity to our generation resource mix. We began our entry into the wind generation arena before any renewable mandates were enacted - it was the smart, economical choice.

Financing the Improvements

To finance these projects, we completed new common stock issuances of $66.8 million in 2006, $69 million in 2007, and $120 million from January 2009 through June 2010. We also issued first mortgage bonds in the amount of $80 million in 2007, $90 million in 2008, and $75 million in 2009.

This past year we issued 4.65% first mortgage bonds with a principal amount of $100 million. Proceeds were used to redeem Empire's 8½% trust preferred securities, and to repay short-term debt that was incurred, in part, to fund the repayment, at maturity, of Empire's 6½% first mortgage bonds due 2010.

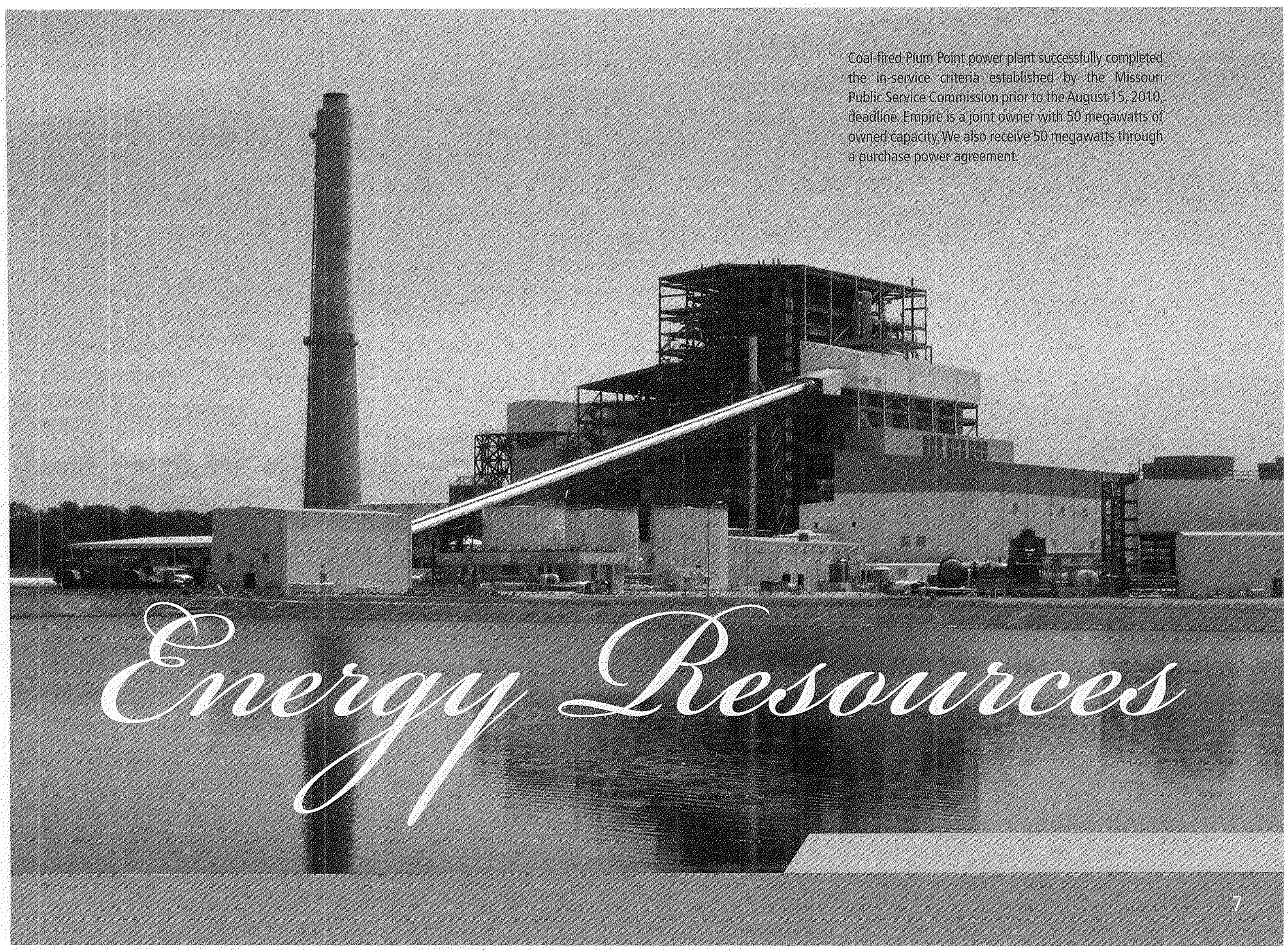
We also issued $50 million principal amount of 5.20% first mortgage bonds in 2010. Funds from this issuance were used to redeem Empire's Senior Notes, 7.05% series due 2022, and to repay short-term debt which was incurred, in part, to fund the construction program. This refinancing allowed us to reduce our annual interest costs by $3.8 million.

Building to Meet Customer Needs

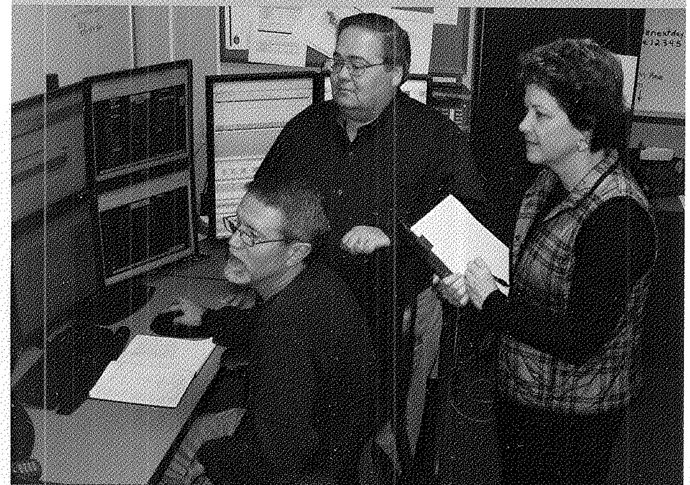
The building projects included in the plan and projections of future customer needs still found us short of base-load generation. To fill that void, in March 2006, we entered into an agreement with other utilities to construct a jointly-owned 665-megawatt, state-of-the-art, coal-fired facility, Plum Point Generating Station. We own 50 megawatts and also secured a 50-megawatt purchase power agreement from Plum Point that can be converted into an ownership position in 2015. Plum Point completed all in-service criteria in August, and was put into commercial operation on September 1, 2010. Empire's share of costs for this project through December 31, 2010, is approximately $86.9 million, excluding allowance for funds used during construction (AFUDC) which totaled $16.5 million.

As provided for in the plan approved by the MPSC, we entered into an agreement to be a co-owner of Iatan 2, a high efficiency, coal-fired power plant. To capitalize on efficiencies from an existing site, the plant is adjacent to Iatan 1 of which we own 12 percent. Our additional 12 percent share of Iatan 2 will provide Empire customers approximately 102 megawatts of capacity. Iatan 2 began commercial operation on December 31, 2010. Our share of the Iatan 2 project costs is expected to be in a range of $237 million to $240 million, excluding AFUDC. Our costs through December 31, 2010, are $228.9 million plus AFUDC of $19.1 million.

An important part of our plan is to ensure that our existing facilities continue to provide economical energy while meeting all environmental standards. This required the completion of upgrades at both the Asbury and Iatan 1 power plants. At Asbury, we installed a $31 million Selective Catalytic Reduction (SCR) system to reduce nitrous oxides. In 2009, a $59 million upgrade that included an SCR, flue gas desulphurization (controlling sulfur dioxides), and bag house (dust filtration system) was completed at Iatan 1.



Coal-fired Plum Point power plant successfully completed the in-service criteria established by the Missouri Public Service Commission prior to the August 15, 2010, deadline. Empire is a joint owner with 50 megawatts of owned capacity. We also receive 50 megawatts through a purchase power agreement.



Members of Supply Management and Fuel Accounting departments work to manage and track the fuel used to generate power. Empire now has fuel adjustment mechanisms in place in all jurisdictions. These mechanisms allow for more timely distribution of actual fuel and purchase power costs to our customers. ***Mike, Supply Management, Bob and Penny, Fuel Accounting.***

Reducing Usage Through Efficiency

To help temper the impact of the rate cases for our customers, we have introduced a number of initiatives to help customers manage their usage. These include rebates for high-efficiency air conditioners, a low-income weatherization program, and other rebate programs and services to help residential, commercial, and industrial customers in Missouri. Similar programs are available in other states served by Empire and can be accessed on our Web site at www.empiredistrict.com. We also have introduced improved, interactive energy calculators on our Web site for evaluating various efficiency improvements.

Through educational and bulb giveaway events in several communities, Empire continues to encourage customers to use compact fluorescent bulbs (CFLs). The events stressed benefits, wattage equivalents, bulb selection, use, and disposal of CFLs. This is just one of Empire's energy efficiency programs geared to help customers reduce their usage.

Energy efficiency programs are available to electric customers in all four states served by Empire and to customers in our gas operations territory. Programs include initiatives for residential, commercial, and industrial customers. Details are available on our Web site: www.empiredistrict.com/energysolutions.

Recovering Costs

Now that these new facilities are providing service, we are allowed to begin recovering their costs. In Missouri, we began this process with a rate case completed in July 2008, which started recovery of costs associated with Riverton 12 and the Asbury environmental upgrade. This case allowed an annual increase of $22 million.

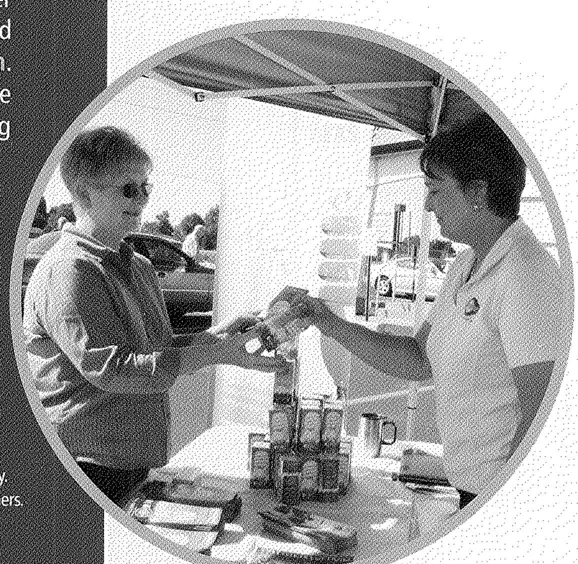
On September 10, 2010, rates took effect in Missouri to begin recovery of costs associated with the Iatan 1 environmental upgrades and Plum Point. This amounted to an annual increase of $46.8 million. We then filed a $36.5 million case on September 28, 2010, to recover the investment in Iatan 2. We expect this case to be complete in summer 2011.

In Kansas, we were granted a $2.8 million increase in July 2010 that covered the environmental upgrades and the capital costs from Plum Point and Iatan 2 through January 2010. The remainder of the capital costs and operation and maintenance expense associated with these facilities will be recovered in an abbreviated rate case that will be filed within the next year.

In Arkansas, we filed a rate case on August 19, 2010. On February 2, 2011, we filed a Stipulated Agreement to increase annual rates by $2.1 million. This will allow us recovery for expenses associated with the environmental upgrades at Iatan 1 and Asbury, and the new generating units, Riverton 12, Iatan 2, and Plum Point.

In Oklahoma, we have been granted a Capital Reliability Rider to collect an annual increase up to $2.6 million, subject to refund. This took effect in two phases. We will now be required to file a rate case within six months of the commercial operation date of Iatan 2, which was December 31, 2010, to make these increases permanent.

We have also filed with the Federal Energy Regulatory Commission for new rates for our wholesale customers.



Customer and Carol, Corporate Communications.

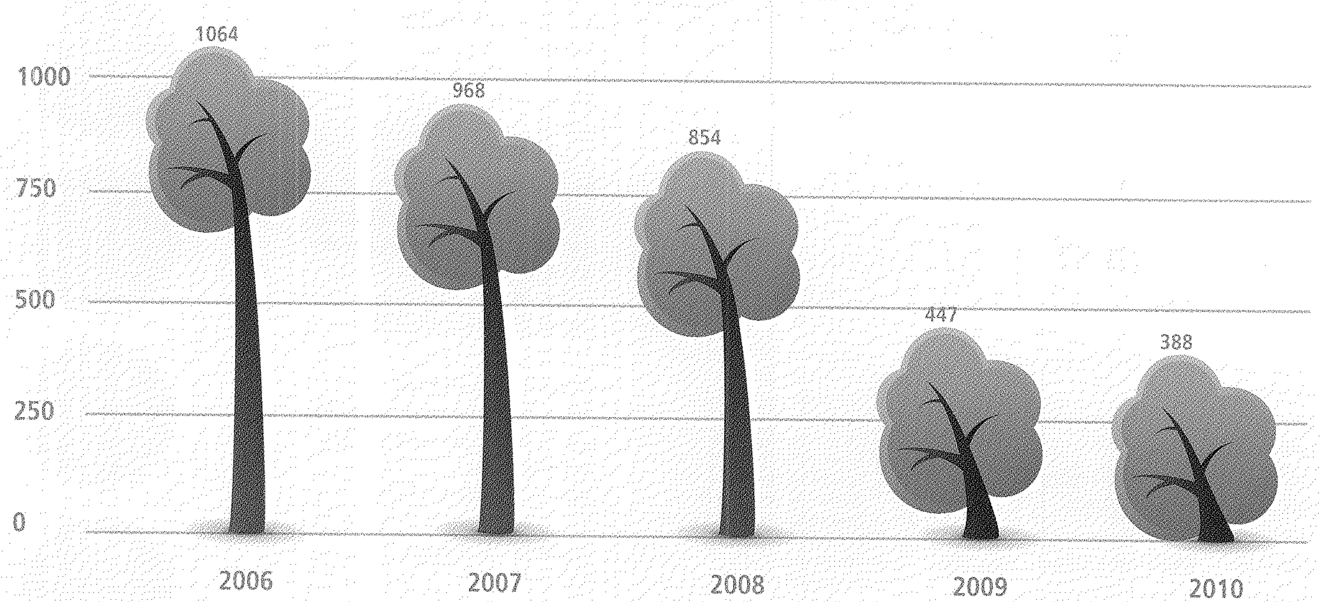
Ensuring Reliable Energy Future

To say that this has been the largest construction cycle in our 100-year history is an understatement; our plant investment has grown from about $860 million in 2004 to $1.5 billion at the end of 2010.

The course we have charted and completed will provide customers with reliable, environmentally responsible, cost-effective energy for many decades. It will provide shareholders the opportunity to earn a fair return on their investment.

As 2010 ended, we were pleased to look back and see the successful completion of our long-range plan. However, we can not rest. New opportunities and challenges lie ahead for us. But, as recent history has illustrated, our resolve will lead us to future success.

Outages Due to Vegetation in Primary Distribution Lines



Our enhanced tree trimming initiative is also helping to ensure reliability.
It is showing big results as the number of vegetation-caused outages has plummeted.

Officers[1]

William L. Gipson[3]
President and Chief Executive Officer
(Age 54, 29 years of service)

Bradley P. Beecher[4]
Executive Vice President
(Age 45, 21 years of service)

Harold R. Colgin[5]
Vice President – Energy Supply
(Age 61, 39 years of service)

Ronald F. Gatz
Vice President and Chief Operating Officer – Gas
(Age 60, 9 years of service)

Gregory A. Knapp
Vice President – Finance and Chief Financial Officer
(Age 59, 31 years of service)

Blake A. Mertens[6]
Vice President – Energy Supply
(Age 33, 9 years of service)

Michael E. Palmer[7]
Vice President – Transmission Policy and Corporate Services
(Age 54, 24 years of service)

Martin O. Penning
Vice President – Commercial Operations
(Age 56, 30 years of service)

Kelly S. Walters[8]
Vice President and Chief Operating Officer – Electric
(Age 45, 18 years of service)

Laurie A. Delano
Controller, Assistant Secretary and Assistant Treasurer
(Age 55, 20 years of service)

Janet S. Watson
Secretary – Treasurer
(Age 58, 16 years of service)

Committees of the Board

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

Strategic Projects Committee – Helton (Chair), Laney, Portney, Sullivan

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

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

Retirement Committee – Hartley, Lind (Chair), Mueller, Sullivan

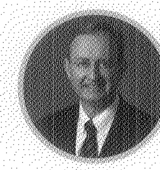
Executive Committee – Gipson (Chair), Helton, Mueller, Portney, Schmidt

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

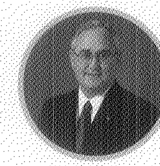
1 Ages shown as of March 1, 2011.
2 Audit Committee Financial Expert.
3 Retiring effective May 31, 2011. Will stand for re-election to the Board of Directors on April 28, 2011.
4 Will become President and Chief Executive Officer on June 1, 2011. Will stand for election to the Board of Directors on April 28, 2011.
5 Retiring effective April 30, 2011.
6 Effective May 1, 2011.
7 Previously, Vice President – Commercial Operations.
8 Previously, Vice President – Regulatory and Services.

Directors[1]

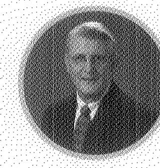
Kenneth R. Allen
Vice President – Finance and Chief Financial Officer
Texas Industries, Inc.
Dallas, Texas
(Age 53, Director since 2005)



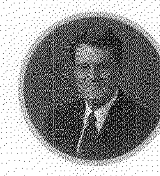
William L. Gipson
President and Chief Executive Officer
The Empire District Electric Company
(Age 54, Director since 2002)



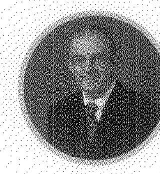
Ross C. Hartley
Co-Founder and Director
NIC, Inc.
Teton Village, Wyoming
(Age 63, Director since 1988)



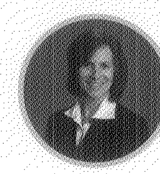
Bill D. Helton
Retired Chairman and Chief Executive Officer
New Century Energies
Amarillo, Texas
(Age 72, Director since 2004)



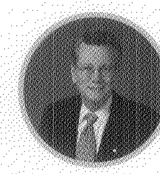
D. Randy Laney
Chairman of the Board of Directors
The Empire District Electric Company
Farmington, Arkansas
(Age 56, Director since 2003)



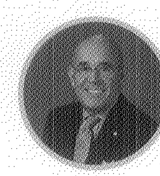
Bonnie C. Lind
Senior Vice President, Chief Financial Officer, and Treasurer
Neenah Paper, Inc.
Alpharetta, Georgia
(Age 52, Director since 2009)



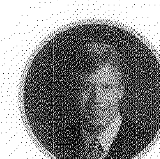
B. Thomas Mueller
Founder and President
SALOV North America Corporation
Montclair, New Jersey
(Age 63, Director since 2003)



Dr. Paul R. Portney
Professor of Economics and former Dean, Eller College of Management
University of Arizona
Tucson, Arizona
(Age 65, Director since 2009)



Herbert J. Schmidt
Executive Vice President Con-way Inc. and President Con-way Truckload
Joplin, Missouri
(Age 55, Director since 2010)



C. James Sullivan
Principal
The Sullivan Group LLC
Birmingham, Alabama
(Age 64, Director since 2010)

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, 2010

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 (State of Incorporation)	**44-0236370** (I.R.S. Employer Identification No.)
602 S. Joplin Avenue, Joplin, Missouri (Address of principal executive offices)	**64801** (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, 2010, was approximately $776,378,968.

As of February 4, 2011, 41,666,218 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 28, 2011	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, 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 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;
- 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;
- the costs and other impacts resulting from natural disasters, such as tornados and ice storms;
- matters such as the effect of changes in credit ratings on the availability and our cost of funds;
- costs and effects of legal and administrative proceedings, settlements, investigations and claims;
- interruptions or changes in our coal delivery, gas transportation or storage agreements or arrangements;
- our exposure to the credit risk of our hedging counterparties;
- operation of our electric generation facilities and electric and gas transmission and distribution systems, including the performance of our joint owners;
- 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 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;
- 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;
- competition, including the regional SPP energy imbalance market;
- electric utility restructuring, including ongoing federal activities and potential state activities;

- changes in accounting requirements, including the potential consequences of International Financial Reporting Standards being required for U.S. SEC registrants rather than U.S. GAAP;
- the performance of our pension assets and other post employment benefit plan assets and the resulting impact on our related funding commitments;
- 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 2010 were derived as follows:

Electric segment sales*	89.6%
Gas segment sales	9.4
Other segment sales	1.0

* 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. Of our total 2010 retail electric revenues, approximately 88.9% came from Missouri customers, 5.3% from Kansas customers, 3.0% from Oklahoma customers and 2.8% from Arkansas customers.

We supply electric service at retail to 120 incorporated communities as of December 31, 2010, 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 49% of our electric operating revenues in 2010 were derived from incorporated communities with franchises having at least ten years remaining and approximately 21% 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 2010 were derived as follows:

Residential	42.4%
Commercial	30.3
Industrial	14.4
Wholesale on-system	4.0
Wholesale off-system	4.7
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 2010 accounted for approximately 3% of electric revenues. No single retail customer accounted for more than 2% of electric revenues in 2010.

Our gas operations serve customers in northwest, north central and west central Missouri. We provide natural gas distribution to 44 communities and 314 transportation customers as of December 31, 2010. 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 2010 were derived as follows:

Residential	63.4%
Commercial	26.2
Industrial	1.6
Other	8.8

No single retail customer accounted for more than 3% of gas revenues in 2010.

Our other segment consists of our fiber optics business. As of December 31, 2010, we have 92 fiber customers.

Electric Generating Facilities and Capacity

At December 31, 2010, our generating plants consisted of:

Plant	*Capacity (megawatts)	Primary Fuel
Asbury	207	Coal
Riverton	286	Coal and Natural Gas
Iatan I (12% ownership)	85**	Coal
Iatan 2 (12% ownership)	102**	Coal
Plum Point Energy Station (7.52% ownership)	50**	Coal
State Line Combined Cycle (60% ownership)	300**	Natural Gas
Empire Energy Center	267	Natural Gas
State Line Unit No. 1	96	Natural Gas
Ozark Beach	16	Hydro
TOTAL	1,409	

* Based on summer rating conditions as utilized by Southwest Power Pool.

** 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 new 665-megawatt, coal-fired generating facility near Osceola, Arkansas which met its in-service criteria on August 13, 2010 and entered commercial operation on September 1, 2010. We own, through an undivided interest, 50 megawatts of the project's capacity. The estimated total cost is approximately $88.0 million, excluding allowance for funds used during construction (AFUDC), and our share of the Plum Point costs through December 31, 2010 was $86.9 million. In addition to the amounts noted above, we have recorded $16.5 million of AFUDC for the Plum Point construction since its inception. We also have a long-term (30 year) purchased power agreement for an additional 50 megawatts of capacity and have the option to purchase an undivided ownership interest in the 50 megawatts covered by the purchased power agreement in 2015.

We also purchased 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 met its in-service criteria on August 26, 2010 and entered commercial operation on December 31, 2010. Our share of the Iatan 2 construction costs is expected to be in a range of approximately $237 million to $240 million, excluding AFUDC. Our share of the Iatan 2 costs through December 31, 2010 was $228.9 million. Current projections estimate $11.1 million being spent in 2011 for our share of expected expenditures for Iatan 2. In addition to the amounts noted above, we recorded $19.1 million of AFUDC for the Iatan 2 construction since its inception.

We have a 20-year purchased power agreement which began on December 15, 2008 with Cloud County Windfarm, LLC, owned by 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 which commenced commercial operation on December 15, 2008. We also have a 20-year contract with Elk River Windfarm, LLC, owned by IBERDROLA RENEWABLES, Inc. (formerly known as PPM Energy), to purchase the energy generated at the 150-megawatt Elk River Windfarm located in Butler County, Kansas. The windfarm was declared commercial on December 15, 2005. 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."

Contract Year	Purchased Power Commitment*	Anticipated Owned Capacity	Total Megawatts
2010	106**	1409	1515
2011	65	1409	1474
2012	65	1409	1474
2013	65	1409	1474
2014	65	1409	1474

* Includes an estimated 7 megawatts for the Elk River Windfarm, LLC and 8 megawatts for the Cloud County Windfarm, LLC.

** The year 2010 included an additional 41 megawatts of purchased power capacity through a contract with Merrill Lynch to address the expected in-service delays of Plum Point and Iatan 2. The costs under that contract were immaterial.

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 1,173 megawatts was set on August 15, 2007. Our previous summer record peak of 1,159 megawatts was established on July 19, 2006.

Gas Facilities

At December 31, 2010, our principal gas utility properties consisted of approximately 87 miles of transmission mains and approximately 1,126 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, 2010, amounted to $440.6 million and retirements during the same period amounted to $39.8 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 $101.2 million in 2010 and for the next three years are estimated for planning purposes to be as follows:

	Estimated Capital Expenditures (amounts in millions)			
	2011	2012	2013	Total
New electric generating facilities:				
Iatan 2	$ 12.6	$ —	$ —	$ 12.6
Riverton Unit 12 combined cycle conversion	—	—	6.7	6.7
Additions to existing electric generating facilities:				
Asbury	1.6	3.7	6.2	11.5
Environmental upgrades — Asbury	3.6	38.9	76.7	119.2
Environmental upgrades — Iatan	3.3	—	—	3.3
Other	13.2	10.2	15.8	39.2
Electric transmission facilities	9.8	15.3	22.1	47.2
Electric distribution system additions	37.6	41.6	43.4	122.6
Non-regulated additions	1.5	1.5	1.5	4.5
General and other additions	19.5	12.4	14.2	46.1
Gas system additions	3.6	3.9	2.3	9.8
TOTAL	$106.3	$127.5	$188.9	$422.7

Construction expenditures for additions to our transmission and distribution systems to meet projected increases in customer demand and environmental upgrades at Asbury constitute the majority of the projected capital expenditures for the three-year period listed above.

Estimated capital expenditures are reviewed and adjusted for, among other things, revised estimates of future capacity needs, the cost of funds necessary for construction 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 2010, based on kilowatt-hours generated, was as follows:

Steam generation units	41.5%
Combustion turbine generation units	24.5
Hydro generation	1.4
Purchased power — windfarms	13.6
Purchased power — other	19.0

Approximately 62.3% of the total fuel requirements for our generating units in 2010 (based on kilowatt-hours generated) were supplied by coal and approximately 37.4% 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 2010 as compared to 2009 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 2010, Asbury burned a coal blend consisting of approximately 87.9% Western coal (Powder River Basin) and 12.1% blend coal on a tonnage basis. Our average coal inventory target at Asbury is approximately 60 days. As of December 31, 2010, we had sufficient coal on hand to supply anticipated requirements at Asbury for 56-70 days, as compared to 52-95 days as of December 31, 2009, depending on the actual blend ratio within this range.

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 2010, Riverton Units 7 and 8 burned an estimated blend of approximately 87.1% Western coal (Powder River Basin) and 12.9% petroleum coke on a tonnage basis. Our average coal inventory target at Riverton is approximately 60 days. Riverton Unit 7 requires a minimum amount of blend fuel to operate, while Riverton Unit 8 can burn 100% Western coal or a mix of Western and blend fuel. Based on these assumptions, we had sufficient coal as of December 31, 2010 to run 40 days on both units as compared to 36 days as of December 31, 2009.

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
2011	100%
2012	65%
2013	61%
2014	31%

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. The overall delivered price of coal is expected to be higher in 2011 than in 2010 as we incur the increased rail costs that went into effect in July of 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. 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 80% of Iatan's requirements for 2011 and approximately 40% for 2012, 35% for 2013, and 20% for 2014. 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 new 665-megawatt, coal-fired generating facility built by Plum Point Energy Associates (PPEA) near Osceola, Arkansas. We own, through an undivided interest, 50 megawatts of the project'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 83% of Plum Point's requirements for 2011 and approximately 84% for 2012, 82% for 2013 and 92% for 2014. During the third quarter of 2009, we entered into a 15 year lease agreement for 54 railcars for our ownership share of Plum Point, which began commercial operation on September 1, 2010. 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 2010, Energy Center generation was 98.6% natural gas with the remainder being fuel oil, and essentially all of the State Line Unit 1 generation came from natural gas. As of December 31, 2010, 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 signed 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	2010	2009	2008
Coal — Iatan	$ 1.193	$ 1.186	$ 1.070
Coal — Asbury	1.877	1.763	1.577
Coal — Riverton	1.833	1.768	1.724
Natural Gas	6.061	7.376	6.909
Oil	15.443	14.318	16.721
Weighted average cost of fuel burned per kilowatt-hour generated	2.9936	3.1698	3.1307

Gas Segment

In June 2007, we acquired 10,000 MMBtus per day of firm transportation from Cheyenne Plains Pipeline Company so that up to 75% of our natural gas purchases going forward could come 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 expanded our supplier base in 2008 and will continue to do so 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	2010	2009	2008
South	Southern Star Central Gas Pipeline	$6.7068	$7.8475	$8.9898
North	Panhandle Eastern Pipe Line Company	6.1151	7.4055	8.3207
Northwest	ANR Pipeline Company	5.3216	7.1160	8.0716
	Weighted average cost per mcf	$6.3745	$7.6395	$8.6964

Employees

At December 31, 2010, we had 750 full-time employees, including 52 employees of EDG. 338 of the EDE employees are members of Local 1474 of The International Brotherhood of Electrical Workers (IBEW). On May 9, 2007, the Local 1474 IBEW voted to ratify a new five-year agreement effective retroactively to November 1, 2006, the expiration date of the last contract. At December 31, 2010, 34 EDG employees were members of Local 1464 of the IBEW. In June 2009, Local 1464 of the IBEW ratified a new four-year agreement with EDG effective June 1, 2009.

ELECTRIC OPERATING STATISTICS[1]

	2010	2009	2008	2007	2006
Electric Operating Revenues (000's):					
Residential	**$ 204,900**	$ 180,404	$ 179,293	$ 174,584	$ 159,381
Commercial	**146,310**	135,800	132,888	129,035	115,059
Industrial	**69,684**	65,983	67,353	67,712	64,820
Public authorities[2]	**12,099**	11,411	10,876	9,933	8,892
Wholesale on-system	**19,254**	18,199	19,229	18,444	17,561
Miscellaneous[3]	**7,573**	6,814	6,976	5,703	4,605
Interdepartmental	**199**	178	154	123	101
Total system	**460,019**	418,789	416,769	405,534	370,419
Wholesale off-system	**22,891**	14,344	29,697	19,627	12,234
Total electric operating revenues[4]	**482,910**	433,133	446,466	425,161	382,653
Electricity generated and purchased (000's of kWh):					
Steam	**2,650,042**	2,259,304	2,228,716	2,074,323	2,589,360
Hydro	**88,104**	76,733	32,601	71,360	22,673
Combustion turbine	**1,566,074**	926,934	1,480,729	1,427,298	955,856
Total generated	**4,304,220**	3,262,971	3,742,046	3,572,981	3,567,889
Purchased	**2,085,550**	2,516,702	2,440,246	2,373,282	2,065,991
Total generated and purchased	**6,389,770**	5,779,673	6,182,292	5,946,263	5,633,880
Interchange (net)	**(1,716)**	(568)	(436)	(940)	(173)
Total system output	**6,388,054**	5,779,105	6,181,856	5,945,323	5,633,707
Transmission by others losses[5]	**(5,688)**	—	—	—	—
Total system input	**6,382,366**	5,779,105	6,181,856	5,945,323	5,633,707
Maximum hourly system demand (Kw)	**1,199,000**	1,085,000	1,152,000	1,173,000	1,159,000
Owned capacity (end of period) (Kw)	**1,409,000**	1,257,000	1,255,000	1,255,000	1,102,000
Annual load factor (%)	**53.17**	55.38	54.29	53.39	52.50
Electric sales (000's of kWh):					
Residential	**2,060,368**	1,866,473	1,952,869	1,930,493	1,898,846
Commercial	**1,644,917**	1,579,832	1,622,048	1,610,814	1,547,077
Industrial	**1,007,033**	992,165	1,073,250	1,110,328	1,145,490
Public authorities[2]	**124,554**	121,816	122,375	115,109	111,204
Wholesale on-system	**355,807**	332,061	344,525	342,347	337,658
Total system	**5,192,679**	4,892,347	5,115,067	5,109,091	5,040,275
Wholesale off-system	**798,084**	515,899	688,203	459,665	303,493
Total Electric Sales	**5,990,763**	5,408,246	5,803,270	5,568,756	5,343,768
Company use (000's of kWh)[6]	**9,598**	9,088	9,209	9,369	9,324
kWh losses (000's of kWh)	**382,005**	361,771	369,377	367,198	280,615
Total System Input	**6,382,366**	5,779,105	6,181,856	5,945,323	5,633,707
Customers (average number):					
Residential	**141,693**	141,206	140,791	139,840	137,689
Commercial	**24,505**	24,412	24,532	24,330	24,035
Industrial	**358**	355	361	362	370
Public authorities[2]	**2,003**	1,995	1,935	1,927	1,907
Wholesale on-system	**4**	4	4	4	4
Total System	**168,563**	167,972	167,623	166,463	164,005
Wholesale off-system	**22**	19	22	20	20
Total	**168,585**	167,991	167,645	166,483	164,025
Average annual sales per residential customer (kWh)	**14,541**	13,218	13,871	13,805	13,791
Average annual revenue per residential customer	**$ 1,446**	$ 1,278	$ 1,273	$ 1,248	$ 1,158
Average residential revenue per kWh	**9.94¢**	9.67¢	9.18¢	9.04¢	8.39¢
Average commercial revenue per kWh	**8.89¢**	8.60¢	8.19¢	8.01¢	7.44¢
Average industrial revenue per kWh	**6.92¢**	6.65¢	6.28¢	6.10¢	5.66¢

(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]

	2010	2009	2008	2007	2006[2]
Gas Operating Revenues (000's):					
Residential	**$32,245**	$36,176	$39,639	$39,205	$15,957
Commercial	**13,336**	15,552	17,416	16,588	7,127
Industrial	**812**	2,066	5,069	752	356
Public authorities	**342**	365	416	373	161
Total retail sales revenues	**46,735**	54,159	62,540	56,918	23,601
Miscellaneous[3]	**436**	221	231	206	93
Transportation revenues	**3,714**	2,934	2,667	2,753	1,451
Total Gas Operating Revenues	**50,885**	57,314	65,438	59,877	25,145
Maximum Daily Flow (mcf)	**73,280**	70,046	66,005	68,379	60,890
Gas delivered to customers (000's of mcf sales)[4]					
Residential	**2,675**	2,687	2,949	2,835	1,101
Commercial	**1,265**	1,278	1,397	1,304	559
Industrial	**108**	218	553	76	32
Public authorities	**33**	30	35	30	12
Total retail sales	**4,081**	4,213	4,934	4,245	1,704
Transportation sales	**4,829**	4,330	4,059	4,300	2,150
Total gas operating and transportation sales	**8,910**	8,543	8,993	8,545	3,854
Company use[4]	**4**	3	4	2	—
Transportation sales (cash outs)	**—**	—	—	56	56
Mcf losses	**70**	36	140	8	(70)
Total system sales	**8,984**	8,582	9,137	8,611	3,840
Customers (average number):					
Residential	**38,277**	38,621	39,159	40,315	40,673
Commercial	**4,968**	5,038	5,119	5,208	5,399
Industrial	**26**	25	26	24	26
Public authorities	**137**	131	127	124	128
Total retail customers	**43,408**	43,815	44,431	45,671	46,226
Transportation customers	**313**	296	272	270	252
Total gas customers	**43,721**	44,111	44,703	45,941	46,478

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

(2) 2006 revenues and mcf sales represent the months of June through December 2006.

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

(4) 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, 2010, positions held during the past five years and effective date 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 12/31/10	Positions With the Company	With the Company Since	Officer Since
William L. Gipson(1)	53	President and Chief Executive Officer (2002)	1981	1997
Bradley P. Beecher(2)	45	Executive Vice President (2011), Executive Vice President and Chief Operating Officer — Electric (2010), Vice President and Chief Operating Officer — Electric (2006)	2001	2001
Harold Colgin(3)	61	Vice President — Energy Supply (2006), General Manager — Energy Supply (2006)	1972	2006
Ronald F. Gatz	60	Vice President and Chief Operating Officer — Gas (2006)	2001	2001
Gregory A. Knapp	59	Vice President — Finance and Chief Financial Officer (2002)	2002	2002
Michael E. Palmer(4)	54	Vice President — Transmission Policy and Corporate Services (2011), Vice President — Commercial Operations (2001)	1986	2001
Kelly S. Walters(5)	45	Vice President and Chief Operating Officer — Electric (2011), Vice President — Regulatory and Services (2006)	2001	2006
Blake Mertens(6)	33	Vice President — Energy Supply (2011), General Manager — Energy Supply (2010), Director of Strategic Projects, Safety and Environmental Services (2010), Assistant Director of Strategic Projects (2009), Manager of Strategic Projects (2006)	2001	2011
Martin O. Penning(7)	55	Vice President — Commercial Operations, (2011), Director of Commercial Operations (2006)	1980	2011
Janet S. Watson	58	Secretary — Treasurer (1995)	1994	1995
Laurie A. Delano	55	Controller, Assistant Secretary and Assistant Treasurer and Principal Accounting Officer (2005)	2002	2005

(1) William L. Gipson will retire from his position as President and Chief Executive Officer effective May 31, 2011.

(2) Bradley P. Beecher will become President and Chief Executive Officer effective June 1, 2011. Effective February 4, 2011, Mr. Beecher has been elected executive vice president.

(3) Harold Colgin will retire from his position as Vice President — Energy Supply effective April 30, 2011.

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

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

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

(7) Martin Penning was elected Vice President — Commercial Operations effective February 4, 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 2010, approximately 89.7% of our electric operating revenues was received from retail customers. Sales subject to FERC jurisdiction represented approximately 9.1% of our electric operating revenues during 2010 with the remaining 1.2% being from miscellaneous sources. The percentage of retail revenues derived from each state follows:

Missouri	88.9%
Kansas	5.3
Oklahoma	3.0
Arkansas	2.8

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 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, 2010, would permit us to issue approximately $362.3 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, 2010, we had retired bonds and net property additions which would enable the issuance of at least $634.0 million principal amount of bonds if the annual interest requirements are met. As of December 31, 2010, we believe 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, 2010, this test would allow us to issue approximately $8.3 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.

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	F2	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 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.

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 higher-cost 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.

With the addition of the Missouri fuel adjustment mechanism effective September 1, 2008, we now have a fuel cost recovery mechanism in all of our jurisdictions, which significantly reduces our net income exposure to the impact of the risks discussed above. 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 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.

We have implemented training, preventive maintenance and other programs, but there is no assurance that these programs will prevent or minimize future breakdowns, outages or failures of our generation facilities. 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.

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.

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 $106.3 million in 2011. 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. Market conditions have positively impacted the return on our pension plan and Other Postretirement Benefits (OPEB) assets. However, our costs also increased, resulting in a $0.7 million increase in our 2009 net pension and OPEB liability. During 2010, our net pension and OPEB liability increased $8.8 million. We expect to fund approximately $23.1 million in 2011 for pension and OPEB liabilities. Future market declines could result in increased pension and OPEB liabilities and funding obligations.

The cost and schedule of construction projects may materially change.

Our capital expenditure budget for the next three years is estimated to be $422.6 million, This includes expenditures for new generating facilities, additions 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.

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) and 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.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Electric Segment Facilities

At December 31, 2010, we owned generating facilities with an aggregate generating capacity of 1,409 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 2010 accounted for approximately 29.4% of the energy generated by us. Routine plant maintenance, during which the entire plant is taken out of service, is scheduled once each year, normally for approximately four weeks in the spring. Approximately every fifth year, the maintenance outage is scheduled to be extended to a total of six weeks to permit inspection of the Unit No. 1 turbine. The last such outage took place in the fall of 2007. The Unit No. 2 turbine is inspected approximately every 35,000 hours of operations and was last inspected in 2001. As of December 31, 2010, Unit No. 2 has operated approximately 3,300 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 194 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 with a summer rated capacity of 150 megawatts. 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. A new air permit was issued for the Iatan Generating Station on January 31, 2006. The new permit covers the entire Iatan Generating Station and includes both Unit No. 1 and Unit No. 2. Iatan 1 was on maintenance outage from the third quarter of 2008 until the second quarter of 2009 for activities ranging from a turbine upgrade and generator rewind to the tie-in of the new air quality control systems. 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 met its in-service criteria on August 13, 2010 and 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 96 megawatts and a Combined Cycle Unit with generating capacity of 500 megawatts of which we are entitled to 60%, or 300 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 stipulations. 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 267 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 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. The $26.6 million payment will have no material impact on net income as we expect the benefits will flow through to our customers. In addition, the SWPA has delayed the implementation of the new minimum flows until 2016.

At December 31, 2010, 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 6,923 miles of line.

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, 2010, our principal gas utility properties consisted of approximately 87 miles of transmission mains and approximately 1,126 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.

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 4, 2011, there were 4,939 record holders and 34,172 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 2010 and 2009 were as follows:

	Price of Common Stock				Dividends Paid Per Share	
	2010		2009			
	High	Low	High	Low	2010	2009
First Quarter	$19.30	$17.75	$18.51	$11.92	$0.32	$0.32
Second Quarter	20.00	17.57	16.66	14.19	0.32	0.32
Third Quarter	20.41	18.41	19.00	16.44	0.32	0.32
Fourth Quarter	22.50	20.06	19.36	17.78	0.32	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. As of December 31, 2010, our retained earnings balance was $5.5 million (compared to $10.1 million at December 31, 2009) after paying out $52.0 million in dividends during 2010. A reduction of our dividend per share, partially or in whole, could have an adverse effect on our common stock price. On February 3, 2011, the Board of Directors declared a quarterly dividend of $0.32 per share on common stock payable March 15, 2011 to holders of record as of March 1, 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 March 11, 2008, we amended the EDE Mortgage in order to provide us with more flexibility to pay dividends to our shareholders by increasing the basket available to pay dividends by

$10.75 million, as described above. As of December 31, 2010, this restriction did not prevent us from issuing dividends.

During 2010, no purchases of our common stock were made by or on behalf of us.

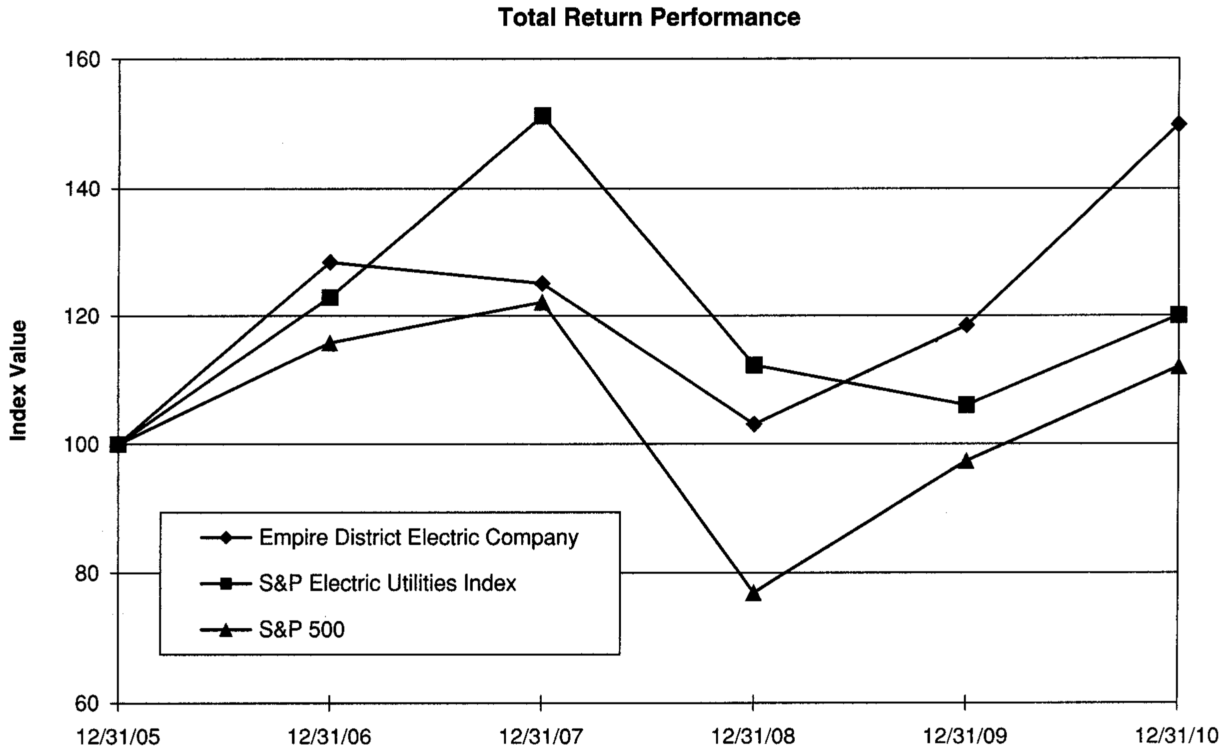
Participants in our Dividend Reinvestment and Stock Purchase Plan may acquire, at a 3% discount, newly issued common shares with reinvested dividends. Participants may also purchase, at an averaged market price, newly issued common shares with optional cash payments on a weekly basis, subject to certain 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, 2005, 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	12/31/2005	12/31/2006	12/31/2007	12/31/2008	12/31/2009	12/31/2010
The Empire District Electric Company	**$100.00**	**$128.47**	**$125.10**	**$103.05**	**$118.46**	**$149.96**
S&P Electric Utilities Index	**$100.00**	**$122.92**	**$151.35**	**$112.24**	**$106.03**	**$120.02**
S&P 500 Index	**$100.00**	**$115.79**	**$122.16**	**$ 76.96**	**$ 97.33**	**$111.99**

ITEM 6. SELECTED FINANCIAL DATA

(in thousands, except per share amounts)[(1)]

	2010	2009	2008	2007	2006[(2)]
Operating revenues	**$ 541,276**	$ 497,168	$ 518,163	$ 490,160	$ 412,171
Operating income	**$ 80,495**	$ 74,495	$ 71,012	$ 65,566	$ 69,821
Total allowance for funds used during construction	**$ 10,174**	$ 14,133	$ 12,518	$ 7,665	$ 4,255
Income from continuing operations	**$ 47,396**	$ 41,296	$ 39,722	$ 33,181	$ 40,029
Income (loss) from discontinued operations, net of tax	**$ —**	$ —	$ —	$ 63	$ (749)
Net income	**$ 47,396**	$ 41,296	$ 39,722	$ 33,244	$ 39,280
Weighted average number of common shares outstanding — basic	**40,545**	34,924	33,821	30,587	28,277
Weighted average number of common shares outstanding — diluted	**40,580**	34,956	33,860	30,610	28,296
Earnings from continuing operations per weighted average share of common stock — basic and diluted	**$ 1.17**	$ 1.18	$ 1.17	$ 1.09	$ 1.42
Loss from discontinued operations per weighted average share of common stock — basic and diluted	**$ —**	$ —	$ —	$ 0.00	$ (0.03)
Total earnings per weighted average share of common stock — basic and diluted	**$ 1.17**	$ 1.18	$ 1.17	$ 1.09	$ 1.39
Cash dividends per share	**$ 1.28**	$ 1.28	$ 1.28	$ 1.28	$ 1.28
Common dividends paid as a percentage of net income	**109.7%**	108.5%	109.0%	117.2%	91.8%
Allowance for funds used during construction as a percentage of net income	**21.5%**	34.2%	31.5%	23.1%	10.8%
Book value per common share (actual) outstanding at end of year	**$ 15.82**	$ 15.75	$ 15.56	$ 16.04	$ 15.49
Capitalization:					
Common equity	**$ 657,624**	$ 600,150	$ 528,872	$ 539,176	$ 468,609
Long-term debt	**$ 693,072**	$ 640,156	$ 611,567	$ 541,880	$ 462,398
Ratio of earnings to fixed charges	**2.63x**	2.15x	2.19x	2.08x	2.60x
Total assets	**$1,921,311**	$1,839,846	$1,713,846	$1,473,074	$1,319,142
Plant in service at original cost	**$2,108,115**	$1,718,584	$1,586,152	$1,506,234	$1,380,431
Capital expenditures (including AFUDC)[(3)]	**$ 108,157**	$ 148,804	$ 206,405	$ 195,568	$ 120,171

(1) 2006 has been adjusted to show continuing operations, reflecting the sale of MAPP and Conversant in 2006 and Fast Freedom in 2007.

(2) Includes EDG data for the months of June through December 2006.

(3) 2006 capital expenditures do not include $103.2 million for the acquisition of the Missouri Gas operations.

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, 2010, our gross operating revenues were derived as follows:

Electric segment sales*	89.6%
Gas segment sales	9.4
Other segment sales	1.0

* 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. 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. We expect our annual electric customer growth to range from approximately 0.85% to 1.35% over the next several years. Our electric customer growth for the year ended December 31, 2010 was 0.2%. 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) 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. In our 2007 rate case, the Missouri Public Service Commission (MPSC) authorized a fuel adjustment clause for our Missouri customers effective September 1, 2008. The MPSC established a base rate 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. With the addition of the Missouri fuel adjustment mechanism, 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 gas segment customer contraction for the year ended December 31, 2010 was 0.9%, which we believe was due to depressed economic conditions. The rate of gas customer contraction is expected to level out during the next two years and begin modest growth after 2012. 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, 2010, basic and diluted earnings per weighted average share of common stock were $1.17 on $47.4 million of net income compared to $1.18 on $41.3 million of net income for the year ended December 31, 2009. The primary positive drivers for 2010 as compared to 2009 were increased electric revenues (resulting from rate increases and increased demand in 2010 due to favorable weather) and decreased interest charges. The primary negative drivers for 2010 as compared to 2009 were increased electric operations and maintenance expenses, increased depreciation and amortization, the dilutive effect of additional shares of common stock issued (mainly due to our equity distribution program), changes in AFUDC amounts and the changes in effective tax rates, including the two non-cash charges in the first quarter of 2010 discussed below.

The table below sets forth a reconciliation of basic and diluted earnings per share between 2009 and 2010, 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. Similar tables presented in our 2010 Form 10-Q filings also reflected the estimated impact of all shares issued during the applicable periods, but split the impact into two line items, "dilutive effect of additional shares issued" (which reflected shares issued pursuant to the equity distribution program completed in June 2010) and "other income and deductions" (which reflected all other shares issued during the applicable periods).

Earnings Per Share — 2009	**$ 1.18**
Revenues	
Electric on-system	$ 0.78
Electric off-system and other	0.18
Gas	(0.12)
Other	0.01
Expenses	
Electric fuel and purchased power	(0.33)
Cost of natural gas sold and transported	0.17
Regulated — electric segment	(0.14)
Regulated — gas segment	0.02
Maintenance and repairs	(0.07)
Depreciation and amortization	(0.14)
Other taxes	(0.03)
Interest charges	0.08
AFUDC	(0.07)
Change in effective income tax rates	(0.15)
Dilutive effect of additional shares issued	(0.19)
Other income and deductions	(0.01)
Earnings Per Share — 2010	**$ 1.17**

Fourth Quarter Results

Earnings for the fourth quarter of 2010 were \$8.5 million, or \$0.20 per share, as compared to \$7.9 million, or \$0.22 per share, in the fourth quarter 2009. Total revenues increased approximately \$11.9 million (9.9%) for the fourth quarter of 2010 as compared to the fourth quarter of 2009 primarily due to increased sales and rate increases in 2010. Partially offsetting the increase in revenues were increases in operations and maintenance expenses and depreciation and amortization.

2010 Activities

New Construction

On March 14, 2006, we entered into contracts to purchase a 50 megawatt, 7.52% undivided interest in the Plum Point Energy Station. The Plum Point Energy Station met its in-service criteria on August 13, 2010 and entered commercial operation on September 1, 2010. We also have a long-term (30 year) purchased power agreement for an additional 50 megawatts of capacity and have the option to purchase an undivided ownership interest in the 50 megawatts covered by the purchased power agreement in 2015.

On June 13, 2006, we announced we had entered into an agreement with Kansas City Power & Light (KCP&L) to purchase an undivided ownership interest in the coal-fired Iatan 2 generating facility. We own 12%, or approximately 102 megawatts, of the 850-megawatt unit. KCP&L reported that Iatan 2 met its in-service criteria on August 26, 2010. Iatan 2 entered commercial operation on December 31, 2010.

Regulatory Matters

We filed several rate cases primarily to recover the costs of the completed plants described above. These are described below.

A stipulated agreement in our 2009 Missouri electric rate case 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. The Plum Point Generating Station completed its in-service criteria testing on August 12, 2010, with an in-service date of August 13, 2010, and the new rates were effective September 10, 2010.

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 the recently completed Missouri rate case. KCP&L reported that Iatan 2 met its in-service criteria on August 26, 2010.

A stipulated agreement in our current Kansas rate case 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.

On August 30, 2010, we were granted a two-phase Capital Reliability Rider (CRR) by the Oklahoma Corporation Commission (OCC) with the first phase effective September 1, 2010. 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 brings the total annual revenue under the OCC to approximately $2.5 million. We will file a general rate case within six months of the commercial operation date of Iatan 2 (which was December 31, 2010) to replace the CRR with permanent rates.

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 includes a general rate increase of $2.1 million, or 19%. The settlement calls 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. A hearing on the settlement has been scheduled for March 8, 2011 at the APSC.

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 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 are now working to finalize the terms of the settlement.

In December 2008, the Office of the Public Counsel (OPC) and intervenors Praxair, Inc. and Explorer Pipeline Company filed Petitions for Writ of Review with the Cole County Circuit Court challenging the tariffs resulting from our 2006 Missouri rate case that went into effect January 1, 2007. The Cole County Circuit Court issued a ruling on December 8, 2009, affirming the Commission's Report and Order. OPC, Praxair and Explorer Pipeline filed appeals with the Western District Court of Appeals. On October 26, 2010, the Western District Court of Appeals affirmed the Commission's Report and Order. Praxair, Inc. and Explorer Pipeline Company filed with the Western District Court of Appeals a Motion for Rehearing and an Application for Transfer to the Supreme Court. On December 7, 2010, the Western District Court of Appeals overruled the Motion for Rehearing and denied the Application for Transfer to the Supreme Court. Praxair, Inc. then asked the Missouri Supreme Court to transfer the case to that court. On January 25, 2011, the request was denied.

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%. On February 24, 2010, the MPSC unanimously approved an agreement among the 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.

For additional information, see "Rate Matters" below.

Iatan 2 Coal Investment Tax Credits

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 the 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 will utilize these credits to reduce our 2010 tax payments and 2010 tax liability. 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. See Note 9 of "Notes to Consolidated Financial Statements" under Item 8.

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 plan to use proceeds under this shelf to fund capital expenditures, refinancings of existing debt or general corporate needs when needed during the effective period. The issuance of securities under this shelf is subject to the receipt of local regulatory approvals.

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.

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 current 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.

Ozark Beach Plant

On September 16, 2010, we received a $26.6 million payment from the Southwest Power Administration (SWPA) to reimburse us for the estimated future lifetime replacement cost of the electrical energy and capacity lost due to the White River Minimum Flows project at Ozark Beach. The $26.6 million payment will have no material impact on net income as we expect the benefits will flow through to our customers. In addition, the SWPA has delayed the implementation of the new minimum flows until 2016. See Item 2, "Properties — Electric Segment Facilities" for additional information.

Healthcare Reform Act — Medicare Part D benefits

On March 23, 2010, the Patient Protection and Affordable Care Act was enacted. This legislation includes a provision that reduces 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 reflect the impact of this change. Our 2010 effective tax rate also increased due to the additional tax expense associated with the changes in the Medicare Part D tax benefit. See Note 9 of "Notes to Consolidated Financial Statements."

Renewable Energy

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, 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 exempt from the solar requirement. A challenge to our exemption brought by two of our customers and Power Source Solar, Inc. is pending in the Missouri Western District Court of Appeals. In July 2010, the MPSC submitted to the Missouri Secretary of State's office its rule for the renewable energy mandate. We are awaiting action from the Missouri Secretary of State but believe we are in compliance with the law. Kansas established a renewable portfolio standard (RPS) in May 2009 which was approved October 27, 2010, effective November 19, 2010. Its final rulemaking was released in November 2010 which calls for 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.

Shareholder Rights Plan

Our shareholder rights plan, dated as of July 26, 2000, expired July 25, 2010, pursuant to its terms.

RESULTS OF OPERATIONS

The following discussion analyzes significant changes in the results of operations for the years 2010, 2009 and 2008.

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

	2010	2009	2008
Electric	\$43.2	\$39.1	\$37.4
Gas	2.6	0.9	1.7
Other	1.6	1.3	0.6
Net income	**\$47.4**	**\$41.3**	**\$39.7**

Electric Segment

Overview

Our electric segment income for 2010 was $43.2 million as compared to $39.1 million for 2009.

Electric operating revenues comprised approximately 89.2% of our total operating revenues during 2010. Electric operating revenues for 2010, 2009, and 2008 were comprised of the following:

	2010	2009	2008
Residential	42.4%	41.6%	40.2%
Commercial	30.3	31.4	29.8
Industrial	14.4	15.2	15.1
Wholesale on-system	4.0	4.2	4.3
Wholesale off-system	4.7	3.3	6.6
Miscellaneous sources*	2.6	2.7	2.5
Other electric revenues	1.6	1.6	1.5

* primarily public authorities

The percentage of revenues provided from our wholesale off-system transactions increased during 2010 as compared to 2009 primarily due to increased market demand resulting from more favorable weather in 2010 as compared to 2009. The percentage of revenues provided from our wholesale off-system transactions decreased during 2009 as compared to 2008 primarily due to decreased market demand resulting from milder weather in 2009 and general economic conditions.

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:

	kWh Sales (in millions)					
Customer Class	2010	2009	% Change*	2009	2008	% Change*
Residential	2,060.4	1,866.5	10.4%	1,866.5	1,952.9	(4.4)%
Commercial	1,644.9	1,579.8	4.1	1,579.8	1,622.0	(2.6)
Industrial	1,007.0	992.2	1.5	992.2	1,073.3	(7.6)
Wholesale on-system	355.8	332.0	7.2	332.0	344.5	(3.6)
Other**	126.5	123.4	2.5	123.4	123.8	(0.3)
Total on-system sales	5,194.6	4,893.9	6.1	4,893.9	5,116.5	(4.3)
Off-system	798.1	515.9	54.7	515.9	688.2	(25.0)
Total KWh Sales	5,992.7	5,409.8	10.8	5,409.8	5,804.7	(6.8)

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

** Other kWh sales include street lighting, other public authorities and interdepartmental usage.

Customer Class	Electric Segment Operating Revenues (in millions)					
	2010	2009	% Change*	2009	2008	% Change*
Residential	$204.9	$180.4	13.6%	$180.4	$179.3	0.6%
Commercial	146.3	135.8	7.7	135.8	132.9	2.2
Industrial	69.7	66.0	5.6	66.0	67.4	(2.0)
Wholesale on-system	19.2	18.2	5.8	18.2	19.2	(5.4)
Other**	12.3	11.6	6.1	11.6	11.0	5.1
Total on-system revenues	452.4	412.0	9.8	412.0	409.8	0.5
Off-system	22.9	14.3	59.6	14.3	29.7	(51.7)
Total revenues from KWh sales	475.3	426.3	11.5	426.3	439.5	(3.0)
Miscellaneous revenues***	7.6	6.8	11.1	6.8	7.0	(2.3)
Total electric operating revenues	$482.9	$433.1	11.5	$433.1	$446.5	(3.0)
Water revenues	1.8	1.8	2.3	1.8	1.7	(1.0)
Total Electric Segment Operating Revenues	$484.7	$434.9	11.5	$434.9	$448.2	(3.0)

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

** Other operating revenues include street lighting, other public authorities and interdepartmental usage.

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

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. We expect our annual customer growth to range from approximately 0.85% to 1.35% over the next several years.

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 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

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 now included as a component of the fuel adjustment clause in our Missouri, Kansas and Oklahoma jurisdictions 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 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
Kansas regulatory adjustments**	(0.1)	0.5
Missouri fuel adjustment deferral**	(4.5)	(2.0)
Missouri fuel adjustment recovery*	3.1	1.7
Unrealized (gain)/loss on derivatives	0.8	(0.3)
Total fuel and purchased power expense per income statement	$199.3	$182.0

* Recovered from customers from prior deferral period.

** 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 (primarily 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*	$ 1.9
General labor costs	1.2
Employee pension expense	1.0
Employee health care expense	1.0
Customer accounts expense**	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***	(1.9)
Other miscellaneous accounts (netted)	0.4
TOTAL	$ 7.0

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

** Mainly increased banking fees and uncollectible accounts.

*** Related to Iatan 1 and Iatan 2 operating costs that we were able to defer in accordance with our agreement with the MPSC that allows deferral of certain costs until the plant additions are included in customer rates.

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*	$ 1.3
Transmission maintenance expense	0.7
Maintenance and repairs expense at the Riverton plant — coal units**	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***	(1.1)
Other miscellaneous accounts (netted)	0.2
TOTAL	$ 3.8

* Mainly due to continued implementation of our system reliability plan.

** Mainly due to the 2010 five-year maintenance outage.

*** 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.

2009 Compared to 2008

On-System Operating Revenues and Kilowatt-Hour Sales

KWh sales for our on-system customers decreased approximately 4.3% during 2009 as compared to 2008 with the associated revenues increasing approximately $2.2 million (0.5%). Weather and other related factors decreased revenues an estimated $20.3 million. Total cooling degree days for 2009 were 12.3% less than 2008 and 18.7% less than the 30-year average. Total heating degree days for 2009 were 4.0% less than 2008 and 0.5% less than the 30-year average. Rate changes, primarily the August 2008 Missouri rate increase (discussed below), contributed an estimated $21.9 million to revenues while continued sales growth contributed an estimated $0.6 million.

Residential and commercial kWh sales decreased in 2009 primarily due to mild weather during the year. The related revenues increased during 2009 primarily due to the August 2008 Missouri rate increase and continued sales growth. Industrial kWh sales decreased 7.6% mainly due to a slowdown created by economic uncertainty while the associated revenues decreased 2.0%, reflecting the economic conditions, partially offset by the Missouri rate increase. On-system wholesale kWh sales and revenues decreased reflecting the general economic conditions and mild weather.

Off-System Electric Transactions

Off-system revenues and related expenses were less during 2009 as compared to 2008 primarily due to decreased market demand and lower gas prices that made it more economical for utilities to generate their own power rather than purchase it. Total purchased power related expenses are included in our discussion of purchased power costs below.

Miscellaneous Revenues

Our miscellaneous revenues were $6.8 million during 2009 as compared to $7.0 million during 2008. These revenues are comprised mainly of transmission revenues, late payment fees and renewable energy credit sales.

Operating Revenue Deductions — Fuel and Purchased Power

Total fuel and purchased power expenses decreased approximately $22.1 million (10.8%) during 2009 as compared to 2008. 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 2009 and 2008.

(in millions)	2009	2008
Actual fuel and purchased power expenditures	$182.1	$204.1
Kansas regulatory adjustments**	0.5	(0.5)
Missouri fuel adjustment deferral*	(2.0)	0.2
Missouri fuel adjustment recovery**	1.7	
Unrealized (gain)/loss on derivatives	(0.3)	0.3
Total fuel and purchased power expense per income statement	$182.0	$204.1

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

** Recovered from customers from prior deferral period.

The overall fuel and purchased power expense decrease primarily reflects the effect of decreased market demand resulting from mild weather in 2009, as well as the effects of an extended outage at the Asbury plant lasting from the fourth quarter of 2007 into the first quarter of 2008 during which time we relied on purchased power as well as our gas-fired units to replace our coal-fired generation. The decrease in fuel costs also includes the effect of decreased off-system sales.

Summarized in the table below are our estimated cost and volume changes in the components of fuel and purchased power expenses when compared to 2008. This table incorporates all the changes mentioned above. As shown below, the largest impacts on fuel and purchased power costs were lower purchased power and natural gas prices and decreased generation by our gas-fired units.

(in millions)	2009 vs 2008
Coal (cost)	$ 3.8
Natural gas (cost)	2.3
Purchased power (cost)	(10.1)
Coal generation volume	(0.6)
Natural gas generation volume	(23.1)
Purchased power spot purchase volume	3.0
Natural gas — gain on unwind of positions	2.1
Other (including fuel adjustments)	0.5
TOTAL	$(22.1)

Operating Revenue Deductions — Other Than Fuel and Purchased Power

Regulated operating expenses increased approximately $1.0 million (1.6%) during 2009 as compared to 2008 primarily due to changes in the following accounts:

(in millions)	2009 vs. 2008
Professional services	$ 1.5
Other steam power expense	1.2
General labor costs	0.8
Customer accounts expense*	0.6
Employee health care expense	(1.3)
Injuries and damages expense	(1.1)
Employee pension expense	(0.4)
Regulatory commission expense	(0.3)
TOTAL	$ 1.0

* Mainly increased banking fees.

We were able to defer $0.6 million in other steam power expense, which is included in the regulated operating expense increase, related to Iatan 1 operating costs 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.

Maintenance and repairs expense increased approximately $4.5 million (16.4%) during 2009 primarily due to changes in the following accounts:

(in millions)	2009 vs. 2008
Distribution maintenance costs*	$ 3.8
Maintenance and repairs expense at the Asbury plant	1.2
Maintenance and repairs expense to the SLCC	0.3
Maintenance and repairs expense to the Riverton gas units	0.1
Maintenance and repairs expense to State Line Unit No. 1	0.1
Maintenance and repairs expense at the Iatan plant	(0.6)
Maintenance and repairs expense to the Riverton coal units	(0.4)
TOTAL	$ 4.5

* Includes $2.5 million of ice storm related amortization

Depreciation and amortization expense decreased approximately $2.3 million (4.5%) during 2009 primarily due to reduced regulatory amortization resulting from the Missouri rate case that went into effect August 23, 2008. Other taxes increased approximately $0.8 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)	2010	2009	% Change	2009	2008	% Change
Residential	2.68	2.69	(0.4)%	2.69	2.95	(8.9)%
Commercial	1.26	1.27	(1.0)	1.27	1.40	(8.6)
Industrial*	0.11	0.22	(50.5)	0.22	0.55	(60.5)
Other**	0.03	0.03	11.6	0.03	0.03	(13.3)
Total retail sales	4.08	4.21	(3.1)	4.21	4.93	(14.6)
Transportation sales*	4.83	4.33	11.5	4.33	4.06	6.7
Total gas operating sales	8.91	8.54	4.3	8.54	8.99	(5.0)

	Operating Revenues and Cost of Gas Sold					
($ in millions)	2010	2009	% Change	2009	2008	% Change
Residential	$32.3	$36.2	(10.9)%	$36.2	$39.6	(8.7)%
Commercial	13.3	15.5	(14.2)	15.5	17.4	(10.7)
Industrial*	0.8	2.1	(60.7)	2.1	5.1	(59.3)
Other**	0.4	0.4	(6.0)	0.4	0.4	(12.8)
Total retail revenues	$46.8	$54.2	(13.7)	$54.2	$62.5	(13.4)
Other revenues	0.4	0.2	107.3	0.2	0.2	(2.1)
Transportation revenues*	3.7	2.9	26.6	2.9	2.7	10.0
Total gas operating revenues	$50.9	$57.3	(11.2)	$57.3	$65.4	(12.4)
Cost of gas sold	26.6	35.6	(25.2)	35.6	42.6	(16.5)
Gas operating revenues over cost of gas in rates	$24.3	$21.7	11.8	$21.7	$22.8	(4.8)

* Percentage change reflects the transfer of a customer from transportation to industrial sales in April 2008 and back to transportation in April 2009 and a customer switching from industrial sales to transportation in October 2009 after an eight-month suspension.

** Other includes other public authorities and interdepartmental usage.

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. We estimate that the rate of gas customer contraction will level out during the next two years and begin modest growth after 2012. 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 (which represents the cost of gas recovered from our customers) 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.

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, 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.

2009 Compared to 2008

Operating Revenues and bcf Sales

Gas retail sales decreased 14.6% during 2009 as compared to 2008 reflecting milder weather, the switching of customers between industrial sales and transportation (see footnote above) and the effect of our gas segment customer contraction of 1.3% in 2009. We believe this contraction was due to depressed economic conditions. Residential and commercial sales decreased during 2009 primarily due to the milder weather as well as customer contraction. Heating degree days were 9.7% lower than 2008 and 3.9% lower than the 30-year average. Industrial sales decreased during 2009 due to the transfer of customers between classes mentioned above.

During 2009, gas segment revenues were approximately $57.3 million as compared to $65.4 million in 2008, a decrease of 12.4%. This decrease was largely driven by the decrease in residential and industrial sales as well as PGA revenue. During 2009, our PGA revenue was approximately $35.6 million as compared to $42.6 million in 2008, a decrease of approximately $7.0 million. This decrease was largely driven by the decrease in sales and decreases in the PGAs that went into effect May 15, 2009 and November 13, 2009.

As of December 31, 2009, we had unrecovered purchased gas costs of $0.4 million recorded as a current regulatory asset and over recovered purchased gas costs of $1.9 million recorded as a regulatory liability.

Operating Revenue Deductions

Total other operating expenses were $10.3 million during 2009 as compared to $10.0 million in 2008, mainly due to a $0.2 million increase in distribution operation expense and a $0.1 million increase in general labor costs.

Our gas segment had net income of $0.9 million in 2009 as compared to $1.7 million in 2008.

Consolidated Company

Income Taxes

The following table shows the increases 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:

	2010	2009	2008
Consolidated provision for income taxes	$10.9	$ 0.4	$ 4.7
Consolidated effective federal and state income tax rates	39.2%	32.5%	32.5%

The effective tax rate for 2010 is higher than 2009 primarily due to the new health care legislation. On March 23, 2010, the Patient Protection and Affordable Care Act became law. This legislation includes a provision that reduces 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 income taxes to reflect the impact of this change. Our 2010 effective tax rate also increased due to the additional tax expense associated with the changes in the Medicare Part D tax benefit. As a result, our effective income tax rate for 2010 was 39.2% as compared to 32.5% in 2009. Excluding these non-cash charges, the effective tax rate in 2010 would have been 35.0%.

As part of an agreement reached in our most recently completed Missouri electric rate case, effective September 10, 2010, we 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 – 2008 and totaled approximately $11.1 million. We 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 will begin in 2012, which is also when we expect to be able to request rate recovery of the asset.

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 will utilize approximately $5.1 million of these credits to reduce our 2010 tax payments and 2010 tax liability and these are reflected as part of our income tax receivable in accounts receivable — other. The remainder is recorded as deferred taxes. 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.

On September 16, 2010, we received approximately $26.6 million from the SWPA as payment regarding the decrease in available net head waters at our hydroelectric generating plant located on the White River at Ozark Beach, Missouri. Currently, we have increased our current liability for income taxes by $10.0 million in anticipation that we will pay income taxes currently on the $26.6 million award, but no impact to our revenues or net income has been recorded to date. See Note 9 of "Notes to Consolidated Financial Statements" under Item 8 for additional information regarding income taxes.

Based on the extension of bonus depreciation through 2012 enacted by Congress, we do not expect to incur any federal income tax liability during 2011. Additionally, we currently estimate that approximately $12 million of advanced coal investment tax credits will be available to partially offset federal tax liabilities in 2012 and possibly 2013.

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 2010 as compared to 2009 and 2008 reflecting the completion of Iatan 2 and the Plum Point Energy Station in 2010. AFUDC increased in 2009 as compared to 2008 due to higher levels of construction in 2009. See Note 1 of "Notes to Consolidated Financial Statements" under Item 8.

($ in millions)	2010	2009	2008
Allowance for equity funds used during construction	$ 4.5	$ 6.2	$ 5.9
Allowance for borrowed funds used during construction	5.7	7.9	6.6
Total AFUDC	$10.2	$14.1	$12.5

Total interest charges on long-term and short-term debt for 2010, 2009 and 2008 are shown below. The decrease in long-term debt interest for 2010, as compared to 2009, reflects 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 decrease for 2010 also reflects 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 increase in long-term debt interest for 2009 reflects the interest on the $75 million principal amount of first mortgage bonds we issued March 27, 2009 and the $90 million principal amount of first mortgage bonds we issued May 16, 2008. The decreases in short-term debt interest for all periods presented primarily reflect lower levels of borrowing.

	Interest Charges ($ in millions)					
	2010	2009	Change	2009	2008	Change
Long-term debt interest	$41.9	$42.1	(0.3)%	$42.1	$36.0	16.8%
Short-term debt interest	0.6	1.1	(43.9)	1.1	1.9	(39.3)
Trust preferred securities interest	2.1	4.3	(50.8)	4.3	4.3	0.0
Iatan 1 and 2 carrying charges*	(3.2)	(1.3)	136.9	(1.3)	—	—
Other interest	0.9	0.6	28.2	0.6	1.1	(42.5)
Total interest charges	$42.3	$46.8	(9.5)	$46.8	$43.3	8.0

* 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 allows deferral of certain costs until the environmental upgrades to Iatan 1 are included in our rate base. We began deferring Iatan 2 carrying charges in the third quarter of 2010. 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. In addition to the information set forth below, see Note 3 of "Notes to Consolidated Financial Statements" under Item 8.

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 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, 2008:

Jurisdiction	Date Requested	Annual Increase Granted	Percent Increase Granted	Date Effective
Missouri — Electric	October 29, 2009	$46,800,000	13.40%	September 10, 2010
Oklahoma — Electric	March 25, 2010	$ 1,456,979	15.70%	September 1, 2010
Kansas — Electric	November 4, 2009	$ 2,800,000	12.4%	July 1, 2010
Missouri — Gas	June 5, 2009	$ 2,600,000	4.37%	April 1, 2010
Missouri — Electric	October 1, 2007	$22,040,395	6.70%	August 23, 2008

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 the 2009 Missouri rate case (see below).

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 will use construction accounting for our Iatan 2 project. See Note 3 and Note 11 of "Notes to Consolidated Financial Statements" under Item 8. 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 will begin in 2012, which is also when we expect to be able to request rate recovery of the asset. See Note 9 of "Notes to Consolidated Financial Statements" under Item 8.

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 order contained two components. The first component provided an addition to base rates of approximately $27.7 million. This increase in base rates was partially offset by a $5.7 million reduction to regulatory amortization, which is the second component to support certain credit metrics of the overall change in revenue authorized by the MPSC. Regulatory amortization provided us additional cash through rates during our construction cycle. This construction, which was part of our long-range plan to ensure reliability, included the facilities at the Riverton Power Plant and Iatan 2 Power Plant, as well as environmental improvements at the Asbury Power Plant and at Iatan 1. The regulatory amortization as a result of this case was approximately $4.5 million annually and was recorded as depreciation expense.

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 order in the rate case approved a Stipulation and Agreement providing for the recovery of deferred expenses of approximately $14.2 million over a five year period for the 2007 ice storms. In addition, the MPSC order required the implementation of a two-way tracking mechanism for recovery of the costs relating to the new MPSC rules on infrastructure inspection and vegetation management. The mechanism authorized by the MPSC created a regulatory liability in any year we spend less than the target amount, which has been set at $8.6 million for our Missouri jurisdiction, and a regulatory asset if we spend more than the target amount. Any regulatory asset and liability amounts created using the tracking mechanism will then be netted against each other and taken into account in our next rate case. The MPSC also approved Stipulations and Agreements providing for the continuation of the pension and other post-retirement employee benefits tracking mechanism established in our 2006 and 2007 Missouri rate orders.

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. Explorer Pipeline was dismissed from the pending appeal on October 18, 2010.

<u>2006 Rate Case</u>

In December 2008, the OPC and intervenors Praxair, Inc. and Explorer Pipeline Company filed Petitions for Writ of Review with the Cole County Circuit Court challenging the tariffs resulting from our 2006 Missouri rate case that went into effect January 1, 2007. The Cole County Circuit Court issued a ruling on December 8, 2009, affirming the Commission's Report and Order. OPC, Praxair and Explorer Pipeline filed appeals with the Western District Court of Appeals. On October 26, 2010, the Western District Court of Appeals affirmed the Commission's Report and Order. Praxair, Inc. and Explorer Pipeline Company filed with the Western District Court of Appeals a Motion for Rehearing and an Application for Transfer to the Supreme Court. On December 7, 2010, the Western District Court of Appeals overruled the Motion for Rehearing and denied the Application for Transfer to the Supreme Court. Praxair, Inc. then asked the Missouri Supreme Court to transfer the case to that court. On January 25, 2011, the request was denied.

<u>Kansas</u>

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 will defer 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, expected to be an abbreviated rate case that will be filed within the next year. These deferrals will be recovered over a 3-5 year period as determined in that next case. We will record AFUDC on all Plum Point and Iatan 2 capital expenditures incurred after January 31, 2010.

<u>Oklahoma</u>

On March 25, 2010, we requested a capital cost recovery rider (CCRR) at the Oklahoma Corporation Commission (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 results 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 brings the total annual revenue under the OCC to approximately $2.5 million. We will file a general rate case within six months of the commercial operation date of Iatan 2 (which was December 31, 2010) to replace the CRR with permanent rates.

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 includes a general rate increase of $2.1 million, or 19%. The settlement calls 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. A hearing on the settlement has been scheduled for March 8, 2011 at the APSC.

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 are now working to finalize the terms of the 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: On February 1, 2007, the Southwest Power Pool (SPP) regional transmission organization (RTO) launched its energy imbalance services market (EIS). In general, the SPP RTO EIS market 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 and its members have been evaluating the costs and benefits on expanding the EIS market into a full day ahead energy market with a co-optimized ancillary services market, which will include the consolidation of all SPP balancing authorities, including ours, into a single

SPP balancing authority. 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) and implement the complete Day-Ahead Market as soon as practical, which is anticipated in late 2013 or early 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 us, 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, which to date has, and is expected to continue to, provide benefits for our customers.

SPP Regional Transmission Development: On August 15, 2008, the SPP filed with the FERC proposed revisions to its open access transmission pro forma tariff (OATT) to establish a process for including a "balanced portfolio" of economic transmission upgrades in the annual SPP Transmission Expansion Plan. The cost of such upgrades will be recovered through a regional rate allocated to SPP members based on their load ratio share within SPP's market area of the balanced portfolio's cost. On October 16, 2008, the FERC accepted the balanced portfolio approach, which sets forth the selection process of a group of projects and regional cost allocation rules based on projected benefits and allocated costs over a ten year period. The plan will be balanced if the portfolio is cost beneficial for each zone, including ours, within the SPP. A balanced portfolio could include projects below the 345 kv level (which is the bright line voltage level for projects to be included in the portfolio) to increase benefits to a particular zone to achieve balance of benefits and costs over the ten year study period. On April 28, 2009, the SPP RSC and the SPP BOD approved the first set of balanced portfolio extra high voltage transmission projects to be constructed within the SPP region. The transmission expansion projects, totaling over $840 million, include projects in Missouri, Kansas, Arkansas, Oklahoma, Nebraska and Texas. We anticipate this set of transmission expansion projects will provide long term benefits to our customers. While we do not project our allocated costs for the balanced portfolio projects to be material, we expect that the costs will be recoverable in future rates. Also on April 28, 2009, the SPP RSC and BOD approved a new report that recommended restructuring of the SPP's regional planning processes, which would establish an integrated planning process for reliability, transmission service and economic transmission projects, based on a new set of planning principles that focus on the construction of a more robust transmission system large enough in both scale and geography to provide flexibility to meet SPP members' and customers' future needs. We will continue to actively participate in the development of these new processes as well as cost allocation and recovery issues with members, prospective customers and the state commission representatives to the SPP RSC.

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 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. It is uncertain as to when or if the FERC will rule on our Request for Rehearing. To date, the SPP's BOD has approved $1.4 billion in highway/byway projects to be constructed over the next several years. As these projects are constructed, we will be allocated a share of the costs of the projects pursuant to the FERC accepted cost allocation method. We expect that these costs will be recoverable in future rates.

In a related but separate filing, on May 17, 2010, the SPP filed revisions to its OATT to incorporate a modified transmission planning process, the Integrated Transmission Plan (ITP) that the SPP will use to determine its near and long term transmission needs to meet reliability and provide economic benefits throughout the SPP region. On June 7, 2010, we made a joint protest filing at the FERC regarding the ITP filing which expressed our concerns over the lack of explicit provisions in the SPP OATT to protect SPP customers from the approval of transmission projects that may not sufficiently benefit the SPP region. On July 15, 2010, the FERC issued an order conditionally accepting SPP proposed ITP planning process and tariff provisions to be effective on July 17, 2010, and ordered SPP to make a compliance filing by August 15, 2010, on the timing of ITP business practices and factors to be considered for changing the allocation of costs methods for dual winding high voltage transformers. We and the other parties to the SPP ITP jointly filed a formal Request for Rehearing at the FERC on the ITP order on August 13, 2010. On September 7, 2010, the FERC granted our Request For Rehearing to allow additional time for FERC's further consideration.

FERC Market Power Order

As part of our market based pricing authority from the FERC, we are required to conduct a market power analysis within our service territory and within the SPP RTO region every three years. We filed our triennial market power analysis with the FERC on July 30, 2009, concluding there were no material changes to our market position. As a result, we did not anticipate any changes to our existing market based rate authority. On July 13, 2010, the FERC issued an order accepting our triennial market power analysis and authorized the continuation of our market based rate authority for wholesale transactions outside our service territory.

Other FERC Activity

On May 21, 2009, the FERC issued an order clarifying that, going forward, small public utilities that have been granted waiver of Order No. 889 (Open Access Same Time Information Systems (OASIS) requirement) and the Standards of Conduct for transmission operations, which includes us, are required to submit a notification filing if there has been a material change in facts that may affect the basis on which a public utility's waiver was premised. The Standards of Conduct generally govern the communications between our day to day transmission operations personnel and our day to day wholesale marketing and sales personnel. We submitted our filing on July 13, 2009 in which we stated our belief that continuation of our waiver, issued in 1997 and reaffirmed in 2004, was appropriate and reasonable. Based on the May 21, 2009 order, it is possible that the FERC will revoke our waiver which would impact communication between our transmission and wholesale marketing and sales functions and operations within our organization. As part of our filing, we sought a twelve month extension in order to comply with the Standard of Conduct requirements in the event the FERC determined that revoking our waiver was appropriate. The FERC's decision on this and other Standard of Conduct waiver filings is pending. As of July 19, 2010, we have voluntarily taken steps to allow us to comply with a FERC order with minimal additional impact.

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 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. We participated in the development of comments by the SPP RTO which were filed at FERC on September 29, 2010. We will continue to monitor the NOPR as it may affect our existing rights to construct transmission facilities in our service territory as well as high voltage transmission expansion and cost allocation that will affect our cost of delivery service to our customers.

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.

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 2011 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 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

	Fiscal Year		
(in millions)	**2010**	**2009**	**2008**
Cash provided by/(used in):			
Operating activities	$ 138.1	$ 129.6	$ 93.0
Investing activities	(109.2)	(154.7)	(211.8)
Financing activities	(20.0)	28.0	117.5
Net change in cash and cash equivalents	$ 8.9	$ 2.9	$ (1.3)

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 in natural gas prices directly impacts the cost of gas stored in inventory. In the third quarter of 2010, we also received a $26.6 million SWPA payment which positively impacted operating cash flows.

2010 compared to 2009. In 2010, our net cash flow 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.

2009 compared to 2008. In 2009, our net cash flow provided from operating activities was $129.6 million, an increase of $36.6 million or 39.3% from 2008. This increase was primarily a result of:

- Draw down of the commodity risk management margin accounts through settlement of hedged positions — $10.3 million.
- Decreased cash payments for income taxes, reflecting positive affects for accelerated tax depreciation — $6.7 million.
- Changes in depreciation and amortization, reflecting collection of deferred ice storm costs from customers — $3.2 million
- Changes in the levels of accounts receivable and inventory, primarily from lower gas prices — $23.3 million.

Capital Requirements and Investing Activities

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 net cash flows used in investing activities decreased $57.1 million from 2008 to 2009. The 2008 capital expenditures reflect cash outlays for the December 2007 ice storm. These expenditures were incurred in 2007 but paid in the first quarter of 2008. In addition, expenditures for new generation and distribution and transmission system additions were lower in 2009 than in 2008.

Our capital expenditures totaled approximately $108.2 million, $148.8 million, and $206.4 million in 2010, 2009 and 2008, respectively.

A breakdown of these capital expenditures for 2010, 2009 and 2008 is as follows:

	Capital Expenditures		
(in millions)	**2010**	**2009**	**2008**
Distribution and transmission system additions	$ 38.8	$ 33.7	$ 46.8
New generation — Plum Point Energy Station	6.9	16.3	30.9
New generation — Iatan 2	42.7	66.2	82.6
Storms	0.1	6.4	4.3
Additions and replacements — electric plant	7.2	22.8	40.2
Gas segment additions and replacements	5.0	2.1	1.9
Transportation	1.3	1.4	1.2
Other (including retirements and salvage — net)(1)	3.4	(1.4)	(3.6)
Subtotal	$105.4	$147.5	$204.3
Non-regulated capital expenditures (primarily fiber optics)	2.8	1.3	2.1
Subtotal capital expenditures incurred(2)	$108.2	$148.8	$206.4
Adjusted for capital expenditures payable(3)	3.8	3.8	6.9
Insurance proceeds receivable	(0.1)	5.6	—
Capital lease, primarily Plum Point unit train	(2.7)	(2.9)	—
Total cash outlay	$109.2	$155.3	$213.3

(1) Other includes equity AFUDC of $(4.5) million, $(6.2) million and $(5.9) million for 2010, 2009 and 2008, respectively. 2009 and 2008 also include proceeds from sale of property of $0.5 million and $1.5 million, respectively.

(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 75%, 55% and 23% of our cash requirements for capital expenditures for 2010, 2009 and 2008, 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 2011, 2012 and 2013 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	2011	2012	2013
Iatan 2	$ 12.6	$ —	$ —
Riverton Unit 12 combined cycle conversion	—	—	6.7
Electric distribution system additions	37.5	41.6	43.4
Electric transmission facilities additions	9.8	15.3	22.1
Additions to existing electric generating facilities — Asbury	3.8	42.6	81.4
Other	42.6	28.0	35.3
Total	$106.3	$127.5	$188.9

We estimate that internally generated funds will provide approximately 99% of the funds required in 2011 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, and 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 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 and increased dividends.

Our net cash flows provided by financing activities decreased $89.5 million to $28.0 million during 2009 as compared to $117.5 million in 2008, primarily due to a decrease in proceeds (net of repayments) of short-term debt borrowings in 2009.

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 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 current 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 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 May 16, 2008, we issued $90 million principal amount of first mortgage bonds. The net proceeds of approximately $89.4 million, less $0.4 million of legal and other financing fees, were added to our general funds and used primarily to pay down short-term indebtedness incurred, in part, as a result of our on-going construction program.

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 plan to use proceeds under this shelf to fund capital expenditures, refinancings of existing debt or general corporate needs when needed during the effective period. The issuance of securities under this shelf is subject to the receipt of local regulatory approvals.

On January 26, 2010, we entered into the Second Amended and Restated Unsecured Credit Agreement which amended and restated our revolving credit facility. This agreement extends the termination date of the revolving credit facility from July 15, 2010 to January 26, 2013. 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 increased from 0.80% to 2.70%. A facility fee is payable quarterly on the full amount of the commitments under the facility and a usage fee is payable on the full amount of the commitments under the facility for any period in which we have drawn less than 33% of the total revolving commitments under the facility, in each case based on our current credit ratings. In addition, upon entering into the amended and restated facility, we paid an upfront fee to the revolving credit banks of $900,000 in the aggregate. The aggregate amount of the revolving commitments remained unchanged at $150 million and 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, 2010, we are in compliance with these ratios. Our total indebtedness is 52.2% of our total capitalization as of December 31, 2010 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, 2010. However, $24.0 million was used to back up our outstanding commercial paper.

On March 11, 2009, we entered into a $50 million unsecured credit agreement. This agreement, which terminated on July 15, 2010, provided for $50 million of revolving loans to be available to us for working capital, general corporate purposes and to back-up our use of commercial paper and was in addition to, and had substantially identical covenants and terms as (other than pricing) our Second Amended and Restated Unsecured Credit Agreement dated January 26, 2010 discussed above.

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, 2010 would permit us to issue approximately $362.3 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, 2010, we had retired bonds and net property additions which would enable the issuance of at least $634.0 million principal amount of bonds if the annual interest requirements are met. As of December 31, 2010, 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, 2010, this test would allow us to issue approximately $8.3 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	F2	P-2	A-3
Outlook	Stable	Stable	Stable

* Not rated.

On March 24, 2010, Standard & Poor's issued a report with our ratings unchanged and upgraded our business profile to "excellent" from "strong". On May 14, 2010, Moody's upgraded our First Mortgage Bonds from Baa1 to A3 and upgraded its outlook from negative to stable. Moody's affirmed all of our other ratings. On April 1, 2010, Fitch affirmed our ratings and revised their rating outlook to stable. The revision took into consideration the anticipated completion of our five-year baseload capital expenditure program in 2010 and assumes we will receive timely and adequate regulatory recovery of newly completed investments.

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, 2010. Not included in these amounts are expected obligations associated with our share of the Iatan 2 construction for which we have not yet been billed. 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 2011-2015 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)	$ 689.8	$ 0.6	$112.3	$ —	$ 576.9
Interest on long-term debt	626.5	40.1	77.6	69.9	438.9
Short-term debt	24.0	24.0	—	—	—
Capital lease obligations	8.1	0.6	1.2	1.1	5.2
Operating lease obligations(2)	6.6	1.0	1.7	1.4	2.5
Electric purchase obligations(3)	338.0	80.5	118.6	71.6	67.3
Gas purchase obligations(4)	50.3	9.1	14.8	12.6	13.8
Open purchase orders	19.0	18.8	0.1	—	0.1
Postretirement benefit obligation funding	26.1	5.7	11.0	9.4	—
Pension benefit funding	79.3	18.2	30.8	30.3	—
Other long-term liabilities(5)	3.5	0.1	0.3	0.3	2.8
TOTAL CONTRACTUAL OBLIGATIONS(6)	$1,871.2	$198.7	$368.4	$196.6	$1,107.5

(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 2011 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.

(6) Our estimate of uncertain tax liabilities totaled $0.4 million at December 31, 2010. Due to the uncertainties surrounding this estimate, we cannot reasonably estimate the timing of potential payments, if any, and have not included any in the table above.

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). As of December 31, 2010, our retained earnings balance was $5.5 million, compared to $10.1 million as of December 31, 2009, after paying out

$52.0 million in dividends during 2010. A reduction of our dividend per share, partially or in whole, could have an adverse effect on our common stock price. On February 3, 2011, the Board of Directors declared a quarterly dividend of $0.32 per share on common stock payable March 15, 2011 to holders of record as of March 1, 2011.

Our diluted earnings per share were $1.17 for the year ended December 31, 2010 and were $1.18 and $1.17 for the years ended December 31, 2009 and 2008, respectively. Dividends paid per share were $1.28 for the year ended December 31, 2010 and for each of the years ended December 31, 2009 and 2008.

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 March 11, 2008, we amended the EDE Mortgage in order to provide us with more flexibility to pay dividends to our shareholders by increasing the basket available to pay dividends by $10.75 million, as described above. As of December 31, 2010, this restriction did not prevent us from issuing dividends.

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 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.

In our 2005 electric Missouri Rate Case, the MPSC ruled that we would be allowed to recover pension costs consistent with our GAAP policy noted above. In accordance with the rate order, we prospectively calculated 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.

The MPSC ruling also allowed us to record the Missouri portion of any costs above or below the amount included in rates as a regulatory asset or liability, respectively. Therefore, the deferral of these costs began in the second quarter of 2005. In our 2006 Kansas Rate Case, the KCC also ruled that we would be allowed to change our recognition of pension costs, deferring the Kansas portion of any costs above or below the amount included in our rate case as a regulatory asset or liability. 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 will be 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 now expect future pension expense or benefits are probable of full recovery in rates charged to our Missouri and Kansas customers, thus lowering our sensitivity to accounting risks and uncertainties.

Our 2006 Missouri rate case order and our 2010 Kansas rate order 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 have concluded that the amount of unfunded defined benefit pension and postretirement plan obligations will be recorded 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 pension and postretirement benefits. 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.

As of December 31, 2010, all derivative instruments are recognized at fair value on the balance sheet with unrealized gains and losses deferred as a regulatory asset or liability, due to our fuel recovery mechanisms for our electric segment and our gas segment. For all our derivative contracts, once settled, the realized gain or loss is recorded to fuel expense and is subject to our fuel adjustment clause mechanisms. Missouri, our largest electric jurisdiction, permits the distribution to customers of 95% of the changes in fuel and purchased power costs prudently incurred above or below the base cost.

Risks and uncertainties affecting the application of this accounting policy 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 in our Consolidated Statement of Income and then deferred to a regulatory asset or liability, given it is probable of recovery through our fuel adjustment mechanisms. 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, 2010, we have recorded $194.4 million in regulatory assets and $88.8 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.

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 2010, 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, 2010 and 2009 was $3.4 million and $3.1 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, 2010, 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. We believe it is unlikely that a change to one of these key assumptions, by itself, would be significant enough to result in an impairment charge. However, if significant negative changes occurred to multiple 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, 2010 indicated the estimated fair market value of the gas reporting unit to be 10 – 15% higher than its carrying value at that time. While we believe the assumptions utilized in our analysis were reasonable, significant adverse developments in future periods could negatively impact goodwill impairment considerations, which could adversely impact earnings.

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 often are 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 62.3% of our 2010 generation fuel supply need through coal. Approximately 92% of our 2010 coal supply was Western coal. We have contracts and binding proposals to supply a portion of the fuel for our coal plants through 2013. These contracts satisfy approximately 100% of our anticipated fuel requirements for 2011, 65% for 2012, 61% for 2013 and 31% 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 February 4, 2011, 88%, or 5.0 million Dths's, of our anticipated volume of natural gas usage for our electric operations for 2011 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 2011, if average natural gas prices should increase 10% more in 2011 than the price at December 31, 2010, our natural gas expenditures would increase by approximately $0.3 million based on our December 31, 2010 total hedged positions for the next twelve months. However, such an increase would be probable of recovery through fuel adjustment mechanisms. With the addition of the Missouri fuel adjustment mechanism effective September 1, 2008, we now have a fuel cost recovery mechanism 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 February 5, 2011, we have 0.6 million Dths in storage on the three pipelines that serve our customers. This represents 28% of our storage capacity. We have an additional 0.7 million Dths hedged through financial derivatives and physical contracts. Our long-term hedge strategy is to mitigate price volatility for our customers by hedging a minimum of 50% of the current year, up to 50% of the second year and up to 20% of third year expected gas usage by the beginning of the ACA year at September 1. 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.

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, 2010 and December 31, 2009. There were no margin deposit liabilities at these dates.

(in millions)	2010	2009
Margin deposit assets	$3.9	$2.9

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, 2010, 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	$15.2
Net unrealized mark-to-market losses for financial natural gas contracts	4.3
Net credit exposure	$19.5

The $4.3 million net unrealized mark-to-market loss for financial natural gas contracts is comprised of $4.3 million of exposure to counterparties of Empire for unrealized losses and no exposure to Empire of unrealized gains. 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, 2010, we have $3.9 million on deposit for NYMEX contract exposure to Empire, of which $3.5 million represents our collateral requirement. If NYMEX gas prices decreased 25% from their December 31, 2010 levels, our collateral requirement would increase $2.2 million. If these prices increased 25%, our collateral requirement would decrease $2.7 million.

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 2011 than in 2010, our interest expense would increase, and income before taxes would decrease by less than $0.5 million. This amount has been determined by considering the impact of the hypothetical interest rates on our highest month-end commercial paper balance for 2010. 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.

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, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010 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, 2010, 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 17, 2011

THE EMPIRE DISTRICT ELECTRIC COMPANY
CONSOLIDATED BALANCE SHEETS

	December 31, 2010	December 31, 2009
	($-000's)	
Assets		
Plant and property, at original cost:		
Electric	$2,001,142	$1,619,949
Natural gas	63,581	58,180
Water	11,128	10,891
Other	32,264	29,564
Construction work in progress	9,337	302,012
	2,117,452	2,020,596
Accumulated depreciation and amortization	598,363	561,586
	1,519,089	1,459,010
Current assets:		
Cash and cash equivalents	14,499	5,620
Accounts receivable — trade, net of allowance of $865 and $1,087, respectively	41,380	36,136
Accrued unbilled revenues	23,595	23,717
Accounts receivable — other	25,445	21,417
Fuel, materials and supplies	45,557	43,973
Unrealized gain in fair value of derivative contracts	39	2,782
Prepaid expenses and other	5,649	4,438
Regulatory assets	4,974	772
	161,138	138,855
Noncurrent assets and deferred charges:		
Regulatory assets	189,404	168,254
Goodwill	39,492	39,492
Unamortized debt issuance costs	9,257	10,638
Unrealized gain in fair value of derivative contracts	194	2,525
Iatan investment tax credits	—	17,713
Other	2,737	3,359
	241,084	241,981
Total assets	$1,921,311	$1,839,846

(Continued)

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

THE EMPIRE DISTRICT ELECTRIC COMPANY

CONSOLIDATED BALANCE SHEETS (Continued)

	December 31, 2010	December 31, 2009
	($-000's)	
Capitalization and liabilities		
Common stock, $1 par value, 100,000,000 shares authorized, 41,576,869 and 38,112,280 shares issued and outstanding, respectively	$ 41,577	$ 38,112
Capital in excess of par value	610,579	551,631
Retained earnings	5,468	10,068
Accumulated comprehensive income/(loss), net of income taxes	—	339
Total common stockholders' equity	657,624	600,150
Long-term debt (net of current portion)		
Note payable to securitization trust	—	50,000
Obligations under capital lease	4,995	2,563
First mortgage bonds and secured debt	488,577	339,643
Unsecured debt	199,500	247,950
Total long-term debt	693,072	640,156
Total long-term debt and common stockholders' equity	1,350,696	1,240,306
Current liabilities:		
Accounts payable and accrued liabilities	58,820	67,406
Current maturities of long-term debt	881	51,021
Short-term debt	24,000	50,500
Customer deposits	11,061	10,394
Interest accrued	6,004	5,698
Other current liabilities	578	—
Unrealized loss in fair value of derivative contracts	760	4,337
Taxes accrued	3,935	3,386
Regulatory liabilities	1,243	—
	107,282	192,742
Commitments and contingencies (Note 11)		
Noncurrent liabilities and deferred credits:		
Regulatory liabilities	87,579	87,533
Deferred income taxes	212,003	194,315
Unamortized investment tax credits	19,597	20,125
Pension and other postretirement benefit obligations	93,405	84,240
Unrealized loss in fair value of derivative contracts	3,564	426
Other	47,185	20,159
	463,333	406,798
Total capitalization and liabilities	$1,921,311	$1,839,846

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,		
	2010	2009	2008
	($-000's, except per share amounts)		
Operating revenues:			
Electric	$482,910	$433,133	$446,466
Gas	50,885	57,314	65,438
Water	1,805	1,764	1,782
Other	5,676	4,957	4,477
	541,276	497,168	518,163
Operating revenue deductions:			
Fuel and purchased power	199,299	182,028	204,058
Cost of natural gas sold and transported	26,614	35,601	42,630
Regulated operating expenses	79,292	73,086	71,918
Other operating expenses	1,950	1,801	1,889
Maintenance and repairs	36,771	33,012	28,549
Depreciation and amortization	58,656	51,494	53,562
Provision for income taxes	30,470	19,571	19,128
Other taxes	27,729	26,080	25,417
	460,781	422,673	447,151
Operating income	80,495	74,495	71,012
Other income and (deductions):			
Allowance for equity funds used during construction	4,538	6,209	5,929
Interest income	176	217	1,057
Benefit/(provision) for other income taxes	(63)	(311)	2
Other — non-operating expense, net	(1,039)	(460)	(1,569)
	3,612	5,655	5,419
Interest charges:			
Long-term debt	41,959	42,084	36,041
Trust preferred securities	2,090	4,250	4,250
Short-term debt	631	1,125	1,854
Allowance for borrowed funds used during construction	(5,636)	(7,924)	(6,589)
Other	(2,333)	(681)	1,153
	36,711	38,854	36,709
Net income	$ 47,396	$ 41,296	$ 39,722
Weighted average number of common shares outstanding — basic	40,545	34,924	33,821
Weighted average number of common shares outstanding — diluted	40,580	34,956	33,860
Total earnings per weighted average share of common stock — basic and diluted	$ 1.17	$ 1.18	$ 1.17
Dividends declared per share of common stock	$ 1.28	$ 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,		
	2010	2009	2008
		($-000's)	
Net income	$ 47,396	$41,296	$ 39,722
Reclassification adjustments for (gain)/loss included in net income or reclassified to regulatory asset or liability	5,814	13,568	(3,872)
Net change in fair market value of open derivative contracts for period	(6,362)	(9,576)	(17,394)
Income taxes	209	(1,521)	8,102
Comprehensive income	$ 47,057	$43,767	$ 26,558

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, 2007	$33,606	$477,385	$ 17,153	$11,032	$539,176
Net income			39,722		39,722
Stock/stock units issued through:					
Stock purchase and reinvestment plans	376	6,058			6,434
Dividends declared			(43,296)		(43,296)
Reclassification adjustment for gains included in net income				(3,872)	(3,872)
Change in fair value of open derivative contracts for period				(17,394)	(17,394)
Income taxes				8,102	8,102
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 losses 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

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,		
	2010	2009	2008
		($-000's)	
Operating activities:			
Net income	$ 47,396	$ 41,296	$ 39,722
Adjustments to reconcile net income to cash flows from operating activities:			
Depreciation and amortization	71,076	62,247	59,066
Pension and other postretirement benefit costs, net of contributions	(3,683)	4,096	8,282
Deferred income taxes and unamortized investment tax credit, net	26,880	15,324	8,580
Allowance for equity funds used during construction	(4,538)	(6,209)	(5,929)
Stock compensation expense	3,478	2,616	2,169
Non cash (gain)/loss on derivatives	1,853	10,350	(39)
Gain on the sale of assets	—	(457)	—
Impairment of other non-operating investment	—	—	556
Cash flows impacted by changes in:			
Accounts receivable and accrued unbilled revenues	(11,211)	2,989	(10,938)
Fuel, materials and supplies	(1,585)	4,635	(4,720)
Prepaid expenses, other current assets and deferred charges	(17,403)	(7,464)	(2,683)
Accounts payable and accrued liabilities	(6,179)	(1,305)	(4,905)
Interest, taxes accrued and customer deposits	1,522	806	2,234
Other liabilities and other deferred credits	3,954	699	1,597
SWPA minimum flows payment	26,564	—	—
Net cash provided by operating activities	138,124	129,623	92,992

(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,		
	2010	2009	2008
		($-000's)	
Investing activities:			
Capital expenditures — regulated	$(106,388)	$(154,016)	$(211,311)
Capital expenditures and other investments — non-regulated	(2,817)	(1,239)	(1,969)
Proceeds from the sale of property, plant and equipment	—	544	1,538
Total net cash used in investing activities	(109,205)	(154,711)	(211,742)
Financing activities:			
Proceeds from first mortgage bonds	149,635	75,000	89,950
Proceeds from issuance of notes payable	—	2,470	—
Long-term debt issuance costs	(1,758)	(2,397)	(3,168)
Proceeds from issuance of common stock, net of issuance costs	60,239	70,271	5,385
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 borrowings (repayments)	(26,500)	(51,500)	68,960
Dividends	(51,996)	(44,807)	(43,296)
Other	(1,356)	(1,058)	(370)
Net cash provided by (used in) financing activities	(20,040)	27,954	117,461
Net increase (decrease) in cash and cash equivalents	8,879	2,866	(1,289)
Cash and cash equivalents, beginning of year	5,620	2,754	4,043
Cash and cash equivalents, end of year	$ 14,499	$ 5,620	$ 2,754

	2010	2009	2008
Supplemental cash flow information:			
Interest paid	$ 43,044	$ 45,730	$ 40,384
Income taxes paid, net of refund	11,264	3,246	8,706
Supplementary non-cash investing activities:			
Change in accrued additions to property, plant and equipment not reported above	$ (3,846)	$ (3,833)	$ (6,895)
Capital lease obligations for purchase of new equipment	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 2010 were derived as follows:

Electric segment sales*	89.6%
Gas segment sales	9.4%
Other segment sales	1.0%

* 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 169,000 customers and the 2010 electric operating revenues were derived as follows:

Customer	% of revenue
Residential	42.4%
Commercial	30.3%
Industrial	14.4%
Wholesale on-system	4.0%
Wholesale off-system	4.7%
Miscellaneous sources, primarily public authorities	2.5%
Other electric revenues	1.7%

Our retail electric revenues for 2010 by jurisdiction were as follows:

Jurisdiction	% of revenue
Missouri	88.9%
Kansas	5.3%
Arkansas	3.0%
Oklahoma	2.8%

Our gas operations serve approximately 44,000 customers and the 2010 gas operating revenues were derived as follows:

Customer	% of revenue
Residential	63.4%
Commercial	26.2%
Industrial	1.6%
Other	8.8%

Basis of Presentation

The consolidated financial statements include the accounts of EDE, EDG, and our other (fiber optic) subsidiary. 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 $10.6 million, $10.2 million and $10.2 million were recorded for each of the years ended December 31, 2010, 2009 and 2008, 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, 2010 and 2009 was $8.3 million and $9.7 million, respectively.

As of December 31, 2010 and 2009, we had recorded accrued cost of removal of $58.8 million and $49.8 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, 2010 and 2009 was $3.9 million and $3.3 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 along with a liability for 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 2009 and 2010 are shown below.

(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

(000's)	Liability Balance 12/31/08	Liabilities Recognized	Liabilities Settled	Accretion	Cash Flow Revisions	Liability Balance at 12/31/09
Asset Retirement Obligation	$3,468	$ —	$ —	$139	$ —	$3,607

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, 2010 and 2009, our regulatory assets relating to asset retirement obligations totaled $3.4 million and $3.3 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 is 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, and our 2010 rate order from the MPSC, we recorded approximately $7.5 million, $4.5 million, and $8.2 million of regulatory amortization during 2010, 2009, and 2008, respectively. This amortization included in our rates was granted in the Experimental Regulatory Plan approved by the MPSC on August 2, 2005. It provided additional cash flow to enhance the financial support for our generation expansion plan. It is related to our investment in Iatan 2 and also includes our Riverton V84.3A2 combustion turbine (Riverton Unit 12) and environmental improvement and upgrades at Asbury and Iatan 1. This amortization is included as 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 7.5% for 2010, 7.0% for 2009 and 7.8% for 2008, compounded semiannually, in determining AFUDC for all of our projects except Iatan 2. The specific Iatan 2 AFUDC rate is a result of our Experimental Regulatory Plan approved by the MPSC on August 2, 2005. 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, 2010 and 2009.

Goodwill

As of December 31, 2010, 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. We believe it is unlikely that a change to one of these key assumptions, by itself, would be significant enough to result in an impairment charge. However, if significant negative changes occurred to multiple 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, 2010 indicated the estimated fair market value of the gas reporting unit to be 10-15% higher than its carrying value at that time. While we believe the assumptions utilized in our analysis were reasonable, significant adverse developments in future periods could negatively impact goodwill impairment considerations, which could adversely impact earnings.

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. We buy and sell power through the SPP RTO energy imbalance services market (EIS). We net settle these market transactions on an hourly basis.

At December 31, 2010, our Missouri and Kansas fuel and purchased power costs were under-recovered by $5.0 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).

Effective March 1, 2005, the MPSC approved a Stipulation and Agreement 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. The banked 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). Changes in the fair value of a derivative that is highly effective and designated and qualifies as a cash-flow hedge are recorded in comprehensive income until earnings are affected by the variability of cash flows (e.g., when periodic settlements on a variable-rate asset or liability are recorded in earnings). Changes in the fair value of non-designated derivative instruments and any ineffective portion of a qualified hedge are reported in current-period earnings in fuel expense. Effective September 1, 2008, in conjunction with the implementation of the Missouri fuel adjustment clause in the July 2008 MPSC rate order, the mark to market unrealized losses or gains from new derivatives used to hedge our fuel costs were 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. Unrealized gains and losses from cash flow hedges existing at September 1, 2008 continued to be recorded through comprehensive income through September 30, 2010. As of December 31, 2010, the remaining hedges we entered into prior to September 1, 2008 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 have reclassified the unrealized loss on these hedges from comprehensive income to a regulatory asset. These hedges, along with any hedges entered into since September 1, 2008, will be accounted for in accordance with the ASC guidance on regulated operations as described above.

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 income.

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

In our 2005 electric Missouri rate case, the MPSC ruled the Company would be allowed to recover pension costs consistent with our GAAP policy noted above. In accordance with the rate order, 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 portion of any costs above or below the amount included in rates as a regulatory asset or liability, respectively. Therefore, the deferral of these costs began in the second quarter of 2005. In our 2006 Kansas rate case, the KCC also ruled that the Company would be allowed to change the recognition of pension costs, deferring the Kansas portion of any costs above or below the amount included in the rate case as a regulatory asset or liability.

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

At December 31, 2010, the balance of other noncurrent liabilities is primarily comprised of a $26.6 million payment we expect to flow through to our customers, as well as accruals for self insurance and customer advances for construction. Our hydroelectric generating plant (FERC Project No. 2221), located on the White River at Ozark Beach, Missouri, has a generating capacity of 16 megawatts. As part of the Energy and Water Development Appropriations Act of 2006 (the Appropriations Act), the level of Bull Shoals Lake will be increased an average of 5 feet which will reduce the generation at Ozark Beach. 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 September 16, 2010, we received a $26.6 million payment from the SWPA recognizing the economic detriment created by the legislation. The $26.6 million payment will have no material impact on net income as we expect the benefits will flow through to our customers. In addition, the SWPA has delayed the implementation of the new minimum flows until 2016.

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 $14.5 million and $14.1 million at December 31, 2010 and 2009, respectively.

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):

	2010	2009
Electric fuel inventory	$17,648	$15,885
Natural gas inventory	4,470	5,404
Materials and supplies	23,439	22,684
TOTAL	$45,557	$43,973

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 $5.1 million of these credits to reduce our 2010 tax payments and 2010 tax liability and these are reflected as a reduction to accrued taxes. 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, 2010 and 2009, our balance sheet included approximately $0.4 million and $0.9 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.

	2010	2009	2008
Weighted Average Number Of Shares			
Basic	40,544,802	34,923,526	33,820,750
Dilutive Securities:			
Performance-based restricted stock awards	14,991	20,513	23,680
Dividend equivalents	12,558	12,122	10,981
Employee stock purchase plan	7,170	103	4,637
Stock options	—	—	—
Total dilutive securities	34,719	32,738	39,298
Diluted weighted average number of shares	40,579,521	34,956,264	33,860,048
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 recognized 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).

Recently Issued and Proposed Accounting Standards

Fair Value: In January 2010, the FASB amended the fair value measurements and disclosures guidance to require additional disclosures about fair value measurements. The revised guidance requires new disclosures about the transfers in and out of Level 1 and 2 measurements, including descriptions of the reasons for the transfers. Additionally, the reconciliation of Level 3 measurements now requires separate presentation of sales, issuances and settlements. This guidance for the Level 1 and 2 measurements was adopted on January 1, 2010 and did not have an effect on our results of operations, financial position or liquidity. The guidance on the Level 3 measurements is effective for periods beginning after December 15, 2010. As this guidance provides only disclosure requirements, the adoption of this standard did not impact our results of operations, cash flows or financial position (See Note 15).

Consolidation: In June 2009, the FASB amended the accounting guidance for consolidations. This amendment is effective for annual periods beginning after November 15, 2009. The amendment requires an entity to complete a qualitative analysis when determining who must consolidate a variable interest entity (VIE). Additionally, the amendment requires additional disclosures, and an ongoing reassessment of who must consolidate a VIE. A controlling financial interest is required for a VIE and this is evidenced by either a voting interest greater than 50% or a risk and reward model that identifies EDE as the primary beneficiary of a VIE.

Upon adoption of the guidance, we concluded that the consolidation of the Empire District Electric Trust I was appropriate and we reflected it in our consolidated balance sheets in the first quarter of 2010. Subsequently, on June 28, 2010, we redeemed all 2 million outstanding shares of our 8.5% trust preferred securities held by the Trust.

We also evaluated our long-term purchase power agreements to determine if we hold a variable interest. This evaluation identified our purchase power agreement with Plum Point Energy Associates, LLC (PPEA, LLC) for capacity with Plum Point Energy Station, as a variable interest. For this contract we considered operations and maintenance of the power plant to be the most significant activity. In addition, we do not have control over the operation and maintenance of the power plant. Additionally, we have not provided debt or equity investments in PPEA, LLC, we receive less than the majority of the output of the facility under the contract and do not provide any other financial support through liquidity arrangements, guarantees or other commitments other than the purchase power agreement described in Note 11. Based on the consideration of these factors, we do not consider ourselves to be the primary beneficiary of this VIE. The adoption of this standard did not have any impact on our financial statements.

2. Property, Plant and Equipment

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

	December 31, 2010	December 31, 2009
Electric plant		
Production	$1,015,040	$ 690,768
Transmission	220,514	203,436
Distribution	682,175	651,657
General(1)	83,413	74,088
Electric plant	2,001,142	1,619,949
Less accumulated depreciation and amortization(2)	575,061	542,226
Electric plant net of depreciation and amortization	1,426,081	1,077,723
Construction work in progress	9,214	301,534
Net electric plant	1,435,295	1,379,257
Gas plant	63,581	58,180
Less accumulated depreciation and amortization	8,994	6,854
Gas plant net of accumulated depreciation	54,587	51,326
Construction work in progress	6	436
Net gas plant	54,593	51,762
Water plant	11,128	10,891
Less accumulated depreciation and amortization	3,855	3,664
Water plant net of depreciation and amortization	7,273	7,227
Construction work in progress	40	5
Net water plant	7,313	7,232
Other		
Fiber	32,264	29,564
Less accumulated depreciation and amortization	10,453	8,842
Non-regulated net of depreciation and amortization	21,811	20,722
Construction work in progress	77	37
Net non-regulated property	21,888	20,759
TOTAL NET PLANT AND PROPERTY	$1,519,089	$1,459,010

(1) Includes intangible property of $20.1 and $12.1 million as of December 31, 2010 and 2009, respectively, primarily related to capitalized software and investments in facility upgrades owned by other utilities. Accumulated amortization related to this property in 2010 and 2009 was $9.2 and $8.5 million respectively.

(2) Includes regulatory amortization of $30.7 million and $23.1 million as of December 30, 2010 and 2009, respectively.

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):

	2010	2009	2008
Provision for depreciation			
Regulated — Electric and Water	$49,254	$44,973	$42,389
Regulated — Gas	3,046	2,072	2,016
Non-Regulated	1,641	1,443	1,319
TOTAL	53,941	48,488	45,724
Amortization[1]	8,347	5,159	9,132
TOTAL	$62,288	$53,647	$54,856

(1) Includes $7.5 million, $4.5 million, and $8.2 million of regulatory amortization for 2010, 2009 and 2008, respectively. This was granted by the MPSC effective January 1, 2007 and updated August 23, 2008, and September 10, 2010.

	2010	2009	2008
Annual depreciation rates			
Electric and water	2.8%	2.9%	3.0%
Gas	5.1%	3.7%	3.7%
Non-Regulated	5.3%	5.0%	4.8%
TOTAL COMPANY	2.9%	3.0%	3.0%

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

	2010	2009	2008
Annual Weighted Average Depreciation Rate			
Electric fixed assets:			
Production plant	2.0%	2.2%	2.2%
Transmission plant	2.4%	2.4%	2.3%
Distribution plant	3.6%	3.6%	3.6%
General plant	6.2%	6.1%	6.2%
Water	2.7%	2.7%	2.8%
Gas	5.1%	3.7%	3.7%
Non-regulated	5.3%	5.0%	4.8%

3. Regulatory Matters

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, our regulatory liability for cost of removal, 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 and 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 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, 2008:

Jurisdiction	Date Requested	Annual Increase Granted	Percent Increase Granted	Date Effective
Missouri — Electric	October 29, 2009	$46,800,000	13.40%	September 10, 2010
Oklahoma — Electric	March 25, 2010	$ 1,456,979	15.70%	September 1, 2010
Kansas — Electric	November 4, 2009	$ 2,800,000	12.4%	July 1, 2010
Missouri — Gas	June 5, 2009	$ 2,600,000	4.37%	April 1, 2010
Missouri — Electric	October 1, 2007	$22,040,395	6.70%	August 23, 2008

Electric Segment

<u>*Missouri*</u>

<u>*2010 Rate Case*</u>

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 the 2009 Missouri rate case (see below).

<u>*2009 Rate Case*</u>

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 will use construction accounting for our Iatan 2 project. See Note 11. We have 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 will begin in 2012, which is also when we expect to be able to request rate recovery of the asset. 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 order contained two components. The first component provided an addition to base rates of approximately $27.7 million. This increase in base rates was partially offset by a $5.7 million reduction to regulatory amortization, which is the second component to support certain credit metrics of the overall change in revenue authorized by the MPSC. Regulatory amortization provided us additional cash through rates during our construction cycle. This construction, which was part of our long-range plan to ensure reliability, included the facilities at the Riverton Power Plant and Iatan 2 Power Plant, as well as environmental improvements at the Asbury Power Plant and at Iatan 1. The regulatory amortization as a result of this case was approximately $4.5 million annually and was recorded as depreciation expense.

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 are 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 order in the rate case approved a Stipulation and Agreement providing for the recovery of deferred expenses of approximately $14.2 million over a five year period for the 2007 ice storms. In addition, the MPSC order required the implementation of a two-way tracking mechanism for recovery of the costs relating to the new MPSC rules on infrastructure inspection and vegetation management. The mechanism authorized by the MPSC created a regulatory liability in any year we spend less than the target amount, which has been set at $8.6 million for our Missouri jurisdiction, and a regulatory asset if we spend more than the target amount. Any regulatory asset and liability amounts created using the tracking mechanism will then be netted against each other and taken into account in our next rate case. The MPSC also approved Stipulations and Agreements providing for the continuation of the pension and other post-retirement employee benefits tracking mechanism established in our 2006 and 2007 Missouri rate orders.

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. Explorer Pipeline was dismissed from the pending appeal on October 18, 2010.

2006 Rate Case

In December 2008, the OPC and intervenors Praxair, Inc. and Explorer Pipeline Company filed Petitions for Writ of Review with the Cole County Circuit Court challenging the tariffs resulting from our 2006 Missouri rate case that went into effect January 1, 2007. The Cole County Circuit Court issued a ruling on December 8, 2009, affirming the Commission's Report and Order. OPC, Praxair and Explorer Pipeline filed appeals with the Western District Court of Appeals. On October 26, 2010, the Western District Court of Appeals affirmed the Commission's Report and Order. Praxair, Inc. and Explorer Pipeline Company filed with the Western District Court of Appeals a Motion for Rehearing and an Application for Transfer to the Supreme Court. On December 7, 2010, the Western District Court of Appeals overruled the Motion for Rehearing and denied the Application for Transfer to the Supreme Court. Praxair, Inc. then asked the Missouri Supreme Court to transfer the case to that court. On January 25, 2011, the request was denied.

Kansas

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 will defer 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, expected to be an abbreviated rate case that will be filed within the next year. These deferrals will be recovered over a 3 – 5 year period as determined in that next case. We will record 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 Oklahoma Corporation Commission (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 results 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 brings the total annual revenue under the OCC to approximately \$2.5 million. We will file a general rate case within six months of the commercial operation date of Iatan 2 (which was December 31, 2010) to replace the CRR with permanent rates.

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 includes a general rate increase of \$2.1 million, or 19%. The settlement calls 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. A hearing on the settlement has been scheduled for March 8, 2011 at the APSC.

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 estimate approximately \$0.6 million of this amount will be subject to refund and have reduced our revenue accordingly. 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 are now working to finalize the terms of the 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: On February 1, 2007, the Southwest Power Pool (SPP) regional transmission organization (RTO) launched its energy imbalance services market (EIS). In general, the SPP RTO EIS market 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 and its members have been evaluating the costs and benefits on expanding the EIS market into a full day ahead energy market with a co-optimized ancillary services market, which will include the consolidation of all SPP balancing authorities, including ours, into a single SPP balancing authority. 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) and implement the complete Day-Ahead Market as soon as practical, which is anticipated in late 2013 or early 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 us, 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, which to date has, and is expected to continue to, provide benefits for our customers.

SPP Regional Transmission Development: On August 15, 2008, the SPP filed with the FERC proposed revisions to its open access transmission pro forma tariff (OATT) to establish a process for including a "balanced portfolio" of economic transmission upgrades in the annual SPP Transmission Expansion Plan. The cost of such upgrades will be recovered through a regional rate allocated to SPP members based on their load ratio share within SPP's market area of the balanced portfolio's cost. On October 16, 2008, the FERC accepted the balanced portfolio approach, which sets forth the selection process of a group of projects and regional cost allocation rules based on projected benefits and allocated costs over a ten year period. The plan will be balanced if the portfolio is cost beneficial for each zone, including ours, within the SPP. A balanced portfolio could include projects below the 345 kv level (which is the bright line voltage level for projects to be included in the portfolio) to increase benefits to a particular zone to achieve balance of benefits and costs over the ten year study period. On April 28, 2009, the SPP RSC and the SPP BOD approved the first set of balanced portfolio extra high voltage transmission projects to be constructed within the SPP region. The transmission expansion projects, totaling over $840 million, include projects in Missouri, Kansas, Arkansas, Oklahoma, Nebraska and Texas. We anticipate this set of transmission expansion projects will provide long term benefits to our customers. While we do not project our allocated costs for the balanced portfolio projects to be material, we expect that the costs will be recoverable in future rates. Also on April 28, 2009, the SPP RSC and BOD approved a new report that recommended restructuring of the SPP's regional planning processes, which would establish an integrated planning process for reliability, transmission service and economic transmission projects, based on a new set of planning principles that focus on the construction of a more robust transmission system large enough in both scale and geography to provide flexibility to meet SPP members' and customers' future needs. We will continue to actively participate in the development of these new processes as well as cost allocation and recovery issues with members, prospective customers and the state commission representatives to the SPP RSC.

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 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. It is uncertain as to when or if the FERC will rule on our Request for Rehearing. To date, the SPP's BOD has approved $1.4 billion in highway/byway projects to be constructed over the next several years. As these projects are constructed, we will be allocated a share of the costs of the projects pursuant to the FERC accepted cost allocation method. We expect that these costs will be recoverable in future rates.

In a related but separate filing, on May 17, 2010, the SPP filed revisions to its OATT to incorporate a modified transmission planning process, the Integrated Transmission Plan (ITP) that the SPP will use to determine its near and long term transmission needs to meet reliability and provide economic benefits throughout the SPP region. On June 7, 2010, we made a joint protest filing at the FERC regarding the ITP filing which expressed our concerns over the lack of explicit provisions in the SPP OATT to protect SPP customers from the approval of transmission projects that may not sufficiently benefit the SPP region. On July 15, 2010, the FERC issued an order conditionally accepting SPP proposed ITP planning process and tariff provisions to be effective on July 17, 2010, and ordered SPP to make a compliance filing by August 15, 2010, on the timing of ITP business practices and factors to be considered for changing the allocation of costs methods for dual winding high voltage transformers. We and the other parties to the SPP ITP jointly filed a formal Request for Rehearing at the FERC on the ITP order on August 13, 2010. On September 7, 2010, the FERC granted our Request For Rehearing to allow additional time for FERC's further consideration.

FERC Market Power Order

As part of our market based pricing authority from the FERC, we are required to conduct a market power analysis within our service territory and within the SPP RTO region every three years. We filed our triennial market power analysis with the FERC on July 30, 2009, concluding there were no material changes to our market position. As a result, we did not anticipate any changes to our existing market based rate authority. On July 13, 2010, the FERC issued an order accepting our triennial market power analysis and authorized the continuation of our market based rate authority for wholesale transactions outside our service territory.

Other FERC Activity

On May 21, 2009, the FERC issued an order clarifying that, going forward, small public utilities that have been granted waiver of Order No. 889 (Open Access Same Time Information Systems (OASIS) requirement) and the Standards of Conduct for transmission operations, which includes us, are required to submit a notification filing if there has been a material change in facts that may affect the basis on which a public utility's waiver was premised. The Standards of Conduct generally govern the communications between our day to day transmission operations personnel and our day to day wholesale marketing and sales personnel. We submitted our filing on July 13, 2009 in which we stated our belief that continuation of our waiver, issued in 1997 and reaffirmed in 2004, was appropriate and reasonable. Based on the May 21, 2009 order, it is possible that the FERC will revoke our waiver which would impact communication between our transmission and wholesale marketing and sales functions and operations within our organization. As part of our filing, we sought a twelve month extension in order to comply with the Standard of Conduct requirements in the event the FERC determined that revoking our waiver was appropriate. The FERC's decision on this and other Standard of Conduct waiver filings is pending. As of July 19, 2010, we have voluntarily taken steps to allow us to comply with a FERC order with minimal additional impact.

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 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. We participated in the development of comments by the SPP RTO which were filed at FERC on September 29, 2010. We will continue to monitor the NOPR as it may affect our existing rights to construct transmission facilities in our service territory as well as high voltage transmission expansion and cost allocation that will affect our cost of delivery service to our customers.

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 $1.5 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.

Regulatory Assets and Liabilities and Other Deferred Credits

The Missouri Public Service Commission (MPSC) approved a regulatory plan in 2005, allowing construction accounting. Construction accounting, for the purposes of this regulatory plan, is specific to Iatan 1 and Iatan 2 and allows us to defer certain charges as regulatory assets. These deferred charges include depreciation, operations and maintenance and carrying costs related to operation of the facilities until the facilities are ultimately included in our rates. The regulatory plan also requires us to continue to defer the fuel and purchased power expense impacts of Iatan 2, which were approximately $3.1 million for the year and are recorded in Non-Current Regulatory Liabilities. Construction accounting began for Iatan 2 which met its in-service criteria on August 26, 2010. In addition, in our recently completed Missouri rate case, construction accounting was approved for Plum Point, which met its in-service criteria on August 13, 2010. Construction accounting for Plum Point applies only to construction costs incurred subsequent to February 28, 2010. All of these deferrals begin at the in-service dates and will be amortized over the life of the plants once they are included in our rates, which we estimate to be upon completion of our Missouri rate case filed on September 28, 2010. (See Note 11 for additional details). The following table sets forth the costs related to construction accounting (in thousands):

Balances as of December 31, 2010	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

Changes to regulatory assets and liabilities regarding their rate base inclusion or amortizable lives since December 31, 2009 include the amortization of Iatan 1 construction accounting costs effective September 10, 2010, of approximately $0.1 million per year, over the life of the plant, amortization of vegetation tracker costs in Missouri over five years, the write off of approximately $1.2 million of tax amortization in the first quarter of 2010 for which we estimated rate recovery would no longer be probable and amortization of ice storm costs in Kansas. See Note 9 — Income Taxes for additional information.

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

	December 31, 2010	December 31, 2009
Regulatory Assets:		
Under recovered purchased gas costs — gas segment — current	$ —	$ 434
Under recovered electric fuel and purchased power costs — current	4,974	338
Regulatory assets, current[1]	4,974	772
Pension and other postretirement benefits[2]	92,192	81,171
Income taxes	50,188	49,230
Storm costs[3]	7,733	11,673
Unamortized loss on reacquired debt	13,099	12,167
Unamortized loss on interest rate derivative	1,776	2,091
Asbury five-year maintenance	948	1,401
Deferred Iatan construction accounting costs	10,521	2,732
Asset retirement obligation	3,412	3,264
Under recovered electric fuel and purchased power costs	—	662
Under recovered purchased gas costs — gas segment	439	—
Unsettled derivative losses — electric segment	3,166	335
Customer programs	2,119	1,255
System reliability — vegetation management	3,338	1,636
Other	473	637
Regulatory assets, long-term	189,404	168,254
TOTAL REGULATORY ASSETS	$194,378	$169,026
Regulatory Liabilities		
Over recovered purchased gas costs — gas segment — current	$ 1,243	$ —
Regulatory liabilities, current[5]	1,243	—
Costs of removal	62,756	53,083
Income taxes	12,715	20,678
Unamortized gain on interest rate derivative	3,881	4,051
Pension and other postretirement benefits[4]	4,604	6,415
Deferred construction accounting costs — fuel	3,126	—
Over recovered electric fuel and purchased power costs[5]	155	1,344
Over recovered purchased gas costs — gas segment	—	1,874
Other	342	88
Regulatory liabilities, long-term	87,579	87,533
TOTAL REGULATORY LIABILITIES	$ 88,822	$ 87,533

(1) Reflects under recovered costs expected to be recovered 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, 2010 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) Primarily reflects ice storm costs incurred in 2007.

(4) 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, 2010, regulatory liabilities and corresponding expenses have been reduced by approximately $0.9 million as a result of ratemaking treatment.

(5) Primarily consists of Missouri over recovered fuel and purchased power costs for the current accumulation period September 2010 through February 2011.

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, 2010, the costs of all of our regulatory assets are currently being recovered except for the deferred Iatan 2 and Plum Point costs discussed above, and approximately $84.4 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 4 to 26 years. The unrecovered fuel costs are generally recovered within a year following their recognition. Ice 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.

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 underwriter.

Stock Based Compensation

We have several stock-based awards and programs, which are described below. Performance based restricted stock awards, 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):

	2010	2009	2008
Compensation expense	$3,193	$2,292	$1,841
Tax benefit recognized	1,160	819	659

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 2008, 2009, and 2010 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.

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 2008, 2009 and 2010 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, 2010, 2009 and 2008 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,		
	2010	2009	2008
Risk-free interest rate	0.30% to 0.62%	0.47% to 1.08%	0.37% to 0.66%
Expected volatility of Empire stock	26.9%	28.8%	26.6%
Expected volatility of peer group stock	21.7% to 82.7%	22.1% to 80.9%	20.5% to 68.7%
Expected dividend yield on Empire stock	6.5%	7.6%	6.4%
Expected forfeiture rates	3%	3%	3%
Plan cycle	3 years	3 years	3 years
Fair value percentage	138.0% to 193.7%	87.0% to 132.0%	99.0% to 124.0%
Weighted average fair value per share	$37.17	$21.00	$19.23

Non-vested restricted stock awards (based on target number) as of December 31, 2010, 2009 and 2008 and changes during the year ended December 31, 2010, 2009 and 2008 were as follows:

	2010		2009		2008	
	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,	52,200	$21.57	52,300	$22.64	43,400	$23.02
Granted	13,000	$18.36	13,500	$18.12	21,000	$21.92
Awarded	(15,104)	$23.81	(12,394)	$22.23	(6,486)	$22.77
Not awarded	(2,596)	$ —	(1,206)	$ —	(5,614)	$ —
Nonvested at December 31,	47,500	$19.86	52,200	$21.57	52,300	$22.64

At December 31, 2010 and 2009, unrecognized compensation expense related to estimated outstanding awards was $0.4 million and $0.4 million, respectively.

Stock Options

Stock options are 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 are 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. The fair value per dividend equivalent grants for 2010, 2009 and 2008 outstanding at December 31, 2010, were $3.79, $3.83 and $3.84, 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, 2010, 2009 and 2008, under a Black-Scholes methodology. The assumptions used in the valuations are shown below:

	Fair Value of Grants Outstanding at December 31,		
	2010	2009	2008
Risk-free interest rate	0.45% to 2.34%	1.11% to 2.98%	0.85% to 1.70%
Dividend yield	6.5%	7.6%	6.4%
Expected volatility	23.0%	24.0%	24.0%
Expected life in months	78	78	78
Market value	$22.20	$18.73	$17.60
Weighted average fair value per option	$2.02	$0.97	$0.78

A summary of option activity under the plan during the years ended December 31, 2010, 2009 and 2008 is presented below:

	2010		2009		2008	
	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price
Outstanding at January 1,	232,600	$22.19	205,600	$22.73	149,200	$23.04
Granted	34,800	$18.36	27,000	$18.12	56,400	$21.92
Exercised	—	$ —	—	$ —	—	$ —
Outstanding at December 31,	267,400	$21.69	232,600	$22.19	205,600	$22.73
Exercisable, end of year	149,200	$23.04	85,000	$22.46	43,300	$22.67

The aggregate intrinsic value at December 31, 2010 was $0.3 million and immaterial for both 2009 and 2008. 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 range of exercise prices for the options outstanding at December 31, 2010 was $18.12 to $23.81. The weighted-average remaining contractual life of outstanding options at December 31, 2010, 2009 and 2008 was 6.6, 6.6 and 7.1 years, respectively. As of December 31, 2010, this includes 149,200 shares at the weighted average price of $23.04, which are vested and exercisable. All others are non-vested. As of December 31, 2010 and 2009, there was $0.2 and $0.2 million, respectively, of unrecognized compensation expense related to non-vested options and related dividend equivalents granted under the plan.

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, 2010, there were 331,021 shares available for issuance in this plan.

	2010	2009	2008
Subscriptions outstanding at December 31,	71,326	68,591	48,413
Maximum subscription price	$ 16.06[(1)]	$ 14.62	$ 18.57
Shares of stock issued	66,723	44,265	38,803
Stock issuance price	$ 14.62	$ 14.10	$ 18.61

(1) Stock will be issued on the closing date of the purchase period, which runs from June 1, 2010 to May 31, 2011.

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

	2010	2009	2008
Weighted average fair value of grants	$ 2.28	$ 3.26	$ 3.46
Risk-free interest rate	0.35%	0.48%	2.17%
Dividend yield	7.20%	7.90%	6.20%
Expected volatility[(1)]	17.00%	40.00%	26.00%
Expected life in months	12	12	12
Grant date	6/1/10	6/1/09	6/2/08

(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. At December 31, 2010 and 2009, there were 139,912 and 112,895 shares accrued to directors' accounts, respectively; and 311,523 and 317,870 shares available for issuance under this plan, respectively.

	2010	2009	2008
Units accrued for service and dividends	33,364	33,024	20,979
Units redeemed for common stock	6,347	34,853	3,484

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, 2010 and 2009, there were 104,601 and 169,431 shares available to be issued, respectively.

	2010	2009	2008
Shares contributed	64,830	73,408	59,253

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. As of December 31, 2010, our retained earnings balance was $5.5 million, compared to $10.1 million at December 31, 2009 after paying out $52.0 million in dividends during 2010. A reduction of our dividend per share, partially or in whole, could have an adverse effect on our common stock price. On February 3, 2011, the Board of Directors declared a quarterly dividend of $0.32 per share on common stock payable March 15, 2011 to holders of record as of March 1, 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 March 11, 2008, we amended the EDE Mortgage in order to provide us with more flexibility to pay dividends to our shareholders by increasing the basket available to pay dividends by $10.75 million, as described above. As of December 31, 2010, this restriction did not prevent us from issuing dividends.

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, 2010 or 2009.

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. There were 38.0 million rights outstanding at December 31, 2009. As a result of the expiration, no rights were outstanding at December 31, 2010.

6. Long-Term Debt

At December 31, 2010 and 2009, the balance of long-term debt outstanding was as follows (in thousands):

	2010	2009
Note payable to securitization trust(1)	$ —	$ 50,000
First mortgage bonds (EDE):		
6½% Series due 2010	—	50,000
7.20% Series due 2016	25,000	25,000
5.3% Pollution Control Series due 2013(2)	8,000	8,000
5.2% Pollution Control Series due 2013(2)	5,200	5,200
5.875% Series due 2037(3)	80,000	80,000
6.375% Series due 2018(3)	90,000	90,000
4.65% Series due 2020(3)	100,000	—
5.20% Series due 2040(3)	50,000	—
7.0% Series due 2024(4)	74,854	74,975
First mortgage bonds (EDG):		
6.82% Series due 2036(3)	55,000	55,000
	488,054	388,175
Senior Notes, 7.05% Series due 2022(2)	—	48,522
Senior Notes, 4½% Series due 2013(3)	98,000	98,000
Senior Notes, 6.70% Series due 2033(3)	62,000	62,000
Senior Notes, 5.80% Series due 2035(3)	40,000	40,000
Other	6,932	5,254
Less unamortized net discount	(1,033)	(774)
	693,953	691,177
Less current obligations of long-term debt	(614)	(50,587)
Less current obligations under capital lease	(267)	(434)
Total long-term debt	$693,072	$640,156

(1) Represented by our Junior Subordinated Debentures, 8½% Series due 2031.

(2) 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.

(3) 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.

(4) 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 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 May 16, 2008, we issued $90 million principal amount of first mortgage bonds. The net proceeds of approximately $89.4 million, less $0.4 million of legal and other financing fees, were added to our general funds and used primarily to pay down short-term indebtedness incurred, in part, as a result of our on-going construction program.

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 plan to use proceeds under this shelf to fund capital expenditures, refinancings of existing debt or general corporate needs during the effective period. The issuance of securities under this shelf is subject to the receipt of local regulatory approvals.

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, 2010 would permit us to issue approximately $362.3 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, 2010, we had retired bonds and net property additions which would enable the issuance of at least $634.0 million principal amount of bonds if the annual interest requirements are met. As of December 31, 2010, 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, 2010, this test would allow us to issue approximately $8.3 million principal amount of new first mortgage bonds.

The carrying amount of our total debt exclusive of capital leases at December 31, 2010 was $689 million compared to a fair market value of approximately $697 million. The carrying amount of our total debt exclusive of capital leases as of December 31, 2009 was $688 million, compared to a fair value of approximately $695 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
2011	$ 881	$ 614	$ 267
2012	917	641	276
2013	111,908	111,615	293
2014	267	—	267
2015	286	—	286
Thereafter	580,727	576,854	3,873
Total long-term debt obligations	694,986	$689,724	$5,262
Less current obligations and unamortized discount	1,914		
Total long-term debt	$693,072		

7. Short-Term Borrowings

At December 31, 2010, total short-term borrowings consisted of $24.0 million in commercial paper and no borrowings from our line of credit. Short-term borrowings outstanding averaged $36.3 million and $68.9 million daily during 2010 and 2009, respectively, with the highest month-end balances being $74.0 million and $123.0 million, respectively. The weighted average interest rates during 2010 and 2009 were 1.74% and 1.63% in each period. The weighted average interest rate of borrowings outstanding at December 31, 2010 and 2009 was 1.15% and 1.05%, respectively.

On January 26, 2010, we entered into the Second Amended and Restated Unsecured Credit Agreement which amended and restated our unsecured revolving credit facility. This agreement extends the termination date of the revolving credit facility from July 15, 2010 to January 26, 2013. 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 increased from 0.80% to 2.70%. A facility fee is payable quarterly on the full amount of the commitments under the facility and a usage fee is payable on the full amount of the commitments under the facility for any period in which we have drawn less than 33% of the total revolving commitments under the facility, in each case based on our current credit ratings. In addition, upon entering into the amended and restated facility, we paid an upfront fee to the revolving credit banks of $900,000 in the aggregate. The aggregate amount of the revolving commitments remained unchanged at $150 million and 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, 2010, we are in compliance with these ratios. Our total indebtedness is 52.2% of our total capitalization as of December 31, 2010 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, 2010. However, $24.0 million was used to back up our outstanding commercial paper.

On March 11, 2009, we entered into a $50 million unsecured credit agreement. This agreement, which terminated on July 15, 2010, provided for $50 million of revolving loans to be available to us for working capital, general corporate purposes and to back-up our use of commercial paper and was in addition to, and had substantially identical covenants and terms as (other than pricing) our Second Amended and Restated Unsecured Credit Agreement dated January 26, 2010 discussed above.

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, 2010, 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 minimum funding requirements of ERISA. 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.

Market conditions in 2009 and 2010 have positively impacted the return on pension plan assets; however plan costs have also increased. As a result, our net pension liability increased $4.5 million and $0.3 million in 2010 and 2009, 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. We expect future pension funding commitments to increase to at least the level of our accrued cost, as required by our regulator. Our contribution is estimated to be approximately $18.2 million for 2011. For 2012, we will also be required to fund at least our accrued cost. The actual minimum funding requirements will be determined based on the results of the actuarial valuations and, in the case of 2012, the performance of our pension assets during 2011.

Expected benefit payments are as follows (in millions):

Year	Payments from Trust	Payments from Company Funds
2011	$ 8.1	$0.1
2012	8.8	0.1
2013	9.4	0.1
2014	10.1	0.1
2015	10.8	0.1
2016 – 2020	$62.8	$0.8

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.

Market conditions in 2009 and 2010 also had a positive impact on the return on OPEB plan assets; however plan costs have increased as well. Our net liability increased $4.3 million and $0.4 million in 2010 and 2009, 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 $4.9 million in 2011.

Estimated benefit payments are as follows (in millions):

Year	Payments from Trust	Expected Federal Subsidy	Payments from Company Funds
2011	$ 2.4	$0.3	$0.1
2012	2.7	0.3	0.1
2013	3.1	0.4	0.1
2014	3.4	0.4	0.2
2015	3.7	0.5	0.2
2016 – 2020	$23.4	$3.2	$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	
	2010	2009	2010	2009	2010	2009
Benefit obligation at beginning of year	$169,055	$154,377	$2,575	$2,337	$69,911	$61,950
Service cost	4,887	4,612	70	61	2,138	1,830
Interest cost	10,115	9,876	153	148	4,329	3,907
Net actuarial (gain)/loss	10,946	8,092	160	92	6,454	3,881
Plan participant's contribution	—	—	—	—	949	832
Benefits and expenses paid	(8,163)	(7,902)	(63)	(63)	(2,966)	(2,885)
Federal subsidy	—	—	—	—	123	396
Benefit obligation at end of year	$186,840	$169,055	$2,895	$2,575	$80,938	$69,911

Reconciliation of Fair Value of Plan Assets:

	Pension		SERP		OPEB	
	2010	2009	2010	2009	2010	2009
Fair value of plan assets at beginning of year	$107,076	$ 92,730	$ —	$ —	$50,036	$42,483
Actual return on plan assets — gain/(loss)	11,740	19,748	—	—	4,825	6,799
Employer contribution	9,700	2,500	—	—	3,681	2,333
Benefits paid	(8,163)	(7,902)	—	—	(2,845)	(2,753)
Plan participant's contribution	—	—	—	—	917	803
Federal subsidy	—	—	—	—	116	371
Fair value of plan assets at end of year	$120,353	$107,076	$ —	$ —	$56,730	$50,036

Reconciliation of Funded Status:

	Pension		SERP		OPEB	
	2010	2009	2010	2009	2010	2009
Fair value of plan assets	$ 120,353	$ 107,076	$ —	$ —	$ 56,730	$ 50,036
Projected benefit obligations	(186,840)	(169,055)	(2,895)	(2,575)	(80,938)	(69,911)
Funded status	$ (66,487)	$ (61,979)	$(2,895)	$(2,575)	$(24,208)	$(19,875)

The employee pension plan accumulated benefit obligation at December 31, 2010 and 2009 is presented in the following table (in thousands):

	Pension Benefits		SERP	
	2010	2009	2010	2009
Accumulated benefit obligation	$164,340	$146,826	$2,431	$1,864

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

	Pension		SERP		OPEB	
	2010	2009	2010	2009	2010	2009
Other current liabilities	$ —	$ —	$ 64	$ 62	$ 121	$ 127
Pension and other postretirement benefit obligation	$66,487	$61,979	$2,831	$2,513	$24,087	$19,748

Net periodic benefit pension cost for 2010, 2009 and 2008, 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		
	2010	2009	2008	2010	2009	2008
Service cost	$ 4,887	$ 4,612	$ 3,568	$ 2,138	$ 1,830	$ 1,651
Interest cost	10,115	9,876	9,048	4,329	3,907	3,617
Expected return on plan assets	(9,847)	(10,379)	(10,729)	(3,844)	(3,843)	(3,750)
Amortization of prior service cost(1)	531	604	744	(1,011)	(1,011)	(1,011)
Amortization of actuarial loss(1)	3,996	3,182	1,693	1,499	869	511
Net periodic benefit cost	$ 9,682	$ 7,895	$ 4,324	$ 3,111	$ 1,752	$ 1,018

Net Periodic Pension Benefit Cost:

	SERP		
	2010	2009	2008
Service cost	$ 70	$ 61	$ 57
Interest cost	153	148	137
Expected return on plan assets	—	—	—
Amortization of prior service cost(1)	(8)	(8)	(8)
Amortization of actuarial loss(1)	96	103	132
Net periodic benefit cost	$311	$304	$318

(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 12/31/09	Current Year Actuarial (Gain)/Loss	Amortization of Actuarial Loss	Amortization of Prior Service (Cost)/Credit	Ending Balance 12/31/10
Pension	$62,524	9,053	(3,996)	(531)	$67,050
SERP	$ 1,218	161	(96)	8	$ 1,291
OPEB	$11,046	5,473	(1,499)	1,011	$16,031

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, 2010, and the subsequent twelve-month period (in thousands):

	Pension Benefits		SERP		OPEB	
	2010	Subsequent Period	2010	Subsequent Period	2010	Subsequent Period
Net actuarial loss	$64,005	$5,411	$1,338	$134	$22,658	$ 2,001
Prior service cost (benefit)	3,045	532	(47)	(8)	(6,627)	(1,011)
Total	$67,050	$5,943	$1,291	$126	$16,031	$ 990

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	
	2010	2009	2010	2009
Discount rate	5.50%	6.00%	5.50%	6.00%
Rate of compensation increase	4.50%	4.50%	4.50%	4.50%

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

	Pension Benefits			OPEB		
	2010	2009	2008	2010	2009	2008
Discount rate	6.00%	6.30%	6.40%	6.00%	6.30%	6.40%
Expected return on plan assets	8.00%	8.50%	8.50%	8.00%	7.45%	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 2010 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 2015 to an ultimate rate of 5.0% in 2015 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	$ 1,167	$ (925)
Effect on post-retirement benefit obligation	$11,838	$(9,617)

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, 2010 (in thousands):

	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	—	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 as of December 31, 2009				
	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	$ —	$ 965	$ —	$ 965	0.9%
Equity securities					
U.S. equity	40,069	—	—	40,069	37.4%
International equity	13,053	—	—	13,053	12.2%
Fixed income	—	29,474	—	29,474	27.5%
Other types of investments					
Equity long/short hedge funds	—	—	23,515	23,515	22.0%
	$53,122	$30,439	$23,515	$107,076	100.0%

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

	2010	2009
	Equity long/short hedge funds	Equity long/short hedge funds
Beginning Balance, January 1,	$23,515	$16,169
Actual return on plan assets:		
Relating to assets still held at the reporting date	(1,177)	2,346
Relating to assets sold during the period	—	—
Purchases, sales and settlements, net	—	5,000
Transfers into and (out of) Level 3	—	—
Ending Balance, December 31,	$22,338	$23,515

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

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 protection
- 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, 2010:

	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 & equivalents	$ 3,986	$ —	$—	$ 3,986	7.0%
Fixed income					
U.S. government issues	—	4,091	—	4,091	7.2%
U.S. corporate issues	—	15,156	—	15,156	26.7%
Foreign issues	—	420	—	420	0.7%
Mutual funds — fixed income	1,496	—	—	1,496	2.6%
Equity securities					
U.S. common stocks	17,592	—	—	17,592	31.0%
Foreign Stocks	1,274	—	—	1,274	2.2%
Mutual funds — equity	12,556	—	—	12,556	22.1%
	36,904	19,667	—	56,571	
Accrued interest & dividends				248	0.5%
				$56,819	100%

	Fair Value Measurements as of December 31, 2009				
	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 & equivalents	$ 1,179	$ —	$—	$ 1,179	2.4%
Fixed income					
U.S. government issues	—	9,307	—	9,307	18.6%
U.S. corporate issues	—	12,969	—	12,969	25.9%
Foreign issues	—	429	—	429	0.9%
Mutual funds — fixed income	145	—	—	145	0.3%
Equity securities					
U.S. common stocks	15,243	—	—	15,243	30.5%
Foreign Stocks	335	—	—	335	0.7%
Mutual funds — equity	10,170	—	—	10,170	20.3%
	27,072	22,705	—	49,777	
Accrued interest & dividends				259	0.4%
				$50,036	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):

	2010	2009	2008
Current income taxes:			
Federal	$ 7,713	$ 3,987	$12,067
State	1,057	572	1,667
TOTAL	8,770	4,559	13,734
Deferred income taxes:			
Federal	17,942	13,854	5,179
State	4,349	1,973	738
TOTAL	22,291	15,827	5,917
Investment tax credit amortization	(528)	(504)	(525)
TOTAL INCOME TAX EXPENSE	$30,533	$19,882	$19,126

Deferred Income Taxes

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

	December 31,	
Deferred Income Taxes	2010	2009
Non-current deferred tax liabilities, net	212,003	194,315
NET DEFERRED TAX LIABILITIES	$212,003	$194,315

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

Temporary Differences	December 31, 2010	December 31, 2009
Deferred tax assets:		
Disallowed plant costs	$ 1,127	$ 1,217
Gains on hedging transactions	1,518	1,583
Plant related basis differences	21,105	19,130
Regulated liabilities related to income taxes	13,702	14,297
Pensions and other post-retirement benefits	1,588	14,558
Carry forward of income tax credit	12,596	—
Income received- deferred	10,044	—
Other	2,262	2,301
Total deferred tax assets	$ 63,942	$ 53,086
Deferred tax liabilities:		
Depreciation, amortization and other plant related differences	$216,685	$191,930
Regulated assets related to income	41,107	38,327
Loss on reacquired debt	3,996	4,496
Accumulated comprehensive income	—	929
Deferred ice storm expenses	2,957	4,448
Deferred fuel costs	1,965	—
Amortization of intangibles	4,850	3,773
Other	4,385	3,498
Total deferred tax liabilities	275,945	247,401
NET DEFERRED TAX LIABILITIES	$212,003	$194,315

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	2010	2009	2008
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	(0.7)	(0.8)	(0.9)
Effect of ratemaking on property related differences	(0.8)	(3.6)	(3.5)
Effect of Medicare part D changes	2.7		
Other	(0.1)	(1.2)	(1.2)
Effective income tax rate	39.2%	32.5%	32.5%

Unrecognized Tax Benefits	2010	2009	2008
Unrecognized tax benefits — January 1,	$ 906,000	$ 2,176,000	$ 328,000
The gross amounts of increases in unrecognized tax benefits taken during prior periods	—	—	1,957,000
The gross amounts of decreases in unrecognized tax benefits taken during the period relating to positions accepted by taxing authorities	—	—	(109,000)
Reductions to unrecognized tax benefits as a result of a lapse of the applicable statute of limitations	(547,000)	(1,270,000)	—
Unrecognized tax benefits — December 31,	$ 359,000	$ 906,000	$2,176,000

If unrecognized tax benefits are recognized, the effective tax rate would change from 39.2% to 39.0% based on recognizing approximately $0.1 million of unrecognized benefits. The Company recognized interest or penalties of $(0.1) million and $(0.1) million during 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 $5.1 million of these credits to reduce our 2010 tax payments and 2010 tax liability and these are reflected as part of an income tax receivable in accounts receivable — other. 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.

Note 1 describes a $26.6 million payment received from the SWPA (see "Other Noncurrent Liabilities of Note 1) which has been deferred for book purposes and treated as a noncurrent liability. We have increased our current tax liability by $10.0 million in recognition that the $26.6 million payment may be considered taxable income in 2010. We may defer recognition of the income for tax purposes if we determine the internal revenue code allows such treatment based on the facts and circumstances of the transaction.

On March 23, 2010, the Patient Protection and Affordable Care Act was enacted. This legislation includes a provision that reduces 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, 2010 and 2009, our property, plant and equipment accounts included the amounts in the following chart (in millions):

Iatan	2010	2009
Cost of ownership in plant in service	$353.9	$134.6
Accumulated Depreciation	$ 70.6	$ 36.6
Expenditures(1)	$ 18.2	$ 9.9

(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. (formerly Aquila) 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. In 2010 we added $0.1 million to plant in service associated with Iatan I environmental upgrades. Iatan 2 met its in-service criteria on August 26, 2010, and entered commercial operation on December 31, 2010. We added $212.2 million to plant in service associated with Iatan 2. During 2010 we also 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, 2010 and 2009, our property, plant and equipment accounts include the amounts in the following chart (in millions):

State Line Combined Cycle Unit	2010	2009
Cost of ownership in plant in service	$164.1	$164.0
Accumulated Depreciation	$ 44.9	$ 40.1
Expenditures(1)	$ 59.6	$ 41.9

(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, 2010 and 2009, our property, plant and equipment accounts included the amounts in the following chart (in millions):

Plum Point Energy Station	2010	2009
Cost of ownership in plant in service	$110.2	—
Accumulated Depreciation	$ 0.7	—
Expenditures(1)	$ 3.4	—

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

All of the dollar amounts listed above represent our ownership share of costs. Each participant must provide their own financing.

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 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 Plaintiff crops due to inappropriate management of the levee system around Iatan, of which we are a 12% owner. No procedural schedule has been established and we are unable to predict the outcome of the law suit.

Coal, Natural Gas and Transportation Contracts

	Firm physical gas and transportation contracts	Coal and coal transportation contracts
	(in millions)	
January 1, 2011 through December 31, 2011	$38.3	$40.1
January 1, 2012 through December 31, 2013	56.9	53.4
January 1, 2014 through December 31, 2015	29.4	33.5
January 1, 2016 and beyond	25.8	14.2

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. Due to damage incurred in March 2009 to our Asbury rail car unloading facility, we issued Force Majeure notices to our western coal suppliers and to the railroads, suspending western coal shipments. This relieved us of our contractual obligations to receive shipments of coal until the railroad unloading facility was repaired and put back in service May 13, 2009. 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 utilities 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.

Our long-term contract with Westar Energy for the purchase of capacity and energy expired on May 31, 2010.

We have a long term (30 year) agreement for the purchase of capacity from the Plum Point Energy Station, a new 665-megawatt, coal-fired generating facility built by Plum Point Energy Associates (PPEA) near Osceola, Arkansas. The Plum Point Energy Station met its in-service criteria on August 13, 2010, and 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 $45.0 million through August 30, 2015.

On June 25, 2007, we entered into a 20-year purchased power agreement with Cloud County Windfarm, LLC, owned by Horizon Wind Energy, Houston, Texas. Pursuant to the terms of the agreement, we will purchase all of the output from 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.

On December 10, 2004, we entered into a 20-year contract with Elk River Windfarm, LLC to purchase all of the energy generated at the 150-megawatt Elk River Windfarm located in Butler County, Kansas. We do not own any portion of the windfarm. Payments for wind energy from the Elk River Windfarm are contingent upon output of the facility. Annual payments can run 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

On March 14, 2006, we entered into contracts to purchase a 50 megawatt, 7.52%, undivided interest in the Plum Point Energy Station described above. The estimated cost was approximately $88.0 million, excluding allowance for funds used during construction (AFUDC) which totaled $16.5 million. Our share of the Plum Point costs through December 31, 2010 was $86.9 million plus AFUDC of $16.5 million. The Plum Point Energy Station met its in-service criteria on August 13, 2010. Plum Point entered commercial operation on September 1, 2010.

We also purchased 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 met its in-service criteria on August 26, 2010 (as reported by KCP&L) and entered commercial operation on December 31, 2010. Our share of the Iatan 2 construction costs are expected to be in a range of approximately $237 million to $240 million, excluding AFUDC which totaled $19.1 million. Our share of the Iatan 2 costs through December 31, 2010 was $228.9 million plus AFUDC of $19.1 million. Current projections estimate $11.1 million being spent in 2011 for our share of expected expenditures for Iatan 2.

Recovery of construction costs

We filed several rate cases primarily to recover the costs of the completed plants described above. These are described below.

A stipulated agreement in our 2009 Missouri electric rate case 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. The Plum Point Generating Station completed its in-service criteria testing on August 12, 2010, with an in-service date of August 13, 2010. Rates went into effect on September 10, 2010.

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 the recently-completed Missouri rate case. Iatan 2 was placed in-service on August 26, 2010.

These construction costs from these facilities will be subject to prudency reviews by our regulators.

A stipulated agreement in our current Kansas rate case 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.

On August 30, 2010, we were granted a two-phase Capital Reliability Rider (CRR) by the Oklahoma Corporation Commission (OCC) with the first phase effective September 1, 2010. 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. We will file a general rate case within six months of the commercial operation date of Iatan 2 to replace the CRR with permanent rates.

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%.

Leases

We have purchased power agreements with Cloud County Wind Farm and Elk River Wind Farm, 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 six service center properties related to our gas segment. As of December 31, 2010, EDG purchased these six service center properties. 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 $6.9 million at December 31, 2010.

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

Capital Leases	Capital Leases	Operating Leases
2011	$ 596	$ 984
2012	589	992
2013	589	752
2014	547	720
2015	546	720
Thereafter	5,193	2,533
Total minimum payments	8,060	6,701
Less amount representing interest	2,798	—
Present value of net minimum lease payments	$5,262	$6,701

Expenses incurred related to operating leases were $0.8 million, $1.4 million and $1.5 million for 2010, 2009, and 2008, respectively, excluding payments for wind generated purchased power agreements. The accumulated amount of amortization for our capital leases was $0.6 million and $0.4 million at December 31, 2010 and 2009, 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 air 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.

SO_2 Emissions

The CAA regulates the amount of SO_2 an affected unit can emit through, among other things, a cap and trade program. Each existing affected unit has been allocated a specific number of emission allowances by the U.S. Environmental Protection Agency (EPA), each of which allows 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 SO_2 allowance bank is exhausted, currently estimated to be early 2012, we will need to purchase additional SO_2 allowances or build a Flue Gas Desulphurization (FGD) scrubber system at our Asbury Plant. Based on current and projected SO_2 allowance prices and high-level estimated FGD scrubber construction costs (discussed below) and absent other, more stringent regulatory requirements, such as the proposed Clean Air Transport Rule (CATR) and Mercury and Electric Steam Generating Unit (EGU) Maximum Achievable Control Technology (MACT) discussed below, it will likely be more economical for us to purchase SO_2 allowances than to build a scrubber at the Asbury Plant. If we were to purchase SO_2 allowances, we would expect their cost to be fully recoverable in our rates.

NOx Emissions

The CAA regulates the amount of NOx an affected unit can emit. Each of our affected units is in compliance with the NOx limits applicable to it as currently operated.

Ozone, also called ground level smog, is formed by the mixing of NOx and Volatile Organic Compounds in the presence of sunlight. On January 6, 2010, the EPA proposed to lower the primary National Ambient Air Quality Standard (NAAQS) for ozone designed to protect public health and to set a secondary NAAQS for ozone designed to protect sensitive vegetation and ecosystems. The EPA is expected to issue final standards by July 31, 2011. Once final standards are set, states will be required to develop State Implementation Plans (SIPs) which reflect these standards.

Clean Air Interstate Rule (CAIR) and Clean Air Transport Rule (CATR)

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 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.

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.

The CAIR requires covered states (including Missouri and Arkansas) to develop SIPs to comply with specific NOx and SO_2 state-wide annual budgets. Missouri and Arkansas have approved SIPs and, based on these SIPs, we believe we will have excess NOx allowances for 2010 which will be banked for future use. However, SO_2 allowances must be utilized at a 2:1 ratio for our Missouri units as compared to our non-CAIR Kansas units beginning in 2010. As a result, based on current SO_2 allowance usage projections, we expect to exhaust our banked allowances by early 2012 and, as discussed above, will need to purchase additional SO_2 allowances or build a scrubber at our Asbury Plant.

In order to meet CAIR requirements and as a requirement for the air permit for Iatan 2, a Selective Catalytic Reduction system (SCR), FGD scrubber system and baghouse were installed at our joint-owner Iatan 1 plant and an SCR was installed at our Asbury plant in 2008.

On July 6, 2010, the EPA published a proposed CAIR replacement rule entitled the Clean Air Transport Rule (CATR). As proposed, the CATR would include Kansas under the annual and ozone season NOx and the SO_2 programs. Missouri would be dropped from the ozone season NOx program while Arkansas would remain in the ozone season NOx program. The beginning date of regulation for the proposed CATR is 2012. The final CATR is expected to be issued by the EPA in July 2011. The proposed rule requires a 71% reduction in SO_2 and a 52% reduction in NOx from 2005 levels by 2014. We do not expect significant impacts on our operations because of new NOx requirements in CATR. We cannot accurately estimate the cost of any final regulation or predict its precise timing and its impact on our operations at this time. To address SO_2 compliance plans range from purchasing additional emission allowances to installing a FGD scrubber at our Asbury facility (see estimated construction costs below) and potential forced retirement or conversion to natural gas of our coal-fired Riverton assets. We expect compliance costs to be recoverable in our rates.

Mercury and Electric Steam Generating Unit (EGU) Maximum Achievable Control Technology (MACT)

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.

Based on CAMR, we installed a mercury analyzer at Asbury and installed two mercury analyzers at Riverton in 2008. We continue to operate the mercury analyzers at Riverton in accordance with the appropriate state environmental regulator's guidance.

The EPA issued an Information Collection Request (ICR) for national emission standards for HAPs, including mercury, for coal and oil-fired electric steam generating units on December 24, 2009. This ICR included our Iatan, Asbury and Riverton plants. We completed the ICR for Asbury and Riverton and submitted them to the EPA on March 31, 2010. KCP&L completed and submitted the Iatan ICR. The EPA ICR is intended for use in developing regulations under Section 112(r) of the CAA maximum achievable emission standards for the control of the emission of HAPs, including mercury. The EPA is under a court order to issue a proposed EGU MACT regulation by March 16, 2011 and to finalize that regulation by November 16, 2011. Absent a successful legal challenge or changes to applicable legislation, we expect EGU MACT regulation of HAPS to ultimately require a scrubber, baghouse and powder activated carbon injection system to be added to our Asbury facility at a cost ranging from $120 million to $180 million and to force retirement of our Riverton coal-fired assets or conversion to natural gas. We expect compliance costs to be recoverable in our rates.

Green House Gases

Our coal and gas plants, vehicles and other facilities, including EDG (our gas segment), emit CO_2 and/or other GHGs which are measured in Carbon Dioxide Equivalents (CO_2e).

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, including EDG that equal or exceed an emission threshold of 25,000 metric tons of CO_2e to report GHGs to the EPA annually commencing in March 2011. We will report our GHG emissions as required to the EPA in 2011 for EDE. EDG is not required to submit its GHG emissions until 2012.

On December 7, 2009, responding to a 2007 US 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 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 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 July 26, 2011 and to issue final GHG NSPS standards by May 26, 2012.

Litigation aimed at controlling GHG emissions has also increased. For example, recently the U.S. Court of Appeals for the Second Circuit has ruled that certain public and private parties can pursue claims that GHG emissions constitute a public nuisance and can seek to recover alleged related damages. The U.S. Supreme Court has agreed to review this decision in the spring of 2011. In contrast, in May 2010, the full U.S. Court of Appeals for the Fifth Circuit took action which left standing the lower court's dismissal of a nuisance claim similar to those upheld by the Second Circuit, which as noted above, is now before the U.S. Supreme Court.

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 CO_2e 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 Plant is 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 submit 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. 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 is expected to revise and re-propose the regulations by March 2011 and to finalize them by November 2011.

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. The EPA has announced its intention to revise its wastewater effluent limitation guidelines under the CWA for coal-fired power plants before 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. It is anticipated that the final regulation will be published in 2011. 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. This preliminary estimate will likely change based on the final CCR rule and design requirements reach final forms. 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. We have received preliminary draft reports on the Asbury and the Riverton impoundments. The reports are currently under final review by the EPA and our comments have been requested. We are not currently in a position to estimate what additional actions if any will result from the EPA's inspections.

Renewable Energy

We currently purchase more than 15% of our energy through long-term Purchased Power Agreements (PPAs) with Elk River Windfarm, LLC and Cloud County Windfarm, LLC. 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, 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. is pending in the Missouri Western District Court of Appeals. In July 2010, the MPSC submitted to the Missouri secretary of state's office its rule for the renewable energy mandate. We are awaiting action from the Missouri secretary of state but believe we are in compliance with the law. Kansas established a renewable portfolio standard (RPS) in May 2009 which was approved October 27, 2010, effective November 19, 2010. Its final rulemaking was released in November 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. Over time, we expect 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				
	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

	2008				
	Electric	Gas	Other	Eliminations	Total
Statement of Income Information:					
Revenues	$448,248	$65,438	$5,005	$(528)	$518,163
Depreciation and amortization	50,305	1,940	1,317	—	53,562
Federal and state income taxes	17,764	987	375	—	19,126
Operating income	64,426	5,420	1,166	—	71,012
Interest income	1,162	390	—	(495)	1,057
Interest expense	39,627	3,962	204	(495)	43,298
Income from AFUDC (debt and equity)	12,508	10	—	—	12,518
Income from continuing operations	$ 37,436	$ 1,677	$ 609	$ —	$ 39,722
Capital Expenditures	$202,295	$ 2,139	$1,952	$ —	$206,386

	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

	December 31, 2009				
	Electric	Gas(1)	Other	Eliminations	Total
Balance Sheet Information:					
Total assets	$1,759,415	$134,355	$21,907	$(75,831)	$1,839,846

(1) Includes goodwill of $39,492 at December 31, 2010 and 2009.

13. Selected Quarterly Information (Unaudited)

The following is a summary of quarterly results for 2010 and 2009 (dollars in thousands except per share amounts):

Quarterly Results for 2010	Quarters			
	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

Quarterly Results for 2009	Quarters			
	First	Second	Third	Fourth
Operating revenues	$136,015	$112,230	$128,053	$120,870
Operating income	$ 18,655	$ 16,027	$ 23,677	$ 16,136
Net Income	$ 10,913	$ 7,627	$ 14,829	$ 7,927
Basic Earning Per Share	$ 0.32	$ 0.22	$ 0.43	$ 0.22
Diluted Earnings Per Share	$ 0.32	$ 0.22	$ 0.43	$ 0.22

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 2010 were $8.5 million, or $0.20 per share, as compared to $7.9 million, or $0.22 per share, in the fourth quarter 2009. Total revenues increased approximately $11.9 million (9.9%) for the fourth quarter of 2010 as compared to the fourth quarter of 2009 primarily due to rate increases which became effective in 2010. Partially offsetting the increase in revenues were increases in operations and maintenance expenses and depreciation and amortization.

14. Risk Management and Derivative Financial Instruments

We currently engage in hedging activities in an effort to minimize our risk from volatile natural gas prices. We enter into 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 expense and gain predictability, and do not engage in speculative activities. 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. Effective September 1, 2008, in conjunction with the implementation of the Missouri fuel adjustment clause, the unrealized losses or gains from new derivatives used to hedge our fuel costs in our electric segment are recorded in regulatory assets or liabilities. All gains and losses from derivatives related to the gas segment are 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. Unrealized gains and losses from derivatives related to our electric segment, entered into prior to September 1, 2008 were being deferred in other comprehensive income; however effective

December 2010 all remaining cash flow hedges entered into prior to September 1, 2008 were de-designated, and given that upon settlement the gain or loss would be recorded as a fuel expense subject to the fuel recovery clause, the unrealized loss of $1.0 million was transferred from other comprehensive income to a regulatory asset.

As of December 31, 2010 and 2009, 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

Derivatives designated as hedging instruments	Balance Sheet Classification	2010 Fair Value	2009 Fair Value
Natural gas contracts, electric segment	Current assets	$ —	$2,233
	Non-current assets and deferred charges	—	2,438
Non-designated hedging instruments due to regulatory accounting			
Natural gas contracts, gas segment	Current assets	39	410
	Non-current assets and deferred charges	117	—
Natural gas contracts, electric segment	Current assets	—	139
	Non-current assets and deferred charges	77	87
Total derivatives assets		$233	$5,307

LIABILITY DERIVATIVES

Derivatives designated as hedging instruments	Balance Sheet Classification	2010 Fair Value	2009 Fair Value
Natural gas contracts, electric segment	Current liabilities	$ —	$4,123
	Non-current liabilities and deferred credits	—	—
Non-designated as hedging instruments due to regulatory accounting			
Natural gas contracts, gas segment	Current liabilities	252	214
	Non-current liabilities and deferred credits	2	—
Natural gas contracts, electric segment	Current liabilities	508	—
	Non-current liabilities and deferred credits	3,562	426
Total derivatives liabilities		$4,324	$4,763

Electric

At December 31, 2010, approximately $0.5 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 with the unrealized gains or losses recognized in OCI. In the future unrealized gains and losses will now be 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 Gain/(Loss) on Derivative	Amount of Gain/(Loss) Reclassed from OCI into Income (Effective Portion)	
		2010	2009
Commodity contracts	Fuel and purchased power expense	$(5,814)	$(13,568)
Total Effective — Electric Segment		$(5,814)	$(13,568)

Derivatives in Cash Flow Hedging Relationships — Electric Segment

	Statement of Comprehensive Income	Amount of Gain/(Loss) Recognized in OCI on Derivative (Effective Portion)	
		2010	2009
Commodity contracts	Fuel and purchased power expense	$(6,362)	$(9,576)
Total Effective — Electric Segment		$(6,362)	$(9,576)

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, 2010 and 2009, respectively.

In accordance with the Missouri fuel adjustment clause discussed above, the recoverable portion of any gain or loss is recorded in a regulatory asset or liability account. 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 Gain/(Loss) on Derivative	Amount of Gain/(Loss) Recognized on Balance Sheet 2010	2009
Commodity contracts — electric segment	Regulatory (assets)/liabilities	$(2,669)	$1,192
Total — Electric Segment		$(2,669)	$1,192

Non-Designated Hedging Instruments — Due to Regulatory Accounting Electric Segment

	Statement of Operations Classification of Gain/(Loss) on Derivative	Amount of Gain/(Loss) Recognized in Income on Derivative 2010	2009
Commodity contracts	Fuel and purchased power expense	$(752)	$(2,249)
Total — Electric Segment		$(752)	$(2,249)

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.

As of February 4, 2011, 88% of our anticipated volume of natural gas usage for our electric operations for the year 2011 is hedged, either through physical (2.0 million Dths) or financial contracts (3.0 million Dths), at an average price of $5.774 per Dekatherm (Dth). In addition, the following volumes and percentages of our anticipated volume of natural gas usage for our electric operations for the next three years are hedged at the following average prices per Dth:

Year	% Hedged	Dth Hedged	Average Price
2012(1)	60%	3,745,000	$6.618
2013(1)	41%	3,460,000	$6.079
2014	20%	1,580,000	$5.607
2015	4%	400,000	$5.500

(1) 1.4 million Dth and 1.4 million Dth of the anticipated volume of natural gas usage for 2012 and 2013, respectively, are hedged through financial derivative contracts.

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	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. As of February 4, 2011, we have 100% of our expected remaining winter heating season usage (through March 2011) hedged with physical storage, physical forward contracts and financial derivative contracts. The average price of these hedges is $4.861 per Dth. 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 February 5, 2011, we had 0.6 million Dths in storage on the three pipelines that serve our customers. This represents 28% of our storage capacity. We have an additional 0.7 million Dth hedged through financial derivatives and physical contracts. Our long-term hedge strategy is to mitigate price volatility for our customers by hedging a minimum of 50% of current year, up to 50% of second year and up to 20% of third year expected gas usage by the beginning of the Actual Cost Adjustment (ACA) year at September 1. 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 Gain or (Loss) on Derivative	Amount of Gain/(Loss) Recognized on Balance Sheet 2010	2009
Commodity contracts	Regulatory (assets)/liabilities	$(626)	$(671)
Total — Gas Segment		$(626)	$(671)

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, 2010 is $0.5 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, 2010, we would have been required to post $0.5 million of collateral with one of our counterparties. On December 31, 2010, 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 provided by a third party that are derived principally from or corroborated by observable market data by correlation. Our Level 3 fair value measurements consist of both quoted price inputs and unobservable quoted inputs provided by a third party.

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, 2010:

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, 2010				
Net derivative assets/(liabilities)*	$(4,091)	$(4,091)	—	—
December 31, 2009				
Net derivative assets/(liabilities)*	$ 544	$ 544	—	—

* The only recurring measurements are derivative related and assets and liabilities are netted together in the table above.

The following tables present the net fair value on a recurring basis using significant unobservable inputs (Level 3) during the twelve months ended December 31, 2010 and 2009 (in thousands):

Fair Value Measurements Using Significant Unobservable Inputs (Level 3)

($ in 000's)	2010 Net Derivatives[1]	2009 Net Derivatives[1]	2008 Net Derivatives[1]
Beginning Balance, January 1,	$ —	$ 6,208	$11,961
Total gains or losses (realized/unrealized)			
Included in earnings (or changes in net assets)	—	—	—
Included in comprehensive income	—	(1,738)	(5,753)
Purchases, issuances, and settlements, net	—	—	—
Transfers in and/or out of Level 3	—	(4,470)	—
Ending Balance, December 31,	$ —	$ —	$ 6,208
Changes in unrealized Gains relating to assets still held at reporting date	$ —	$ 1,738	$ 5,753

(1) Net derivatives at December 31, 2010 and 2009 included no derivative assets and no derivative liabilities, respectively. Net derivatives at December 31, 2008 included assets of $6.2 million and no 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, 2010	December 31, 2009
Accounts receivable for plant reimbursements, line extensions, highway projects, etc.	$ 5,322	$ 2,812
Taxes receivable — overpayment of estimated income taxes[1]	10,807	3,191
Accounts receivable for energy trading margin deposit[2]	3,878	2,914
Accounts receivable for true-up on maintenance contracts[3]	1,512	1,831
Accounts receivable for insurance proceeds for SLCC generator failure[4]	2,596	9,270
Accounts receivable from Westar Generating, Inc., for commonly-owned facility	636	817
Accounts receivable for gas segment	27	37
Accounts receivable for non-regulated subsidiary companies	602	454
Other	65	91
Total Accounts Receivable — Other	$25,445	$21,417

(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 belong to Westar Generating, Inc., and is 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,		
	2010	2009	2008
Electric transmission and distribution expense	$12,996	$11,063	$10,891
Natural gas transmission and distribution expense	2,194	2,161	1,995
Power operation expense (other than fuel)	11,356	12,315	11,671
Customer accounts & assistance expense	11,618	10,597	10,166
Employee pension expense[(1)]	5,899	5,557	5,892
Employee healthcare plan[(1)]	6,930	5,908	7,136
General office supplies and expense	11,584	10,070	9,330
Administrative and general expense	12,896	12,211	11,728
Bad debt expense	3,651	3,125	2,944
Miscellaneous expense	168	79	165
Total	$79,292	$73,086	$71,918

(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, 2010.

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, 2010.

Audit of Internal Control Over Financial Reporting

The effectiveness of our internal control over financial reporting as of December 31, 2010, 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 2010 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 28, 2011, 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 28, 2011, 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 28, 2011, 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, 2010:

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 . . .	573,638	$20.51	1,164,690
Equity compensation plans not approved by security holders . . .	—	—	—
TOTAL	573,638	$20.51	1,164,690

(1) The weighted average exercise price of $20.51 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, 56,400, 64,200 and 41,700 options granted to executive officers in 2010, 2009, 2008, 2007 and 2006, respectively, under the 2006 Stock Incentive Plan and 71,326 subscriptions outstanding for our ESPP. The two stock incentive plans had a weighted average exercise price of $21.69 and the ESPP had an exercise price of $16.06. There is no exercise price for 95,000 performance-based stock awards awarded under the 2006 Stock Incentive Plans or for 139,912 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 28, 2011 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 28, 2011 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) 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).

(p) 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).

(q) 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).

(r) 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).

(s) 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).

(t) 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).

(u) 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) Equity Distribution Agreement dated February 25, 2009 between The Empire District Electric Company and UBS Securities LLC (Incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K dated February 25, 2009 and filed February 26, 2009, File No. 1-3368).

(u) Amendment No. 1, dated October 22, 2009 to the Equity Distribution Agreement dated February 25, 2009 between The Empire District Electric Company and UBS Securities LLC (Incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K dated October 22, 2009 and filed October 22, 2009, File No. 1-3368).

(v) 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).

(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.*~

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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.

~ 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, 2010, 2009 and 2008:

	Balance At Beginning Of Period	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, 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
Year ended **December 31, 2008**:							
Reserve deducted from assets: accumulated provision for uncollectible accounts.	$1,140,955	$2,903,922	Recovery of amounts previously written off	$1,877,576	Accounts written off	$4,657,032	$1,265,421

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 17, 2011

By /s/ WILLIAM L. GIPSON

William L. Gipson, 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.

/s/ WILLIAM L. GIPSON William L. Gipson, President, Chief Executive Officer, Director (Principal Executive Officer)	Date: February 17, 2011
/s/ GREGORY A. KNAPP Gregory A. Knapp, Vice President-Finance (Principal Financial Officer)	
/s/ LAURIE A. DELANO Laurie A. Delano, 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/ BILL D. HELTON* Bill D. Helton, 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/ GREGORY A. KNAPP *By (Gregory A. Knapp, As attorney in fact for each of the persons indicated)	

Computation of Ratios of Earnings to Fixed Charges

	Year ended December 31,				
	2010	**2009**	**2008**	**2007**	**2006**
Income before provision for income taxes and fixed charges (Note A)	**$125,706,453**	$114,457,760	$108,185,260	$91,690,922	$99,409,515
Fixed Charges:					
Interest on long-term debt	**$ 41,958,541**	$ 42,084,023	$ 36,040,957	$31,120,122	$25,947,191
Interest on short-term debt	**630,913**	1,124,883	1,853,682	2,940,317	2,275,939
Interest on trust preferred securities	**2,089,583**	4,250,000	4,250,000	4,250,000	4,250,000
Other interest	**(2,332,530)**	(680,863)	1,152,588	1,069,206	1,029,135
Rental expense representative of an interest factor (Note B)	**5,430,863**	6,501,484	6,040,062	4,686,748	4,798,490
Total fixed charges	**$ 47,777,370**	$ 53,279,527	$ 49,337,289	$44,066,393	$38,300,755
Ratio of earnings to fixed charges	**2.63**	2.15	2.19	2.08	2.60

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, William L. Gipson, 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 17, 2011

By: /s/ William L. Gipson

Name: William L. Gipson
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, Gregory A. Knapp, 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 17, 2011

By: /s/ Gregory A. Knapp

Name: Gregory A. Knapp
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, 2010 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), William L. Gipson, 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/ William L. Gipson

Name: William L. Gipson
Title: President and Chief Executive Officer

Date: February 17, 2011

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, 2010 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Gregory A. Knapp, 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/ Gregory A. Knapp

Name: Gregory A. Knapp
Title: Vice President — Finance and Chief Financial Officer

Date: February 17, 2011

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.

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Annual Meeting

The annual meeting of shareholders will be held Thursday, April 28, 2011, at 10:30 a.m., CDT, at the Memorial Hall, 212 West 8th Street, 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)
www.wellsfargo.com/shareownerservices (for general inquiries)

Stock Trading

As of December 31, 2010, there were 4,953 common shareholders of record. Empire common stock is listed on the New York Stock Exchange under the ticker symbol EDE.

Stock Prices and Dividends

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

2009	Quarter	High	Low	Dividend Paid
	First	$18.51	$11.92	$0.32
	Second	$16.66	$14.19	$0.32
	Third	$19.00	$16.44	$0.32
	Fourth	$19.36	$17.78	$0.32

Credit Ratings

	Standard & Poor's	Moody's	Fitch
Corporate Credit Rating	BBB-	Baa2	N/R*
EDE First Mortgage Bonds	BBB+	A3	BBB+
Commercial Paper	A-3	P-2	F2
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)
www.wellsfargo.com/shareownerservices (for 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, 2010.

Inquiries

Investor, shareholder, and financial information is also available from:

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.

The Empire District Electric Company
602 S. Joplin Avenue
PO Box 127
Joplin, MO 64802-0127
tel 417.625.5100

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SERVICES YOU COUNT ON