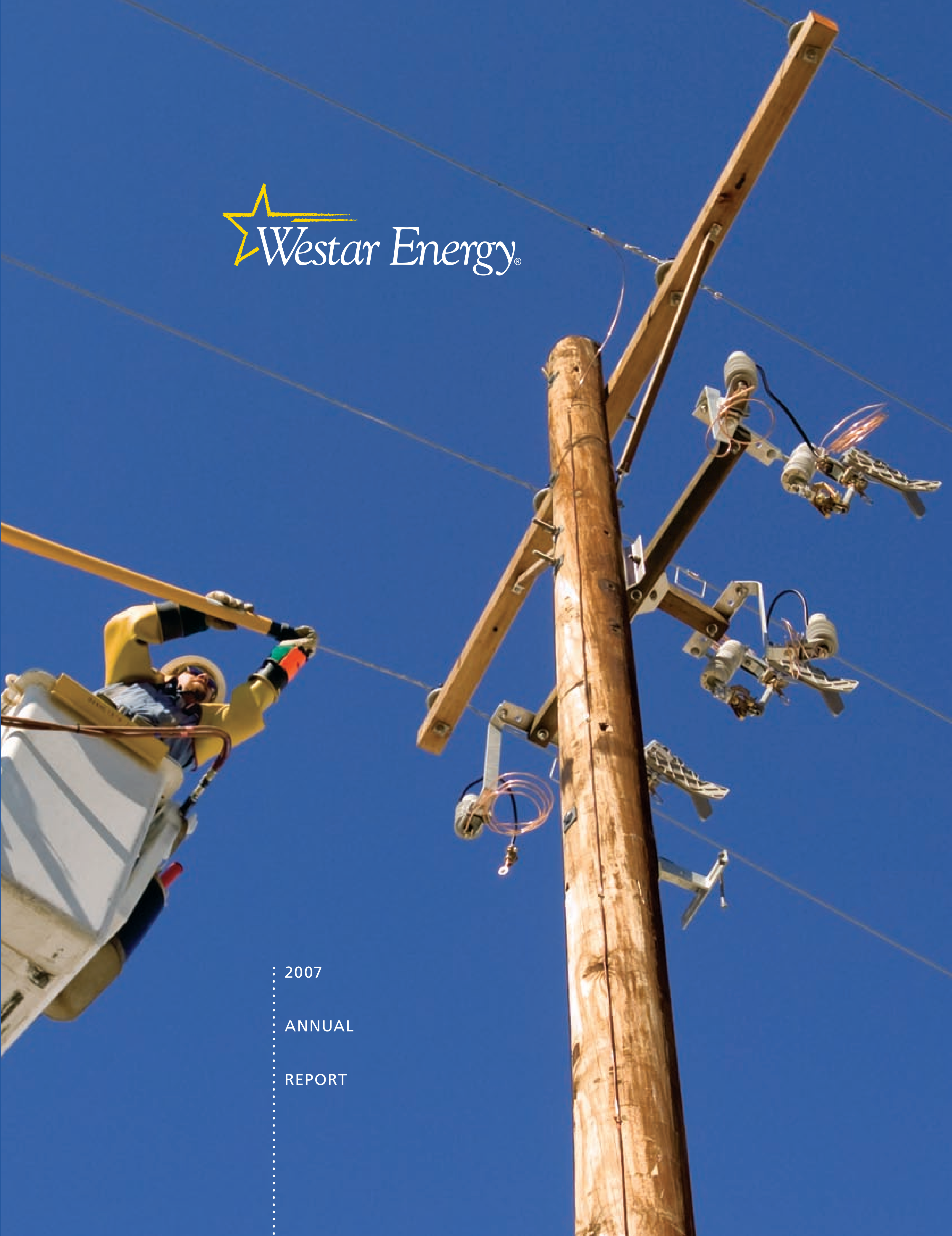
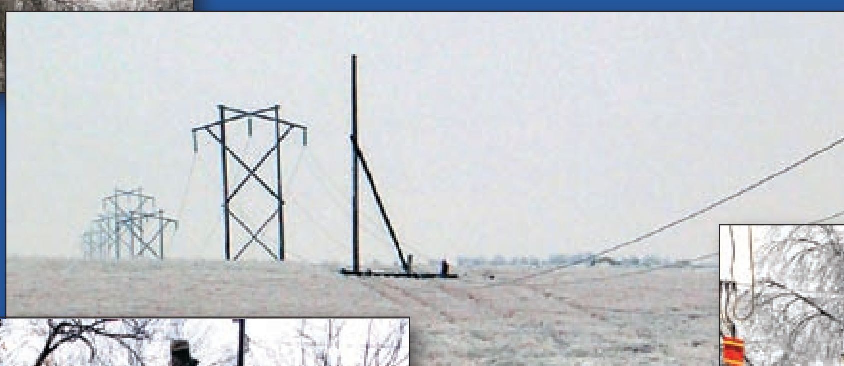
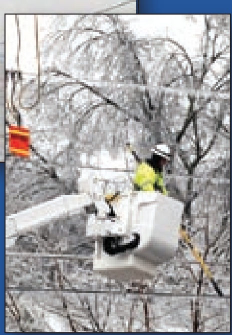
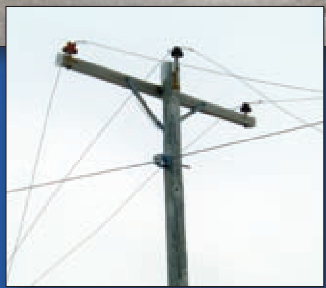

Westar Energy®
2007
ANNUAL
REPORT

The December 2007 ice storm is unparalleled in Westar Energy's history, costing an estimated $73-85 million and affecting nearly our entire service territory. The first wave hit our southeast region on December 9 and the second wave pummeled the rest of our territory on December 10. Power was knocked out to about 204,000 customers. The storm damaged a significant portion of our electric distribution system: 82 transmission circuits; 560 distribution circuits; 17,965 service lines; 7,872 spans of primary and secondary lines; 5,401 fuses; 2,090 power poles and a variety of other equipment. More than 1,000 Westar employees, 1,995 line workers from 21 states, 1,254 tree clearance personnel and some retirees worked to restore power as quickly as possible. By December 20, power was restored to all customers who could receive power.







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Dear Shareholders:

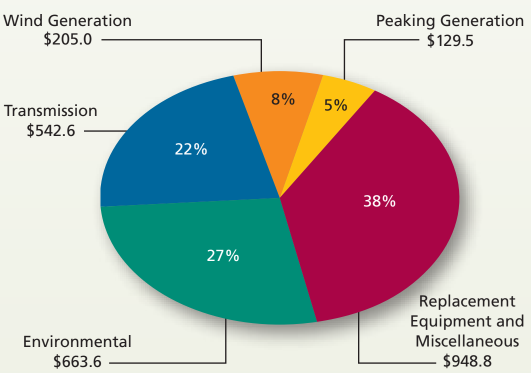
2007 was a watershed year for Westar Energy. In 2007 our focus shifted from planning to doing. For the past few years we have been planning for the growth of your company and your investment, working with regulators and public officials to improve the clarity and timeliness of how we recover our investments in the prices we charge and firming up our investment plans to meet our customers' growing need for electricity. In the years ahead, we will focus both on refining and executing plans to grow your company.

Throughout this annual report we share with you the various ways your company is growing for the future and how your management team here is executing our plans for making good utility investments. Specifically, you will see that our investment strategy is large and diverse. Our investment strategy is large because of the growing energy demands of our customers and the requirements of developing environmental regulations. It is not a stretch to say an environmental overlay now affects almost everything we do. It is diverse, certainly not in the sense that we are venturing off into some non-utility businesses, but rather in the sense that we are investing in nearly every facet of electric utility operations. A diversified investment strategy is critical because the future of the energy business is harder than ever to predict. Our strategy increases the probability that Westar will continue to succeed in uncertain times and reduces the probability that we will risk too much capital in just one area of our integrated business. Examples of this are our decision to defer construction of a new base load coal plant and our commitment to additional, more flexible, natural gas fired generation paired with wind energy and energy efficiency.

Over the next few years we expect to double our investment in utility plants. Our expansion plan includes investments across asset types: replacing equipment as it wears out; enhancing the environmental controls of our coal plants; building new gas peaking generators and new high capacity transmission lines; and making significant investments in renewable, wind energy and energy efficiency programs. We hope you will take a few moments to review these projects in more detail as we have highlighted them in the next few pages.

PLANNED CAPITAL INVESTMENT

(Dollars in Millions)



As consumer demand for electricity continues to grow we expect to meet that need in a variety of ways. Over the next few years we expect to double our investment in capital to serve our customers' needs.

We are pleased to report that all this planning and managing of major construction projects did not cause us to lose sight of current performance. We have maintained safety, reliability and strong financial performance as we implemented strategies for the future. 2007 was another solid year for earnings and dividend growth, with dividends up 8 percent from their 2006 level. Your board of directors also just recently announced another increase in the quarterly dividend of 7.4 percent, which on an indicated annual basis now reflects a dividend of $1.16 per share.

Westar is proud to remain a basic utility. And our employees remain focused on the fundamentals of reliable electric service and on making our service area a great place to work and live.

- Our power plants continued to operate safely and reliably. By way of example, in 2007, Wolf Creek operated at full output the whole year, and our largest coal units were available 86.9 percent of the time.
- We continued our quest toward ever improving service reliability and customer satisfaction. As measured by both frequency and duration of outages, our service levels improved.
- We improved the effectiveness of responding to customers, and expanded ways in which customers can get their needs met, whether through traditional conversations, automated call handling or via Internet.
- Employees from all across Westar continue to volunteer, contribute and improve the quality of life in the communities we serve, large and small.

William B. Moore, left, president and chief executive officer, and Charles Q. Chandler IV, chairman of the board.

Part of managing for the future is developing upcoming leaders. Evidence of that is the smooth transition in the office of our CEO. In June we said good-bye and thank you to Jim Haines for having led Westar well for over four years and promoted one of our own. During the transition, we were also able to retain our entire senior management team, and seize opportunities to cross train, expand and develop the talents of our senior leadership team.

Finally, nature dealt us quite a blow in December 2007. An ice storm caused the most widespread damage to our lines that we have ever experienced. At its worst, about 30 percent of our customers were without power, and many customers saw their power restored only to be disappointed by yet another outage caused when another tree fell into one of our lines. In total, we made more than 400,000 customer restorations. We proudly thank our linemen and support team, which included the assistance of nearly 2,000 dedicated craftspersons from across the country, who came to help with the most rapid and safe storm restoration efforts of this magnitude in our history. We were also pleased that the Edison Electric Institute recognized Westar Energy with its Emergency Assistance Award for times we lent a hand to other utilities in the wake of six winter storms in 2007.

2008 will be another active year for your company as we file for a significant increase in our rates to reflect the expenditures made since 2004. Thank you for your ownership in Westar Energy.

Charles Q. Chandler IV
Chairman of the Board

William B. Moore
President & CEO

Social, political and environmental developments are reshaping our industry. It is time for new thinking, new approaches.

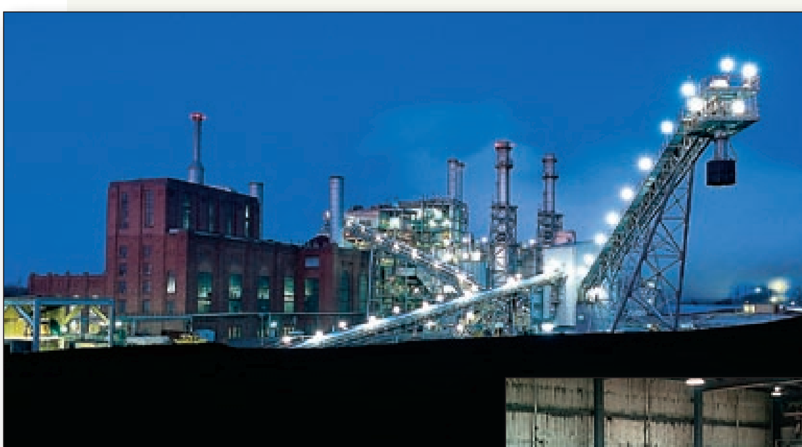
One of several stacks at the Emporia Energy Center.

Westar Energy, like all electric utilities, is operating in a rapidly changing world. Consumer use of electricity is growing at a pace that is beginning to draw down the reserves of power in the industry's supply network. This demand comes at a time when new power plant development is caught in the rising public and political debate about global warming. The issues are far from settled, and rhetoric sometimes blurs the facts; the future is far from certain and long-term investments today may confront new risks and challenges yet unknown.

We believe the best course in this environment is to embrace these uncertainties, rather than attempt to judge or predict their outcome, to ensure we navigate the turmoil and preserve the advantage Kansas has enjoyed over the decades in our energy investments and strategies.

Fundamentally, our approach is to keep our options open, invest in a range of proven and logical technologies, and adapt our plans as conditions continue to change. We are investing in wind and gas-fired generation, environmental improvements at our coal-fired plants and efficiency programs to meet our customers' immediate growing needs. Our approach is designed to delay the need for additional base load generation as long as it is prudent to do so in light of costs and to let emerging technology develop. Base load needs have traditionally been met with coal-fired and nuclear generation, both of which involve high initial costs and are uncertain politically. During the past few years, the costs to build a coal plant have doubled.

By making thoughtful decisions, we can maintain the favorable rates Kansans enjoy and ensure reliable service.



A night view of Tecumseh Energy Center.

The turbine deck at Jeffrey Energy Center.

Westar Energy is poised to meet the growing electricity needs of consumers.

First, we are partnering with our customers to make sure we are all using energy effectively and efficiently. Second, we have developed a carefully thought-out, flexible investment plan to meet their growing needs.

Our industry is undergoing changes, and we are confident and ready to be part of the future. During this time of growth, we expect our utility investment to double. As we discuss here, the ways in which we expect to invest in our utility assets are varied.

Despite all of the uncertainty, many of the decisions made in the past continue to serve us well and provide flexibility today. Our singular focus remains on the electricity needs of Kansas and our determination to help our state maintain its self-reliance and price advantage as we move ahead.

The Shawnee Service Center is home base to more than 50 employees.

Tim Hunter, line foreman, and Blake Seib, journeyman lineman, unload poles that will be relocated for a public improvement project in Shawnee.

Communities and industries around the world share responsibility for the environment. We need to work together for sound, science-based solutions.

Energy consumption is growing among all segments of our customer base – industrial, commercial and residential. Similar growth is happening around the world, and it impacts our energy supply and our environment.

In Kansas, we have seen growth in the number of residential customers we serve and in the amount of electricity they use. Homes are bigger and most contain more fun or useful gadgets than just a few years ago. Our reasonable rates and reliable service have helped the state attract new business and encourage expansion of existing businesses. This growth is important to our state, but it also means increasing needs for electricity generation. It is important that we take a thoughtful, balanced approach to meeting these growing needs.

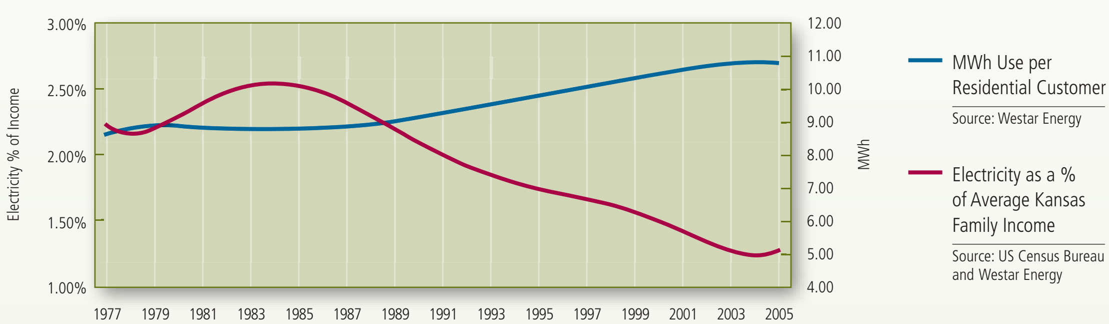
Solutions must be sound, science-based and economically feasible. Success will require a renewed commitment to energy conservation, public policy recognition of the uncertainties we face and prices that support the level of investment needed to maintain our energy advantage in Kansas.

Through energy efficiency we become partners with our consumers in shaping our energy and environmental future.

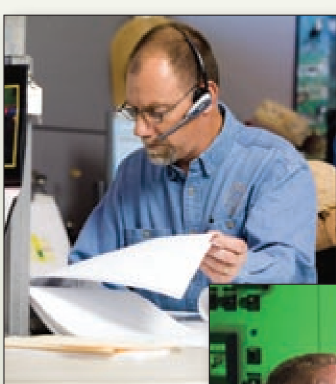
Energy efficiency programs can help Kansas manage its own destiny during this uncertain time. With a new generation of tools available, energy efficiency programs can also be a cost-effective way to solve energy and environmental challenges. Along with building additional power plants to produce electricity, it is our responsibility to help our consumers understand how their use impacts the larger picture. This is important with so much at stake environmentally and economically.

Our education programs offer consumers from schoolchildren to retirees simple solutions to curb their energy use, to use energy more wisely and to reduce their impact on the environment. Programs targeting spikes in summer use help delay the need for plants that would only be used a few times during the hottest months. Encouraging the use of high-efficiency electric heat pumps saves consumers money and helps us use our power plants more cost-effectively by increasing their use during the winter.

AVERAGE ELECTRICITY USAGE AND COST AS A % OF HOUSEHOLD INCOME



While the amount of electricity used per residential customer (shown in blue) has increased, the percentage of household income that goes to pay for electricity (shown in red) has declined.



Jim Godbout, technical specialist design, at the Shawnee Service Center.

Mike Headding, operations and maintenance person 04-MI, at Gordon Evans Energy Center.

Smart meters enable smarter decisions.

Metering technology has also rapidly advanced in recent years. Smart meters, as they are often called, include communication devices that give consumers and utilities an accurate picture of when energy is being used and how the system is performing. Real-time pricing can help consumers better understand how to manage their energy use. Return signals allow us quickly to determine the scope of power outages and provide periodic reports of electricity use for billing. In addition, some utilities have employed this technology to allow customers to prepay for their service. Westar is evaluating advanced metering technology and may conduct a pilot to test its effectiveness.

Craig Hansberry, Shawnee Division line foreman, prepares underground primary cable that will be used to service a new residential development.

Steve Asmann, technical specialist design, at the Shawnee Service Center.

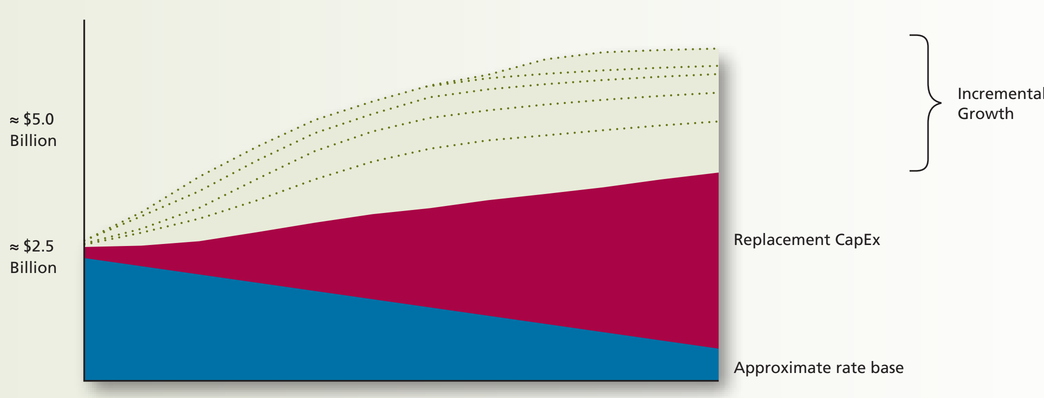
With a century invested in Kansas, helping customers, ensuring sound reliability and protecting our environment are so important they weave through everything we do.

We are committed to Kansas for the long haul, and our employees are part of the communities we serve. In recent years, we have been implementing new programs that have led to greater customer service and satisfaction. We have enhanced our online services, improved programs that support businesses of all sizes and implemented technology to provide customers more information should they experience an occasional power outage.

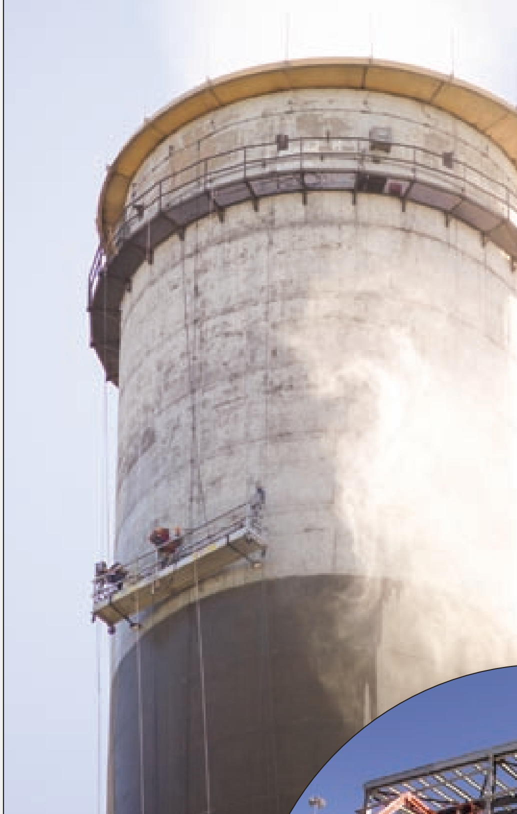
Our employee-led Green Team completed 53 projects in 2007. They included tree plantings in tornado-devastated Greensburg and across many other Kansas communities, construction and erection of osprey nest platforms at Big Hill Reservoir and wildlife rehabilitation pens in Hill City and Pittsburg, completion of a bridge at the Battle of Black Jack Historic Site, and donation of more than 400 bluebird, wood duck, bat and sparrow hawk nest boxes to groups across Kansas. All wood was recycled from used power poles.

As we enter a new phase in the utility industry, our commitment to being a basic electric utility and our commitment to our communities is steadfast. We are maintaining our existing infrastructure and investing in new infrastructure as consumption continues to grow.

PLANNED CAPITAL EXPANSION



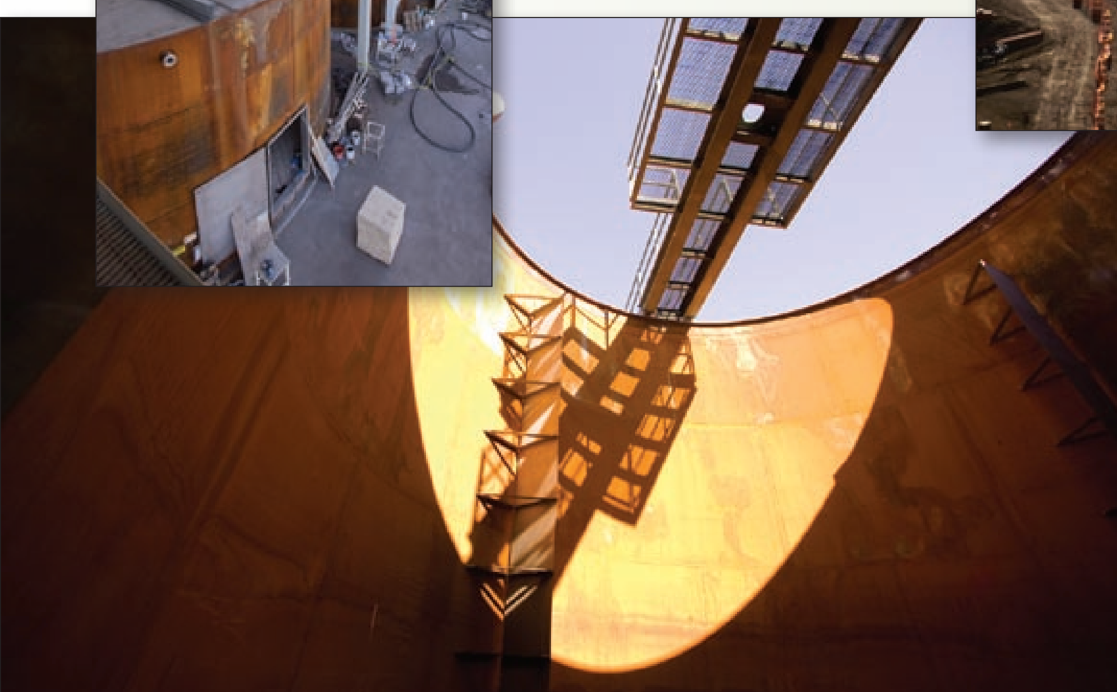
Over about the next six years we expect to double our utility investment. The first slice of our growth chart shows existing investment and, with all such investments, how they depreciate over time. As we enter a new era of growth, we will also continue to maintain and look for ways to extend the life of our existing investments. Through sound management of these assets, we have been able to extend their useful lives.



Crews clean one of the stacks at Jeffrey Energy Center as part of the scrubber retrofit.

Contractors work on the scrubber dewatering building at Jeffrey Energy Center.

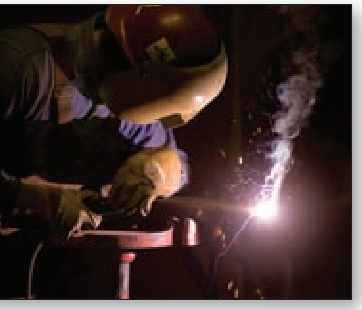
Circulating water line replacement work on unit 3 at Jeffrey Energy Center.



Scrubber reaction tank construction at Jeffrey Energy Center.

Continued on page 81

Financial Measures 2007:



A welder working on environmental upgrades at Jeffrey Energy Center.

	2007	2006
FINANCIAL DATA *(Dollars in Millions)*		
INCOME HIGHLIGHTS		
Sales	**$1,727**	$1,606
Income from continuing operations	**168**	165
Earnings available for common stock	**167**	164
BALANCE SHEET HIGHLIGHTS		
Total assets	**$6,395**	$5,455
Common stock equity	**1,827**	1,539
Capital structure:		
Common equity	**49%**	49%
Preferred stock	**1%**	1%
Long-term debt	**50%**	50%
OPERATING DATA		
Sales (Thousands of MWh)		
Retail	**20,124**	19,558
Wholesale	**10,026**	7,418
Customers	**674,000**	669,000
COMMON STOCK DATA		
PER SHARE HIGHLIGHTS		
Basic earnings per share	**$1.85**	$1.88
Dividends declared per common share	**$1.08**	$1.00
Book value per share	**$19.14**	$17.61
STOCK PRICE PERFORMANCE		
Common stock price range:		
High	**$28.57**	$27.24
Low	**$22.84**	$20.09
Stock price at year end	**$25.94**	$25.96
Average equivalent common shares outstanding (in thousands)	**90,676**	87,510
Dividend yield (based on year end annualized dividend)	**4.2%**	3.9%

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

FORM 10-K

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

For the fiscal year ended December 31, 2007

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 1-3523

WESTAR ENERGY, INC.

(Exact name of registrant as specified in its charter)

Kansas	**48-0290150**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)

818 South Kansas Avenue, Topeka, Kansas 66612 (785)575-6300

(Address, including Zip code and telephone number, including area code, of registrant's principal executive offices)

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

Common Stock, par value $5.00 per share **First Mortgage Bonds, 6.10% Series due 2047**	**New York Stock Exchange** **New York Stock Exchange**
(Title of each class)	(Name of each exchange on which registered)

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

Preferred Stock, 4-1/2% Series, $100 par value

(Title of Class)

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

Indicate by check mark whether 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 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, or a non-accelerated filer, or a smaller reporting company (as defined in Rule 12b-2 of the Act).
Check one: Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

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

The aggregate market value of the voting common equity held by non-affiliates of the registrant was approximately $2,203,151,369 at June 29, 2007.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date.

Common Stock, par value $5.00 per share	**97,750,463 shares**
(Class)	(Outstanding at February 19, 2008)

DOCUMENTS INCORPORATED BY REFERENCE:

Description of the document	**Part of the Form 10-K**
Portions of the Westar Energy, Inc. definitive proxy statement to be used in connection with the registrant's 2008 Annual Meeting of Shareholders	Part III (Item 10 through Item 14) (Portions of Item 10 are not incorporated by reference and are provided herein)

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FORWARD-LOOKING STATEMENTS

Certain matters discussed in this Annual Report on Form 10-K are "forward-looking statements." The Private Securities Litigation Reform Act of 1995 has established that these statements qualify for safe harbors from liability. Forward-looking statements may include words like we "believe," "anticipate," "target," "expect," "pro forma," "estimate," "intend" and words of similar meaning. Forward-looking statements describe our future plans, objectives, expectations or goals. Such statements address future events and conditions concerning matters such as, but not limited to: amount, type and timing of capital expenditures; earnings; cash flow; liquidity and capital resources; litigation; accounting matters; possible corporate restructurings, acquisitions and dispositions; compliance with debt and other restrictive covenants; interest rates and dividends; environmental matters; regulatory matters; nuclear operations; and the overall economy of our service area and economic well-being of our customers.

What happens in each case could vary materially from what we expect because of such things as: regulated and competitive markets; economic and capital market conditions, including the impact of changes in interest rates and the availability of capital; changes in accounting requirements and other accounting matters; changing weather; the impact of regional transmission organizations and independent system operators, including the development of new market mechanisms for energy markets in which we participate; rates, cost recoveries and other regulatory matters including the outcome of our request for reconsideration of the September 6, 2006, Federal Energy Regulatory Commission Order; the impact of changes and downturns in the energy industry and the market for trading wholesale energy; the outcome of the notice of violation received on January 22, 2004, from the Environmental Protection Agency and other environmental matters including possible future legislative or regulatory mandates related to emissions of presently unregulated gases or substances; political, legislative, judicial and regulatory developments at the municipal, state and federal level that can affect us or our industry, including in particular those relating to environmental laws; the impact of our potential liability to David C. Wittig and Douglas T. Lake for unpaid compensation and benefits and the impact of claims they have made against us related to the termination of their employment and the publication of the report of the special committee of the board of directors; the impact of changes in interest rates on pension and other post-retirement and post-employment benefit liability calculations, as well as actual and assumed investment returns on invested plan assets; the impact of changes in estimates regarding our Wolf Creek Generating Station decommissioning obligation; changes in regulation of nuclear generating facilities and nuclear materials and fuel, including possible shutdown or required modification of nuclear generating facilities; uncertainty regarding the establishment of interim or permanent sites for spent nuclear fuel storage and disposal; homeland security considerations; coal, natural gas, uranium, oil and wholesale electricity prices; availability and timely provision of equipment, supplies, labor and fuel we need to operate our business; and other circumstances affecting anticipated operations, sales and costs.

These lists are not all-inclusive because it is not possible to predict all factors. This report should be read in its entirety. No one section of this report deals with all aspects of the subject matter. Any forward-looking statement speaks only as of the date such statement was made, and we are not obligated to update any forward-looking statement to reflect events or circumstances after the date on which such statement was made except as required by applicable laws or regulations.

GLOSSARY OF TERMS

The following is a glossary of frequently used abbreviations or acronyms that are found throughout this report.

Abbreviation or Acronym	Definition
2005 KCC Order	December 28, 2005, KCC Order
Form 10-K	Annual Report on Form 10-K for the year ended December 31, 2007
AFUDC	Allowance for Funds Used During Construction
Aquila	Aquila, Inc.
BNSF	Burlington Northern Santa Fe
BNYCMI	BNY Capital Markets, Inc.
CO_2	Carbon Dioxide
Btu	British Thermal Units
Central States Compact	Central Interstate Low-Level Radioactive Waste Compact
COLI	Corporate-owned Life Insurance
DOE	Department of Energy
DOJ	Department of Justice
DSPP	Direct Stock Purchase Plan
ECRR	Environmental Cost Recovery Rider
EITF	Emerging Issues Task Force
EPA	Environmental Protection Agency
ERISA	Employee Retirement Income Security Act of 1974
FASB	Financial Accounting Standards Board
February 2007 KCC Order	February 8, 2007, KCC Order
FERC	Federal Energy Regulatory Commission
FIN	Financial Accounting Standards Board Interpretation No.
Fitch	Fitch Investors Service
Forward sale agreement	Forward equity sale agreement
GAAP	Generally Accepted Accounting Principles
Guardian	Guardian International, Inc.
IRC	Internal Revenue Code
IRS	Internal Revenue Service
IRS Appeals Settlement	December 2007 tentative settlement with the IRS Office of Appeals
JPM	J.P. Morgan Securities, Inc.
July 2006 Court Order	July 7, 2006, the Kansas Court of Appeals Order
July 2007 KCC Order	July 31, 2007, KCC Order
KCC	Kansas Corporation Commission

Abbreviation or Acronym	Definition
KCPL	Kansas City Power & Light Company
KDHE	Kansas Department of Health and Environment
KGE	Kansas Gas and Electric Company
kV	Kilovolt
La Cygne	La Cygne Generating Station
LTISA Plan	Long-Term Incentive and Share Award Plan
Medicare Act	Medicare Prescription Drug Improvement and Modernization Act of 2003
MMBtu	Millions of Btu
Moody's	Moody's Investor's Service
MW	Megawatts
MWh	Megawatt hours
NEIL	Nuclear Electric Insurance Limited
NOx	Nitrogen Oxide
NRC	Nuclear Regulatory Commission
NSR Investigation	EPA New Source Review Investigation
ONEOK	ONEOK, Inc.
PCB	Polychlorinated Biphenyl
PPA	Pension Protection Act of 2006
PRB	Powder River Basin
Protection One	Protection One, Inc.
RECA	Retail energy cost adjustment
RSU	Restricted share units
RTO	Regional Transmission Organization
S&P	Standard & Poor's Ratings Group
SAB	Staff Accounting Bulletin
SEC	Securities and Exchange Commission
Section 114	Section 114(a) of the Clean Air Act
SFAS	Statement of Financial Accounting Standards
SPP	Southwest Power Pool
SSCGP	Southern Star Central Gas Pipeline
SO_2	Sulfur Dioxide
UBS	UBS AG, London Branch
VaR	Value-at-Risk
WCNOC	Wolf Creek Nuclear Operating Corporation
Wolf Creek	Wolf Creek Generating Station

PART I

ITEM 1. BUSINESS

GENERAL

We are the largest electric utility in Kansas. Unless the context otherwise indicates, all references in this Annual Report on Form 10-K to "the company," "we," "us," "our" and similar words are to Westar Energy, Inc. and its consolidated subsidiaries. The term "Westar Energy" refers to Westar Energy, Inc., a Kansas corporation incorporated in 1924, alone and not together with its consolidated subsidiaries.

We provide electric generation, transmission and distribution services to approximately 674,000 customers in Kansas. Westar Energy provides these services in central and northeastern Kansas, including the cities of Topeka, Lawrence, Manhattan, Salina and Hutchinson. Kansas Gas and Electric Company (KGE), Westar Energy's wholly owned subsidiary, provides these services in south-central and southeastern Kansas, including the city of Wichita. KGE owns a 47% interest in the Wolf Creek Generating Station (Wolf Creek), a nuclear power plant located near Burlington, Kansas. Both Westar Energy and KGE conduct business using the name Westar Energy. Our corporate headquarters is located at 818 South Kansas Avenue, Topeka, Kansas 66612.

SIGNIFICANT BUSINESS DEVELOPMENTS

New Generation and Transmission Construction Plans

We are making and will continue to make significant investments in new generation, new transmission and air emission controls at existing fossil-fueled power plants. These investments relate to new projects as well as previously announced projects. The cost estimates for some previously announced projects have increased due to rising prices of labor, materials and supplies.

In August 2006, we announced plans to build a new natural gas-fired combustion turbine peaking power plant near Emporia in Lyon County, Kansas. We expect the new plant, which we have named the Emporia Energy Center, to have an initial generating capacity of approximately 310 megawatts (MW), with additional capacity to be added in a second phase to bring the total capacity to approximately 610 MW. We expect the total investment in the plant to be about $318.0 million. Construction on the new plant began in March 2007. The initial phase of the plant is scheduled to begin operation in May of 2008. The second phase is scheduled to begin operation in May of 2009.

In September 2006, we announced plans to build a 345 kilovolt (kV) transmission line from our Gordon Evans Energy Center northwest of Wichita, Kansas, to a new substation near Hutchinson, Kansas, then on to our Summit substation near Salina, Kansas, a distance totaling approximately 97 miles. In January 2007, we filed an application with the Kansas Corporation Commission (KCC) to request permission to site the line. The KCC granted our permit on May 16, 2007. We expect to complete construction in late 2009. We expect the total investment in the line to be approximately $150.0 million. In addition to this line, we plan to construct a new 345 kV line from our Rose Hill substation near Wichita to the Kansas-Oklahoma border, where we will interconnect with new facilities built by an Oklahoma-based utility. The preliminary estimate of the total investment in the line is approximately $70.0 million, which is subject to change pending selection of the final route and engineering design, among other factors. On December 27, 2007, we filed an application with the KCC to request permission to site this line. The KCC has until April 25, 2008, to act on our application.

On January 11, 2008, we announced that we reached agreements with developers who will build three wind farms in Kansas totaling approximately 300 MWs. Under the terms of the agreements, we plan to own approximately half of the wind generators at an expected cost of approximately $290.0 million and to purchase energy produced by the wind farms under twenty year supply contracts for the other half. All three wind farms are expected to be producing energy by the end of 2008.

Energy Efficiency

Energy efficiency is important to our plan. We believe that many energy efficiency technologies can be deployed faster and at lower cost than supply-side options. Accordingly, we view energy efficiency as a priority energy resource.

For energy efficiency to have a meaningful impact we believe policymakers will have to align incentives for utilities and their customers. The KCC has opened two dockets to address how Kansas utilities might deploy energy efficiency programs and how such costs will be treated for ratemaking.

Changes in Rates

On December 28, 2005, the KCC issued an order (2005 KCC Order) authorizing changes in our rates, which we began billing in the first quarter of 2006, and approving various other changes in our rate structures. In April 2006, interveners to the rate review filed appeals with the Kansas Court of Appeals challenging various aspects of the 2005 KCC Order. On July 7, 2006, the Kansas Court of Appeals reversed and remanded for further consideration by the KCC three elements of the 2005 KCC Order (July 2006 Court Order). The balance of the 2005 KCC Order was upheld.

The Kansas Court of Appeals held: (i) the KCC's approval of a transmission delivery charge, in the circumstances of this case, violated the Kansas statutes that authorize a transmission delivery charge, (ii) the KCC's approval of recovery of terminal net salvage, adjusted for inflation, in our depreciation rates was not supported by substantial competent evidence, and (iii) the KCC's reversal of its prior rate treatment of the La Cygne Generating Station (La Cygne) unit 2 sale-leaseback transaction was not sufficiently justified and was thus unreasonable, arbitrary and capricious.

On February 8, 2007, the KCC issued an order (February 2007 KCC Order) in response to the July 2006 Court Order. The February 2007 KCC Order: (i) confirmed the original decision regarding treatment of the La Cygne unit 2 sale-leaseback transaction; (ii) reversed the KCC's original decision with regard to the inclusion in depreciation rates of a component for terminal net salvage; and (iii) permits recovery of transmission related costs in a manner similar to how we recover our other costs. On November 30, 2007, we filed with the KCC to implement a separate transmission delivery charge in a manner consistent with the applicable Kansas statute. The February 2007 KCC Order required us to refund to our customers amounts we collected related to terminal net salvage. On July 31, 2007, the KCC issued an order (July 2007 KCC Order) resolving issues raised by us and interveners following the February 2007 KCC Order. The July 2007 KCC Order: (i) confirmed the earlier decision concerning recovery of terminal net salvage and quantified the effect of that ruling; and (ii) approved a Stipulation and Agreement between us and the KCC Staff. The Stipulation and Agreement approved by the KCC quantified the refund obligation related to amounts previously collected from customers for transmission related costs and established the amount of transmission costs to be included in retail rates, prospectively. Interveners filed petitions for reconsideration of the July 2007 KCC Order on August 15, 2007. These petitions were denied by the KCC on September 13, 2007. The interveners filed appeals with the Kansas Court of Appeals. On February 11, 2008, the Kansas Court of Appeals issued an opinion which affirmed the July 2007 KCC Order. We filed new tariffs and a plan for implementing refunds that became effective on August 29, 2007. Refunds were substantially completed in November.

OPERATIONS

General

Westar Energy supplies electric energy at retail to approximately 363,000 customers in central and northeast Kansas and KGE supplies electric energy at retail to approximately 311,000 customers in south-central and southeastern Kansas. We also supply electric energy at wholesale to the electric distribution systems of 35 cities in Kansas and four electric cooperatives in Kansas pursuant to contracts of various length. We have other contracts for the sale, purchase or exchange of wholesale electricity with other utilities. In addition, we engage in energy marketing and purchase and sell wholesale electricity in areas outside our retail service territory.

In 2006, we implemented a retail energy cost adjustment (RECA) that allows us to recover the cost of fuel consumed in generating electricity and purchased power needed to serve our retail customers. Through the RECA, we bill our customers on a month ahead estimate. The RECA provides for an annual review and reconciliation of estimated and actual fuel and purchased power costs. The annual review also affords the KCC a means to determine the prudence of our fuel and purchased power expenses. The first such review was completed in mid 2007 and resulted in no adjustments.

Generation Capacity

We have 6,178 MW of accredited generating capacity in service, of which 2,575 MW is owned or leased by KGE. See "Item 2. Properties" for additional information on our generating units.

The capacity by fuel type is summarized below.

Fuel Type	Capacity (MW)	Percent of Total Capacity
Coal	3,461.0	56.0
Nuclear	545.0	8.8
Natural gas or oil	2,090.0	33.9
Diesel fuel	81.0	1.3
Wind	1.4	—
Total	6,178.4	100.0

Our aggregate 2007 peak system net load of 4,836 MW occurred on August 15, 2007. This included 109 MW of potentially interruptible load. Our net generating capacity, combined with firm capacity purchases and sales and the ability to interrupt 109 MW of load, provided a capacity margin of 13.5% above system peak responsibility at the time of our 2007 peak system net load.

Under wholesale agreements, we provide firm generating capacity to other entities as set forth below.

Utility[(a)]	Capacity (MW)	Period Ending
Midwest Energy, Inc.	130	May 2008
Kansas Electric Power Cooperative	187	May 2008
Midwest Energy, Inc.	125	May 2010
Empire District Electric Company	162	May 2010
Oklahoma Municipal Power Authority	60	December 2013
Oneok Energy Services Co.	75	December 2015
Mid-Kansas Electric Company, LLC	174	January 2019
Total	913	

[(a)] *Under a wholesale agreement that expires in May 2027, we provide base load capacity to the city of McPherson, Kansas, and McPherson provides peaking capacity to us. During 2007, we provided approximately 84 MW to, and received approximately 151 MW from, McPherson. The amount of base load capacity provided to McPherson is based on a fixed percentage of McPherson's annual peak system load.*

Fossil Fuel Generation

Fuel Mix

The effectiveness of a fuel to produce heat is measured in British thermal units (Btu). The higher the Btu content of a fuel, the less fuel it takes to produce electricity. We measure the quantity of heat consumed during the generation of electricity in millions of Btu (MMBtu).

Based on MMBtus, our 2007 fuel mix was 79% coal, 15% nuclear and 6% natural gas, oil and diesel fuel. We expect in 2008 to use a higher percentage of coal and a lower percentage of uranium because in 2008 we will refuel Wolf Creek. We did not refuel Wolf Creek in 2007. Our fuel mix fluctuates with the operation of Wolf Creek, fluctuations in fuel costs, plant availability, customer demand and the cost and availability of power in the wholesale market.

Coal

Jeffrey Energy Center: The three coal-fired units at Jeffrey Energy Center have an aggregate capacity of 2,190 MW, of which we own and lease a combined 92% share, or 2,016 MW. We have a long-term coal supply contract with Foundation Coal West to supply coal to Jeffrey Energy Center from surface mines located in the Powder River Basin (PRB) in Wyoming. The contract contains a schedule of minimum annual MMBtu delivery quantities. All of the coal used at Jeffrey Energy Center is purchased under this contract. The contract expires December 31, 2020. The contract provides for price escalation based on certain costs of production. The price for quantities purchased in excess of the scheduled annual minimum is subject to renegotiation every five years to provide an adjusted price for the ensuing five years that reflects then current market prices. The next re-pricing for those quantities over the scheduled annual minimum will occur in 2013.

The Burlington Northern Santa Fe (BNSF) and Union Pacific railroads transport coal for Jeffrey Energy Center from Wyoming under a long-term rail transportation contract. The contract term continues through December 31, 2013. The contract price is subject to price escalation based on certain costs incurred by the rail carriers. We expect increases in the cost of transporting coal due to higher prices for the items subject to contractual escalation.

The average delivered cost of coal burned at Jeffrey Energy Center during 2007 was approximately $1.39 per MMBtu, or $23.38 per ton.

La Cygne Generating Station: The two coal-fired units at La Cygne have an aggregate generating capacity of 1,418 MW, of which we own or lease a 50% share, or 709 MW. La Cygne unit 1 uses a blended fuel mix containing approximately 85% PRB coal and 15% Kansas/Missouri coal. La Cygne unit 2 uses PRB coal. The operator of La Cygne, Kansas City Power & Light Company (KCPL), arranges coal purchases and transportation services for La Cygne. All of the La Cygne unit 1 and La Cygne unit 2 PRB coal is supplied through fixed price contracts through 2010 and is transported under KCPL's Omnibus Rail Transportation Agreement with the BNSF and Kansas City Southern Railroad through December 31, 2010. As the PRB coal contracts expire, we anticipate that KCPL will negotiate new supply contracts or purchase coal on the spot market. The La Cygne unit 1 Kansas/Missouri coal is purchased from time to time from local Kansas and Missouri producers.

During 2007, the average delivered cost of all coal burned at La Cygne unit 1 was approximately $1.12 per MMBtu, or $18.81 per ton. The average delivered cost of coal burned at La Cygne unit 2 was approximately $0.99 per MMBtu, or $16.87 per ton.

Lawrence and Tecumseh Energy Centers: The coal-fired units located at the Lawrence and Tecumseh Energy Centers have an aggregate generating capacity of 774 MW. During 2005, we began purchasing coal under a contract with Arch Coal, Inc. (Arch). The current contract with Arch is expected to provide 100% of the coal requirement for these energy centers through 2010.

BNSF transports coal for these energy centers from Wyoming under a contract that expires in December 2008.

During 2007, the average delivered cost of all coal burned in the Lawrence units was approximately $1.16 per MMBtu, or $20.15 per ton. The average delivered cost of all coal burned in the Tecumseh units was approximately $1.16 per MMBtu, or $20.48 per ton.

Natural Gas

We use natural gas as a primary fuel at our Gordon Evans, Murray Gill, Neosho, Abilene and Hutchinson Energy Centers, in the gas turbine units at Tecumseh Energy Center and in the combined cycle units at the State Line facility and the Spring Creek Energy Center. We can also use natural gas as a supplemental fuel in the coal-fired units at the Lawrence and Tecumseh Energy Centers. During 2007, we purchased 18.3 million MMBtu of natural gas for a total cost of $119.5 million. Natural gas accounted for approximately 6% of our total MMBtu of fuel burned during 2007 and approximately 25% of our total fuel expense. From time to time, we may purchase derivative contracts in an effort to mitigate the effect of high natural gas prices. For additional information on our exposure to commodity price risks, see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

We maintain natural gas transportation arrangements for the Abilene and Hutchinson Energy Centers with Kansas Gas Service, a division of ONEOK, Inc. (ONEOK). This contract expires April 30, 2008. We will be renegotiating this contract during the first quarter of 2008. We meet a portion of our natural gas transportation requirements for the Gordon Evans, Murray Gill, Neosho, Lawrence and Tecumseh Energy Centers through firm natural gas transportation capacity agreements with Southern Star Central Gas Pipeline (SSCGP). We meet all of the natural gas transportation requirements for the State Line facility through a firm natural gas transportation agreement with SSCGP. The firm transportation agreement that serves the Gordon Evans, and Murray Gill Energy Centers has been restructured and extended through April 1, 2020. The agreement for the Neosho and State Line facilities extends through June 1, 2016. We will meet a portion of the natural gas transportation requirements at the Emporia Energy Center through firm natural gas transportation capacity agreements with SSCGP. The term of the agreement will be for 20 years commencing December 1, 2008, and terminating December 1, 2028, which will be renewable for five-year terms thereafter. During the period of April 1, 2008, through November 30, 2008, transportation will be handled through a combination of firm and interruptible agreements. We meet all of the natural gas transportation requirements for the Spring Creek Energy Center through an interruptible natural gas transportation agreement with ONEOK Gas Transportation, LLC.

Oil

Once started with natural gas, the steam units at our Gordon Evans, Murray Gill, Neosho and Hutchinson Energy Centers have the capability to burn #6 oil or natural gas. We can use #6 oil as an emergency alternate fuel when no natural gas supply is available. During 2007, we did not burn any #6 oil.

We also use #2 diesel to start some of our coal generating stations, as a primary fuel in the Hutchinson No. 4 combustion turbine and in our diesel generators. We purchase #2 diesel in the spot market. We maintain quantities in inventory that we believe will allow us to facilitate economic dispatch of power, to satisfy emergency requirements and to protect against reduced availability of natural gas for limited periods.

During 2007, we burned 0.2 million MMBtu of oil at a total cost of $3.3 million. Oil accounted for less than 1% of our total MMBtu of fuel burned during 2007 and approximately 1% of our total fuel expense. For additional information on our exposure to commodity price risks, see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

Other Fuel Matters

The table below provides our weighted average cost of fuel, including transportation costs.

	2007	2006	2005
Per MMBtu:			
Nuclear	$ 0.43	$ 0.41	$ 0.42
Coal	1.27	1.25	1.20
Natural gas	6.51	6.49	8.53
Oil	15.18	9.19	4.97
Per MWh Generation:			
Nuclear	$ 4.46	$ 4.28	$ 4.34
Coal	13.92	13.69	13.20
Natural gas/oil	67.65	66.91	68.19
All generating stations	15.51	14.94	15.36

Purchased Power

At times, we purchase electricity instead of generating it ourselves. Factors that cause us to make such purchases include planned and unscheduled outages at our generating plants, prices for wholesale energy, extreme weather conditions and other factors. Transmission constraints may limit our ability to bring purchased electricity into our control area, potentially requiring us to curtail or interrupt our customers as permitted by our tariffs and terms and conditions of service. Purchased power for the year ended December 31, 2007, comprised approximately 19% of our total fuel and purchased power expenses. The weighted average cost of purchased power was $61.04 per megawatt hour (MWh) in 2007, $54.90 per MWh in 2006 and $59.05 per MWh in 2005.

Energy Marketing Activities

We engage in both financial and physical trading with the objective of increasing profits, managing commodity price risk and enhancing system reliability. We trade electricity, coal and natural gas. We use a variety of financial instruments, including forward contracts, options and swaps, and we trade energy commodity contracts.

Nuclear Generation

General

Wolf Creek is a 1,160 MW nuclear power plant located near Burlington, Kansas. KGE owns a 47% interest in Wolf Creek, or 545 MW, which represents 9% of our total generating capacity. KCPL owns an equal 47% interest, with Kansas Electric Power Cooperative, Inc. holding the remaining 6% interest. The co-owners pay operating costs equal to their percentage ownership in Wolf Creek.

In September 2006, Wolf Creek Nuclear Operating Corporation (WCNOC), the operating company for Wolf Creek, filed a request with the Nuclear Regulatory Commission (NRC) for a 20 year extension of Wolf Creek's operating license. Currently, the operating license will expire in 2025. The NRC's milestone schedule for its review of this request projects a decision by late 2008. The NRC may impose conditions as part of any approval. Based on the experience of other nuclear plant operators, we believe that the NRC will approve the request.

Fuel Supply

The owners of Wolf Creek have on hand or under contract all of the uranium and conversion services needed to operate Wolf Creek through March 2011 and approximately 86% of uranium and conversion services after that date through September 2018. The owners also have under contract 100% of the uranium enrichment and fabrication required to operate Wolf Creek through March 2025.

Because of a production delay at a mine from which Wolf Creek expected to receive future supplies of uranium, it is possible that contracted uranium deliveries scheduled for 2010 and some years beyond could be reduced, necessitating an increase in the amount of uranium planned for purchase in those years. Wolf Creek's on-going operations strategies, including previous acquisition of inventory, are expected to minimize the impact of such reductions.

We have entered into all uranium, uranium conversion and uranium enrichment arrangements, as well as the fabrication agreements, in the ordinary course of business. We believe Wolf Creek is not substantially dependent on these agreements. However, contraction and consolidation among suppliers of these commodities and services, increasing worldwide demand, past inventory draw-downs and flooding of a key mine of a leading industry supplier have introduced uncertainty as to the ability to replace, if necessary, volumes under these contracts in the event of a protracted supply disruption. We believe this uncertainty is not unique in the nuclear industry.

Radioactive Waste Disposal

Under the Nuclear Waste Policy Act of 1982, the Department of Energy (DOE) is responsible for the permanent disposal of spent nuclear fuel. Wolf Creek pays into a federal Nuclear Waste Fund administered by the DOE a quarterly fee for the future disposal of spent nuclear fuel. Our share of the fee was $4.4 million in 2007, $4.1 million in 2006 and $3.8 million in 2005 and is calculated as one-tenth of a cent for each kilowatt-hour of net nuclear generation delivered to customers. We include these costs in fuel and purchased power expense.

In 2002, the Yucca Mountain site in Nevada was approved for the development of a nuclear waste repository for the disposal of spent nuclear fuel and high level nuclear waste from the nation's defense activities. This action allows the DOE to apply to the NRC to license the project. The DOE announced in

December 2007, that it planned to submit a license application to the NRC no later than June 20, 2008. However, in January 2008, DOE officials announced that that filing date was in jeopardy because of fiscal year 2008 budget allocation reductions. The opening of the Yucca Mountain site has been delayed many times and could be delayed further due to litigation and other issues related to the site as a permanent repository for spent nuclear fuel. Wolf Creek has on-site temporary storage for spent nuclear fuel expected to be generated by Wolf Creek through 2025, the term of its existing operating license.

Wolf Creek disposes of all classes of its low-level radioactive waste at existing third-party repositories. The State of South Carolina has announced that after June 30, 2008, the disposal site at Barnwell, South Carolina, will no longer accept waste from generators other than those located in South Carolina, Connecticut, and New Jersey — the three states that make up the Atlantic Interstate Low-Level Radioactive Waste Management Compact. We expect that another site in the state of Utah will remain available to Wolf Creek. Should disposal capability become unavailable, we believe Wolf Creek is able to store its low-level radioactive waste in an on-site facility. We believe that a temporary loss of low-level radioactive waste disposal capability would not affect Wolf Creek's continued operation.

The Low-Level Radioactive Waste Policy Amendments Act of 1985 mandated that the various states, individually or through interstate compacts, develop alternative low-level radioactive waste disposal facilities. The states of Kansas, Nebraska, Arkansas, Louisiana and Oklahoma formed the Central Interstate Low-Level Radioactive Waste Compact (Central States Compact), and the Central States Compact Commission, which is responsible for creating new disposal capability for the member states. The Central States Compact Commission selected Nebraska as the host state for the disposal facility.

In December 1998, the Nebraska agencies responsible for considering the developer's license application denied the application. Most of the utilities that had provided the project's pre-construction financing and the Central States Compact Commission filed a lawsuit in federal court contending Nebraska officials acted in bad faith while handling the license application. In September 2002, the court entered a judgment of $151.4 million, about one-third of which constitutes pre-judgment interest, in favor of the Central States Compact Commission and against Nebraska, finding that Nebraska had acted in bad faith in handling the license application. In August 2004, following unsuccessful appeals of the decision, Nebraska and the Central States Compact Commission settled the case. In August 2005, we received $9.2 million in proceeds from the Central States Compact as a result of the settlement.

Outages

Wolf Creek operates on an 18-month planned refueling and maintenance outage schedule. Wolf Creek was shut down for 34 days in 2006 for its fifteenth scheduled refueling and maintenance outage. During outages at the plant, we meet our electric demand primarily with our other generating units and by purchasing power. As provided by the KCC, we defer and amortize evenly the incremental maintenance costs incurred for planned refueling outages over the unit's 18 month operating cycle. Wolf Creek is next scheduled to be taken off-line in the spring of 2008 for its sixteenth refueling and maintenance outage.

An extended or unscheduled shutdown of Wolf Creek could cause us to purchase replacement power, rely more heavily on our other generating units and reduce amounts of power available for us to sell at wholesale.

The NRC evaluates, monitors and rates various inspection findings and performance indicators for Wolf Creek based on their safety significance. Wolf Creek currently meets all NRC oversight objectives and receives the minimum regimen of NRC inspections. Although not expected, the NRC could impose an unscheduled plant shutdown due to security or other concerns. Those concerns need not be related to Wolf Creek specifically, but could be due to concerns about nuclear power generally, or circumstances at other nuclear plants in which we have no ownership.

Nuclear Decommissioning

Nuclear decommissioning is a nuclear industry term for the permanent shutdown of a nuclear power plant and the removal of radioactive components in accordance with NRC requirements. The NRC will terminate a plant's license and release the property for unrestricted use when a company has reduced the residual radioactivity of a nuclear plant to a level mandated by the NRC. The NRC requires companies with nuclear plants to prepare formal financial plans to fund nuclear decommissioning. These plans are designed so that sufficient funds required for nuclear decommissioning will be accumulated prior to the expiration of the license of the related nuclear power plant. Wolf Creek files a nuclear decommissioning and dismantlement study with the KCC every three years.

The KCC reviews nuclear decommissioning plans in two phases. Phase one is the approval of the revised nuclear decommissioning study, the current-year funding and future funding. Phase two involves the review and approval by the KCC of a "funding schedule" by the owner of the nuclear facility detailing how it plans to fund the future-year dollar amount of its pro rata share of the plant.

In 2005, Wolf Creek filed an updated nuclear decommissioning site study with the KCC. Based on the site study of decommissioning costs, including the costs of decontamination, dismantling and site restoration, our share of such costs is estimated to be $243.3 million. This amount compares to the 2002 site study estimate for decommissioning costs of $220.0 million. The site study cost estimate represents the estimate to decommission Wolf Creek as of the site study year. The actual nuclear decommissioning costs may vary from the estimates because of changes in regulations or technology and changes in costs for labor, materials and equipment.

Electric rates charged to customers provide for recovery of these nuclear decommissioning costs over the life of Wolf Creek, which, as determined by the KCC for purposes of the funding schedule, will be through 2045. The NRC requires that funds to meet its nuclear decommissioning funding assurance requirement be in our nuclear decommissioning fund by the time our license expires. We believe that the KCC approved funding level will also be sufficient to meet the NRC minimum financial assurance requirement. Our consolidated results of operations would be materially adversely affected if we are not allowed to recover in utility rates the full amount of the funding requirement.

We recovered in rates and deposited in an external trust fund approximately $2.9 million for nuclear decommissioning in 2007 and $3.9 million in 2006 and 2005. We record our investment in the nuclear decommissioning fund at fair value. The fair value approximated $122.3 million as of December 31, 2007 and $111.1 million as of December 31, 2006.

Competition and Deregulation

The Federal Energy Regulatory Commission (FERC) requires owners of regulated transmission assets to allow third party wholesale providers of electricity nondiscriminatory access to their transmission systems to transport electric power to wholesale customers. FERC also requires us to provide transmission services to others under terms comparable to those we allow ourselves. In December 1999, FERC issued an order encouraging the formation of regional transmission organizations (RTO). RTOs are designed to control the wholesale transmission services of the utilities in their regions, thereby facilitating competitive wholesale power markets.

Regional Transmission Organization

We are a member of the Southwest Power Pool (SPP), the RTO in our region. On September 19, 2006, the KCC approved an order allowing us to transfer functional control of our transmission system to the SPP under its membership agreement and applicable tariff. The SPP coordinates the operation of our transmission system within an interconnected transmission system that covers all or portions of eight states. The SPP collects revenues for the use of each transmission owner's transmission system. Transmission customers transmit throughout the entire SPP system power purchased and generated for sale or bought for resale in the wholesale market. Transmission capacity is sold on a first come/first served non-discriminatory basis. All transmission customers are charged rates applicable to the transmission system in the zone where energy is delivered, including transmission customers that may sell power inside our certificated service territory.

Real-Time Energy Imbalance Market

On February 1, 2007 the SPP implemented the real-time energy imbalance market as required by FERC to accommodate financial settlement of energy imbalances within the SPP region. The real-time market system permits an efficient balancing of energy production and consumption through the use of a least cost economic dispatch system. It also provides a ready market for the economical purchase and sale of excess energy maximizing the available transmission system. During 2007 the company was an active participant in this market.

Regulation and Rates

Kansas law gives the KCC general regulatory authority over our rates, extensions and abandonments of service and facilities, the classification of accounts, the issuance of some securities and various other matters. We are also subject to the jurisdiction of FERC, which has authority over wholesale sales of electricity, the transmission of electric power and the issuance of some securities. We are subject to the jurisdiction of the NRC for nuclear plant operations and safety.

FERC Proceedings

Request for Change in Transmission Rates: On May 2, 2005, we filed applications with FERC that proposed a formula transmission rate providing for annual adjustments to our transmission tariff. This is consistent with our proposals filed with the KCC on May 2, 2005, to charge retail customers separately for transmission service through a transmission delivery charge. The proposed FERC transmission rates became effective, subject to refund, December 1, 2005. On November 7, 2006, FERC issued an order reflecting a unanimous settlement reached by the parties to the proceeding. The settlement modified the rates we proposed and required us to refund approximately $3.4 million, which included the amount we collected in the interim rates since December 2005 and interest on that amount.

On December 28, 2007, we filed applications with FERC that proposed changes to our formula transmission rate, which provides for annual adjustments to our transmission tariff. While the formula already allows recovery of the prior year's actual costs, the changes, if accepted by FERC, will allow us to include in our formula rate our anticipated transmission capital expenditures for the current year. We have requested the changes take effect on June 1, 2008. In addition, we made a simultaneous filing requesting authority for incentives related to new transmission investments as permitted by FERC.

On November 6, 2007, we filed applications with FERC that proposed the use of a consolidated capital structure in our formula transmission rate. On December 19, 2007, FERC issued an order accepting this change. On January 28, 2008, we filed applications with FERC requesting that this change be effective June 1, 2007. Accordingly, we have recorded a $3.7 million refund obligation, which includes the amount we have collected since June 1, 2007, and interest on that amount.

On January 11, 2008, we filed a request with FERC for authority to issue short-term securities and to pledge mortgage bonds in order to increase the size of our revolving credit facility to $750.0 million. On February 15, 2008, FERC granted our request. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Capital Resources" for more information.

Environmental Matters

General

We are subject to various federal, state and local environmental laws and regulations. Environmental laws and regulations affecting power plants are overlapping, complex, and subject to changes in interpretation and implementation and have tended to become more stringent over time. These laws and regulations relate primarily to discharges into the air, air quality, discharges of effluents into water, the use of water, and the handling, disposal and clean-up of hazardous substances and wastes. These laws and regulations require a lengthy and complex process for obtaining licenses, permits and approvals from governmental agencies for our new, existing or modified facilities. If we fail to comply with such laws, regulations and permits, or fail to obtain and maintain necessary permits, we could be fined or otherwise sanctioned by regulators. We have incurred and will continue to incur capital and other expenditures to comply with environmental laws and regulations. Certain of these costs are recoverable through the environmental cost recovery rider (ECRR) established by the 2005 KCC Order, which allows for the timely inclusion in rates of capital investments related directly to environmental improvements required by the Clean Air Act as well as many of the costs relating to compliance with other environmental laws and regulations. However, there can be no assurance that we will be able to recover all such costs from our customers or that our business, consolidated financial condition or results of operations will not be materially and adversely affected as a result of costs to comply with existing or future environmental laws and regulations.

Air Emissions

The Clean Air Act, state laws and implementing regulations impose, among other things, limitations on pollutants generated during our operations, including sulfur dioxide (SO_2), particulate matter and nitrogen oxides (NOx).

Certain Kansas Department of Health and Environment (KDHE) regulations applicable to our generating facilities prohibit the emission of SO_2 in excess of prescribed levels. In order to meet these standards, we use low-sulfur coal, fuel oil and natural gas and have equipped our generating facilities with pollution control equipment.

In addition, we must comply with the provisions of the Clean Air Act Amendments of 1990 that require a two-phase reduction in certain emissions. We have installed continuous monitoring and reporting equipment in order to meet these requirements.

Title IV of the Clean Air Act created an SO_2 allowance and trading program as part of the federal acid rain program. Under the allowance and trading program, the Environmental Protection Agency (EPA) allocated annual SO_2 allowances for each affected emitting unit. An SO_2 allowance is a limited authorization to emit one ton of SO_2 during a calendar year. At the end of each year, each emitting unit must have enough allowances to cover its emissions for that year. Allowances are tradable so that operators of affected units that are anticipated to emit SO_2 in excess of their allowances may purchase allowances in the market in which such allowances are traded. In 2007, we had SO_2 allowances adequate to meet planned generation and we expect to have enough in 2008. In the future we may need to purchase additional allowances and as a result our operating costs may increase. We expect to recover the cost of emission allowances through the RECA although there are no guarantees we will be able to do so. The price of emissions allowances is determined by market forces and changes over time.

On March 15, 2005, the EPA issued the Clean Air Mercury Rule. The rule caps permanently, and seeks to reduce, the amount of mercury that may be emitted from coal-fired power plants. The rule requires implementation of reductions in two phases, the first starting in 2010. We received an allocation of mercury emission allowances pursuant to the rule. Preliminary testing indicates that the expected allocation of allowances will be insufficient to allow us to operate our coal-fired units in compliance with the first phase requirements of the rule. If the allocated allowances are insufficient, we may need to purchase allowances in the market, install additional equipment or take other actions to reduce our mercury emissions. However, on February 8, 2008, the U.S. District Court of Appeals for the District of Columbia vacated the Clean Air Mercury Rule. While the ultimate impact of this ruling on our operations is currently unknown, we believe that mercury emissions controls may be required in the future and that the costs to comply with these requirements may be material.

On August 29, 2007 we filed an application with the KDHE to implement a plan to improve efficiency and to install new equipment to reduce regulated emissions from Jeffrey Energy Center. The projects outlined in a proposed agreement filed with the KDHE on August 30, 2007, are designed to meet requirements of the Clean Air Visibility Rule and reduce emissions of our entire generating fleet by eliminating more than 70% of SO_2 and reducing nitrous oxides and particulates between 50% and 65%.

Environmental requirements have been changing substantially. Accordingly, we may be required to further reduce emissions of presently regulated gases and substances, such as SO_2, NOx, particulate matter and mercury and we may be required to reduce or limit emissions of gases and substances not presently regulated (e.g., carbon dioxide (CO_2)). Proposals and bills in those respects include:

- the EPA's national ambient air quality standards for particulate matter and ozone,
- additional legislation introduced in the past few years in Congress requiring reductions of presently unregulated gases related primarily to concerns about climate change, and
- state legislation introduced recently that could require mitigation of CO_2 emissions.

Based on currently available information, we cannot estimate our costs to comply with these proposed laws, but we believe such costs could be material.

Environmental Costs

We have identified the potential for us to make up to $1.2 billion of capital expenditures at our power plants for environmental air emissions projects described above during approximately the next eight to ten years. This estimate could increase depending on the resolution of the EPA New Source Review Investigation (NSR Investigation) described below. In addition to the capital investment, in the event we install new equipment as a result of the NSR Investigation, we anticipate that we would incur significant annual expense to operate and maintain the equipment and the operation of the equipment would reduce net production from our plants. The degree to which we will need to reduce emissions and the timing of when such emissions controls may be required is uncertain. Both the timing and the nature of required investments depend on specific outcomes that result from interpretation of existing regulations, new regulations, legislation and the resolution of the NSR Investigation described below. In addition, the availability of equipment and contractors can affect the timing and ultimate cost of the equipment.

The ECRR allows for the timely inclusion in rates of capital expenditures tied directly to environmental improvements, including those required by the Clean Air Act. However, increased operating and maintenance costs other than expenses related to production-related consumables can be recovered only through a change in base rates following a rate review.

New Source Review Investigation

Under Section 114(a) of the Clean Air Act (Section 114), the EPA is conducting investigations nationwide to determine whether modifications at coal-fired power plants are subject to the New Source Review permitting program or New Source Performance Standards. These investigations focus on whether projects at coal-fired plants were routine maintenance or whether the projects were substantial modifications that could reasonably have been expected to result in a significant net increase in emissions. The New Source Review program requires companies to obtain permits and, if necessary, install control equipment to address emissions when making a major modification or a change in operation if either is expected to cause a significant net increase in emissions.

The EPA requested information from us under Section 114 regarding projects and maintenance activities that have been conducted since 1980 at three coal-fired plants we operate. On January 22, 2004, the EPA notified us that certain projects completed at Jeffrey Energy Center violated certain requirements of the New Source Review program.

We have been in discussions with the EPA and the Department of Justice (DOJ) concerning this matter in an attempt to reach a settlement. We expect that any settlement could require us to update or install emissions controls at Jeffrey Energy Center. Additionally, we might be required to update or install emissions controls at our other coal-fired plants, pay fines or penalties, or take other remedial action. If settlement discussions fail, DOJ may consider whether to pursue an enforcement action against us in federal district court. Our ultimate costs to resolve the NSR Investigation could be material. We believe that costs related to updating or installing emissions controls would qualify for recovery through the ECRR. If, however, a penalty is assessed against us, the penalty could be material and may not be recovered in rates. We are not able to estimate the possible loss or range of loss at this time.

Manufactured Gas Sites

We have been identified as being responsible for clean-ups of a number of former manufactured gas sites located in Kansas and Missouri. We and the KDHE entered into a consent agreement in 1994 governing all future work at the Kansas sites. Under the terms of the consent agreement, we agreed to investigate and, if necessary, remediate these sites. Pursuant to an environmental indemnity agreement with ONEOK, the current owner of some of the sites, ONEOK assumed total liability for remediation of seven sites, and we share liability for remediation with ONEOK for five sites. Our total liability for the five shared sites is capped at $3.8 million. We have sole responsibility for remediation with respect to three sites.

Our liability for the former manufactured gas sites identified in Missouri is limited to $7.5 million by the terms of an environmental indemnity agreement with the purchaser of our former Missouri assets.

SEASONALITY

As a summer peaking utility, our sales are seasonal. The third quarter typically accounts for our greatest sales. Sales volumes are affected by weather conditions, the economy of our service territory and the performance of our customers.

EMPLOYEES

As of February 19, 2008, we had 2,323 employees. Our current contract with Local 304 and Local 1523 of the International Brotherhood of Electrical Workers extends through June 30, 2008. The contract covered 1,308 employees as of February 19, 2008.

ACCESS TO COMPANY INFORMATION

Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q and Current Reports on Form 8-K are available free of charge either through our Internet website at www.westarenergy.com or by responding to requests addressed to our investor relations department. These reports are available as soon as reasonably practicable after such material is electronically filed with, or furnished to, the Securities and Exchange Commission (SEC). The information contained on our Internet website is not part of this document.

EXECUTIVE OFFICERS OF THE COMPANY

Name	Age	Present Office	Other Offices or Positions Held During the Past Five Years
William B. Moore	55	Director, Chief Executive Officer and President (since July 2007)	**Westar Energy, Inc.** President and Chief Operating Officer (March 2006 to June 2007) Executive Vice President and Chief Operating Officer (December 2002 to March 2006)
James J. Ludwig	49	Executive Vice President, Public Affairs and Consumer Services (since July 2007)	**Westar Energy, Inc.** Vice President, Regulatory and Public Affairs (March 2006 to June 2007) Vice President, Public Affairs (January 2003 to March 2006)
Mark A. Ruelle	46	Executive Vice President and Chief Financial Officer (since January 2003)	**Sierra Pacific Resources, Inc.** President, Nevada Power Company (June 2001 to May 2002)
Douglas R. Sterbenz	44	Executive Vice President and Chief Operating Officer (since July 2007)	**Westar Energy, Inc.** Executive Vice President, Generation and Marketing (March 2006 to June 2007) Senior Vice President, Generation and Marketing (October 2001 to March 2006)
Bruce A. Akin	43	Vice President, Operations Strategy and Support (since July 2007)	**Westar Energy, Inc.** Vice President, Administrative Services (December 2001 to June 2007)
Jeffrey L. Beasley	49	Vice President, Corporate Compliance and Internal Audit (since September 2007)	**Westar Energy, Inc.** Executive Director, Corporate Compliance and Internal Audit (September 2006 to September 2007) Director, Corporate Finance (March 2005 to September 2006) Director, Accounting Services (June 2003 to March 2005) Director, Budget and Performance Reporting (January 1999 to June 2003)
Larry D. Irick	51	Vice President, General Counsel and Corporate Secretary (since February 2003)	**Westar Energy, Inc.** Vice President and Corporate Secretary (December 2001 to February 2003)
Michael Lennen	62	Vice President, Regulatory Affairs (since July 2007)	**Morris, Laing, Evans, Brock & Kennedy, Chartered** Partner (January 1990 to July 2007)
Lee Wages	59	Vice President, Controller (since December 2001)	

Executive officers serve at the pleasure of the board of directors. There are no family relationships among any of the executive officers, nor any arrangements or understandings between any executive officer and other persons pursuant to which he was appointed as an executive officer.

ITEM 1A. RISK FACTORS

Like other companies in our industry, our consolidated financial results will be impacted by weather, the economy of our service territory and the energy use of our customers. The value of our common stock and our creditworthiness will be affected by national and international macroeconomic trends, general market conditions and the expectations of the investment community, all of which are largely beyond our control. In addition, the following statements highlight risk factors that may affect our consolidated financial condition and results of operations. These are not intended to be an exhaustive discussion of all such risks, and the statements below must be read together with factors discussed elsewhere in this document and in our other filings with the SEC.

Our Revenues Depend Upon Rates Determined by the KCC

The KCC regulates many aspects of our business and operations, including the rates that we charge customers for retail electric service. Retail rates are set by the KCC using a cost-of-service approach that takes into account historical operating expenses, fixed obligations and recovery of and a return on capital investments. Using this approach, the KCC sets rates at a level calculated to recover such costs and a permitted return on investment. Other parties to a rate review or the KCC staff may contend that our rates are excessive. Effective January 2006, the KCC authorized changes that left our base rates virtually unchanged but approved various changes to our rate structure that allow some adjustment to our prices. The KCC approved the RECA, which allows us to recover cost of fuel for generation and purchased power expense (less margins earned on wholesale sales). It also authorized us to implement the ECRR, which allows us to change our rates to reflect the impact of capital expenditures made to upgrade our equipment to environmental standards required by the Clean Air Act.

Our Costs May Not be Fully Recovered in Retail Rates

Except to the extent the KCC permits us to modify our prices by using specific adjustments and riders such as the RECA and the ECRR, once established by the KCC, our rates generally remain fixed until changed in a subsequent rate review. We may apply to change our rates or intervening parties may request that the KCC review our rates for possible adjustment, subject to any limitations that may have been ordered by the KCC.

Equipment Failures and Other External Factors Can Adversely Affect Our Results

The generation and transmission of electricity requires the use of expensive and complicated equipment. While we have maintenance programs in place, generating plants are subject to unplanned outages because of equipment failure. In these events, we must either produce replacement power from our other, usually less efficient, units or purchase power from others at unpredictable and potentially higher cost in order to meet our sales obligations. In addition, equipment failure can limit our ability to make opportunistic sales to wholesale customers.

Fuel Deliveries Can Be Interrupted or Slowed and Transmission Systems May Be Constrained

Coal deliveries from the PRB region of Wyoming, the primary source for our coal, can be interrupted or can be slowed due to rail traffic congestion, equipment or track failure, or due to loading problems at the mines. This may require that we implement coal conservation efforts and/or take other compensating measures. We experienced these problems and conserved coal to varying degrees in 2005 and 2006. These measures may include, but are not limited to, reducing coal consumption by revising normal dispatch of generation units, purchasing power or using more expensive power to serve customers and decreasing or, if necessary, eliminating opportunistic wholesale sales. In addition, decisions or mistakes by other utilities may adversely affect our ability to use transmission lines to deliver or import power, thus subjecting us to unexpected expenses or to the cost and uncertainty of public policy initiatives. These factors, along with the prices and price volatility of fuel and wholesale electricity are largely beyond our control. Costs that are not recovered through the RECA could have a material adverse effect on our consolidated earnings, cash flows and financial position. We engage in energy marketing transactions to reduce risk from market fluctuations, enhance system reliability and increase profits. The events mentioned above could reduce our ability to participate in energy marketing opportunities, which could reduce our profits.

We May Have Material Financial Exposure Relating to Environmental Matters

On January 22, 2004, the EPA notified us that certain projects completed at Jeffrey Energy Center violated certain New Source Review permitting requirements under the Clean Air Act. This notification was delivered as part of an investigation by the EPA regarding maintenance activities that have been conducted since 1980 at Jeffrey Energy Center. The costs to resolve this investigation, or any related enforcement action, could be material and could include fines and penalties as well as costs to install new emission control systems at Jeffrey Energy Center and at certain of our other coal-fired power plants.

Our activities are subject to extensive and changing environmental regulation by federal, state, and local governmental authorities, particularly relating to air emissions. In addition to laws currently in effect, numerous laws and regulations have been enacted and proposed relating to increasing national and international concern about possible global warming caused by the atmospheric release of CO_2 and other gases by industrial and other sources, including the utility industry. On November 15, 2007, the governors of six Midwestern states, including Kansas, signed the Midwest Greenhouse Gas Reduction Accord, under which the member states will, among other things, establish greenhouse gas reduction targets and develop a market-based and multi-sector cap-and-trade mechanism to help achieve such targets. In addition, on October 18, 2007, the KDHE denied an application by an unrelated utility for an air quality permit for two new proposed coal generators in Western Kansas in part because of concerns about the increase in CO_2 and emissions and the potential ill effects those plants might have on the environment and health. The KDHE noted that the decision constituted a first step in emerging policy to address existing and future CO_2 emissions in Kansas. The Midwest Greenhouse Gas Reduction Accord or other new or changed laws and regulations, as well as third party litigation that may be brought against us or our competitors, could result in requirements to install costly equipment, increase our operating expense, reduce production from our plants or take other actions we are unable to identify at this time.

The degree to which we may need to reduce emissions and the timing of when such emissions control equipment may be required is uncertain. Both the timing and the nature of required investments depend on specific outcomes that result from interpretation of existing regulations, new regulations, legislation, and the resolution of the NSR Investigation described above. Although we expect to recover in our rates most of the costs that we incur to comply with environmental regulations, we can provide no assurance that we will be able to fully and timely recover such costs or the costs of any failure to comply with laws and regulations. Failure to recover these associated costs could have a material adverse effect on our consolidated financial statements.

Accounting Regulations Unique to Public Utilities Could Change

We currently apply the accounting principles of Statement of Financial Accounting Standard (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation," to our regulated business. As of December 31, 2007, we had recorded $533.8 million of regulatory assets, net of regulatory liabilities. In the event we determined that we could no longer apply the principles of SFAS No. 71, either as: (i) a result of the establishment of retail competition in our service territory; (ii) a change in the regulatory approach for setting rates from cost-based ratemaking to another form of ratemaking; or (iii) other regulatory actions that restrict cost recovery to a level insufficient to recover costs, we would be required to record a charge against income in the amount of the remaining unamortized net regulatory assets. Such an action would materially reduce our shareholders' equity. We periodically review these criteria to ensure the continuing application of SFAS No. 71 is appropriate. Based upon current evaluation of the various factors that are expected to impact future cost recovery, we believe that our regulatory assets are probable of recovery.

We Face Financial Risks Associated With Wolf Creek

Risks of substantial liability arise from the ownership and operation of nuclear facilities, including, among others, structural problems at a nuclear facility, the storage, handling and disposal of radioactive materials, limitations on the amounts and types of insurance coverage commercially available, uncertainties with respect to the cost and technological aspects of nuclear decommissioning at the end of their useful lives and costs or measures associated with public safety. In the event of an extended or unscheduled outage at Wolf Creek, we would be required to generate power from more costly generating units, purchase power in the open market to replace the power normally produced at Wolf Creek and we would have less power available for sale into the wholesale markets. If we were not permitted by the KCC to recover these costs, such events would likely have an adverse impact on our consolidated financial condition.

Our Planned Capital Expenditures Are Significant To Our Results Of Operations

During the period from 2008 through 2010 and for the immediate years beyond, we plan to continue significant capital expenditures toward large projects including the expansion and modernization of our generation fleet and transmission network. Our anticipated capital expenditures for the period from 2008 through 2010, including costs of removal, are approximately $2.5 billion. Estimated costs for these capital projects have increased, in some cases significantly, as a result of rising demand for material, equipment and labor. In addition, delays in engineering and construction times can occur throughout our industry. Because our capital expenditure program is large in comparison to our revenues and assets, cost increases or delays could materially affect our consolidated financial statements.

In addition, in order to fund our capital expenditure program, we rely to a large degree on access to our short-term credit facility and to long-term capital markets for debt and equity as sources of liquidity for capital requirements not satisfied by the cash flow from our operations. The secured debt of Westar Energy and KGE is rated investment grade by all three of the best known rating agencies, and the unsecured debt of Westar Energy and KGE is rated investment grade by two of the three best known rating agencies, but we cannot assure that such debt will continue to be rated investment grade. If the rating agencies were to downgrade Westar Energy's or KGE's secured or unsecured debt, our borrowing costs and the interest rates we pay on short-term and long-term debt would likely increase, possibly significantly. Further, market disruptions could increase our cost of borrowing or adversely affect our ability to access financial markets. Additional issuance of equity securities could dilute the value of our shares of our common stock and cause the market price of our common stock to fall. These factors could hinder our access to capital markets and limit or delay our ability to carry out our capital expenditure program.

Further, our recovery of capital expenditures depends in large degree on the outcome of retail and wholesale rate proceedings. Decisions made by the KCC or FERC, or delays in making such decisions, could have a material impact on our consolidated financial statements.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Name/Location	Unit No.	Year Installed	Principal Fuel	Unit Capacity (MW) By Owner: Westar Energy	KGE	Total Company
Abilene Energy Center:						
Abilene, Kansas						
Combustion Turbine	1	1973	Gas	72.0	—	72.0
Gordon Evans Energy Center:						
Colwich, Kansas						
Steam Turbines	1	1961	Gas – Oil	—	152.0	152.0
	2	1967	Gas – Oil	—	374.0	374.0
Combustion Turbines	1	2000	Gas	74.0	—	74.0
	2	2000	Gas	72.0	—	72.0
	3	2001	Gas	150.0	—	150.0
Diesel Generator	1	1969	Diesel	—	3.0	3.0
Hutchinson Energy Center:						
Hutchinson, Kansas						
Steam Turbine	4	1965	Gas – Oil	170.0	—	170.0
Combustion Turbines	1	1974	Gas	51.0	—	51.0
	2	1974	Gas	51.0	—	51.0
	3	1974	Gas	56.0	—	56.0
	4	1975	Diesel	75.0	—	75.0
Diesel Generator	1	1983	Diesel	3.0	—	3.0
Jeffrey Energy Center (92%):						
St. Marys, Kansas						
Steam Turbines	1 [d]	1978	Coal	526.0	146.0	672.0
	2 [d]	1980	Coal	526.0	146.0	672.0
	3 [d]	1983	Coal	526.0	146.0	672.0
Wind Turbines	1 [d]	1999	—	0.5	0.2	0.7
	2 [d]	1999	—	0.5	0.2	0.7
La Cygne Station (50%):						
La Cygne, Kansas						
Steam Turbines	1 [a]	1973	Coal	—	368.0	368.0
	2 [b]	1977	Coal	—	341.0	341.0
Lawrence Energy Center:						
Lawrence, Kansas						
Steam Turbines	3	1954	Coal	49.0	—	49.0
	4	1960	Coal	110.0	—	110.0
	5	1971	Coal	373.0	—	373.0
Murray Gill Energy Center:						
Wichita, Kansas						
Steam Turbines	1	1952	Gas	—	39.0	39.0
	2	1954	Gas – Oil	—	63.0	63.0
	3	1956	Gas – Oil	—	95.0	95.0
	4	1959	Gas – Oil	—	90.0	90.0
Neosho Energy Center:						
Parsons, Kansas						
Steam Turbine	3	1954	Gas – Oil	—	67.0	67.0
Spring Creek Energy Center:						
Edmond, Oklahoma						
Combustion Turbines	1	2001 [c]	Gas	70.0	—	70.0
	2	2001 [c]	Gas	68.0	—	68.0
	3	2001 [c]	Gas	66.0	—	66.0
	4	2001 [c]	Gas	68.0	—	68.0

				Unit Capacity (MW) By Owner		
Name/Location	**Unit No.**	**Year Installed**	**Principal Fuel**	**Westar Energy**	**KGE**	**Total Company**
State Line (40%):						
Joplin, Missouri						
Combined Cycle	2-1 [(a)]	2001	Gas	65.0	—	65.0
	2-2 [(a)]	2001	Gas	65.0	—	65.0
	2-3 [(a)]	2001	Gas	74.0	—	74.0
Tecumseh Energy Center:						
Tecumseh, Kansas						
Steam Turbines	7	1957	Coal	74.0	—	74.0
	8	1962	Coal	130.0	—	130.0
Combustion Turbines	1	1972	Gas	19.0	—	19.0
	2	1972	Gas	19.0	—	19.0
Wolf Creek Generating Station (47%):						
Burlington, Kansas						
Nuclear	1 [(a)]	1985	Uranium	—	545.0	545.0
Total				3,603.0	2,575.4	6,178.4

[(a)] *We jointly own La Cygne unit 1 generating unit (50%), Wolf Creek Generating Station (47%) and State Line (40%). Unit capacity amounts reflect our ownership only.*

[(b)] *In 1987, KGE entered into a sale-leaseback transaction involving its 50% interest in the La Cygne unit 2 generating unit.*

[(c)] *We acquired Spring Creek Energy Center in 2006.*

[(d)] *We acquired an 8% leasehold interest in Jeffrey Energy Center in 2007, which brought our total interest to 92%. Prior to 2007, we owned 84% of all units at Jeffrey Energy Center. Unit capacity amounts reflect our 92% interest.*

We own and have in service approximately 6,100 miles of transmission lines, approximately 23,700 miles of overhead distribution lines and approximately 3,900 miles of underground distribution lines.

Substantially all of our utility properties are encumbered by first priority mortgages pursuant to which bonds have been issued and are outstanding.

ITEM 3. LEGAL PROCEEDINGS

Information on other legal proceedings is set forth in Notes 3, 14, 16 and 17 of the Notes to Consolidated Financial Statements, "Rate Matters and Regulation," "Commitments and Contingencies — New Source Review Investigation," "Legal Proceedings" and "Potential Liabilities to David C. Wittig and Douglas T. Lake," respectively, which are incorporated herein by reference.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None.

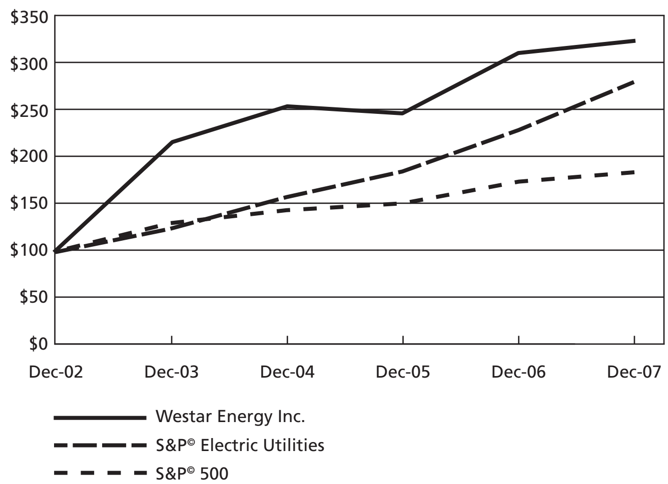
PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

STOCK PERFORMANCE GRAPH

The following performance graph compares the performance of our common stock during the period that began on December 31, 2002, and ended on December 31, 2007, to the Standard & Poor's 500 Index and the Standard & Poor's Electric Utility Index. The graph assumes a $100 investment in our common stock and in each of the indices at the beginning of the period and a reinvestment of dividends paid on such investments throughout the period.

CUMULATIVE TOTAL RETURN
Based upon an initial investment of $100 on December 31, 2002 with dividends reinvested



	Dec-2002	Dec-2003	Dec-2004	Dec-2005	Dec-2006	Dec-2007
Westar Energy Inc.	$100	$214	$252	$246	$310	$323
S&P 500.	$100	$129	$143	$150	$173	$183
S&P Electric Utilities	$100	$124	$157	$185	$228	$280

STOCK TRADING

Our common stock is listed on the New York Stock Exchange and traded under the ticker symbol WR. As of February 19, 2008, there were 24,742 common shareholders of record. For information regarding quarterly common stock price ranges for 2007 and 2006, see Note 22 of the Notes to Consolidated Financial Statements, "Quarterly Results (Unaudited)."

DIVIDENDS

Holders of our common stock are entitled to dividends when and as declared by our board of directors. However, prior to the payment of common dividends, we must first pay dividends to the holders of preferred stock based on the fixed dividend rate for each series.

Quarterly dividends on common and preferred stock have historically been paid on or about the first business day of January, April, July and October to shareholders of record as of or about the ninth day of the preceding month. Our board of directors reviews our common stock dividend policy from time to time. Among the factors the board of directors considers in determining our dividend policy are earnings, cash flows, capitalization ratios, regulation, competition and financial loan covenants. During 2007 our board of directors declared four quarterly dividends, each at $0.27 per share, reflecting an annual dividend of $1.08 per share. On February 20, 2008, our board of directors declared a quarterly dividend of $0.29 per share on our common stock payable to shareholders on April 1, 2008. The indicated annual dividend rate is $1.16 per share.

Our articles of incorporation restrict the payment of dividends or the making of other distributions on our common stock while any preferred shares remain outstanding unless we meet certain capitalization ratios and other conditions. We were not limited by any such restrictions during 2007. We provide further information on these restrictions in Note 19 of the Notes to Consolidated Financial Statements, "Common and Preferred Stock." We do not expect these restrictions to have an impact on our ability to pay dividends on our common stock.

ITEM 6. SELECTED FINANCIAL DATA

Year Ended December 31,	2007	2006	2005	2004	2003
			(In Thousands)		
Income Statement Data:					
Sales	$ 1,726,834	$ 1,605,743	$ 1,583,278	$ 1,464,489	$ 1,461,143
Income from continuing operations	168,354	165,309	134,868	100,080	162,915
Earnings available for common stock	167,384	164,339	134,640	177,900	84,042

As of December 31,	2007	2006	2005	2004	2003
			(In Thousands)		
Balance Sheet Data:					
Total assets	$ 6,395,430	$ 5,455,175	$ 5,210,069	$ 5,001,144	$ 5,672,520
Long-term obligations and mandatorily redeemable preferred stock[a]	2,022,493	1,580,108	1,681,301	1,724,967	2,259,880

Year Ended December 31,	2007	2006	2005	2004	2003
Common Stock Data:					
Basic earnings per share available for common stock from continuing operations	$ 1.85	$ 1.88	$ 1.54	$ 1.19	$ 2.24
Basic earnings per share available for common stock	$ 1.85	$ 1.88	$ 1.55	$ 2.14	$ 1.16
Dividends declared per share	$ 1.08	$ 1.00	$ 0.92	$ 0.80	$ 0.76
Book value per share	$ 19.14	$ 17.61	$ 16.31	$ 16.13	$ 13.98
Average equivalent common shares outstanding (in thousands)[b][c]	90,676	87,510	86,855	82,941	72,429

[a] *Includes long-term debt, capital leases, affiliate long-term debt and shares subject to mandatory redemption.*
[b] *In 2004, we issued and sold approximately 12.5 million shares of common stock realizing net proceeds of $245.1 million.*
[c] *In 2007, we issued and sold approximately 8.1 million shares of common stock realizing net proceeds of $195.4 million.*

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

INTRODUCTION

We are the largest electric utility in Kansas. We produce, transmit and sell electricity at retail in Kansas and at wholesale in a multi-state region in the central United States under the regulation of the KCC and FERC.

In Management's Discussion and Analysis, we discuss our general financial condition, significant changes that occurred during 2007, and our operating results for the years ended December 31, 2007, 2006 and 2005. As you read Management's Discussion and Analysis, please refer to our consolidated financial statements and the accompanying notes, which contain our operating results.

SUMMARY OF SIGNIFICANT ITEMS

Overview

Several significant items have impacted or may impact us and our operations since January 1, 2007:

- Our gross margin for the year ended December 31, 2007, increased compared to the prior year due largely to increased wholesale sales. See "— Increased Gross Margin" below for additional information;
- We estimate that we incurred approximately $72.0 million in maintenance costs and capital expenditures to restore our electric distribution and transmission systems as a result of a severe ice storm that occurred in December 2007. We deferred $53.8 million of these costs as a regulatory asset, which we will ask for recovery of in our next rate cases that are planned for 2008;
- We issued 7.6 million shares of common stock for net proceeds of $193.8 million through Sales Agency Financing Agreements with BNYCMI and a forward sale agreement and $325.0 million in first mortgage bonds as part of our efforts to raise the capital needed to fund our construction projects. We expect to continue to issue equity and debt as external funds are needed to complete planned capital investments;
- We started construction on a 610 MW peaking power plant and are expanding our transmission network. We also announced agreements with developers to build approximately 300 MW of wind generation of which we will either own or enter into supply contracts related thereto. See "— Increased Capacity and Future Plan" below for additional information;
- Changes in Federal income tax law allowed us to recognize $11.8 million in tax benefits from the utilization of a net operating loss that had not previously been applied against income.

Increased Gross Margin

Our net income was $168.4 million and $165.3 million for the years ended December 31, 2007 and 2006, respectively. Our gross margin for the year ended December 31, 2007, increased compared to the previous year due primarily to significant increases in wholesale sales. We sold 10.0 million MWh of electricity to wholesale customers for the year ended December 31, 2007, compared to 7.4 million MWh last year. We were able to sell more electricity to our wholesale customers this year due to our not having had to conserve coal and our not having a planned refueling outage at Wolf Creek as we did last year.

Increased Capacity and Future Plans

On January 11, 2008, we announced that we reached agreements with developers who will build three wind farms in Kansas totaling approximately 300 MWs. Under the terms of the agreements, we plan to own approximately half of the wind generators at an expected cost of approximately $290.0 million and purchase energy produced by the wind farms under twenty year supply contracts for the other half. All three wind farms are expected to be producing energy by the end of 2008.

On April 1, 2007, we completed the purchase of Aquila, Inc.'s (Aquila) 8% leasehold interest in Jeffrey Energy Center for $25.8 million and assumed the related lease obligation. This lease expires on January 3, 2019, and has a purchase option at the end of the lease term. Based on current economic and other conditions, we expect to exercise the purchase option. Based upon these expectations, we recorded a capital lease of $118.5 million.

In September 2006, we announced plans to build a 345 kV transmission line from our Gordon Evans Energy Center northwest of Wichita, Kansas, to a new substation near Hutchinson, Kansas, then on to our Summit substation near Salina, Kansas, a distance totaling approximately 97 miles. In January 2007, we filed an application with the KCC to request permission to site the line. The KCC granted our permit on May 16, 2007. We expect to complete construction in late 2009. We expect the total investment in the line to be approximately $150.0 million. In addition to this line, we plan to construct a new 345 kV line from our Rose Hill substation near Wichita to the Kansas-Oklahoma border, where we will interconnect with new facilities built by an Oklahoma-based utility. The preliminary estimate of the total investment in the line is approximately $70.0 million, which is subject to change pending selection of the final route and engineering design, among other factors. On December 27, 2007, we filed an application with the KCC to request permission to site this line. The KCC has until April 25, 2008, to act on our application.

In August 2006, we announced plans to build a new natural gas-fired combustion turbine peaking power plant near Emporia in Lyon County, Kansas. We expect the new plant, which we have named the Emporia Energy Center, to have an initial generating capacity of approximately 310 MW, with additional capacity to be added in a second phase, bringing the total capacity to approximately 610 MW. We expect the total investment in the plant to be about $318.0 million. Construction on the new plant began in March 2007. The initial phase of the plant is scheduled to begin operation in May of 2008. The second phase is scheduled to begin operation in May of 2009.

CRITICAL ACCOUNTING ESTIMATES

Our discussion and analysis of financial condition and results of operations are based on our consolidated financial statements, which have been prepared in conformity with generally accepted accounting principles (GAAP). Note 2 of the Notes to Consolidated Financial Statements, "Summary of Significant Accounting Policies," contains a summary of our significant accounting policies, many of which require the use of estimates and assumptions by management. The policies highlighted below have an impact on our reported results that may be material due to the levels of judgment and subjectivity necessary to account for uncertain matters or their susceptibility to change.

Regulatory Accounting

We currently apply accounting standards for our regulated utility operations that recognize the economic effects of rate regulation in accordance with SFAS No. 71. Accordingly, we have recorded regulatory assets and liabilities when required by a regulatory order or based on regulatory precedent. Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery in utility rates. Regulatory liabilities represent probable future reductions in revenue or refunds to customers.

The deferral of costs as regulatory assets is appropriate only when the future recovery of such costs is probable. In assessing probability, we consider such factors as specific regulatory orders, regulatory precedent and the current regulatory environment. To the extent recovery of costs is no longer deemed to be probable, we would record a charge against income in the amount of the related regulatory assets.

Pension and Post-retirement Benefit Plans Actuarial Assumptions

We and Wolf Creek calculate our pension benefit and post-retirement medical benefit obligations and related costs using actuarial concepts within the guidance provided by SFAS No. 87, "Employers' Accounting for Pensions", SFAS No. 106, "Employers' Accounting for Post-retirement Benefits Other Than Pensions" and SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Post-retirement Plans — An Amendment of FASB Statements No. 87, 88, 106, and 132(R)."

In accounting for our retirement plans and other post-retirement benefits, we make assumptions regarding the valuation of benefit obligations and the performance of plan assets. The reported costs of our pension plans are impacted by estimates regarding earnings on plan assets, contributions to the plan, discount rates used to determine our projected benefit obligation and pension costs and employee demographics including age, compensation levels and employment periods. A change in any of these assumptions could have a significant impact on future costs, which may be reflected as an increase or decrease in net income in the current and future periods, or on the amount of related liabilities reflected on our consolidated balance sheets or may also require cash contributions.

The following table shows the annual impact of a 0.5% change in our pension plan discount rate, salary scale and rate of return on plan assets.

Actuarial Assumption	Change in Assumption	Annual Change in Projected Benefit Obligation	Annual Change in Pension Liability/ Asset	Annual Change in Projected Pension Expense
			(In Thousands)	
Discount rate	0.5% decrease	$45,071	$45,071	$4,409
	0.5% increase	(42,194)	(42,194)	(4,307)
Salary scale	0.5% decrease	(12,067)	(12,067)	(2,370)
	0.5% increase	12,310	12,310	2,440
Rate of return on plan assets	0.5% decrease	—	—	2,603
	0.5% increase	—	—	(2,603)

We recorded pension expense of approximately $21.4 million in both 2007 and 2006 and $12.2 million in 2005. These amounts reflect the pension expense of Westar Energy and our 47% responsibility for the pension expense of Wolf Creek. The increase in pension expense from 2005 to current levels is due primarily to the amortization of investment losses from prior years that are recognized on a rolling four-year average basis and changes in assumptions including lower returns on assets, increases in salaries and updated mortality tables. Pension expense for 2008 is expected to be approximately $23.0 million.

The following table shows the annual impact of a 0.5% change in the discount rate and rate of return on plan assets on our post-retirement benefit plans other than pension plans.

Actuarial Assumption	Change in Assumption	Annual Change in Projected Benefit Obligation	Annual Change in Post-retirement Liability/ Asset	Annual Change in Projected Post-retirement Expense
			(In Thousands)	
Discount rate	0.5% decrease	$7,615	$7,615	$437
	0.5% increase	(7,228)	(7,228)	(448)
Rate of return on plan assets	0.5% decrease	—	—	285
	0.5% increase	—	—	(285)

Revenue Recognition — Energy Sales

We record revenue as electricity is delivered. Amounts delivered to individual customers are determined through the systematic monthly readings of customer meters. At the end of each month, the electric usage from the last meter reading is estimated and corresponding unbilled revenue is recorded.

The accuracy of the unbilled revenue estimate is affected by factors that include fluctuations in energy demands, weather, line losses and changes in the composition of customer classes. We had estimated unbilled revenue of $43.7 million as of December 31, 2007, and $38.4 million as of December 31, 2006.

We account for energy marketing derivative contracts under the mark-to-market method of accounting. Under this method, we recognize changes in the portfolio value as gains or losses in the period of change. With the exception of a fuel supply contract and a capacity sale contract, which are recorded as regulatory liabilities, we include the net mark-to-market change in sales on our consolidated statements of income. We record the resulting unrealized gains and losses as energy marketing long-term or short-term assets and liabilities on our consolidated balance sheets as appropriate. We use quoted market prices to value our energy marketing derivative contracts when such data is available. When market prices are not readily available or determinable, we use alternative approaches, such as model pricing. Prices used to value these transactions reflect our best estimate of the fair value of our contracts. Results actually achieved from these activities could vary materially from intended results and could affect our consolidated financial results.

The tables below show the fair value of energy marketing contracts that were outstanding as of December 31, 2007, their sources and maturity periods.

	Fair Value of Contracts
	(In Thousands)
Net fair value of contracts outstanding as of December 31, 2006	$ 20,625
Contracts outstanding at the beginning of the period that were realized or otherwise settled during the period	(9,948)
Changes in fair value of contracts outstanding at the beginning and end of the period	9,407
Fair value of new contracts entered into during the period	21,418
Fair value of contracts outstanding as of December 31, 2007[(a)]	$ 41,502

[(a)] *Approximately $34.0 million of the fair value of energy marketing contracts, which is comprised of a fuel supply contract and a capacity sale contract, is recognized as a regulatory liability.*

The sources of the fair values of the financial instruments related to these contracts as of December 31, 2007, are summarized in the following table.

		Fair Value of Contracts at End of Period			
Sources of Fair Value	Total Fair Value	Maturity Less Than 1 Year	Maturity 1-3 Years	Maturity 4-5 Years	Maturity Over 5 Years
		(In Thousands)			
Prices provided by other external sources (swaps and forwards)	$ 31,323	$ 9,910	$ 13,677	$ 4,039	$ 3,697
Prices based on option pricing models (options and other)[(a)]	10,179	5,151	6,581	(803)	(750)
Total fair value of contracts outstanding	$ 41,502	$ 15,061	$ 20,258	$ 3,236	$ 2,947

[(a)] *Options are priced using a series of techniques, such as the Black option pricing model.*

Income Taxes

We use the asset and liability method of accounting for income taxes as required by SFAS No. 109, "Accounting for Income Taxes." Under the asset and liability method, we recognize deferred tax assets and liabilities for the future tax consequences attributable to temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. We recognize the future tax benefits to the extent that realization of such benefits is more likely than not. We amortize deferred investment tax credits over the lives of the related properties.

We record deferred tax assets for capital losses, operating losses and tax credit carryforwards. However, when we believe we do not, or will not have sufficient future capital gain income or taxable income to realize the benefit of the capital loss, operating loss or tax credit carryforwards, we reduce the deferred tax assets by a valuation allowance. We recognize a valuation allowance if we determine, based on available evidence that it is unlikely that we will realize some portion or all of the deferred tax asset. We report the effect of a change in the valuation allowance in the current period tax expense.

As of January 1, 2007, we account for uncertainty in income taxes in accordance with Financial Accounting Standards Board (FASB) Interpretation No. (FIN) 48. The application of income tax law is inherently complex. Laws and regulations in this area are voluminous and are often ambiguous. As such, we are required to make many subjective assumptions and judgments regarding our income tax exposures. Interpretations of and guidance surrounding income tax laws and regulations change over time. As such, changes in our subjective assumptions and judgments can materially affect amounts recognized in the consolidated financial statements. See Note 11 to the Notes to Consolidated Financial Statements, "Income Taxes," for additional detail of our uncertainty in income taxes.

Asset Retirement Obligations

We calculate our asset retirement obligations and related costs using the guidance provided by SFAS No. 143, "Accounting for Asset Retirement Obligations" and FIN 47, "Accounting for Conditional Asset Retirement Obligations."

We estimate our asset retirement obligations based on the fair value of the asset retirement obligation we incurred at the time the related long-lived asset was either acquired, placed in service or when regulations establishing the obligation become effective.

In determining our asset retirement obligations, we make assumptions regarding probable disposal costs. A change in these assumptions could have a significant impact on our asset retirement obligations reflected on our consolidated balance sheets.

Contingencies and Litigation

We are currently involved in certain legal proceedings and have estimated the probable cost for the resolution of these claims. These estimates are based on an analysis of potential results, assuming a combination of litigation and settlement strategies. It is possible that our future results could be materially affected by changes in our assumptions. See "— Future Cash Requirements" and Notes 16 and 17 of the Notes to Consolidated Financial Statements, "Legal Proceedings" and "Potential Liabilities to David C. Wittig and Douglas T. Lake," for more detailed information.

OPERATING RESULTS

We evaluate operating results based on earnings per share. We have various classifications of sales, defined as follows:

Retail: Sales of energy made to residential, commercial and industrial customers.

Other retail: Sales of energy for lighting public streets and highways, net of revenue subject to refund.

Tariff-based wholesale: Sales of energy to electric cooperatives, municipalities and other electric utilities, the rates for which are generally based on cost as prescribed by FERC tariffs. This category also includes changes in valuations of contracts that have yet to settle, the sales from which will be recorded as tariff-based wholesale.

Market-based wholesale: Includes: (i) sales of energy to wholesale customers, the rates for which are generally based on prevailing market prices as allowed by FERC approved market-based tariff, or where not permitted, pricing is based on incremental cost plus a permitted margin and (ii) changes in valuations for contracts that have yet to settle, the sales of which will be recorded as market-based wholesale.

Energy marketing: Includes: (i) transactions based on market prices with volumes not related to the production of our generating assets or the demand of our retail customers; (ii) financially settled products and physical transactions sourced outside our control area; (iii) fees we earn for marketing services that we provide for third parties; and (iv) changes in valuations for contracts that have yet to settle that are not recorded in tariff- or market-based wholesale revenues.

Transmission: Reflects transmission revenues, including those based on a tariff with the SPP.

Other: Miscellaneous electric revenues including ancillary service revenues and rent from electric property leased to others.

Regulated electric utility sales are significantly impacted by such things as rate regulation, customer conservation efforts, wholesale demand, the economy of our service area and competitive forces. Our wholesale sales are impacted by, among other factors, demand, cost and availability of fuel and purchased power, price volatility, available generation capacity and transmission availability. Changing weather affects the amount of electricity our customers use. Hot summer temperatures and cold winter temperatures prompt more demand, especially among our residential customers. Mild weather serves to reduce customer demand.

2007 Compared to 2006

Below we discuss our operating results for the year ended December 31, 2007, compared to the results for the year ended December 31, 2006. Changes in results of operations are as follows:

Year Ended December 31,	2007	2006	Change	% Change
	(In Thousands, Except Per Share Amounts)			
SALES:				
Residential	$ 491,163	$ 486,107	$ 5,056	1.0
Commercial	448,368	438,342	10,026	2.3
Industrial	264,566	266,922	(2,356)	(0.9)
Other retail	(18,133)	(32,098)	13,965	43.5
Total Retail Sales	1,185,964	1,159,273	26,691	2.3
Tariff-based wholesale	218,647	195,428	23,219	11.9
Market-based wholesale	161,796	105,768	56,028	53.0
Energy marketing	36,978	35,562	1,416	4.0
Transmission[(a)]	97,717	83,764	13,953	16.7
Other	25,732	25,948	(216)	(0.8)
Total Sales	1,726,834	1,605,743	121,091	7.5
OPERATING EXPENSES:				
Fuel and purchased power	544,421	483,959	60,462	12.5
Operating and maintenance	473,525	463,785	9,740	2.1
Depreciation and amortization	192,910	180,228	12,682	7.0
Selling, general and administrative	178,587	171,001	7,586	4.4
Total Operating Expenses	1,389,443	1,298,973	90,470	7.0
INCOME FROM OPERATIONS	337,391	306,770	30,621	10.0
OTHER INCOME (EXPENSE):				
Investment earnings	6,031	9,212	(3,181)	(34.5)
Other income	6,726	18,000	(11,274)	(62.6)
Other expense	(14,072)	(13,711)	(361)	(2.6)
Total Other (Expense) Income	(1,315)	13,501	(14,816)	(109.7)
Interest expense	103,883	98,650	5,233	5.3
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	232,193	221,621	10,572	4.8
Income tax expense	63,839	56,312	7,527	13.4
NET INCOME	168,354	165,309	3,045	1.8
Preferred dividends	970	970	—	—
EARNINGS AVAILABLE FOR COMMON STOCK	$ 167,384	$ 164,339	$ 3,045	1.9
BASIC EARNINGS PER SHARE	$ 1.85	$ 1.88	$ (0.03)	(1.6)

[(a)] ***Transmission:*** *Includes an SPP network transmission tariff. In 2007, our SPP network transmission costs were $82.0 million. This amount, less $9.2 million that was retained by the SPP as administration cost, was returned to us as revenue. In 2006, our SPP network transmission costs were $76.0 million with an administration cost of $10.1 million retained by the SPP.*

The following table reflects changes in electric sales volumes, as measured by thousands of MWh of electricity. No sales volumes are shown for energy marketing, transmission or other. Energy marketing activities are unrelated to the amount of electricity we generate at our generating plants.

Year Ended December 31,	2007	2006	Change	% Change
	(Thousands of MWh)			
Residential	6,677	6,456	221	3.4
Commercial	7,537	7,185	352	4.9
Industrial	5,819	5,824	(5)	(0.1)
Other retail	91	93	(2)	(2.2)
Total Retail	20,124	19,558	566	2.9
Tariff-based wholesale	6,360	5,505	855	15.5
Market-based wholesale	3,666	1,913	1,753	91.6
Total	30,150	26,976	3,174	11.8

Retail sales were $26.7 million higher for the year ended December 31, 2007, due principally to increases in other retail, commercial and residential sales. Other retail sales increased $14.0 million due primarily to decreases in refund obligations. Commercial and residential sales increased a combined $15.1 million due primarily to cooler weather during the winter months, and customer growth in our service territory. When measured by heating degree days, the weather during 2007 was 16% cooler than during 2006.

Tariff-based wholesale sales were $23.2 million higher than last year, due principally to increased sales volumes that were primarily the result of additional sales from the long-term sale agreement entered into in 2007 with Mid-Kansas Electric Company, LLC. The average price per MWh for these sales, however, was about 3% lower than the same period last year.

Market-based wholesale sales were $56.0 million higher than last year, due principally to increased sales volumes that were primarily the result of coal conservation efforts and a scheduled refueling outage at Wolf Creek, both of which occurred last year and did not recur this year. The average price per MWh for these sales, however, was about 13% lower than the same period last year.

Fuel and purchased power expense increased $60.5 million compared to last year. The change in fuel and purchased power expense resulted from a number of factors, including: the volumes of power we produced and purchased, prevailing market prices and contract provisions that allow for price changes. We used 12% more fuel in our generating plants in 2007, due primarily to our not having had to conserve coal this year as we did last year. This resulted in $53.6 million higher fuel expense compared with 2006. Purchased power expense increased $6.8 million over 2006 due primarily to higher prices, but were largely offset by a 4% reduction in purchased volumes. In 2007 through the RECA, we deferred for future recovery $26.7 million of fuel and purchased power costs as a regulatory asset compared with $6.9 million in 2006.

Operating and maintenance expense increased $9.7 million compared to last year. This was due primarily to higher maintenance costs of $8.7 million for our power plants, electrical distribution system and transmission system and a $6.0 million increase in SPP network transmission costs that are in large part recovered through higher transmission revenues.

Depreciation and amortization expense increased $12.7 million compared to last year. This was due principally to depreciation expense associated with a higher plant balance including the capital lease associated with the purchase of Aquila's 8% leasehold interest in Jeffrey Energy Center.

The $7.6 million increase in selling, general and administrative expense was due primarily to a $6.2 million increase in employee benefit costs and a $6.0 million increase in labor costs. This increase was partially offset by reduced legal fees associated with matters having to deal with former management.

Other income decreased $11.3 million compared to last year due primarily to our having $0.7 million from COLI proceeds this year compared to $16.4 million in proceeds from COLI last year. Partially offsetting this decrease was $4.3 million of equity allowance for funds used during construction (AFUDC) for the year ended December 31, 2007. We recorded no equity AFUDC for the same period last year.

Income tax expense increased $7.5 million compared to last year due primarily to decreases in the utilization of previously unrecognized capital loss carryforwards to offset realized capital gains and decreases in non-taxable income from COLI. The increase was partially offset by increased tax benefits from the utilization of a net operating loss that had not previously been applied against income for other carryback or carryover years.

2006 Compared to 2005

Below we discuss our operating results for the year ended December 31, 2006, compared to the results for the year ended December 31, 2005. Changes in results of operations are as follows.

Year Ended December 31,	2006	2005	Change	% Change
	(In Thousands, Except Per Share Amounts)			
SALES:				
Residential	$ 486,107	$ 458,806	$ 27,301	6.0
Commercial	438,342	404,590	33,752	8.3
Industrial	266,922	242,383	24,539	10.1
Other retail	(32,098)	376	(32,474)	(b)
Total Retail Sales	1,159,273	1,106,155	53,118	4.8
Tariff-based wholesale	195,428	185,598	9,830	5.3
Market-based wholesale	105,768	145,875	(40,107)	(27.5)
Energy marketing	35,562	46,842	(11,280)	(24.1)
Transmission[(a)]	83,764	76,591	7,173	9.4
Other	25,948	22,217	3,731	16.8
Total Sales	1,605,743	1,583,278	22,465	1.4
OPERATING EXPENSES:				
Fuel and purchased power	483,959	528,229	(44,270)	(8.4)
Operating and maintenance	463,785	437,741	26,044	5.9
Depreciation and amortization	180,228	150,520	29,708	19.7
Selling, general and administrative	171,001	166,060	4,941	3.0
Total Operating Expenses	1,298,973	1,282,550	16,423	1.3
INCOME FROM OPERATIONS	306,770	300,728	6,042	2.0
OTHER INCOME (EXPENSE):				
Investment earnings	9,212	11,365	(2,153)	(18.9)
Other income	18,000	9,948	8,052	80.9
Other expense	(13,711)	(17,580)	3,869	22.0
Total Other Income	13,501	3,733	9,768	261.7
Interest expense	98,650	109,080	(10,430)	(9.6)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	221,621	195,381	26,240	13.4
Income tax expense	56,312	60,513	(4,201)	(6.9)
INCOME FROM CONTINUING OPERATIONS	165,309	134,868	30,441	22.6
Results of discontinued operations, net of tax	—	742	(742)	(100.0)
NET INCOME	165,309	135,610	29,699	21.9
Preferred dividends	970	970	—	—
EARNINGS AVAILABLE FOR COMMON STOCK	$ 164,339	$ 134,640	$ 29,699	22.1
BASIC EARNINGS PER SHARE	$ 1.88	$ 1.55	$ 0.33	21.3

[(a)] *Transmission: Includes an SPP network transmission tariff. In 2006, our SPP network transmission costs were $76.0 million. This amount, less $10.1 million that was retained by the SPP as administration cost, was returned to us as revenue. In 2005, our SPP network transmission costs were $66.2 million with an administration cost of $5.5 million retained by the SPP.*
[(b)] *Change greater than 1000%*

The following table reflects changes in electric sales volumes, as measured by thousands of MWh of electricity. No sales volumes are shown for energy marketing, transmission or other. Energy marketing activities are unrelated to the amount of electricity we generate at our generating plants.

Year Ended December 31,	2006	2005	Change	% Change
	(Thousands of MWh)			
Residential	6,456	6,384	72	1.1
Commercial	7,185	7,151	34	0.5
Industrial	5,824	5,581	243	4.4
Other retail	93	101	(8)	(7.9)
Total Retail	19,558	19,217	341	1.8
Tariff-based wholesale	5,505	5,490	15	0.3
Market-based wholesale	1,913	2,950	(1,037)	(35.2)
Total	26,976	27,657	(681)	(2.5)

The increase in retail sales reflects the change in rates, including the effect of implementing the RECA, and warmer weather. When measured by cooling degree days, the weather during 2006 was 2% warmer than during 2005 and approximately 16% warmer than the 20-year average. The increase in industrial sales was due primarily to additional oil refinery load. The change in other retail sales reflects the recognition in 2006 of revenue subject to refund, of which: (i) $19.9 million is due to the difference between estimated fuel and purchased power costs billed to our customers and actual fuel and purchased power costs incurred for our Westar Energy customers; (ii) $3.3 million is due to amounts associated with a transmission delivery charge approved by the KCC in its 2005 Order; (iii) $4.0 million collected for property taxes in excess of our actual property taxes obligations; and (iv) $16.4 million related to amounts we collected in rates related to terminal net salvage that the February 2007 KCC Order requires us to refund. The revenue subject to refund was partially offset by our having stopped accruing for rebates to customers in December 2005.

We made tariff-based sales in 2006 at an average price that was about 5% higher than the price of these sales in 2005. We attribute about $1.3 million, or 14%, of the increase in tariff-based wholesale sales to higher prices reflecting an adjustment for our fuel costs as permitted in FERC tariffs.

Our market-based wholesale sales and sales volumes decreased in 2006 due primarily to our having conserved coal inventories, but the average price per MWh that we received for these sales in 2006 was about 7% higher than in 2005.

The change in fuel and purchased power expense is the result of changing volumes produced and purchased, prevailing market prices and contract provisions that allow for price changes. We burned about 4% less fuel in our generating plants in 2006, due primarily to our having conserved coal inventories. We also used less expensive generation. In addition, during 2006 we deferred as a regulatory asset $6.9 million for the difference between the estimated fuel and purchased power costs that we billed our KGE customers and our higher actual fuel and purchased power costs that we are allowed to collect under the terms of the RECA. As a result, our fuel expense was $45.5 million lower in 2006 than in 2005. We also experienced a $1.2 million increase in our purchased power expense due primarily to our having purchased 9% greater volumes than in 2005.

We experienced an increase in our operating and maintenance expense due primarily to four factors: (i) the amortization of $10.7 million of previously deferred storm restoration expenses as authorized by the 2005 KCC Order; (ii) a $9.9 million increase in SPP network transmission costs; (iii) a $4.7 million increase in taxes other than income taxes due primarily to higher property taxes; and (iv) an increase in maintenance expenses for outages at La Cygne and the Gordon Evans Energy Center. These higher expenses were partially offset by a $5.4 million reduction in the lease expense related to La Cygne unit 2. Operating and maintenance expense in 2005 included a $10.4 million loss as a result of the decrease in the present value of previously disallowed plant costs associated with the original construction of Wolf Creek due to the extension of the recovery period.

We experienced an increase in our depreciation and amortization expense of $29.7 million. This increase was due primarily to the reduction of depreciation expense of $20.1 million in 2005 due to the establishment of a regulatory asset for the differences between the depreciation rates we used for financial reporting purposes and the depreciation rates authorized by the KCC for the period of August 2001 to March 2002. Provisions of the 2005 KCC Order allowed us to record this regulatory asset.

Selling, general and administrative expenses increased due primarily to increased employee pension and benefit costs. Partially offsetting these increases were lower legal fees associated with matters having to deal with former management and a decline in insurance costs.

Other income increased due primarily to COLI. We received $16.4 million in income from COLI in 2006 compared to $7.2 million in 2005. Associated with our having terminated an accounts receivable sales facility, we experienced a $3.9 million decrease in other expense.

Interest expense decreased due primarily to a $16.7 million reduction in interest expense on long-term debt due primarily to a lower long-term debt balance and lower interest rates resulting from the refinancing activities discussed in detail in "— Liquidity and Capital Resources — Debt Financings." This decline was partially offset by an increase of $6.3 million in interest expense on short-term debt due to increased borrowings under our revolving credit facility.

The decrease in income tax expense is due primarily to the utilization of previously unrecognized capital loss carryforwards to offset realized capital gains and increases in non-taxable income from COLI.

FINANCIAL CONDITION

A number of factors affected amounts recorded on our balance sheet as of December 31, 2007, compared to December 31, 2006.

Inventories and supplies increased $44.6 million due primarily to a $30.6 million increase in coal inventory that resulted largely from our having placed into service additional railcars that allowed for more frequent deliveries.

The fair market value of energy marketing contracts increased $20.9 million to $41.5 million at December 31, 2007. This was due primarily to favorable changes in market values of contracts entered into in 2007, in addition to contracts outstanding the entire period.

Regulatory assets, net of regulatory liabilities, increased to $533.8 million at December 31, 2007, from $476.0 million at December 31, 2006. Total regulatory assets increased $66.0 million due primarily to the accumulation and deferral for future recovery of $53.8 million in costs related to restoring our electric distribution and transmission systems from damage sustained as a result of the December 2007 ice storm. Also significantly contributing to the increase in regulatory assets was a $25.8 million increase in fuel costs deferred for future recovery. Total regulatory liabilities increased $8.1 million to $141.6 million due primarily to a $14.4 million increase to mark-to-market gains recognized on our coal supply contract for Lawrence and Tecumseh Energy centers. Removal costs increased regulatory liabilities an additional $11.8 million as a result of amounts collected and not yet spent to retire assets which we are not legally obligated to retire. The increases were offset due to our refunding to customers $39.4 million, of which $19.7 million was recorded as a regulatory liability as of December 31, 2006, as required in the February 2007 KCC Order.

We increased our borrowings under the Westar Energy revolving credit facility. As a result our short-term debt increased $20.0 million.

Long-term debt, net of current maturities increased $326.5 million due principally to the issuance of $325.0 million of first mortgage bonds as discussed in detail in Note 10 of the Notes to Consolidated Financial Statements, "Long-Term Debt."

Obligations under capital leases increased $111.5 million due primarily to our assuming Aquila's 8% leasehold interest in Jeffrey Energy Center as discussed in detail in Note 20 of the Notes to Consolidated Financial Statements, "Leases."

Other long-term liabilities increased $77.4 million due primarily to the recognition of uncertain tax liabilities, including interest, pursuant to the adoption of FIN 48.

Common stock and paid-in capital increased $208.8 million due principally to the issuance of 7.6 million shares of common stock for net proceeds of $193.8 million through Sales Agency Financing Agreements with BNYCMI and a forward sale agreement.

LIQUIDITY AND CAPITAL RESOURCES

Overview

We believe we will have sufficient cash to fund future operations, pay debt maturities and dividends from a combination of cash on hand, cash flows from operations and access to debt and equity capital markets. Our available sources of funds include: cash, Westar Energy's revolving credit facility and access to capital markets. Uncertainties affecting our ability to meet these cash requirements include, among others: factors affecting sales described in "Operating Results" above, economic conditions, regulatory actions, conditions in the capital markets and compliance with environmental regulations.

Capital Resources

As of December 31, 2007, we had $5.8 million in unrestricted cash and cash equivalents. In addition, Westar Energy has a $500.0 million revolving credit facility against which $180.0 million had been borrowed and $45.5 million of letters of credit had been issued. This left $274.5 million available under this facility. On January 11, 2008, we filed a request with FERC for authority to issue short-term securities and to pledge mortgage bonds in order to increase the size of our revolving credit facility to $750.0 million. On February 15, 2008, FERC granted our request and on February 22, 2008, a syndicate of banks in our credit facility increased their commitments, which in the aggregate total $750.0 million. As of February 22, 2008, $270.0 million had been borrowed and $55.0 million of letters of credit had been issued, leaving $425.0 million available under this facility.

The Westar Energy and KGE mortgages each contain provisions restricting the amount of first mortgage bonds that can be issued by each entity. We must comply with such restrictions prior to the issuance of additional first mortgage bonds or other secured indebtedness.

The Westar Energy mortgage prohibits additional first mortgage bonds from being issued, except in connection with certain refundings, unless Westar Energy's unconsolidated net earnings available for interest, depreciation and property retirement (which as defined, does not include earnings or losses attributable to the ownership of securities of subsidiaries), for a period of 12 consecutive months within 15 months preceding the issuance, are not less than the greater of twice the annual interest charges on, and 10% of the principal amount of, all first mortgage bonds outstanding after giving effect to the proposed issuance. In addition, the issuance of bonds is subject to limitations based on the amount of bondable property additions. As of December 31, 2007, based on an assumed interest rate of 6%, $408.0 million principal amount of additional first mortgage bonds could be issued under the most restrictive provisions in the mortgage, except in connection with certain refundings.

The KGE mortgage prohibits additional first mortgage bonds from being issued, except in connection with certain refundings, unless KGE's net earnings before income taxes and before provision for retirement and depreciation of property for a period of 12 consecutive months within 15 months preceding the issuance are not less than either two and one-half times the annual interest charges on, or 10% of the principal amount of, all KGE first mortgage bonds outstanding after giving effect to the proposed issuance. In addition, the issuance of bonds is subject to limitations based on the amount of bondable property additions. As of December 31, 2007, based on an assumed interest rate of 6%, approximately $820.1 million principal amount of additional KGE first mortgage bonds could be issued under the most restrictive provisions in the mortgage.

On April 12, 2007, we entered into a Sales Agency Financing Agreement with BNY Capital Markets, Inc. (BNYCMI). As of July 12, 2007, we had sold $100.0 million of common stock (3,701,568 shares) through BNYCMI, as agent, pursuant to the agreement. We received $99.0 million in proceeds net of a commission paid to BNYCMI equal to 1% of the sales price of all shares it sold under the agreement. We used the proceeds to repay borrowings under our revolving credit facility, which is the primary liquidity facility for acquiring capital equipment, and any remainder was used for working capital and general corporate purposes.

On August 24, 2007, we entered into a subsequent Sales Agency Financing Agreement with BNYCMI. Under the terms of the agreement, we may offer and sell shares of our common stock from time to time through BNYCMI, as agent, up to an aggregate of $200.0 million for a period of no more than three years. We will pay BNYCMI a commission equal to 1% of the sales price of all shares sold under the agreement. As of December 31, 2007, we had sold $20.0 million of common stock (783,745 shares) through BNYCMI. We received $19.8 million in proceeds net of commission paid to BNYCMI. We used the proceeds to repay borrowings under our revolving credit facility, which is the primary liquidity facility for acquiring capital equipment, and any remainder was used for working capital and general corporate purposes. Pursuant to the same program, in the period January 1, 2008, through February 19, 2008, we sold an additional 75,177 shares for $1.9 million, net of commission.

On November 15, 2007, we entered into a forward equity sale agreement (forward sale agreement) with UBS AG, London Branch (UBS), as forward purchaser, relating to 8.2 million shares of our common stock. The forward sale agreement provides for the sale of our common stock within approximately twelve months at a stated settlement price. In connection with the forward sale agreement, UBS borrowed an equal number of shares of our common stock from stock lenders and sold the borrowed shares to J.P. Morgan Securities, Inc. (JPM) under an underwriting agreement among Westar Energy, JPM and UBS Securities, LLC, as co-managers for the underwriters. The underwriters subsequently offered the borrowed shares to the public at a price per share of $25.25.

The use of a forward sale agreement allows us to avoid equity market uncertainty by pricing a stock offering under then existing market conditions, while mitigating share dilution by postponing the issuance of stock until funds are needed. Except in specified circumstances or events that would require physical share settlement, we are able to elect to settle the forward sale agreement by means of a physical share, cash or net share settlement and are also able to elect to settle the agreement in whole, or in part, earlier than the stated maturity date at fixed settlement prices. Under a physical share or net share settlement, the maximum number of shares that are deliverable under the terms of the forward sale agreement is limited to 8.2 million shares.

On December 28, 2007, we delivered 3.1 million newly issued shares of our common stock to UBS, and received proceeds of $75.0 million as partial settlement of the forward sale agreement. Additionally, on February 7, 2008, we delivered 2.1 million shares and received proceeds of $50.0 million as partial settlement of the forward sale agreement. Assuming gross share settlement of all remaining shares under the forward sale agreement, we could receive additional aggregate proceeds of approximately $75.0 million, based on a forward price of $24.25 per share for 3.0 million shares. Proceeds from these offerings were used to repay borrowings under our revolving credit facility, which is the primary liquidity facility for acquiring capital equipment, and any remainder was used for working capital and general corporate purposes.

Cash Flows from Operating Activities

Cash flows from operating activities decreased $9.2 million to $246.8 million in 2007, from $256.0 million in 2006. During 2007, as compared to 2006, we paid approximately $48.3 million more for natural gas used in our power plants, $29.8 million more for coal inventory and $29.4 million more in customer refunds. Offsetting these amounts were a $10.1 million reduction in La Cygne unit 2 lease payments, $9.0 million less in voluntary contributions to our pension trust and cash realized from higher gross margins. During 2006, we also used $65.0 million related to the termination of our accounts receivable sales program.

Cash flows from operating activities decreased $97.9 million to $256.0 million in 2006, from $353.9 million in 2005. During 2006, we used $72.4 million to pay Federal and state income taxes and made a $20.8 million contribution to our defined benefit pension trust. During 2005, we used approximately $33.1 million for system restoration costs related to the ice storm that affected our service territory in January 2005. We received $57.4 million in tax refunds during 2005.

Cash Flows used in Investing Activities

In general, cash used for investing purposes relates to the growth and improvement of our electric utility business. The utility business is capital intensive and requires significant investment in plant on an annual basis. We spent $748.2 million in 2007, $344.9 million in 2006 and $212.8 million in 2005 on net additions to utility property, plant and equipment. This increase is due primarily to our having begun construction on several generation and transmission projects and our having purchased other generating facilities during 2007.

Cash Flows used in Financing Activities

We received net cash flows from financing activities of $502.8 million in 2007. In 2007, proceeds from the issuance of long-term debt provided $322.3 million and proceeds from the issuance of common stock provided $195.4 million. We used cash to pay $89.5 million in dividends.

In 2006, we received net cash flows from financing activities of $12.8 million. In 2006, an increase in short-term debt was the principal source of cash flows from financing activities. Cash from financing activities was used to retire long-term debt and to pay dividends.

In 2005, we received cash primarily from the issuance of long-term debt and we used cash primarily to retire long-term debt and pay dividends.

Future Cash Requirements

Our business requires significant capital investments. Through 2010, we expect we will need cash primarily for utility construction programs designed to improve facilities providing electric service, which include but are not limited to expenditures for future peaking capacity needs, construction of new transmission lines and for compliance with environmental regulations. We expect to meet these cash needs with internally generated cash flow, borrowings under Westar Energy's revolving credit facility and through the issuance of securities in the capital markets.

We have incurred and expect to continue to incur material costs to comply with existing and future environmental laws and regulations, all of which are subject to changing interpretations and amendments. In addition, the current focus on the effect of air emissions on the global environment could result in significantly more stringent laws and regulations or interpretations thereof that could affect our company and industry in particular. These laws, regulations and interpretations could result in more stringent terms in our existing operating permits or a failure to obtain new permits, could cause there to be a material increase in our capital or operational costs and could otherwise have a material effect on our operations.

While we believe we can generally recover environmental costs through rate increases, there is no guarantee that we will be able to do so. In addition, we may be subject to significant fines and penalties in connection with the NSR Investigation or other matters, and such fines and penalties cannot be recovered through rate increases.

Capital expenditures for 2007 and anticipated capital expenditures for 2008 through 2010, including many environmental costs and costs of removal, are shown in the following table.

	Actual 2007	2008	2009	2010
	(In Thousands)			
Generation:				
Replacements and other	$ 45,271	$ 98,200	$ 136,800	$ 133,100
Additional capacity	189,757	96,500	56,400	12,300
Wind generation	79,195	205,000	—	—
Environmental	207,781	198,400	206,200	259,000
Nuclear fuel	38,168	18,100	20,000	33,900
Transmission	70,651	148,100	228,600	165,900
Distribution:				
Replacements and other	34,797	35,600	84,800	92,100
New customers	60,521	57,000	59,200	61,600
Other	22,015	31,300	28,300	23,100
Total capital expenditures	$ 748,156	$ 888,200	$ 820,300	$ 781,000

We prepare these estimates for planning purposes and revise our estimates from time to time. Actual expenditures will differ, perhaps materially, from our estimates due to changing environmental requirements, changing costs, delays in engineering, construction or permitting, and other factors discussed above in "Item 1A. Risk Factors." We and our generating plant co-owners periodically evaluate these estimates, and this may result in frequent and possibly material changes in actual costs. In addition, these amounts do not include any estimates for expenditures that may be incurred as a result of the NSR Investigation or for potentially new environmental requirements relating to mercury and CO_2 emissions.

Maturities of long-term debt as of December 31, 2007, are as follows.

Year	Principal Amount
	(In Thousands)
2008	$ 558
2009	145,684
2010	633
2011	28
Thereafter	1,746,243
Total long-term debt maturities	$1,893,146

Debt Financings

On August 14, 2007, KGE entered into a bond purchase agreement for the private placement of its first mortgage bonds. Pursuant to the agreement, on October 15, 2007, KGE issued $175.0 million principal amount of 6.53% first mortgage bonds maturing in 2037 in a private placement to an institutional investor. Proceeds from the offering were used to repay borrowings under our revolving credit facility, which is the primary liquidity facility for acquiring capital equipment, and any remainder was used for working capital and general corporate purposes.

On May 16, 2007, Westar Energy sold $150.0 million aggregate principal amount of 6.1% Westar Energy first mortgage bonds maturing in 2047. Proceeds from the offering were used to repay borrowings under our revolving credit facility, which is the primary liquidity facility for acquiring capital equipment, and any remainder was used for working capital and general corporate purposes.

On February 2, 2007, Westar Energy exercised its right to request a one-year extension of the termination date for the commitments of the lenders under the revolving credit facility dated March 17, 2006. Effective March 16, 2007, $480.0 million of the commitments of the lenders under the revolving credit facility terminate on March 17, 2012. The remaining $20.0 million of the commitments terminate on March 17, 2011. So long as there is no default or event of default under the revolving credit facility, Westar Energy may elect to extend the term of the credit facility for up to an additional year, subject to lender participation. The facility allows us to borrow up to an aggregate amount of $500.0 million, including letters of credit up to a maximum aggregate amount of $150.0 million. On January 11, 2008, we filed a request with FERC for authority to issue short-term securities and to pledge mortgage bonds in order to increase the size of our revolving credit facility to $750.0 million. On February 15, 2008, FERC granted our request and on February 22, 2008, a syndicate of banks in our credit facility increased their commitments, which in the aggregate total $750.0 million. As of February 22, 2008, $270.0 million had been borrowed and $55.0 million of letters of credit had been issued, leaving $425.0 million available under this facility.

A default by Westar Energy or KGE under other indebtedness totaling more than $25.0 million is a default under this facility. Westar Energy is required to maintain a consolidated indebtedness to consolidated capitalization ratio not greater than 65% at all times. Available liquidity under the facility is not impacted by a decline in Westar Energy's credit ratings. Also, the facility does not contain a material adverse effect clause requiring Westar Energy to represent, prior to each borrowing, that no event resulting in a material adverse effect has occurred.

On June 1, 2006, we refinanced $100.0 million of pollution control bonds, which were to mature in 2031. We replaced this issue with two new pollution control bond series of $50.0 million each. One series carries an interest rate of 4.85% and matures in 2031. The second series carries a variable interest rate and also matures in 2031.

On January 17, 2006, we repaid $100.0 million aggregate principal amount of 6.2% first mortgage bonds with cash on hand and borrowings under the revolving credit facility.

Debt Covenants

Some of our debt instruments contain restrictions that require us to maintain leverage ratios as defined in the agreements. We calculate these ratios in accordance with our credit agreements. These ratios are used solely to determine compliance with our various debt covenants. We were in compliance with these covenants as of December 31, 2007.

Credit Ratings

Standard & Poor's Ratings Group (S&P), Moody's Investors Service (Moody's) and Fitch Investors Service (Fitch) are independent credit-rating agencies that rate our debt securities. These ratings indicate the agencies' assessment of our ability to pay interest and principal when due on our securities.

In September 2007, S&P upgraded its credit ratings for Westar Energy's first mortgage bonds/senior secured debt securities. In May 2006, Moody's upgraded its credit ratings for our securities as shown in the table below and changed its outlook for our ratings to stable. In March 2006, Fitch upgraded its credit ratings for our securities as shown in the table below and changed its outlook for our ratings to stable.

As of February 19, 2008, ratings with these agencies are as shown in the table below.

	Westar Energy First Mortgage Bond Rating	Westar Energy Unsecured Debt	KGE First Mortgage Bond Rating
S&P	BBB	BB+	BBB
Moody's	Baa2	Baa3	Baa2
Fitch	BBB	BBB-	BBB

In general, less favorable credit ratings make debt financing more costly and more difficult to obtain on terms that are economically favorable to us. Westar Energy and KGE have credit rating conditions under the Westar Energy revolving credit agreement that affect the cost of borrowing but do not trigger a default. We may enter into new credit agreements that contain credit conditions, which could affect our liquidity and/or our borrowing costs.

Capital Structure

As of December 31, 2007 and 2006, our capital structure excluding short-term debt was as follows:

	2007	2006
Common equity	49%	49%
Preferred stock	1%	1%
Long-term debt	50%	50%
Total	100%	100%

OFF-BALANCE SHEET ARRANGEMENTS

Forward Equity Transaction

On November 15, 2007, we entered into a forward sale agreement relating to 8.2 million shares of our common stock. The use of a forward sale agreement allowed us to avoid equity market uncertainty by pricing a stock offering under then current market conditions, while mitigating share dilution by postponing the issuance of stock until funds were needed. On December 28, 2007, we delivered 3.1 million newly issued shares of our common stock to UBS, and received proceeds of $75.0 million as partial settlement of the forward sale agreement. Additionally, on February 7, 2008, we delivered 2.1 million shares and received proceeds of $50.0 million as partial settlement of the forward sale agreement. Assuming gross share settlement of all remaining shares under the forward sale agreement, we could receive additional aggregate proceeds of approximately $75.0 million, based on a forward price of $24.25 per share for 3.0 million shares.

As of December 31, 2007, we did not have any additional off-balance sheet financing arrangements, other than our operating leases entered into in the ordinary course of business. For additional information on our operating leases, see Note 20 of the Notes to Consolidated Financial Statements, "Leases."

CONTRACTUAL OBLIGATIONS AND COMMERCIAL COMMITMENTS

In the course of our business activities, we enter into a variety of obligations and commercial commitments. Some of these result in direct obligations reflected on our consolidated balance sheets while others are commitments, some firm and some based on uncertainties, not reflected in our underlying consolidated financial statements. The obligations listed below include amounts for on-going needs for which contractual obligations existed as of December 31, 2007.

Contractual Cash Obligations

The following table summarizes the projected future cash payments for our contractual obligations existing as of December 31, 2007.

	Total	2008	2009-2010	2011-2012	Thereafter
	(In Thousands)				
Long-term debt[a]	$1,893,146	$ 558	$ 146,317	$ 28	$1,746,243
Interest on long-term debt[b]	2,069,862	103,934	197,466	187,070	1,581,392
Adjusted long-term debt	3,963,008	104,492	343,783	187,098	3,327,635
Pension and post-retirement benefit expected contributions[c]	33,100	33,100	—	—	—
Capital leases[d]	201,230	17,637	32,335	26,867	124,391
Operating leases[e]	567,548	48,067	93,046	90,965	335,470
Fossil fuel[f]	1,596,217	269,661	396,597	358,511	571,448
Nuclear fuel[g]	330,621	19,780	50,736	34,904	225,201
Unconditional purchase obligations	608,235	489,780	106,192	12,263	—
Unrecognized income tax benefits including interest[h]	4,946	4,946	—	—	—
Total contractual obligations, including adjusted long-term debt	$7,304,905	$ 987,463	$1,022,689	$710,608	$4,584,145

[a] *See Note 10 of the Notes to Consolidated Financial Statements, "Long-Term Debt," for individual long-term debt maturities.*

[b] *We calculate interest on our variable rate debt based on the effective interest rate as of December 31, 2007.*

[c] *Pension and post-retirement benefit expected contributions represent the minimum funding requirements under the Employee Retirement Income Securities Act of 1974 plus additional amounts as deemed fiscally appropriate. These amounts for future periods are not yet known. See Notes 12 and 13 of the Notes to Consolidated Financial Statements, "Employee Benefit Plans" and "Wolf Creek Employee Benefit Plans," for additional information regarding pensions.*

[d] *Includes principal and interest on capital leases, including the 8% leasehold interest in Jeffrey Energy Center that was purchased in 2007.*

[e] *Includes the La Cygne unit 2 lease, office space, operating facilities, office equipment, operating equipment, rail car leases and other miscellaneous commitments.*

[f] *Coal and natural gas commodity and transportation contracts.*

[g] *Uranium concentrates, conversion, enrichment, fabrication and spent nuclear fuel disposal.*

[h] *We have an additional $79.4 million of unrecognized income tax benefits, including interest, that are not included in this table because we cannot reasonably estimate the timing of the cash payments to taxing authorities assuming those unrecognized tax benefits are settled at the amounts recognized pursuant to FIN 48 as of December 31, 2007.*

Commercial Commitments

Our commercial commitments existing as of December 31, 2007, consist of outstanding letters of credit that expire in 2008, some of which automatically renew annually. The letters of credit are comprised of $30.7 million related to our energy marketing and trading activities, $10.9 million related to worker's compensation and $4.9 million related to other operating activities for a total outstanding balance of $46.5 million.

OTHER INFORMATION

Stock Based Compensation

Effective January 1, 2006, we adopted SFAS No. 123R using the modified prospective transition method. Since 2002, we have used restricted share units (RSU) exclusively for our stock-based compensation awards. Given the characteristics of our stock-based compensation awards, the adoption of SFAS No. 123R did not have a material impact on our consolidated results of operations.

Total unrecognized compensation cost related to RSU awards was $8.9 million as of December 31, 2007. We expect to recognize these costs over a remaining weighted-average period of 2.4 years. Upon adoption of SFAS No. 123R, we were required to charge $10.3 million of unearned stock compensation against additional paid-in capital. There were no modifications of awards during the years ended December 31, 2007, 2006 or 2005.

Prior to the adoption of SFAS No. 123R, we reported all tax benefits resulting from the vesting of RSU awards and exercise of stock options as operating cash flows in the consolidated statements of cash flows. SFAS No. 123R requires cash retained as a result of excess tax benefits resulting from the tax deductions in excess of the related compensation cost recognized in the financial statements to be classified as cash flows from financing activities in the consolidated statements of cash flows.

Pension Obligation

We made an $11.8 million voluntary pension contribution to the Westar Energy pension trust in 2007. We currently expect to make a voluntary contribution to the pension trust of an estimated $15.2 million in 2008. We may make additional contributions into the pension trust in 2008 depending on how the funded status of the pension plan changes, regulatory treatment for the contributions and conclusions reached as there is more clarity with respect to the Pension Protection Act of 2006 (PPA). The United States Treasury Department is in the process of developing implementation guidance for the PPA; however, it is likely the PPA will accelerate minimum funding requirements beginning in 2009. We may choose to pre-fund some of the anticipated required funding.

Customer Refunds and Rebates

We refunded $39.4 million to customers in 2007 related to the remand of the 2005 KCC Order. We also made rebates to customers of $10.0 million during the year ended December 31, 2006, in accordance with a July 25, 2003, KCC Order.

Impact of Regulatory Accounting

We currently apply accounting standards that recognize the economic effects of rate regulation and record regulatory assets and liabilities related to our electric utility operations. If we determine that we no longer meet the criteria of SFAS No. 71, we may have a material non-cash charge to earnings.

As of December 31, 2007, we had recorded regulatory assets currently subject to recovery in future rates of approximately $675.5 million and regulatory liabilities of $141.6 million as discussed in greater detail in Note 2 of the Notes to Consolidated Financial Statements, "Summary of Significant Accounting Policies — Regulatory Accounting." We believe that it is probable that our regulatory assets will be recovered in the future.

Asset Retirement Obligations

Legal Liability

In accordance with SFAS No. 143 and FIN 47 we have recognized legal obligations associated with the disposal of long-lived assets that result from the acquisition, construction, development or normal operation of such assets. Concurrent with the recognition of the liability, the estimated cost of an asset retirement obligation is capitalized and depreciated over the remaining life of the asset.

We initially recorded asset retirement obligations at fair value for the estimated cost to decommission Wolf Creek (our 47% share), dispose of asbestos insulating material at our power plants, remediate ash disposal ponds and dispose of polychlorinated biphenyl (PCB) contaminated oil.

As of December 31, 2007 and 2006, we have recorded asset retirement obligations of $88.7 million and $84.2 million, respectively. For additional information on our legal asset retirement obligations, see Note 15 of the Notes to Consolidated Financial Statements, "Asset Retirement Obligations."

Non-Legal Liability — Cost of Removal

We recover in rates, as a component of depreciation, the costs to dispose of utility plant assets that do not represent legal retirement obligations. As of December 31, 2007 and 2006, we had $25.2 million and $13.4 million, respectively, in amounts collected, but unspent, for removal costs classified as a regulatory liability. The net amount related to non-legal retirement costs can fluctuate based on amounts recovered in rates compared to removal costs incurred.

Guardian International Preferred Stock

On March 6, 2006, Guardian was acquired by Devcon International Corporation in a merger. In connection with this merger, we received approximately $23.2 million for 15,214 shares of Guardian Series D preferred stock and 8,000 shares of Guardian Series E preferred stock held of record by us. We beneficially owned 354.4 shares of the Guardian Series D preferred stock and 312.9 shares of the Guardian Series E preferred stock. We recognized a gain of approximately $0.3 million as a result of this transaction. Certain current and former officers beneficially owned the remaining shares. Of these shares, 14,094 shares of Guardian Series D preferred stock and 7,276 shares of Guardian Series E preferred stock were beneficially owned by Mr. Wittig and Mr. Lake. The ownership of the shares beneficially owned by either Mr. Wittig or Mr. Lake, as well as related dividends, and now the cash received for the shares, is disputed and is the subject of the arbitration proceeding with Mr. Wittig and Mr. Lake discussed in Note 17, "Potential Liabilities to David C. Wittig and Douglas T. Lake." As a result of this transaction, we no longer hold any Guardian securities.

New Accounting Pronouncements

SFAS No. 159 – The Fair Value Option for Financial Assets and Financial Liabilities

In February 2007, FASB released SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities — Including an amendment to FASB Statement No. 115." SFAS No. 159 permits entities to choose to measure many financial instruments and certain other items at fair value. A business entity shall report unrealized gains and losses on items for which fair value option has been elected in earnings at each subsequent reporting date. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007, with the cumulative effect of the change in accounting principle recorded as an adjustment to opening retained earnings. We adopted the guidance effective January 1, 2008. The adoption of SFAS No. 159 did not have a material impact on our consolidated financial statements.

SFAS No. 157 — Fair Value Measurements

In September 2006, FASB released SFAS No. 157, "Fair Value Measurements." SFAS No. 157 defines fair value, establishes a framework for measuring fair value in GAAP, and expands disclosures about fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007, with the cumulative effect of the change in accounting principle recorded as an adjustment to opening retained earnings. We adopted the guidance effective January 1, 2008. The adoption of SFAS No. 157 did not have a material impact on our consolidated financial statements.

FIN 48 — Accounting for Uncertainty in Income Taxes

We adopted the provisions of FIN 48, "Accounting for Uncertainty in Income Taxes – an Interpretation of FASB Statement No. 109" as of January 1, 2007. The cumulative effect of adopting FIN 48 was an increase of $10.5 million to the January 1, 2007, retained earnings balance.

Allowance for Funds Used During Construction

AFUDC represents the cost of capital used to finance utility construction activity. AFUDC is computed by applying a composite rate to qualified construction work in progress. The amount of AFUDC capitalized as a construction cost is credited to other income (for equity funds) and interest expense (for borrowed funds) on the accompanying consolidated statements of income, as follows:

Year Ended December 31,	2007	2006	2005
	(In Thousands)		
Borrowed funds	$ 13,090	$ 4,053	$ 2,655
Equity funds	4,346	—	—
Total	$ 17,436	$ 4,053	$ 2,655
Average AFUDC Rates	6.6%	5.3%	4.2%

We expect both AFUDC for borrowed funds and equity funds to fluctuate over the next several years as we add capacity, expand our transmission system, make environmental improvements and begin to recover the related costs in rates.

Interest Expense

We expect interest expense to increase significantly over the next several years as we issue new debt securities to fund our capital expenditures program. We believe the increase in interest expense will be recovered from our customers in future rate proceedings.

Wholesale Sales Margins

The terms of the RECA require that we include, as a credit to recoverable fuel costs beginning in April of each year, an amount based on the average of the margins realized from market-based wholesale sales during the immediately prior three-year period ending June 30. Effective April 1, 2007, we began crediting our retail customers an annual amount of $40.1 million. Beginning on April 1, 2008, we will begin crediting our retail customers an annual amount of $51.5 million. It is possible that we will not realize market-based wholesale sales margins at least equal to the amount of the credit. This would adversely affect our financial results.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our fuel procurement and energy marketing activities involve primary market risk exposures, including commodity price risk, interest rate risk and credit risk. Commodity price risk is the potential adverse price impact related to purchase or sell of electricity and fuel procurement for our generating units. Interest rate risk is the potential adverse financial impact related to changes in interest rates. Credit risk is the potential adverse financial impact resulting from non-performance by a counterparty of its contractual obligations.

Market Price Risks

We engage in physical and financial trading activities with the goals of reducing risk from market fluctuations, enhancing system reliability and increasing profits. We procure and trade electricity, coal, natural gas and other energy related products by utilizing energy commodity contracts and a variety of financial instruments, including forward and futures contracts, options and swaps.

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. The inability to make wholesale purchases may require that we interrupt or curtail services to our customers. Net open positions exist, or are established, due to the origination of new transactions and our assessment of, and response to, changing market conditions. To the extent we have open positions, we are exposed to changes in market prices. Additional factors that affect our commodity price exposure are the quantity and availability of fuel used for generation and the quantity of electricity customers consume. The availability and deliverability of generating fuel, including fossil and nuclear fuels, can vary significantly from one period to the next. Our customers' electricity usage could also vary from year to year based on the weather or other factors. The loss of revenues or higher costs associated with such conditions could be material and adverse to our consolidated results of operations and financial condition. Our risk of loss is mitigated through the use of the RECA and similar adjustment mechanisms that we maintain for many of our wholesale sales contracts and tariffs.

Hedging Activity

In an effort to mitigate market risk associated with fuel procurement and energy marketing, we may use economic hedging arrangements to reduce our exposure to price changes. We may use physical contracts and financial derivative instruments to hedge the price of a portion of our anticipated fossil fuel needs or excess generation sales. At the time we enter into these transactions, we are unable to determine the hedge value until the agreements are actually settled. Our future exposure to changes in prices will be dependent on the market prices and the extent and effectiveness of any economic hedging arrangements into which we enter.

Commodity Price Exposure

We manage and measure the market price risk exposure of our trading portfolio using a variance/covariance value-at-risk (VaR) model. In addition to VaR, we employ additional risk control processes such as stress testing, daily loss limits, credit limits and position limits. We expect to use similar control processes in 2008. The use of VaR requires assumptions, including the selection of a confidence level for potential losses and the estimated holding period. We express VaR as a potential dollar loss based on a 95% confidence level using a one-day holding period. It is possible that actual results may differ markedly from assumptions. Accordingly, VaR may not accurately reflect our levels of exposures. The energy trading and market-based wholesale portfolio VaR amounts for 2007 and 2006 were as follows:

	2007	2006
	(In Thousands)	
High	$1,966	$2,178
Low	176	449
Average	639	1,089

We have considered a variety of risks and costs associated with the future contractual commitments included in our trading portfolios. These risks include valuation and marking of illiquid pricing locations and products, interest rate movement and the financial condition of our counterparties. We may use swaps or other financial instruments to manage interest rate risk. We have exposure to counterparty default risk with our retail, wholesale and energy marketing activities, including participation in regional transmission organizations. We maintain credit policies intended to reduce overall credit risk. We employ additional credit risk control mechanisms that we believe are appropriate, such as requiring counterparties to issue letters of credit or parental guarantees in our favor and entering into master netting agreements with counterparties that allow for offsetting exposures. There can be no assurance that the employment of VaR, credit practices or other risk management tools we employ will eliminate possible losses.

Interest Rate Exposure

We have entered into various fixed and variable rate debt obligations. For details, see Note 10 of the Notes to Consolidated Financial Statements, "Long-Term Debt." We compute and present information about the sensitivity to changes in interest rates for variable rate debt and current maturities of fixed rate debt by assuming a 100 basis point change in the current interest rate applicable to such debt over the remaining time the debt is outstanding.

We had approximately $452.5 million of variable rate debt and current maturities of fixed rate debt as of December 31, 2007. A 100 basis point change in interest rates applicable to this debt would impact income before income taxes on an annualized basis by approximately $4.5 million. As of December 31, 2007, we had $271.9 million of variable rate bonds insured by bond insurers. Interest rates payable under these bonds are set at periodic auctions. Recent conditions in the credit markets have decreased the demand of auction bonds generally and have caused our borrowing costs to increase. Additionally, should those bond insurers experience a decrease in credit rating, such event would most likely increase our borrowing costs as well. In addition, a decline in interest rates generally can serve to increase our pension and post retirement obligations and affect investment returns.

Security Price Risk

We maintain trust funds, as required by the NRC and Kansas state laws, to fund certain costs of nuclear plant decommissioning. As of December 31, 2007, these funds were comprised of 70% equity securities, 27% debt securities and 3% cash and cash equivalents. The fair value of these funds was $122.3 million as of December 31, 2007, and $111.1 million as of December 31, 2006. By maintaining a diversified portfolio of securities, we seek to maximize the returns to fund the decommissioning obligation within acceptable risk tolerances. However, debt and equity securities in the portfolio are exposed to price fluctuations in the capital markets. If the value of the securities diminishes, the cost of funding the obligation rises. We actively monitor the portfolio by benchmarking the performance of the investments against relevant indices and by maintaining and periodically reviewing the asset allocation in relation to established policy targets. Our exposure to equity price market risk is, in part, mitigated because we are currently allowed to recover decommissioning costs in the rates we charge our customers.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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SCHEDULES OMITTED

The following schedules are omitted because of the absence of the conditions under which they are required or the information is included on our consolidated financial statements and schedules presented:

I, III, IV, and V.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

We are responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is defined in Rules 13a-15(f) promulgated under the Securities Exchange Act of 1934 as a process designed by, or under the supervision of, the company's principal executive and principal financial officers and effected by the company's board of directors, management and other personnel, 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 and includes those policies and procedures that:

- Pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the company;
- 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
- 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. 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.

We assessed the effectiveness of our internal control over financial reporting as of December 31, 2007. In making this assessment, we used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control-Integrated Framework. Based on the assessment, we believe that, as of December 31, 2007, our internal control over financial reporting is effective based on those criteria. Our independent registered public accounting firm has issued an audit report on the company's internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and
Shareholders of Westar Energy, Inc.
Topeka, Kansas

We have audited the internal control over financial reporting of Westar Energy, Inc. and subsidiaries (the "Company") as of December 31, 2007, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, including the accompanying management's report on internal control over financial reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel 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 (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) 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 (3) 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 the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting 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.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2007 of the Company and our report dated February 28, 2008 expressed an unqualified opinion on those financial statements and financial statement schedule and included explanatory paragraphs regarding the Company's adoption of new accounting standards.

/s/ Deloitte & Touche LLP

Kansas City, Missouri
February 28, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and
Shareholders of Westar Energy, Inc.
Topeka, Kansas

We have audited the accompanying consolidated balance sheets of Westar Energy, Inc. and subsidiaries (the "Company") as of December 31, 2007 and 2006, and the related consolidated statements of income, comprehensive income, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2007. Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Westar Energy, Inc. and subsidiaries as of December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

As discussed in Note 2 to the consolidated financial statements, the Company adopted Financial Accounting Standards Board (FASB) Interpretation No. FIN 48, "Accounting for Uncertainty in Income Taxes — an interpretation of FASB Statement No.109" as of January 1, 2007.

As discussed in Note 12 to the consolidated financial statements, in 2006, the Company adopted Statement of Financial Accounting Standard No. 123(R), "Share-Based Payment," and Statement of Financial Accounting Standard No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans."

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2007, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2008 expressed an unqualified opinion on Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Kansas City, Missouri
February 28, 2008

WESTAR ENERGY, INC. CONSOLIDATED BALANCE SHEETS

As of December 31,	2007	2006
(Dollars in Thousands)		
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 5,753	$ 18,196
Accounts receivable, net of allowance for doubtful accounts of $5,721 and $6,257, respectively	195,785	179,859
Inventories and supplies, net	192,533	147,930
Energy marketing contracts	57,702	67,267
Taxes receivable	71,111	15,142
Deferred tax assets	—	853
Prepaid expenses	31,576	29,620
Regulatory assets	98,204	58,777
Other	15,015	19,076
Total Current Assets	667,679	536,720
PROPERTY, PLANT AND EQUIPMENT, NET	4,803,672	4,071,607
OTHER ASSETS:		
Regulatory assets	577,256	550,703
Nuclear decommissioning trust	122,298	111,135
Energy marketing contracts	34,088	11,173
Other	190,437	173,837
Total Other Assets	924,079	846,848
TOTAL ASSETS	$6,395,430	$ 5,455,175
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Current maturities of long-term debt	$ 558	$ —
Short-term debt	180,000	160,000
Accounts payable	278,299	150,424
Accrued taxes	47,370	102,219
Energy marketing contracts	42,641	57,281
Accrued interest	41,416	32,928
Deferred tax liabilities	2,310	—
Regulatory liabilities	32,932	49,836
Other	119,237	110,488
Total Current Liabilities	744,763	663,176
LONG-TERM LIABILITIES:		
Long-term debt, net	1,889,781	1,563,265
Obligation under capital leases	123,854	12,316
Deferred income taxes	897,293	906,311
Unamortized investment tax credits	59,619	61,668
Deferred gain from sale-leaseback	119,522	125,017
Accrued employee benefits	283,924	246,930
Asset retirement obligations	88,711	84,192
Energy marketing contracts	7,647	534
Regulatory liabilities	108,685	83,664
Other	217,927	140,536
Total Long-Term Liabilities	3,796,963	3,224,433
COMMITMENTS AND CONTINGENCIES (see Notes 14 and 16)		
TEMPORARY EQUITY (See Note 12)	5,224	6,671
SHAREHOLDERS' EQUITY:		
Cumulative preferred stock, par value $100 per share; authorized 600,000 shares; issued and outstanding 214,363 shares	21,436	21,436
Common stock, par value $5 per share; authorized 150,000,000 shares; issued 95,463,180 shares and 87,394,886 shares, respectively	477,316	436,974
Paid-in capital	1,085,099	916,605
Retained earnings	264,477	185,779
Accumulated other comprehensive income, net	152	101
Total Shareholders' Equity	1,848,480	1,560,895
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$6,395,430	$ 5,455,175

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

WESTAR ENERGY, INC. CONSOLIDATED STATEMENTS OF INCOME

Year Ended December 31,	**2007**	2006	2005
(Dollars in Thousands, Except Per Share Amounts)			
SALES	**$1,726,834**	$ 1,605,743	$ 1,583,278
OPERATING EXPENSES:			
Fuel and purchased power	**544,421**	483,959	528,229
Operating and maintenance	**473,525**	463,785	437,741
Depreciation and amortization	**192,910**	180,228	150,520
Selling, general and administrative	**178,587**	171,001	166,060
Total Operating Expenses	**1,389,443**	1,298,973	1,282,550
INCOME FROM OPERATIONS	**337,391**	306,770	300,728
OTHER INCOME (EXPENSE):			
Investment earnings	**6,031**	9,212	11,365
Other income	**6,726**	18,000	9,948
Other expense	**(14,072)**	(13,711)	(17,580)
Total Other (Expense) Income	**(1,315)**	13,501	3,733
Interest expense	**103,883**	98,650	109,080
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	**232,193**	221,621	195,381
Income tax expense	**63,839**	56,312	60,513
INCOME FROM CONTINUING OPERATIONS	**168,354**	165,309	134,868
Results of discontinued operations, net of tax	**—**	—	742
NET INCOME	**168,354**	165,309	135,610
Preferred dividends	**970**	970	970
EARNINGS AVAILABLE FOR COMMON STOCK	**$ 167,384**	$ 164,339	$ 134,640
BASIC AND DILUTED EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING (SEE NOTE 2):			
Basic earnings available from continuing operations	**$ 1.85**	$ 1.88	$ 1.54
Discontinued operations, net of tax	**—**	—	0.01
Basic earnings available	**$ 1.85**	$ 1.88	$ 1.55
Diluted earnings available from continuing operations	**$ 1.83**	$ 1.87	$ 1.53
Discontinued operations, net of tax	**—**	—	0.01
Diluted earnings available	**$ 1.83**	$ 1.87	$ 1.54
Average equivalent common shares outstanding	**90,675,511**	87,509,800	86,855,485
DIVIDENDS DECLARED PER COMMON SHARE	**$ 1.08**	$ 1.00	$ 0.92

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

WESTAR ENERGY, INC. CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year Ended December 31,	**2007**	2006	2005
(Dollars in Thousands)			
NET INCOME	**$ 168,354**	$ 165,309	$ 135,610
OTHER COMPREHENSIVE INCOME (LOSS):			
Unrealized holding gain (loss) on marketable securities arising during the period	**51**	(57)	45
Minimum pension liability adjustment	**—**	31,841	(68,321)
Other comprehensive income (loss), before tax	**51**	31,784	(68,276)
Income tax (expense) benefit related to items of other comprehensive income	**—**	(12,666)	27,176
Other comprehensive income (loss), net of tax	**51**	19,118	(41,100)
COMPREHENSIVE INCOME	**$ 168,405**	$ 184,427	$ 94,510

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

WESTAR ENERGY, INC. CONSOLIDATED STATEMENTS OF CASH FLOWS

Year Ended December 31,	**2007**	2006	2005
(Dollars in Thousands)			
CASH FLOWS FROM (USED IN) OPERATING ACTIVITIES:			
Net income	**$ 168,354**	$ 165,309	$ 135,610
Adjustments to reconcile net income to net cash provided by operating activities:			
Discontinued operations, net of tax	**—**	—	(742)
Depreciation and amortization	**192,910**	180,228	150,520
Amortization of nuclear fuel	**16,711**	13,851	13,315
Amortization of deferred gain from sale-leaseback	**(5,495)**	(5,495)	(8,469)
Amortization of corporate-owned life insurance	**13,693**	15,336	16,265
Non-cash compensation	**5,800**	3,389	3,219
Net changes in energy marketing assets and liabilities	**7,647**	(7,505)	5,799
Accrued liability to certain former officers	**931**	3,813	2,018
Gain on sale of utility plant and property	**—**	(570)	—
Net deferred income taxes and credits	**14,084**	(4,203)	25,552
Stock based compensation excess tax benefits	**(1,058)**	(854)	—
Allowance for equity funds used during construction	**(4,346)**	—	—
Changes in working capital items, net of acquisitions and dispositions:			
Accounts receivable	**(15,926)**	(55,148)	(32,179)
Inventories and supplies	**(44,603)**	(46,112)	22,745
Prepaid expenses and other	**(72,212)**	(4,095)	(65,635)
Accounts payable	**59,488**	22,625	6,929
Accrued taxes	**(50,027)**	(13,160)	91,938
Other current liabilities	**(50,179)**	(5,708)	(20,876)
Changes in other assets	**(54,668)**	19,412	20,374
Changes in other liabilities	**65,712**	(25,127)	(12,492)
Cash flows from operating activities	**246,816**	255,986	353,891
CASH FLOWS FROM (USED IN) INVESTING ACTIVITIES:			
Additions to property, plant and equipment	**(748,156)**	(344,860)	(212,814)
Allowance for equity funds used during construction	**4,346**	—	—
Investment in corporate-owned life insurance	**(18,793)**	(19,127)	(19,346)
Purchase of securities within the nuclear decommissioning trust fund	**(240,067)**	(345,541)	(372,426)
Sale of securities within the nuclear decommissioning trust fund	**238,414**	341,410	367,570
Proceeds from investment in corporate-owned life insurance	**544**	22,684	10,997
Proceeds from sale of plant and property	**—**	1,695	—
Proceeds from other investments	**1,653**	53,411	13,990
Cash flows used in investing activities	**(762,059)**	(290,328)	(212,029)
CASH FLOWS FROM (USED IN) FINANCING ACTIVITIES:			
Short-term debt, net	**20,000**	160,000	—
Proceeds from long-term debt	**322,284**	99,662	642,807
Retirements of long-term debt	**(25)**	(200,000)	(741,847)
Repayment of capital leases	**(5,729)**	(4,813)	(4,898)
Borrowings against cash surrender value of corporate-owned life insurance	**61,472**	59,697	58,039
Repayment of borrowings against cash surrender value of corporate-owned life insurance	**(2,209)**	(24,133)	(13,026)
Stock based compensation excess tax benefits	**1,058**	854	—
Issuance of common stock, net	**195,420**	2,394	5,584
Cash dividends paid	**(89,471)**	(80,894)	(74,593)
Cash flows from (used in) financing activities	**502,800**	12,767	(127,934)
CASH FLOWS FROM DISCONTINUED OPERATIONS:			
Cash flows from investing activities	**—**	1,232	—
Cash from discontinued operations	**—**	1,232	—
NET (DECREASE) INCREASE IN CASH AND CASH EQUIVALENTS	**(12,443)**	(20,343)	13,928
CASH AND CASH EQUIVALENTS:			
Beginning of period	**18,196**	38,539	24,611
End of period	**$ 5,753**	$ 18,196	$ 38,539

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

WESTAR ENERGY, INC. CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

	Cumulative preferred stock	Common stock	Paid-in capital	Unearned compensation	Retained earnings	Accumulated other comprehensive (loss) income	Total Shareholders' Equity
			(Dollars in Thousands)				
Balance at December 31, 2004	$ 21,436	$430,149	$ 912,932	$ (10,361)	$ 55,053	$ 113	$1,409,322
Net income	—	—	—	—	135,610	—	135,610
Issuance of common stock, net	—	4,028	13,171	—	—	—	17,199
Preferred dividends, net of retirements	—	—	—	—	(970)	—	(970)
Dividends on common stock	—	—	—	—	(79,706)	—	(79,706)
Grant of restricted stock	—	—	2,986	(2,986)	—	—	—
Amortization of restricted stock	—	—	—	3,019	—	—	3,019
Forfeited restricted stock	—	—	—	71	—	—	71
Stock compensation and tax benefit	—	—	(6,006)	—	—	—	(6,006)
Unrealized gain on marketable securities	—	—	—	—	—	45	45
Minimum pension liability adjustment	—	—	—	—	—	(68,321)	(68,321)
Income tax benefit	—	—	—	—	—	27,176	27,176
Balance at December 31, 2005	21,436	434,177	923,083	(10,257)	109,987	(40,987)	1,437,439
Net income	—	—	—	—	165,309	—	165,309
Issuance of common stock, net	—	2,797	9,585	—	—	—	12,382
Preferred dividends, net of retirements	—	—	—	—	(970)	—	(970)
Dividends on common stock	—	—	—	—	(88,547)	—	(88,547)
Reclass to Temporary Equity	—	—	(6,671)	—	—	—	(6,671)
Reclass of unearned compensation	—	—	(10,257)	10,257	—	—	—
Amortization of restricted stock	—	—	2,956	—	—	—	2,956
Stock compensation and tax benefit	—	—	(2,091)	—	—	—	(2,091)
Unrealized loss on marketable securities	—	—	—	—	—	(57)	(57)
Minimum pension liability adjustment	—	—	—	—	—	31,841	31,841
Income tax expense	—	—	—	—	—	(12,666)	(12,666)
Reclass to regulatory asset	—	—	—	—	—	21,970	21,970
Balance at December 31, 2006	**21,436**	**436,974**	**916,605**	**—**	**185,779**	**101**	**1,560,895**
Net income	**—**	**—**	**—**	**—**	**168,354**	**—**	**168,354**
Issuance of common stock, net	**—**	**40,342**	**165,623**	**—**	**—**	**—**	**205,965**
Preferred dividends, net of retirements	**—**	**—**	**—**	**—**	**(970)**	**—**	**(970)**
Dividends on common stock	**—**	**—**	**—**	**—**	**(99,153)**	**—**	**(99,153)**
Reclass to Temporary Equity	**—**	**—**	**1,447**	**—**	**—**	**—**	**1,447**
Amortization of restricted stock	**—**	**—**	**5,116**	**—**	**—**	**—**	**5,116**
Stock compensation and tax benefit	**—**	**—**	**(3,692)**	**—**	**—**	**—**	**(3,692)**
Unrealized gain on marketable securities	**—**	**—**	**—**	**—**	**—**	**51**	**51**
Adjustment to Retained Earnings — FIN 48	**—**	**—**	**—**	**—**	**10,467**	**—**	**10,467**
Balance at December 31, 2007	**$ 21,436**	**$ 477,316**	**$1,085,099**	**$ —**	**$ 264,477**	**$ 152**	**$1,848,480**

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

WESTAR ENERGY, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. DESCRIPTION OF BUSINESS

We are the largest electric utility in Kansas. Unless the context otherwise indicates, all references in this Annual Report on Form 10-K to "the company," "we," "us," " "our" and similar words are to Westar Energy, Inc. and its consolidated subsidiaries. The term "Westar Energy" refers to Westar Energy, Inc., a Kansas corporation incorporated in 1924, alone and not together with its consolidated subsidiaries.

We provide electric generation, transmission and distribution services to approximately 674,000 customers in Kansas. Westar Energy provides these services in central and northeastern Kansas, including the cities of Topeka, Lawrence, Manhattan, Salina and Hutchinson. Kansas Gas and Electric Company (KGE), Westar Energy's wholly owned subsidiary, provides these services in south-central and southeastern Kansas, including the city of Wichita. KGE owns a 47% interest in the Wolf Creek Generating Station (Wolf Creek), a nuclear power plant located near Burlington, Kansas. Both Westar Energy and KGE conduct business using the name Westar Energy. Our corporate headquarters is located at 818 South Kansas Avenue, Topeka, Kansas 66612.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation

We prepare our consolidated financial statements in accordance with generally accepted accounting principles (GAAP) for the United States of America. Our consolidated financial statements include all operating divisions and majority owned subsidiaries for which we maintain controlling interests. Undivided interests in jointly-owned generation facilities are included on a proportionate basis. Intercompany accounts and transactions have been eliminated in consolidation. In our opinion, all adjustments, consisting only of normal recurring adjustments considered necessary for a fair presentation of the financial statements, have been included.

Use of Management's Estimates

When we prepare our consolidated financial statements, we are required 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 our consolidated 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 bad debts, inventories, valuation of commodity contracts, depreciation, unbilled revenue, investments, valuation of our energy marketing portfolio, intangible assets, forecasted fuel costs included in our retail energy cost adjustment (RECA) billed to customers, income taxes, pension and other post-retirement and post-employment benefits, our asset retirement obligations including decommissioning of Wolf Creek, environmental issues, contingencies and litigation. Actual results may differ from those estimates under different assumptions or conditions.

Regulatory Accounting

We apply accounting standards for our regulated utility operations that recognize the economic effects of rate regulation in accordance with Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation," and, accordingly, have recorded regulatory assets and liabilities when required by a regulatory order or based on regulatory precedent.

Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery in customer rates. Regulatory liabilities represent probable future reductions in revenue or refunds to customers through the rate making process. Regulatory assets and liabilities reflected on our consolidated balance sheets are as follows.

As of December 31,	2007	2006
	(In Thousands)	
Regulatory Assets:		
Amounts due from customers for future income taxes, net	$151,279	$160,147
Debt reacquisition costs	91,110	97,342
Deferred employee benefit costs	202,545	189,226
Disallowed plant costs	16,650	16,733
2002 ice storm costs	9,998	14,897
2005 ice storm costs	17,626	24,540
2007 ice storm costs	53,838	—
Asset retirement obligations	20,071	19,312
Depreciation	64,665	58,863
Wolf Creek outage	6,984	14,975
Retail energy cost adjustment	32,794	6,950
Other regulatory assets	7,900	6,495
Total regulatory assets	$675,460	$609,480
Regulatory Liabilities:		
Fuel supply and capacity sale contracts	$ 34,042	$ 12,794
Nuclear decommissioning	56,006	48,793
Retail energy cost adjustment	6,015	19,884
State Line purchased power	5,001	6,623
Terminal net salvage	15	16,439
Removal costs	25,157	13,355
Other regulatory liabilities	15,381	15,612
Total regulatory liabilities	$141,617	$133,500

Below we summarize the nature and period of recovery for each of the regulatory assets listed in the table above.

- **Amounts due from customers for future income taxes, net:** In accordance with various rate orders, we have reduced rates to reflect the tax benefits associated with certain tax deductions, thereby passing on these benefits to customers at the time we receive them. We believe it is probable that the net future increases in income taxes payable will be recovered from customers when these temporary tax benefits reverse in future periods. We have recorded a regulatory asset for these amounts. We also have recorded a regulatory liability for our obligation to customers for taxes recovered from customers in earlier periods when corporate tax rates were higher than the current tax rates. The benefit will be returned to customers as these temporary differences reverse in future periods. The tax-related regulatory assets and liabilities as well as unamortized investment tax credits are also temporary differences for which deferred income taxes have been provided. These items are measured by the expected cash flows to be received or settled through future rates.

- **Debt reacquisition costs:** This includes costs incurred to reacquire and refinance debt. Debt reacquisition costs are amortized over the term of the new debt.
- **Deferred employee benefit costs:** Employee benefit costs include $203.4 million, less $3.1 million for applicable taxes, for pension and post-retirement benefit obligations pursuant to SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Post-retirement Plans — An Amendment of FASB Statements No. 87, 88, 106, and 132(R)" and $2.2 million for post-retirement expenses in excess of amounts paid. We will amortize to expense approximately $19.7 million during 2008 for the benefit obligation. The post-retirement expenses are recovered over a period of five years.
- **Disallowed plant costs:** In 1985, the Kansas Corporation Commission (KCC) disallowed certain costs associated with the original construction of Wolf Creek. In 1987, the KCC authorized KGE to recover these costs in rates over the useful life of Wolf Creek.
- **2002 ice storm costs:** We accumulated and deferred for future recovery costs related to restoring our electric distribution system from the damage it suffered as a result of an ice storm that occurred in January 2002. The KCC authorized us to accrue carrying costs on this item. As allowed by the December 28, 2005, KCC Order (2005 KCC Order), in 2006 Westar Energy began recovering $7.7 million over a three year period and KGE began recovering $11.7 million over a five year period. We earn a return on this asset.
- **2005 ice storm costs:** We accumulated and deferred for future recovery costs related to restoring our electric distribution system from the damage it sustained as a result of an ice storm that occurred in January 2005. The KCC authorized us to accrue carrying costs on this item. As allowed by the 2005 KCC Order, in 2006 Westar Energy began recovering $5.6 million over a three year period and KGE began recovering $25.3 million over a five year period. We earn a return on this asset.
- **2007 ice storm costs:** We accumulated and deferred for future recovery costs related to restoring our electric transmission and distribution systems from the damage it sustained as a result of an ice storm that occurred in December 2007. Recovery of this asset will be considered during the 2008 rate reviews.
- **Asset retirement obligations:** This represents amounts associated with our asset retirement obligations as discussed in Note 15, "Asset Retirement Obligations." We recover this item over the life of the utility plant.
- **Depreciation:** This represents the difference between the regulatory depreciation expense and the depreciation expense we record for financial reporting purposes. We earn a return on this asset. We recover this item over the life of the related utility plant.
- **Wolf Creek outage:** Wolf Creek incurs a refueling and maintenance outage approximately every 18 months. The expenses associated with these maintenance and refueling outages are deferred and amortized over the period of time between such planned outages.
- **Retail energy cost adjustment:** We are allowed to adjust our retail prices to reflect changes in the cost of fuel and purchased power needed to serve our customers. This item represents the difference in the actual cost of fuel consumed in producing electricity and the cost of purchased power and amounts we have collected from customers. We expect to recover in our rates this shortfall over a one year period. We have two retail jurisdictions, each of which has a unique RECA and a separate cost of fuel. This can result in our simultaneously reporting both a regulatory asset and a regulatory liability for this item.
- **Other regulatory assets:** This item includes various regulatory assets that individually are small in relation to the total regulatory asset balance. Other regulatory assets have various recovery periods, most of which range from three to five years.

Below we summarize the nature and period of amortization for each of the regulatory liabilities listed in the table above.

- **Fuel supply and capacity sale contracts:** We use mark-to-market accounting for some of our fuel supply and capacity sale contracts. This item represents the non-cash net gain position on fuel supply and capacity sale contracts that are marked-to-market in accordance with the requirements of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." Under the RECA, fuel supply contract market gains accrue to the benefit of our customers.
- **Nuclear decommissioning:** We have a legal obligation to decommission Wolf Creek at the end of its useful life. This amount represents the difference between the fair value of our asset retirement obligation and the fair value of the assets in our decommissioning trust. See Note 6, "Financial Investments and Trading Securities" and Note 15, "Asset Retirement Obligations," for information regarding our Nuclear Decommissioning Trust Fund and our asset retirement obligation.
- **Retail energy cost adjustment:** We are allowed to adjust our retail prices to reflect changes in the cost of fuel and purchased power needed to serve our customers. We bill customers based on our estimated costs. This item represents the amount we collected from customers that was in excess of our actual cost of fuel and purchased power. We will refund to customers this excess recovery over a one year period. We have two retail jurisdictions, each of which has a unique RECA and a separate cost of fuel. This can result in our simultaneously reporting both a regulatory asset and a regulatory liability for this item.
- **State Line purchased power:** This represents amounts received from customers in excess of costs incurred under Westar Energy's purchased power agreement with Westar Generating, Inc., a wholly owned subsidiary.
- **Terminal net salvage:** This represents amounts collected in rates for terminal net salvage. Pursuant to the February 8, 2007, KCC Order (February 2007 KCC Order), the KCC ordered us to refund amounts previously collected. We refunded this amount during 2007.

- **Removal costs:** This represents amounts collected, but unspent, for costs to dispose of utility plant assets that do not represent legal retirement obligations. The liability will be discharged as removal costs are incurred.
- **Other regulatory liabilities:** This includes various regulatory liabilities that individually are relatively small in relation to the total regulatory liability balance. Other regulatory liabilities will be credited over various periods, most of which range from one to five years.

Cash and Cash Equivalents

We consider investments that are highly liquid and that have maturities of three months or less when purchased to be cash equivalents.

Inventories and Supplies

We state inventories and supplies at average cost.

Property, Plant and Equipment

We record the value of property, plant and equipment at cost. For utility plant, cost includes contracted services, direct labor and materials, indirect charges for engineering and supervision, and an allowance for funds used during construction (AFUDC). AFUDC represents the cost of capital used to finance utility construction activity. AFUDC is computed by applying a composite rate to qualified construction work in progress. The amount of AFUDC capitalized as a construction cost is credited to other income (for equity funds) and interest expense (for borrowed funds) on the accompanying consolidated statements of income as follows:

Year Ended December 31,	2007	2006	2005
	(In Thousands)		
Borrowed funds	$ 13,090	$ 4,053	$ 2,655
Equity funds	4,346	—	—
Total	$ 17,436	$ 4,053	$ 2,655
Average AFUDC Rates	6.6%	5.3%	4.2%

We charge maintenance costs and replacement of minor items of property to expense as incurred, except for maintenance costs incurred for our refueling outages at Wolf Creek. As authorized by regulators, we amortize these amounts to expense ratably over the 18-month period between such scheduled outages. Normally, when a unit of depreciable property is retired, we charge to accumulated depreciation the original cost, less salvage value.

Depreciation

We depreciate utility plant using a straight-line method at rates based on the estimated remaining useful lives of the assets. These rates are based on an average annual composite basis using group rates that approximated 2.7% in both 2007 and 2006 and 2.5% in 2005.

Depreciable lives of property, plant and equipment are as follows.

	Years
Fossil fuel generating facilities	15 to 75
Nuclear fuel generating facility	40 to 60
Transmission facilities	45 to 65
Distribution facilities	19 to 65
Other	5 to 35

In the 2005 KCC Order, the KCC approved a change in our depreciation rates. This change increased our annual depreciation expense by approximately $8.8 million.

Nuclear Fuel

We record as property, plant and equipment our share of the cost of nuclear fuel used in the process of refinement, conversion, enrichment and fabrication. We reflect this at original cost and amortize such amounts to fuel expense based on the quantity of heat consumed during the generation of electricity, as measured in millions of British thermal units (MMBtu). The accumulated amortization of nuclear fuel in the reactor was $36.4 million as of December 31, 2007, and $19.6 million as of December 31, 2006. Spent nuclear fuel charged to fuel and purchased power expense was $21.7 million in 2007, $18.8 million in 2006 and $18.0 million in 2005.

Cash Surrender Value of Life Insurance

We recorded on our consolidated balance sheets in other long-term assets the following amounts related to corporate-owned life insurance policies (COLI).

As of December 31,	2007	2006
	(In Thousands)	
Cash surrender value of policies	$1,117,828	$1,053,231
Borrowings against policies	(1,031,155)	(971,892)
Corporate-owned life insurance, net	$ 86,673	$ 81,339

We record income for increases in cash surrender value and death proceeds. We offset against policy income the interest expense that we incur on policy loans. Income recognized from death proceeds is highly variable from period to period. Death benefits approximated $2.4 million in 2007, $18.9 million in 2006 and $9.5 million in 2005.

Revenue Recognition — Energy Sales

We record revenue as electricity is delivered. Amounts delivered to individual customers are determined through the systematic monthly readings of customer meters. At the end of each month, the electric usage from the last meter reading is estimated and corresponding unbilled revenue is recorded.

The accuracy of the unbilled revenue estimate is affected by factors that include fluctuations in energy demands, weather, line losses and changes in the composition of customer classes. We had estimated unbilled revenue of $43.7 million as of December 31, 2007, and $38.4 million as of December 31, 2006.

We account for energy marketing derivative contracts under the mark-to-market method of accounting. Under this method, we recognize changes in the portfolio value as gains or losses in the period of change. With the exception of a fuel supply contract and a capacity sale contract, which are recorded as regulatory liabilities, we include the net mark-to-market change in sales on our consolidated statements of income. We record the resulting unrealized gains and losses as energy marketing long-term or short-term assets and liabilities on our consolidated balance sheets as appropriate. We use quoted market prices to value our energy marketing derivative contracts when such data is available. When market prices are not readily available or determinable, we use alternative approaches, such as model pricing. Prices used to value these transactions reflect our best estimate of the fair value of our contracts. Results actually achieved from these activities could vary materially from intended results and could affect our consolidated financial results.

Income Taxes

We use the asset and liability method of accounting for income taxes as required by SFAS No. 109, "Accounting for Income Taxes." Under the asset and liability method, we recognize deferred tax assets and liabilities for the future tax consequences attributable to temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. We recognize the future tax benefits to the extent that realization of such benefits is more likely than not. We amortize deferred investment tax credits over the lives of the related properties.

As of January 1, 2007, we account for uncertainty in income taxes in accordance with Financial Accounting Standards Board (FASB) Interpretation No. (FIN) 48. The application of income tax law is inherently complex. Laws and regulations in this area are voluminous and are often ambiguous. As such, we are required to make many subjective assumptions and judgments regarding our income tax exposures. Interpretations of and guidance surrounding income tax laws and regulations change over time. As such, changes in our subjective assumptions and judgments can materially affect amounts recognized in the consolidated financial statements. See Note 11 to the Notes to Consolidated Financial Statements, "Income Taxes," for additional detail of our uncertainty in income taxes.

Sales Taxes

We account for the collection and remittance of sales tax on a net basis. As a result, these amounts are not reflected in the consolidated statements of income.

Dilutive Shares

We report basic earnings per share applicable to equivalent common stock based on the weighted average number of common shares outstanding and shares issuable in connection with vested restricted share units (RSU) during the period reported. Diluted earnings per share include the effects of potential issuances of common shares resulting from the assumed vesting of all outstanding RSUs, the exercise of all outstanding stock options issued pursuant to the terms of our stock-based compensation plans and the physical settlement of a forward sale agreement. The dilutive effect of shares issuable under our stock-based compensation plans and forward sale agreement is computed using the treasury stock method.

The following table reconciles the weighted average number of equivalent common shares outstanding used to compute basic and diluted earnings per share.

Year Ended December 31,	2007	2006	2005
DENOMINATOR FOR BASIC AND DILUTED EARNINGS PER SHARE:			
Denominator for basic earnings per share — weighted average equivalent shares	90,675,511	87,509,800	86,855,485
Effect of dilutive securities:			
Employee stock options	952	788	1,750
Restricted share units	517,694	589,352	552,423
Forward sale agreement	66,686	—	—
Denominator for diluted earnings per share — weighted average equivalent shares	91,260,843	88,099,940	87,409,658
Potentially dilutive shares not included in the denominator because they are antidilutive	74,890	158,080	214,340

Supplemental Cash Flow Information

Year Ended December 31,	2007	2006	2005
		(In Thousands)	
CASH PAID FOR:			
Interest on financing activities, net of amount capitalized	$ 84,291	$ 88,872	$ 87,634
Income taxes	74,970	72,407	772
NON-CASH INVESTING TRANSATIONS:			
Jeffrey Energy Center 8% leasehold interest	118,538	—	—
Other property, plant and equipment additions	100,039	29,134	10,800
NON-CASH FINANCING TRANSACTIONS:			
Issuance of common stock for reinvested dividends and RSUs	10,553	10,094	11,728
Capital lease for Jeffrey Energy Center 8% leasehold interest	118,538	—	—
Other assets acquired through capital leases	3,228	4,491	3,716

New Accounting Pronouncements

SFAS No. 159 — The Fair Value Option for Financial Assets and Financial Liabilities

In February 2007, FASB released SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities — Including an amendment to FASB Statement No. 115." SFAS No. 159 permits entities to choose to measure many financial instruments and certain other items at fair value. A business entity shall report unrealized gains and losses on items for which fair value option has been elected in earnings at each subsequent reporting date. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007, with the cumulative effect of the change in accounting principle recorded as an adjustment to opening retained earnings. We adopted the guidance effective January 1, 2008. The adoption of SFAS No. 159 did not have a material impact on our consolidated financial statements.

SFAS No. 157 — Fair Value Measurements

In September 2006, FASB released SFAS No. 157, "Fair Value Measurements." SFAS No. 157 defines fair value, establishes a framework for measuring fair value in GAAP, and expands disclosures about fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007, with the cumulative effect of the change in accounting principle recorded as an adjustment to opening retained earnings. We adopted the guidance effective January 1, 2008. The adoption of SFAS No. 157 did not have a material impact on our consolidated financial statements.

3. RATE MATTERS AND REGULATION

Changes in Rates

On December 28, 2005, the KCC issued an order (2005 KCC Order) authorizing changes in our rates, which we began billing in the first quarter of 2006, and approving various other changes in our rate structures. In April 2006, interveners to the rate review filed appeals with the Kansas Court of Appeals challenging various aspects of the 2005 KCC Order. On July 7, 2006, the Kansas Court of Appeals reversed and remanded for further consideration by the KCC three elements of the 2005 KCC Order (July 2006 Court Order). The balance of the 2005 KCC Order was upheld.

The Kansas Court of Appeals held: (i) the KCC's approval of a transmission delivery charge, in the circumstances of this case, violated the Kansas statutes that authorize a transmission delivery charge, (ii) the KCC's approval of recovery of terminal net salvage, adjusted for inflation, in our depreciation rates was not supported by substantial competent evidence, and (iii) the KCC's reversal of its prior rate treatment of the La Cygne Generating Station (La Cygne) unit 2 sale-leaseback transaction was not sufficiently justified and was thus unreasonable, arbitrary and capricious.

On February 8, 2007, the KCC issued an order (February 2007 KCC Order) in response to the July 2006 Court Order. The February 2007 KCC Order: (i) confirmed the original decision regarding treatment of the La Cygne unit 2 sale-leaseback transaction; (ii) reversed the KCC's original decision with regard to the inclusion in depreciation rates of a component for terminal net salvage; and (iii) permits recovery of transmission related costs in a manner similar to how we recover our other costs. On November 30, 2007, we filed with the KCC to implement a separate transmission delivery charge in a manner consistent with the applicable Kansas statute. The February 2007 KCC Order required us to refund to our customers amounts we collected related to terminal net salvage. On July 31, 2007, the KCC issued an order (July 2007 KCC Order) resolving issues raised by us and interveners following the February 2007 KCC Order. The July 2007 KCC Order: (i) confirmed the earlier decision concerning recovery of terminal net salvage and quantified the effect of that ruling; and (ii) approved a Stipulation and Agreement between us and the KCC Staff. The Stipulation and Agreement approved by the KCC quantified the refund obligation related to amounts previously collected from customers for transmission related costs and established the amount of transmission costs to be included in retail rates, prospectively. Interveners filed petitions for reconsideration of the July 2007 KCC Order on August 15, 2007. These petitions were denied by the KCC on September 13, 2007. The interveners filed appeals with the Kansas Court of Appeals. On February 11, 2008, the Kansas Court of Appeals issued an opinion which affirmed the July 2007 KCC Order. We filed new tariffs and a plan for implementing refunds that became effective on August 29, 2007. Refunds were substantially completed in November.

FERC Proceedings

Request for Change in Transmission Rates

On May 2, 2005, we filed applications with the Federal Energy Regulatory Commission (FERC) that proposed a formula transmission rate providing for annual adjustments to our transmission tariff. This is consistent with our proposals filed with the KCC on May 2, 2005, to charge retail customers separately for transmission service through a transmission delivery charge. The proposed FERC transmission rates became effective, subject to refund, December 1, 2005. On November 7, 2006, FERC issued an order reflecting a unanimous settlement reached by the parties to the proceeding. The settlement modified the rates we proposed and required us to refund approximately $3.4 million, which included the amount we collected in the interim rates since December 2005 and interest on that amount.

On December 28, 2007, we filed applications with FERC that proposed changes to our formula transmission rate, which provides for annual adjustments to our transmission tariff. While the formula already allows recovery of the prior year's actual costs, the changes, if accepted by FERC, will allow us to include in our formula rate our anticipated transmission capital expenditures for the current year. We have requested the changes take effect on June 1, 2008. In addition, we made a simultaneous filing requesting authority for incentives related to new transmission investments as permitted by FERC.

On November 6, 2007, we filed applications with FERC that proposed the use of a consolidated capital structure in our formula transmission rate. On December 19, 2007, FERC issued an order accepting this change. On January 28, 2008, we filed applications with FERC requesting that this change be effective June 1, 2007. Accordingly, we have recorded a $3.7 million refund obligation, which includes the amount we have collected since June 1, 2007, and interest on that amount.

Rate Review Request

We will file a request for a rate review with the KCC during 2008, based on a test year consisting of the 12 months ended December 31, 2007.

4. ACCOUNTS RECEIVABLE SALES PROGRAM

We terminated our accounts receivable sales program in March 2006. The amounts sold to the bank and commercial paper conduit were $65.0 million as of December 31, 2005. We recorded this activity on the consolidated statements of cash flows for the year ended December 31, 2005, in the "accounts receivable, net" line of cash flows from operating activities.

5. FINANCIAL INSTRUMENTS, ENERGY MARKETING AND RISK MANAGEMENT

Values of Financial Instruments

We estimate the fair value of each class of our financial instruments for which it is practicable to estimate that value as set forth in SFAS No. 107, "Disclosures about Fair Value of Financial Instruments."

Cash and cash equivalents, short-term borrowings and variable-rate debt are carried at cost, which approximates fair value. The nuclear decommissioning trust is recorded at fair value, which is estimated based on the quoted market prices as of December 31, 2007 and 2006. See Note 6, "Financial Investments and Trading Securities," for additional information about our nuclear decommissioning trust. The fair value of fixed-rate debt is estimated based on quoted market prices for the same or similar issues or on the current rates offered for instruments of the same remaining maturities and redemption provisions.

The recorded amounts of accounts receivable and other current financial instruments approximate fair value.

We base estimates of fair value on information available as of December 31, 2007 and 2006. These fair value estimates have not been comprehensively revalued for the purpose of these financial statements since that date and current estimates of fair value may differ from the amounts below. The carrying values and estimated fair values of our financial instruments are as shown in the table below.

	Carrying Value		Fair Value	
As of December 31,	2007[(a)]	2006	2007[(a)]	2006
	(In Thousands)			
Fixed-rate debt, net of current maturities	$1,619,381	$1,294,405	$1,586,407	$1,277,497

[(a)] *This amount does not include an equipment financing loan of $1.8 million.*

Derivative Instruments

We are exposed to market risks from changes in commodity prices and interest rates that could affect our consolidated results of operations and financial condition. We manage our exposure to these market risks through our regular operating and financing activities and, when deemed appropriate, economically hedge a portion of these risks through the use of derivative financial instruments. We use the term economic hedge to mean a strategy designed to manage risks of volatility in prices or rate movements on some assets, liabilities or anticipated transactions by creating a relationship in which gains or losses on derivative instruments are expected to counterbalance the losses or gains on the assets, liabilities or anticipated transactions exposed to such market risks. We use derivative instruments as risk management tools consistent with our business plans and prudent business practices and for energy marketing purposes.

We use derivative financial and physical instruments primarily to manage risk as it relates to changes in the prices of commodities including natural gas, oil, coal and electricity. We classify derivative instruments used to manage commodity price risk inherent in fossil fuel and electricity purchases and sales as energy marketing contracts on our consolidated balance sheets. We report energy marketing contracts representing unrealized gain positions as assets; energy marketing contracts representing unrealized loss positions are reported as liabilities.

Energy Marketing Activities

We engage in both financial and physical trading to increase profits, manage our commodity price risk and enhance system reliability. We trade electricity, coal and natural gas. We use a variety of financial instruments, including forward contracts, options and swaps, and we trade energy commodity contracts.

Within the trading portfolio, we take certain positions to economically hedge a portion of physical sale or purchase contracts and we take certain positions to take advantage of market trends and conditions. With the exception of a fuel supply contract and a capacity sale contract, which are recorded as regulatory liabilities, we include the net mark-to-market change in sales on our consolidated statements of income. We believe financial instruments help us manage our contractual commitments, reduce our exposure to changes in cash market prices and take advantage of selected market opportunities. We refer to these transactions as energy marketing activities.

We are involved in trading activities to reduce risk from market fluctuations, enhance system reliability and increase profits. Net open positions exist, or are established, due to the origination of new transactions and our assessment of, and response to, changing market conditions. To the extent we have open positions, we are exposed to the risk that changing market prices could have a material, adverse impact on our consolidated financial position or results of operations.

We have considered a number of risks and costs associated with the future contractual commitments included in our energy portfolio. These risks include credit risks associated with the financial condition of counterparties, product location (basis) differentials and other risks. Declines in the creditworthiness of our counterparties could have a material adverse impact on our overall exposure to credit risk. We maintain credit policies with regard to our counterparties that, in management's view, reduce our overall credit risk.

We are also exposed to commodity price changes. We use derivative contracts for non-trading purposes and a mix of various fuel types primarily to reduce exposure relative to the volatility of market and commodity prices. The wholesale power market is extremely volatile in price and supply. This volatility impacts our costs 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 purchase power in the wholesale market to the extent it is available, subject to possible transmission constraints, and/or implement curtailment or interruption procedures as permitted in our tariffs and terms and conditions of service.

We use various fossil fuel types, including coal, natural gas and oil, to operate our plants. A significant portion of our coal requirements are purchased under long-term contracts.

Additional factors that affect our commodity price exposure are the quantity and availability of fuel used for generation and the quantity of electricity customers consume. Quantities of fossil fuel used for generation vary from year to year based on availability, price and deliverability of a given fuel type as well as planned and unscheduled outages at our facilities that use fossil fuels and the nuclear refueling schedule. Our customers' electricity usage could also vary from year to year based on weather or other factors.

The prices we use to value price risk management activities reflect our estimate of fair values considering various factors, including closing exchange and over-the-counter quotations, time value of money and price volatility factors underlying the commitments. We adjust prices to reflect the potential impact of liquidating our position in an orderly manner over a reasonable period of time under present market conditions. We consider a number of risks and costs associated with the future contractual commitments included in our energy portfolio, including credit risks associated with the financial condition of counterparties and the time value of money. We continuously monitor the portfolio and value it daily based on present market conditions.

6. FINANCIAL INVESTMENTS AND TRADING SECURITIES

Some of our investments in debt and equity securities are subject to the requirements of SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities." We report these investments at fair value and we use the specific identification method to determine their cost for computing realized gains or losses. We classify these investments as either trading securities or available-for-sale securities as described below.

Trading Securities

We have investments in trust assets securing certain executive benefits that are classified as trading securities. We include any unrealized gains or losses on these securities in investment earnings on our consolidated statements of income. There were an unrealized gain of $2.8 million as of December 31, 2007, an unrealized gain of $1.7 million as of December 31, 2006, and an unrealized loss of $0.3 million as of December 31, 2005.

Available-for-Sale Securities

We hold investments in debt and equity securities in a trust fund for the purpose of funding the decommissioning of Wolf Creek. We have classified these investments in debt and equity securities as available-for-sale and have recorded all such investments at their fair market value as of December 31, 2007 and 2006. Investments by the nuclear decommissioning trust fund are allocated 70% to equity securities, 27% to fixed-income securities and 3% to cash and cash equivalents. Fixed-income investments are limited to U.S. government or agency securities, municipal bonds, or corporate securities. Using the specific identification method to determine cost, the gross realized gains on those sales were $5.7 million in 2007, $7.5 million in 2006 and $3.2 million in 2005. We reflect net realized and unrealized gains and losses in regulatory liabilities on our consolidated balance sheets. This reporting is consistent with the method we use to account for the decommissioning costs recovered in rates. Gains or losses on assets in the trust fund could result in lower or higher funding requirements for decommissioning costs, which we believe would be reflected in electric rates paid by our customers.

The following table presents the costs and fair values of investments in debt and equity securities in the nuclear decommissioning trust fund as of December 31, 2007 and 2006. Changes in the fair value of the trust fund are recorded as an increase or decrease to the regulatory liability recorded in connection with the decommissioning of Wolf Creek.

		Gross Unrealized		
Security Type	**Cost**	**Gain**	**Loss**	**Fair Value**
		(In Thousands)		
2007:				
Debt securities	$ 33,705	$ 450	$ (528)	$ 33,627
Equity securities	69,505	19,031	(2,971)	85,565
Cash equivalents	3,106	—	—	3,106
Total	$106,316	$ 19,481	$(3,499)	$ 122,298
2006:				
Debt securities	$ 36,947	$ 349	$ (168)	$ 37,128
Equity securities	57,202	13,754	(1,288)	69,668
Cash equivalents	4,339	—	—	4,339
Total	$ 98,488	$ 14,103	$(1,456)	$ 111,135

The following table presents the costs and fair values of investments in debt securities in the nuclear decommissioning trust fund according to their contractual maturities.

As of December 31, 2007	**Cost**	**Fair Value**
	(In Thousands)	
Less than 5 years	$ 5,820	$ 5,881
5 years to 10 years	5,035	5,092
Due after 10 years	11,870	12,020
Sub-total	22,725	22,993
Fixed Income Fund	10,980	10,634
Total	$ 33,705	$ 33,627

The following table presents the fair value and the gross unrealized losses of the available-for-sale securities held in the nuclear decommissioning trust fund that were not deemed to be other-than-temporarily impaired, aggregated by investment category and the length of time that individual securities have been in a continuous unrealized loss position, at December 31, 2007.

	Less than 12 Months		12 Months or Greater		Total	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	(In Thousands)					
Debt securities	$13,781	$ (488)	$ 849	$ (40)	$14,630	$ (528)
Equity securities	11,758	(2,488)	565	(483)	12,323	(2,971)
Total	$25,539	$ (2,976)	$1,414	$(523)	$26,953	$ (3,499)

7. PROPERTY, PLANT AND EQUIPMENT

The following is a summary of our property, plant and equipment balance.

As of December 31,	2007	2006
	(In Thousands)	
Electric plant in service	$ 6,452,522	$ 6,066,954
Electric plant acquisition adjustment	802,318	802,318
Accumulated depreciation	(3,142,550)	(2,979,159)
	4,112,290	3,890,113
Construction work in progress	630,782	142,351
Nuclear fuel, net	60,566	39,109
Net utility plant	4,803,638	4,071,573
Non-utility plant in service	34	34
Net property, plant and equipment	$ 4,803,672	$ 4,071,607

We recorded depreciation expense on utility property, plant and equipment of $170.0 million in 2007, $159.9 million in 2006 and $130.1 million in 2005.

8. JOINT OWNERSHIP OF UTILITY PLANTS

Under joint ownership agreements with other utilities, we have undivided ownership interests in four electric generating stations. Energy generated and operating expenses are divided on the same basis as ownership with each owner reflecting its respective costs in its statements of income. Information relative to our ownership interest in these facilities as of December 31, 2007, is shown in the table below.

	Our Ownership as of December 31, 2007					
	In-Service Dates	Investment	Accumulated Depreciation	Construction Work in Progress	Net MW	Ownership Percent
		(Dollars in Thousands)				
La Cygne unit 1[(a)]	June 1973	$ 269,618	$ 129,068	$ 1,825	368.0	50
Jeffrey unit 1[(b)]	July 1978	326,539	176,606	75,539	672.0	92
Jeffrey unit 2[(b)]	May 1980	318,898	156,603	42,183	672.0	92
Jeffrey unit 3[(b)]	May 1983	471,736	220,432	63,678	672.0	92
Jeffrey wind 1[(b)]	May 1999	966	392	—	0.7	92
Jeffrey wind 2[(b)]	May 1999	966	392	—	0.7	92
Wolf Creek[(c)]	Sept. 1985	1,417,485	647,489	26,517	545.0	47
State Line[(d)]	June 2001	106,994	28,113	149	204.0	40
Total		$ 2,913,202	$1,359,095	$209,891	3,134.4	

[(a)] *Jointly owned with Kansas City Power & Light Company (KCPL)*
[(b)] *Jointly owned with Aquila, Inc.*
[(c)] *Jointly owned with KCPL and Kansas Electric Power Cooperative, Inc.*
[(d)] *Jointly owned with Empire District Electric Company*

Amounts and capacity presented above represent our share. We include in operating expenses on our consolidated statements of income our share of operating expenses of the above plants, as well as such expenses for a 50% undivided interest in La Cygne unit 2 (representing 341 megawatts of capacity) sold and leased back to KGE in 1987. Our share of other transactions associated with the plants is included in the appropriate classification on our consolidated financial statements.

In 2007, we purchased an 8% leasehold interest in Jeffrey Energy Center and assumed the related lease obligation. We recorded a capital lease of $118.5 million related to this transaction. This increased our interest in Jeffrey Energy Center to 92%. Amounts presented above do not include this capital lease or related depreciation.

9. SHORT-TERM DEBT

A syndicate of banks provides us a revolving credit facility on a committed basis totaling $500.0 million. Effective March 16, 2007, $480.0 million of the commitments of the lenders under the revolving credit facility terminate on March 17, 2012. The remaining $20.0 million of the commitments terminate on March 17, 2011. So long as there is no default or event of default under the revolving credit facility, we may elect to extend the term of the credit facility for one year. This one year extension can be requested twice during the term of the facility, subject to lender participation. The facility allows us to borrow up to an aggregate amount of $500.0 million, including letters of credit up to a maximum aggregate amount of $150.0 million. As of December 31, 2007, we had borrowings of $180.0 million and $45.5 million of letters of credit outstanding under this facility. On January 11, 2008, we filed a request with FERC for authority to issue short-term securities and to pledge mortgage bonds in order to increase the size of our revolving credit facility to $750.0 million. On February 15, 2008, FERC granted our request and on February 22, 2008, a syndicate of banks in our credit facility increased their commitments, which in the aggregate total $750.0 million. As of February 22, 2008, $270.0 million had been borrowed and $55.0 million of letters of credit had been issued, leaving $425.0 million available under this facility.

Information regarding our short-term borrowings is as follows.

As of December 31,	2007	2006
	(Dollars in Thousands)	
Weighted average short-term debt outstanding during the year	$157,372	$ 122,392
Weighted daily average interest rates during the year, excluding fees	5.83%	5.71%

Our interest expense on short-term debt was $9.7 million in 2007, $7.6 million in 2006 and $1.3 million in 2005.

10. LONG-TERM DEBT

Outstanding Debt

The following table summarizes our long-term debt outstanding.

As of December 31,	2007	2006
	(In Thousands)	
Westar Energy		
First mortgage bond series:		
6.000% due 2014	$ 250,000	$ 250,000
5.150% due 2017	125,000	125,000
5.950% due 2035	125,000	125,000
5.100% due 2020	250,000	250,000
5.875% due 2036	150,000	150,000
6.100% due 2047	150,000	—
	1,050,000	900,000
Pollution control bond series:		
Variable due 2032, 4.35% as of December 31, 2007; 3.65% as of December 31, 2006	45,000	45,000
Variable due 2032, 4.35% as of December 31, 2007; 3.55% as of December 31, 2006	30,500	30,500
5.000% due 2033	58,340	58,340
	133,840	133,840
Other long-term debt:		
4.360% Equipment financing loan due 2010	1,825	—
7.125% unsecured senior notes due 2009	145,078	145,078
	146,903	145,078
KGE		
First mortgage bond series:		
6.530% due 2037	175,000	—
	175,000	—
Pollution control bond series:		
5.100% due 2023	13,463	13,488
Variable due 2027, 5.25% as of December 31, 2007; 3.50% as of December 31, 2006	21,940	21,940
5.300% due 2031	108,600	108,600
5.300% due 2031	18,900	18,900
Variable due 2031, 5.00% as of December 31, 2007; 3.47% as of December 31, 2006	100,000	100,000
Variable due 2032, 5.25% as of December 31, 2007; 3.45% as of December 31, 2006	14,500	14,500
Variable due 2032, 4.50% as of December 31, 2007; 3.44% as of December 31, 2006	10,000	10,000
4.850% due 2031	50,000	50,000
Variable due 2031, 5.25% as of December 31, 2007; 3.85% as of December 31, 2006	50,000	50,000
	387,403	387,428
Total long-term debt	1,893,146	1,566,346
Unamortized debt discount[a]	(2,807)	(3,081)
Long-term debt due within one year	(558)	—
Long-term debt, net	$1,889,781	$1,563,265

[a] *We amortize debt discount over the term of the respective issue.*

The Westar Energy mortgage and the KGE mortgage each contain provisions restricting the amount of first mortgage bonds that could be issued by each entity. We must comply with such restrictions prior to the issuance of additional first mortgage bonds or other secured indebtedness.

The amount of Westar Energy's first mortgage bonds authorized by its Mortgage and Deed of Trust, dated July 1, 1939, as supplemented, is unlimited subject to certain limitations as described below. The amount of KGE's first mortgage bonds authorized by the KGE Mortgage and Deed of Trust, dated April 1, 1940, as supplemented, is limited to a maximum of $2.0 billion, unless amended. First mortgage bonds are secured by utility assets. Amounts of additional bonds that may be issued are subject to property, earnings and certain restrictive provisions, except in connection with certain refundings, of each mortgage. As of December 31, 2007, based on an assumed interest rate of 6%, $408.0 million principal amount of additional first mortgage bonds could be issued under the most restrictive provisions in Westar Energy's mortgage. As of December 31, 2007, based on an assumed interest rate of 6%, approximately $820.1 million principal amount of additional KGE first mortgage bonds could be issued under the most restrictive provisions in KGE's mortgage.

On October 15, 2007, KGE issued $175.0 million principal amount of 6.53% first mortgage bonds maturing in 2037 in a private placement to an institutional investor. Proceeds from the offering were used to repay borrowings under our revolving credit facility, which is the primary liquidity facility for acquiring capital equipment, and any remainder was used for working capital and general corporate purposes.

On May 16, 2007, Westar Energy sold $150.0 million aggregate principal amount of 6.1% Westar Energy first mortgage bonds maturing in 2047. Proceeds from the offering were used to repay borrowings under our revolving credit facility, which is the primary liquidity facility for acquiring capital equipment, and any remainder was used for working capital and general corporate purposes.

On June 1, 2006, we refinanced $100.0 million of pollution control bonds, which were to mature in 2031. We replaced this issue with two new pollution control bond series of $50.0 million each. One series carries an interest rate of 4.85% and matures in 2031. The second series carries a variable interest rate and also matures in 2031.

On January 17, 2006, we repaid $100.0 million aggregate principal amount of 6.2% first mortgage bonds with cash on hand and borrowings under the revolving credit facility.

Debt Covenants

Some of our debt instruments contain restrictions that require us to maintain leverage ratios as defined in the agreements. We calculate these ratios in accordance with our credit agreements. We use these ratios solely to determine compliance with our various debt covenants. We were in compliance with these covenants as of December 31, 2007.

Maturities

Maturities of long-term debt as of December 31, 2007, are as follows.

Year	Principal Amount
	(In Thousands)
2008	$ 558
2009	145,684
2010	633
2011	28
Thereafter	1,746,243
Total long-term debt maturities	$1,893,146

Our interest expense on long-term debt was $94.2 million in 2007, $91.0 million in 2006 and $107.8 million in 2005.

11. TAXES

Income tax expense (benefit) is composed of the following components.

Year Ended December 31,	2007	2006	2005
		(In Thousands)	
Income Tax Expense (Benefit) from Continuing Operations:			
Current income taxes:			
Federal	$40,648	$46,211	$ 30,132
State	9,107	14,303	4,829
Deferred income taxes:			
Federal	9,962	(1,150)	24,831
State	6,240	578	3,511
Investment tax credit amortization	(2,118)	(3,630)	(2,790)
Income tax expense from continuing operations	63,839	56,312	60,513
Income Tax Expense from Discontinued Operations:			
Current income taxes:			
Federal	—	—	29
State	—	—	7
Deferred income taxes:			
Federal	—	—	370
State	—	—	84
Income tax expense from discontinued operations	—	—	490
Total income tax expense	$63,839	$56,312	$ 61,003

Deferred tax assets and liabilities are reflected on our consolidated balance sheets as follows.

December 31,	2007	2006
	(In Thousands)	
Current deferred tax assets	$ —	$ 853
Current deferred tax liabilities	2,310	—
Non-current deferred tax liabilities	897,293	906,311
Net deferred tax liabilities	$899,603	$905,458

The tax effect of the temporary differences and carryforwards that comprise our deferred tax assets and deferred tax liabilities are summarized in the following table.

December 31,	2007	2006
	(In Thousands)	
Deferred tax assets:		
Deferred gain on sale-leaseback	$ 52,616	$ 54,978
Accrued liabilities	29,248	30,531
Disallowed costs	15,301	15,955
Long-term energy contracts	8,262	9,314
Deferred employee benefit costs	82,752	77,155
Capital loss carryforward[(a)]	216,626	219,795
Other[(b)]	93,796	74,963
Total gross deferred tax assets	498,601	482,691
Less: Valuation allowance[(a)]	220,146	223,227
Deferred tax assets	$ 278,455	$ 259,464
Deferred tax liabilities:		
Accelerated depreciation	$ 644,707	$ 642,493
Acquisition premium	219,985	227,999
Amounts due from customers for future income taxes, net	151,279	160,147
Deferred employee benefit costs	79,693	74,111
Other	82,394	60,172
Total deferred tax liabilities	$1,178,058	$1,164,922
Net deferred tax liabilities	$ 899,603	$ 905,458

[(a)] *As of December 31, 2007, we have a net capital loss of $544.6 million available to offset any future capital gains through 2009. However, as we do not expect to realize any significant capital gains in the future, a valuation allowance of $216.6 million has been established. In addition, a valuation allowance of $3.5 million has been established for certain deferred tax assets related to the write-down of other investments. The total valuation allowance related to the deferred tax assets was $220.1 million as of December 31, 2007, and $223.2 million as of December 31, 2006. The net reduction in valuation allowance of $3.1 million was due primarily to capital gains realized in 2007. See the discussion below regarding the filing of amended Federal income tax returns for years 2003 and 2004.*

[(b)] *As of December 31, 2006, we had available general business tax credits of $0.5 million generated from affordable housing partnerships in which we sold the majority of our interests in 2001. These tax credits expire beginning 2019 through 2025. We believe these tax credits will be fully utilized on the 2007 tax return.*

In accordance with various rate orders, we have reduced rates to reflect the tax benefits associated with certain tax deductions. We believe it is probable that the net future increases in income taxes payable will be recovered from customers when these temporary tax benefits reverse. We have recorded a regulatory asset for these amounts. We also have recorded a regulatory liability for our obligation to reduce rates charged customers for deferred taxes recovered from customers at corporate tax rates higher than the current tax rates. The rate reduction will occur as the temporary differences resulting in the excess deferred tax liabilities reverse. The tax-related regulatory assets and liabilities as well as unamortized investment tax credits are also temporary differences for which deferred income taxes have been provided. The net deferred tax liability related to these temporary differences is classified above as amounts due from customers for future income taxes.

The effective income tax rates are computed by dividing total Federal and state income taxes by the sum of such taxes and net income. The difference between the effective tax rates and the Federal statutory income tax rates are as follows.

For the Year Ended December 31,	2007	2006	2005
Statutory Federal income tax rate from continuing operations	35.0 %	35.0 %	35.0 %
Effect of:			
State income taxes	4.4	4.4	2.8
Amortization of investment tax credits	(0.9)	(1.6)	(1.4)
Corporate-owned life insurance policies	(5.8)	(8.3)	(6.9)
Accelerated depreciation flow through and amortization	2.1	1.4	1.2
Net operating loss utilization	(5.1)	(0.9)	(0.2)
Capital loss utilization	(1.2)	(4.0)	(0.8)
Other	(1.0)	(0.6)	1.3
Effective income tax rate from continuing operations	27.5 %	25.4 %	31.0 %
Statutory Federal income tax rate from discontinued operations	— %	— %	35.0 %
Effect of:			
State income taxes	—	—	4.8
Effective income tax rate from discontinued operations	— %	— %	39.8 %

We file income tax returns in the U.S. Federal jurisdiction, and various states and foreign jurisdictions. The income tax returns we filed will likely be audited by the Internal Revenue Service (IRS) or other taxing authorities. With few exceptions, the statute of limitations with respect to U.S. Federal, state and local, or non-U.S. income tax examinations by tax authorities are closed for years before 1995.

The IRS has examined our Federal income tax returns for the years 1995 through 2002. We reached a tentative settlement with the IRS Office of Appeals (IRS Appeals Settlement) in December 2007. The principal issues related to the method for capitalizing and allocating overhead costs, the carry back of capital losses and net operating losses and the deduction of and credit for research and development costs. The IRS Appeals Settlement was approved by the Joint Committee on Taxation and accepted by the IRS in February 2008. As a result, we will receive a tax refund of approximately $18.8 million, excluding interest. The Federal statute of limitations for years 1995 through 2002 remains open until 90 days after either the IRS or we send the prescribed notice ending the agreement. We believe that the statute of limitations for the affected years will close within the next 12 months.

The IRS is currently examining our Federal income tax returns for years 2003 and 2004. On December 21, 2007, we filed amended Federal income tax returns for years 2003 and 2004. The amended returns change the original Federal income tax characterization of the loss we incurred on the sale of Protection One, Inc. (Protection One) in 2004 from a capital loss to an ordinary loss. The characterization of the loss as either capital or ordinary affects our ability to carry back and carry forward the loss to tax years in which the loss can be deducted. The IRS has challenged the position reported on the amended returns and the ultimate outcome cannot be predicted at this time. If the re-characterization of the tax loss is ultimately upheld, the loss would be available for carry back to year 2003 and carried forward 20 years to offset future taxable income. In addition, under the terms of our tax sharing agreement, we reimburse subsidiaries for current tax benefits used in our consolidated tax return. Under a settlement agreement relating to the sale transaction, we agreed to reimburse Protection One an amount equal to 50% of the tax benefit attributable to the net operating loss carryforward arising from the sale. As shown below, we have not recognized tax benefits related to the amended returns. The IRS has not paid us a refund and, thus, the unrecognized tax benefits related to this uncertain tax position do not constitute liabilities. We believe that it is reasonably possible that the examination of years 2003 and 2004 will be completed by the end of 2008. We have extended the statute of limitations for these years until December 31, 2008.

Our 2007, 2006 and 2005 income tax returns are subject to audit by Federal and state taxing authorities.

We adopted the provisions of FIN 48 as of January 1, 2007. The cumulative effect of adopting FIN 48 was an increase of $10.5 million to the January 1, 2007, retained earnings balance.

At January 1, 2007, the amount of unrecognized tax benefits and the FIN 48 liability were $50.2 million. During the year 2007, the FIN 48 liability increased to $70.8 million and the amount of unrecognized tax benefits increased to $209.6 million. The net increase in FIN 48 liability is primarily attributable to the deductions related to the December 2007 ice storm. It is reasonably possible that a reduction of unrecognized tax benefits in the range of $39.9 million to $178.7 million may occur in the next 12 months due to the expiration of the statute of limitations with respect to years 1995 through 2002 and developments pertaining to the examination of years 2003 and 2004. A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

	(In Thousands)
FIN 48 liability at January 1, 2007	$ 50,211
Additions based on tax positions related to the current year	21,660
Additions for tax positions of prior years	5,197
Reductions for tax positions of prior years	—
Settlements	(6,235)
FIN 48 liability at December 31, 2007	70,833
Unrecognized tax benefits related to amended returns filed in 2007	138,778
Unrecognized tax benefits at December 31, 2007	$209,611

As of December 31, 2007, the amount of unrecognized tax benefits that, if recognized, would favorably impact our effective tax rate, is $172.2 million (net of tax). Included in the FIN 48 liability at December 31, 2007, are $33.4 million (net of tax) of tax positions, which if recognized, would favorably impact our effective income tax rate.

With the adoption of FIN 48, we changed our practice of including interest related to income tax uncertainties in income tax expense. Effective January 1, 2007, interest is classified as interest expense and accrued interest liability. We had $13.5 million and $18.9 million accrued for interest related to income tax liabilities at December 31, 2007, and January 1, 2007, respectively. There were no penalties accrued at December 31, 2007, or January 1, 2007, and no penalties were recognized during 2007.

As of December 31, 2007 and 2006, we maintained reserves of $5.2 million and $6.9 million, respectively, for probable assessments of taxes other than income taxes.

12. EMPLOYEE BENEFIT PLANS

Pension

We maintain a qualified non-contributory defined benefit pension plan covering substantially all of our employees. For the majority of our employees, pension benefits are based on years of service and the employee's compensation during the 60 highest paid consecutive months out of 120 before retirement. Our funding policy for the pension plan is to contribute amounts sufficient to meet the minimum funding requirements under the Employee Retirement Income Security Act of 1974 (ERISA) and the Internal Revenue Code plus additional amounts as considered appropriate. Non-union employees hired after December 31, 2001, are covered by the same defined benefit plan with benefits derived from a cash balance account formula. We also maintain a non-qualified Executive Salary Continuation Plan for the benefit of certain current and retired officers.

In addition to providing pension benefits, we provide certain post-retirement health care and life insurance benefits for substantially all retired employees. The cost of post-retirement benefits are accrued during an employee's years of service and recovered through rates. We fund the portion of net periodic post-retirement benefit costs that are included in rates.

As a co-owner of Wolf Creek, we are indirectly responsible for 47% of the liabilities and expenses associated with the Wolf Creek pension and post-retirement plans. See Note 13, "Wolf Creek Employee Benefit Plans" for information about Wolf Creek's benefit plans.

The following tables summarize the status of our pension and other post-retirement benefit plans.

	Pension Benefits		Post-retirement Benefits	
As of December 31,	2007	2006	2007	2006
	(In Thousands)			
Change in Benefit Obligation:				
Benefit obligation, beginning of year	$ 551,728	$ 549,132	$ 124,546	$ 128,185
Service cost	9,641	9,178	1,548	1,492
Interest cost	32,418	30,522	7,574	6,875
Plan participants' contributions	—	—	4,164	3,380
Benefits paid	(28,450)	(28,345)	(11,481)	(11,306)
Actuarial losses (gains)	12,718	(8,759)	(5,994)	(4,080)
Amendments	136	—	13,778	—
Benefit obligation, end of year	$ 578,191	$ 551,728	$ 134,135	$ 124,546
Change in Plan Assets:				
Fair value of plan assets, beginning of year	$ 451,824	$ 422,300	$ 52,778	$ 44,196
Actual return on plan assets	31,208	35,302	3,215	3,374
Employer contribution	11,800	20,750	12,400	12,200
Plan participants' contributions	—	—	4,030	3,380
Part D Reimbursements	—	—	814	677
Benefits paid	(26,644)	(26,528)	(11,814)	(11,049)
Fair value of plan assets, end of year	$ 468,188	$ 451,824	$ 61,423	$ 52,778
Funded status, end of year	$(110,003)	$ (99,904)	$ (72,712)	$ (71,768)
Amounts Recognized in the Balance Sheets Consist of:				
Current liability	$ (1,838)	$ (1,930)	$ (130)	$ —
Noncurrent liability	(108,165)	(97,974)	(72,582)	(71,768)
Net amount recognized	$(110,003)	$ (99,904)	$ (72,712)	$ (71,768)
Amounts Recognized in Regulatory Assets Consist of:				
Net actuarial loss	$ 114,325	$ 102,172	$ 19,636	$ 26,570
Prior service cost	11,517	13,926	12,858	17
Transition obligation	—	—	19,979	23,909
Net amount recognized	$ 125,842	$ 116,098	$ 52,473	$ 50,496

	Pension Benefits		Post-retirement Benefits	
As of December 31,	2007	2006	2007	2006
	(Dollars in Thousands)			
Pension Plans With a Projected Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$ 578,191	$ 551,728	$ —	$ —
Accumulated benefit obligation	497,169	483,511	—	—
Fair value of plan assets	468,188	451,824	—	—
Pension Plans With an Accumulated Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$ 578,191	$ 551,728	$ —	$ —
Accumulated benefit obligation	497,169	483,511	—	—
Fair value of plan assets	468,188	451,824	—	—
Post-retirement Plans With an Accumulated Post-retirement Benefit Obligation In Excess of Plan Assets:				
Accumulated post-retirement benefit obligation	$ —	$ —	$ 134,135	$ 124,546
Fair value of plan assets	—	—	61,423	52,778
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Benefit Obligation:				
Discount rate	6.25%	5.90%	6.10%	5.80%
Compensation rate increase	4.00%	4.00%	—	—

We use a measurement date of December 31 for our pension and post-retirement benefit plans.

We use an interest rate yield curve to make judgments pursuant to Emerging Issues Task Force (EITF) No. D-36, "Selection of Discount Rates Used for Measuring Defined Benefit Pension Obligations and Obligations of Post Retirement Benefit Plans Other Than Pensions." The yield curve is constructed based on the yields on over 500 high-quality, non-callable corporate bonds with maturities between zero and 30 years. A theoretical spot rate curve constructed from this yield curve is then used to discount the annual benefit cash flows of our pension plan and develop a single-point discount rate matching the plan's payout structure.

We amortize the prior service cost (benefit) on a straight-line basis over the average future service of the active employees (plan participants) benefiting under the plan at the time of the amendment. The net actuarial loss subject to amortization is amortized on a straight-line basis over the average future service of active plan participants benefiting under the plan, without application of the amortization corridor described in SFAS No. 87, "Employers' Accounting for Pensions" and SFAS No. 106, "Employers' Accounting for Post-retirement Benefits Other Than Pensions."

Year Ended December 31,	Pension Benefits 2007	2006	2005
	(Dollars in Thousands)		
Components of Net Periodic Cost (Benefit):			
Service cost	$ 9,641	$ 9,178	$ 6,735
Interest cost	32,418	30,522	28,764
Expected return on plan assets	(38,506)	(35,939)	(36,272)
Amortization of unrecognized:			
Transition obligation, net	—	—	—
Prior service costs/(benefit)	2,545	2,892	2,761
Actuarial loss, net	7,864	8,759	5,347
Net periodic cost	$13,962	$15,412	$ 7,335
Other Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets:			
Current year actuarial (gain)/loss	$20,017	$ —	$ —
Amortization of actuarial loss	(7,864)	—	—
Current year prior service cost	136	—	—
Amortization of prior service cost	(2,545)	—	—
Amortization of transition obligation	—	—	—
Total recognized in regulatory assets	$ 9,744	$ —	$ —
Total recognized in net periodic cost and regulatory assets	$23,706	$15,412	$ 7,335
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost (Benefit):			
Discount rate	5.90%	5.65%	5.90%
Expected long-term return on plan assets	8.50%	8.50%	8.75%
Compensation rate increase	4.00%	3.50%	3.00%

Year Ended December 31,	Post-retirement Benefits 2007	2006	2005
	(Dollars in Thousands)		
Components of Net Periodic Cost (Benefit):			
Service cost	$ 1,548	$ 1,492	$ 1,615
Interest cost	7,574	6,875	7,049
Expected return on plan assets	(3,827)	(2,971)	(2,552)
Amortization of unrecognized:			
Transition obligation, net	3,930	3,931	3,931
Prior service costs/(benefit)	937	(415)	(467)
Actuarial loss, net	1,503	2,001	1,934
Net periodic cost	11,665	$10,913	$ 11,510
Other Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets:			
Current year actuarial (gain)/loss	$ (5,431)	$ —	$ —
Amortization of actuarial loss	(1,503)	—	—
Current year prior service cost	13,778	—	—
Amortization of prior service cost	(937)	—	—
Amortization of transition obligation	(3,930)	—	—
Total recognized in regulatory assets	$ 1,977	$ —	$ —
Total recognized in net periodic cost and regulatory assets	$13,642	$10,913	$ 11,510
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost (Benefit):			
Discount rate	5.80%	5.65%	5.90%
Expected long-term return on plan assets	7.75%	7.75%	8.25%
Compensation rate increase	—	—	—

The estimated amounts that will be amortized from regulatory assets into net periodic benefit cost in 2008 are as follows:

	Pension Benefits	Other Post-retirement Benefits
	(In Thousands)	
Actuarial loss	$ 8,340	$ 1,404
Prior service cost	2,545	1,412
Transition obligation	—	3,930
Total	$10,885	$ 6,746

We base the expected long-term rate of return on plan assets on historical and projected rates of return for current and planned asset classes in the plans' investment portfolio. Assumed projected rates of return for each asset class were selected after analyzing long-term historical experience and future expectations of the volatility of the various asset classes. Based on target asset allocations for each asset class, the overall expected rate of return for the portfolio was developed, adjusted for historical and expected experience of active portfolio management results compared to benchmark returns and for the effect of expenses paid from plan assets.

In December 2003, the Medicare Prescription Drug Improvement and Modernization Act of 2003 (Medicare Act) became law. The Medicare Act introduced a prescription drug benefit under Medicare as well as a federal subsidy beginning in 2006. This subsidy will be paid to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare. We believe our retiree health care benefits plan is at least actuarially equivalent to Medicare and is eligible for the federal subsidy. We adopted the guidance in the third quarter of 2004. Treating the future subsidy under the Medicare Act as an actuarial experience gain, as required by the guidance, decreased the accumulated post-retirement benefit obligation by approximately $4.6 million in both 2007 and 2006. The subsidy also decreased the net periodic post-retirement benefit cost by approximately $0.6 million for both 2007 and 2006.

For measurement purposes, the assumed annual health care cost growth rates were as follows.

As of December 31,	2007	2006
Health care cost trend rate assumed for next year	8.00%	9.00%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	5.00%	5.00%
Year that the rate reaches the ultimate trend rate	2014	2011

The health care cost trend rate affects the projected benefit obligation. A 1% change in assumed health care cost growth rates would have effects shown in the following table.

	One-Percentage-Point Increase	One-Percentage-Point Decrease
	(In Thousands)	
Effect on total of service and interest cost	$ 15	$ (18)
Effect on post-retirement benefit obligation	144	(249)

The asset allocation for the pension plans and the post-retirement benefit plans at the end of 2007 and 2006, and the target allocations for 2008, by asset category, are as shown in the following table.

	Target Allocations	Plan Assets	
Asset Category	**2008**	**2007**	**2006**
Pension Plans:			
Equity securities	65%	67%	62%
Debt securities	35%	29%	35%
Cash	0% - 5%	4%	3%
Total		100%	100%
Post-retirement Benefit Plans:			
Equity securities	65%	60%	64%
Debt securities	30%	29%	28%
Cash	5%	11%	8%
Total		100%	100%

We manage pension and retiree welfare plan assets in accordance with the "prudent investor" guidelines contained in the ERISA. The plan's investment strategy supports the objective of the funds, which is to earn the highest possible return on plan assets consistent with a reasonable and prudent level of risk. Investments are diversified across classes, sectors and manager style to minimize the risk of large losses. We delegate investment management to specialists in each asset class and where appropriate, provide the investment manager with specific guidelines, which include allowable and/or prohibited investment types. Investment risk is measured and monitored on an ongoing basis through quarterly investment portfolio reviews and annual liability measurements.

The following table shows the expected cash flows for the pension plans and post-retirement benefit plans for future years.

	Pension Benefits		Post-retirement Benefits	
Expected Cash Flows	**To/(From) Trust**	**To/(From) Company Assets**	**To/(From) Trust**	**To/(From) Company Assets**
	(In Millions)			
Expected contributions:				
2008[a]	$ 15.2	$ 1.8	$ 12.6	$ 0.1
Expected benefit payments:				
2008	$ (26.5)	$ (1.8)	$ (8.0)	$ (0.1)
2009	(26.5)	(1.8)	(8.3)	(0.1)
2010	(26.8)	(1.8)	(8.5)	(0.1)
2011	(27.4)	(1.8)	(8.7)	(0.1)
2012	(28.2)	(1.8)	(8.8)	(0.1)
2013 – 2017	(167.5)	(9.1)	(49.1)	(0.7)

[a] *We expect to make a voluntary contribution of $15.2 million to the Westar Energy pension trust in 2008.*

In September 2006, FASB released SFAS No. 158. Under the new standard, companies must recognize a net liability or asset to report the funded status of their defined benefit pension and other post-retirement benefit plans on their balance sheets. On December 31, 2006, we adopted the recognition and disclosure provisions of SFAS No. 158. The effect of adopting SFAS No. 158 on our financial condition at December 31, 2006, has been included in the accompanying consolidated financial statements. We received an accounting authority order from the KCC to recognize as a regulatory asset the pension and post-retirement liabilities that otherwise would have been charged to other comprehensive income.

The incremental effect of adopting the provisions of SFAS No. 158 on our statement of financial position at December 31,2006, including the effect on our portion of Wolf Creek's pension and post-retirement plans, are presented in the following table. The adoption of SFAS No. 158 had no effect on our consolidated statement of income for the year ended December 31, 2006, or for any prior period presented.

Incremental Effect of Applying SFAS No. 158 on Individual Line Items in the Consolidated Balance Sheet as of December 31, 2006

	Before SFAS No. 158	Adjustments	After SFAS No. 158
		(In Thousands)	
CURRENT ASSETS:			
Regulatory assets	$ —	$ 17,582	$ 17,582
Total Current Assets	—	17,582	17,582
OTHER ASSETS:			
Regulatory assets	—	168,732	168,732
Other	14,412	(14,412)	—
Total Other Assets	14,412	154,320	168,732
TOTAL ASSETS	14,412	171,902	186,314
CURRENT LIABILITIES:			
Other	—	2,467	2,467
Total Current Liabilities	—	2,467	2,467
LONG-TERM LIABILITIES:			
Deferred income taxes	(16,948)	11,466	(5,482)
Accrued employee benefits	71,274	135,999	207,273
Total Long-Term Liabilities	54,326	147,465	201,791
SHAREHOLDERS' EQUITY:			
Accumulated other comprehensive (loss) income, net	(21,970)	21,970	—
Total Shareholders' Equity	(21,970)	21,970	—
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 32,356	$ 171,902	$ 204,258

Savings Plans

We maintain a qualified 401(k) savings plan in which most of our employees participate. We match employees' contributions in cash up to specified maximum limits. Our contributions to the plans are deposited with a trustee and are invested at the direction of plan participants into one or more of the investment alternatives we provide under the plan. Our contributions were $5.6 million in 2007, $4.8 million in 2006 and $4.1 million in 2005.

Stock Based Compensation Plans

We have a long-term incentive and share award plan (LTISA Plan), which is a stock-based compensation plan in which employees and directors are eligible for awards. The LTISA Plan was implemented as a means to attract, retain and motivate employees and directors. Under the LTISA Plan, we may grant awards in the form of stock options, dividend equivalents, share appreciation rights, RSUs, performance shares and performance share units to plan participants. Up to five million shares of common stock may be granted under the LTISA Plan. As of December 31, 2007, awards of 3,981,261 shares of common stock had been made under the LTISA Plan. Dividend equivalents accrue on the awarded RSUs. Dividend equivalents are the right to receive cash equal to the value of dividends paid on our common stock.

Effective January 1, 2006, we adopted SFAS No. 123R, "Share-Based Payment," for stock-based compensation plans. Under SFAS No. 123R, all stock-based compensation is measured at the grant date, based on the fair value of the award, and is recognized as an expense in the consolidated statement of income over the requisite service period. On March 29, 2005, the Securities and Exchange Commission (SEC) staff issued Staff Accounting Bulletin (SAB) No. 107 on Share-Based Payment to express the views of the staff regarding the interaction between SFAS No. 123R and SEC rules and regulations as well as provide staff's view on valuation of stock-based compensation arrangements for public companies. The SAB No. 107 guidance was taken into consideration with the implementation of SFAS No. 123R.

We adopted SFAS No. 123R using the modified prospective transition method. Under the modified prospective transition method, we are required to record stock-based compensation expense for all awards granted after the adoption date and for the unvested portion of previously granted awards outstanding as of the adoption date. Compensation cost related to the unvested portion of previously granted awards is based on the grant-date fair value estimated in accordance with the original provisions of SFAS No. 123. Compensation cost for awards granted after the adoption date are based on the grant-date fair value estimated in accordance with the provisions of SFAS No. 123R. Since 2002, we have used RSUs exclusively for our stock-based compensation awards. RSUs are valued in the same manner under SFAS Nos. 123 and 123R.

The table below shows compensation expense and income tax benefits related to stock-based compensation arrangements that are included in our net income.

Twelve Months Ended December 31,	2007	2006	2005
		(In Thousands)	
Compensation expense	$ 5,735	$ 3,395	$4,560
Income tax benefits related to stock-based compensation arrangements	2,281	1,350	1,814

The incremental amount of stock-based compensation expense that was disclosed and not included in our consolidated statements of income for the year ended December 31, 2005, was not material to our consolidated results of operations.

RSU awards are grants that entitle the holder to receive shares of common stock as the awards vest. These RSU awards are defined in SFAS No. 123R as nonvested shares and do not include restrictions once the awards have vested. We measure the fair value of the RSU awards based on the market price of the underlying common stock as of the date of grant and recognize that cost as an expense in the consolidated statement of income over the requisite service period. The requisite service periods range from one to ten years. RSU awards issued after adoption of SFAS No. 123R with only service conditions that have a graded vesting schedule will be recognized as an expense in the consolidated statement of income on a straight-line basis over the requisite service period for the entire award. Awards issued prior to adoption of SFAS No. 123R will continue to be recognized as an expense in the consolidated statement of income on a straight-line basis over the requisite service period for each separately vesting portion of the award.

During the year ended December 31, 2007, our RSU activity was as follows:

As of December 31,	2007		2006		2005	
	Shares	Weighted-Average Grant Date Fair Value	Shares	Weighted-Average Grant Date Fair Value	Shares	Weighted-Average Grant Date Fair Value
	(In Thousands)		(In Thousands)		(In Thousands)	
Nonvested balance, beginning of year	933.4	$20.82	1,094.5	$18.54	1,298.4	$17.50
Granted	413.8	26.76	160.3	23.91	135.5	22.04
Vested	(308.5)	20.53	(306.6)	14.96	(336.0)	13.28
Forfeited	(54.5)	26.79	(14.8)	21.56	(3.4)	20.43
Nonvested balance, end of year	984.2	23.11	933.4	20.82	1,094.5	18.54

Total unrecognized compensation cost related to RSU awards was $8.9 million as of December 31, 2007. These costs are expected to be recognized over a remaining weighted-average period of 2.4 years. Upon adoption of SFAS No. 123R, we were required to charge $10.3 million of unearned stock compensation against additional paid-in capital. The total fair value of shares vested during the years ended December 31, 2007, 2006 and 2005, was $8.3 million, $7.2 million and $7.5 million, respectively. There were no modifications of awards during the years ended December 31, 2007, 2006 or 2005.

SFAS No. 123R requires that forfeitures be estimated over the vesting period, rather than being recognized as a reduction of compensation expense when the forfeiture actually occurs. The cumulative effect of the use of the estimated forfeiture method for prior periods upon adoption of SFAS No. 123R was not material.

RSU awards that can be settled in cash upon a change in control were reclassified from permanent equity to temporary equity upon adoption of SFAS No. 123R. As of December 31, 2007, we had $5.2 million of temporary equity on our consolidated balance sheet. If we determine it is probable that these awards will be settled in cash, the awards will be reclassified as a liability.

Stock options granted between 1997 and 2001 are completely vested and expire 10 years from the date of grant. All 77,290 outstanding options are exercisable. There were no options exercised and 83,190 options forfeited during the year ended December 31, 2007. We currently have no plans to issue new stock option awards.

Another component of the LTISA Plan is the Executive Stock for Compensation program, where in the past eligible employees were entitled to receive deferred stock in lieu of current cash compensation. Although this plan was discontinued in 2001, dividends will continue to be paid to plan participants on their outstanding plan balance until distribution. Plan participants were awarded 4,214 shares of common stock for dividends in 2007, 4,407 shares in 2006 and 3,936 shares in 2005. Participants received common stock distributions of 505 shares in 2007, 1,936 shares in 2006 and 12,271 shares in 2005.

Prior to the adoption of SFAS No. 123R, we reported all tax benefits resulting from the vesting of RSU awards and exercise of stock options as operating cash flows in the consolidated statements of cash flows. SFAS No. 123R requires cash retained as a result of excess tax benefits resulting from the tax deductions in excess of the related compensation cost recognized in the financial statements to be classified as cash flows from financing activities in the consolidated statements of cash flows.

13. WOLF CREEK EMPLOYEE BENEFIT PLANS

Pension and Post-retirement Benefits

As a co-owner of Wolf Creek, KGE is indirectly responsible for 47% of the liabilities and expenses associated with the Wolf Creek pension and post-retirement plans. KGE accrues its 47% of the Wolf Creek cost of pension and post-retirement benefits during the years an employee provides service. The following tables summarize the net periodic costs for KGE's 47% share of the Wolf Creek pension and post-retirement benefit plans.

	Pension Benefits		Post-retirement Benefits	
As of December 31,	**2007**	**2006**	**2007**	**2006**
	(In Thousands)			
Change in Benefit Obligation:				
Benefit obligation, beginning of year	$ 79,213	$ 71,537	$ 7,391	$ 7,005
Service cost	3,436	3,245	234	248
Interest cost	4,696	4,293	435	412
Plan participants' contributions	—	—	294	253
Benefits paid	(1,809)	(1,185)	(509)	(610)
Actuarial losses/(gains)	2,071	1,278	(114)	83
Amendments	34	45	—	—
Curtailments, settlements and special termination benefits	2,205	—	865	—
Benefit obligation, end of year	$ 89,846	$ 79,213	$ 8,596	$ 7,391
Change in Plan Assets:				
Fair value of plan assets, beginning of year	$ 47,869	$ 39,752	$ —	$ —
Actual return on plan assets	3,314	4,346	—	—
Employer contribution	5,618	4,766	—	—
Benefits paid	(1,809)	(995)	—	—
Fair value of plan assets, end of year	$ 54,992	$ 47,869	$ —	$ —
Funded status	$ (34,854)	$ (31,344)	$ (8,596)	$ (7,391)
Post-measurement date adjustments	1,072	1,164	—	—
Accrued post-retirement benefit costs	$ (33,782)	$ (30,180)	$ (8,596)	$ (7,391)
Amounts Recognized in the Balance Sheets Consist of:				
Current liability	$ (168)	$ (190)	$ (632)	$ (347)
Noncurrent liability	(33,614)	(29,990)	(7,964)	(7,044)
Net amount recognized	$ (33,782)	$ (30,180)	$ (8,596)	$ (7,391)
Amounts Recognized in Regulatory Assets Consist of:				
Net actuarial loss	$ 21,120	$ 19,397	$ 3,127	$ 2,531
Prior service cost	178	202	—	—
Transition obligation	227	284	288	346
Net amount recognized	$ 21,525	$ 19,883	$ 3,415	$ 2,877

As of December 31,	Pension Benefits 2007	Pension Benefits 2006	Post-retirement Benefits 2007	Post-retirement Benefits 2006
	(Dollars in Thousands)			
Pension Plans With a Projected Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$ 89,846	$ 79,213	$ —	$ —
Accumulated benefit obligation	68,302	62,339	—	—
Fair value of plan assets	54,992	47,869	—	—
Pension Plans With an Accumulated Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$ 89,846	$ 79,213	$ —	$ —
Accumulated benefit obligation	68,302	62,339	—	—
Fair value of plan assets	54,992	47,869	—	—
Post-retirement Plans With an Accumulated Post-retirement Benefit Obligation In Excess of Plan Assets:				
Accumulated post-retirement benefit obligation	$ —	$ —	$ 8,596	$ 7,931
Fair value of plan assets	—	—	—	—
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Benefit Obligation:				
Discount rate	6.15%	5.70%	6.05%	5.80%
Compensation rate increase	4.00%	3.25%	—	—

Wolf Creek uses a measurement date of December 1 for the majority of its pension and post-retirement benefit plans.

Wolf Creek uses an interest rate yield curve to make judgments pursuant to EITF Topic No. D-36, "Selection of Discount Rates Used for Measuring Defined Benefit Pension Obligations and Obligations of Post Retirement Benefit Plans Other Than Pensions." The yield curve is constructed based on the yields on over 500 high-quality, non-callable corporate bonds with maturities between zero and 30 years. A theoretical spot rate curve constructed from this yield curve is then used to discount the annual benefit cash flows of Wolf Creek's pension plan and develop a single-point discount rate matching the plan's payout structure.

The prior service cost is amortized on a straight-line basis over the average future service of the active employees (plan participants) benefiting under the plan at the time of the amendment. The net actuarial loss subject to amortization is amortized on a straight-line basis over the average future service of active plan participants benefiting under the plan, without application of the amortization corridor described in SFAS Nos. 87 and 106.

Year Ended December 31,	Pension Benefits 2007	Pension Benefits 2006	Pension Benefits 2005
	(Dollars in Thousands)		
Components of Net Periodic Cost:			
Service cost	$ 3,436	$ 3,245	$ 2,820
Interest cost	4,696	4,293	3,730
Expected return on plan assets	(4,101)	(3,428)	(3,114)
Amortization of unrecognized:			
Transition obligation, net	57	57	57
Prior service costs	57	31	31
Actuarial loss, net	1,855	1,813	1,340
Curtailments, settlements and special termination benefits	1,486	—	—
Net periodic cost	$ 7,486	$ 6,011	$ 4,864
Other Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets:			
Current year actuarial loss	$ 3,578	$ —	$ —
Amortization of actuarial loss	(1,855)	—	—
Current year prior service cost	34	—	—
Amortization of prior service cost	(57)	—	—
Amortization of transition obligation	(57)	—	—
Total recognized in regulatory assets	$ 1,643	$ —	$ —
Total recognized in net periodic cost and regulatory assets	$ 9,129	$ 6,011	$ 4,864
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost:			
Discount rate	5.70%	5.75%	6.00%
Expected long-term return on plan assets	8.25%	8.25%	8.75%
Compensation rate increase	3.25%	3.25%	3.00%

Year Ended December 31,	Post-retirement Benefits 2007	Post-retirement Benefits 2006	Post-retirement Benefits 2005
	(Dollars in Thousands)		
Components of Net Periodic Cost:			
Service cost	$ 234	$ 248	$ 238
Interest cost	435	412	384
Expected return on plan assets	—	—	—
Amortization of unrecognized:			
Transition obligation, net	58	58	58
Prior service costs	—	—	—
Actuarial loss, net	191	196	170
Curtailments, settlements and special termination benefits	259	—	—
Net periodic cost	$ 1,177	$ 914	$ 850
Other Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets:			
Current year actuarial loss	$ 786	$ —	$ —
Amortization of actuarial loss	(191)	—	—
Current year prior service cost	—	—	—
Amortization of prior service cost	—	—	—
Amortization of transition obligation	(58)	—	—
Total recognized in regulatory assets	$ 537	$ —	$ —
Total recognized in net periodic cost and regulatory assets	$ 1,714	$ 914	$ 850
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost:			
Discount rate	5.80%	5.75%	6.00%
Expected long-term return on plan assets	—	—	—
Compensation rate increase	—	—	—

In January 2007, Wolf Creek Nuclear Operating Corporation offered a selective retirement incentive to certain employees. The incentive increased the pension benefit for eligible employees who elected retirement. This resulted in $1.5 million in additional pension benefits and $0.3 million in additional post-retirement benefits for the year ended December 31, 2007.

The estimated amounts that will be amortized from regulatory assets into net periodic benefit cost in 2008 are as follows:

	Pension Benefits	Other Post-retirement Benefits
	(In Thousands)	
Actuarial loss	$ 1,640	$ 219
Prior service cost	57	—
Transition obligation	57	58
Total	$ 1,754	$ 277

The expected long-term rate of return on plan assets is based on historical and projected rates of return for current and planned asset classes in the plans' investment portfolio. Assumed projected rates of return for each asset class were selected after analyzing long-term historical experience and future expectations of the volatility of the various asset classes. Based on target asset allocations for each asset class, the overall expected rate of return for the portfolio was developed, adjusted for historical and expected experience of active portfolio management results compared to benchmark returns and for the effect of expenses paid from plan assets.

For measurement purposes, the assumed annual health care cost growth rates were as follows.

As of December 31,	2007	2006
Health care cost trend rate assumed for next year	8.0%	9.0%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	5.0%	5.0%
Year that the rate reaches the ultimate trend rate	2014	2011

The health care cost trend rate affects the projected benefit obligation. A 1% change in assumed health care cost growth rates would have effects shown in the following table.

	One-Percentage-Point Increase	One-Percentage-Point Decrease
	(In Thousands)	
Effect on total of service and interest cost	$ (6)	$ 5
Effect on the present value of the projected benefit obligation	(44)	33

The asset allocation for the pension plans at the end of 2007 and 2006, and the target allocation for 2008, by asset category are as shown in the following table.

	Target Allocations	Plan Assets	
Asset Category	2008	2007	2006
Pension Plans:			
Equity securities	65%	67%	63%
Debt securities	35%	28%	34%
Cash	0%	5%	3%
Total		100%	100%

The Wolf Creek pension plan investment strategy supports the objective of the fund, which is to earn the highest possible return on plan assets consistent with a reasonable and prudent level of risk. Investments are diversified across classes, sectors and manager style, to maximize returns and to minimize the risk of large losses. Wolf Creek delegates investment management to specialists in each asset class and where appropriate, provides the investment manager with specific guidelines, which include allowable and/or prohibited investment types. We measure and monitor investment risk on an ongoing basis through quarterly investment portfolio reviews.

	Pension Benefits		Post-retirement Benefits	
Expected Cash Flows	To/(From) Trust	To/(From) Company Assets	To/(From) Trust	To/(From) Company Assets
	(In Millions)			
Expected contributions:				
2008	$ 5.3	$ 0.2	$ —	$ 0.6
Expected benefit payments:				
2008	$ (2.0)	$ (0.2)	$ —	$ (0.6)
2009	(1.7)	(0.2)	—	(0.4)
2010	(2.0)	(0.2)	—	(0.5)
2011	(2.4)	(0.2)	—	(0.5)
2012	(2.9)	(0.2)	—	(0.5)
2013 – 2017	(24.2)	(0.8)	—	(3.2)

Savings Plan

Wolf Creek maintains a qualified 401(k) savings plan in which most of its employees participate. They match employees' contributions in cash up to specified maximum limits. Wolf Creek's contribution to the plan is deposited with a trustee and is invested at the direction of plan participants into one or more of the investment alternatives provided under the plan. KGE's portion of expense associated with Wolf Creek's matching contributions was $0.9 million in 2007, $0.9 million in 2006 and $0.9 million in 2005.

14. COMMITMENTS AND CONTINGENCIES

Purchase Orders and Contracts

As part of our ongoing operations and construction program, we have purchase orders and contracts, excluding fuel, which is discussed below under "— Purchased Power and Fuel Commitments," that have an unexpended balance of approximately $818.2 million as of December 31, 2007, of which $608.2 million has been committed. The $608.2 million commitment relates to purchase obligations issued and outstanding at year-end.

The yearly detail of the aggregate amount of required payments as of December 31, 2007, was as follows.

	Committed Amount
	(In Thousands)
2008	$ 489,780
2009	93,281
2010	12,911
Thereafter	12,263
Total amount committed	$ 608,235

Clean Air Act

We must comply with the Clean Air Act, state laws and implementing regulations that impose, among other things, limitations on pollutants generated during our operations, including sulfur dioxide (SO_2), particulate matter and nitrogen oxides (NOx). In addition, we must comply with the provisions of the Clean Air Act Amendments of 1990 that require a two-phase reduction in certain emissions. We have installed continuous monitoring and reporting equipment in order to meet these requirements.

Environmental Projects

We have identified the potential for us to make up to $1.2 billion of capital expenditures at our power plants for environmental air emissions projects during approximately the next eight to ten years. This estimate could increase depending on the resolution of the EPA New Source Review Investigation (NSR Investigation) described below. In addition to the capital investment, in the event we install new equipment as a result of the NSR Investigation, we anticipate that we would incur significant annual expense to operate and maintain the equipment and the operation of the equipment would reduce net production from our plants. The degree to which we will need to reduce emissions and the timing of when such emissions controls may be required is uncertain. Both the timing and the nature of required investments depend on specific outcomes that result from interpretation of existing regulations, new regulations, legislation and the resolution of the NSR Investigation described below. In addition, the availability of equipment and contractors can affect the timing and ultimate cost of the equipment.

The environmental cost recovery rider (ECRR) allows for the timely inclusion in rates of capital expenditures tied directly to environmental improvements, including those required by the Clean Air Act. However, increased operating and maintenance costs other than expenses related to production-related consumables can be recovered only through a change in base rates following a rate review.

On August 29, 2007, we filed an application with the Kansas Department of Health and Environment (KDHE) to implement a plan to improve efficiency and to install new equipment to reduce regulated emissions from Jeffrey Energy Center. The projects outlined in a proposed agreement filed with the KDHE on August 30, 2007, are designed to meet requirements of the Clean Air Visibility Rule and reduce emissions over our entire generating fleet by eliminating more than 70% of SO_2 and reducing nitrous oxides and particulates between 50% and 65%.

On March 15, 2005, the EPA issued the Clean Air Mercury Rule. The rule caps permanently, and seeks to reduce, the amount of mercury that may be emitted from coal-fired power plants. The rule requires implementation of reductions in two phases, the first starting in 2010. We received an allocation of mercury emission allowances pursuant to the rule. Preliminary testing indicates that the expected allocation of allowances will be insufficient to allow us to operate our coal-fired units in compliance with the first phase requirements of the rule. If the allocated allowances are insufficient, we may need to purchase allowances in the market, install additional equipment or take other actions to reduce our mercury emissions. However, on February 8, 2008, the U.S. District Court of Appeals for the District of Columbia vacated the Clean Air Mercury Rule. While the ultimate impact of this ruling on our operations is currently unknown, we believe that mercury emissions controls may be required in the future and that the costs to comply with these requirements may be material.

New Source Review Investigation

Under Section 114(a) of the Clean Air Act (Section 114), the EPA is conducting investigations nationwide to determine whether modifications at coal-fired power plants are subject to the New Source Review permitting program or New Source Performance Standards. These investigations focus on whether projects at coal-fired plants were routine maintenance or whether the projects were substantial modifications that could reasonably have been expected to result in a significant net increase in emissions. The New Source Review program requires companies to obtain permits and, if necessary, install control equipment to address emissions when making a major modification or a change in operation if either is expected to cause a significant net increase in emissions.

The EPA requested information from us under Section 114 regarding projects and maintenance activities that have been conducted since 1980 at three coal-fired plants we operate. On January 22, 2004, the EPA notified us that certain projects completed at Jeffrey Energy Center violated certain requirements of the New Source Review program.

We have been in discussions with the EPA and the Department of Justice (DOJ) concerning this matter in an attempt to reach a settlement. We expect that any settlement could require us to update or install emissions controls at Jeffrey Energy Center. Additionally, we might be required to update or install emissions controls at our other coal-fired plants, pay fines or penalties, or take other remedial action. If settlement discussions fail, DOJ may consider whether to pursue an enforcement action against us in federal district court. Our ultimate costs to resolve the NSR Investigation could be material. We believe that costs related to updating or installing emissions controls would qualify for recovery through the ECRR. If, however, a penalty is assessed against us, the penalty could be material and may not be recovered in rates. We are not able to estimate the possible loss or range of loss at this time.

Manufactured Gas Sites

We have been identified as being responsible for clean-ups of a number of former manufactured gas sites located in Kansas and Missouri. We and the KDHE entered into a consent agreement in 1994 governing all future work at the Kansas sites. Under the terms of the consent agreement, we agreed to investigate and, if necessary, remediate these sites. Pursuant to an environmental indemnity agreement with ONEOK, Inc. (ONEOK), the current owner of some of the sites, ONEOK assumed total liability for remediation of seven sites, and we share liability for remediation with ONEOK for five sites. Our total liability for the five shared sites is capped at $3.8 million. We have sole responsibility for remediation with respect to three sites.

Our liability for the former manufactured gas sites identified in Missouri is limited to $7.5 million by the terms of an environmental indemnity agreement with the purchaser of our former Missouri assets.

Nuclear Decommissioning

Nuclear decommissioning is a nuclear industry term for the permanent shutdown of a nuclear power plant and the removal of radioactive components in accordance with the Nuclear Regulatory Commission (NRC) requirements. The NRC will terminate a plant's license and release the property for unrestricted use when a company has reduced the residual radioactivity of a nuclear plant to a level mandated by the NRC. The NRC requires companies with nuclear plants to prepare formal financial plans to fund nuclear decommissioning. These plans are designed so that sufficient funds required for nuclear decommissioning will be accumulated prior to the expiration of the license of the related nuclear power plant. Wolf Creek files a nuclear decommissioning and dismantlement study with the KCC every three years.

The KCC reviews nuclear decommissioning plans in two phases. Phase one is the approval of the revised nuclear decommissioning study, the current-year funding and future funding. Phase two involves the review and approval by the KCC of a "funding schedule" by the owner of the nuclear facility detailing how it plans to fund the future-year dollar amount of its pro rata share of the plant.

In 2005, Wolf Creek filed an updated nuclear decommissioning site study with the KCC. Based on the site study of decommissioning costs, including the costs of decontamination, dismantling and site restoration, our share of such costs is estimated to be $243.3 million. This amount compares to the 2002 site study estimate for decommissioning costs of $220.0 million. The site study cost estimate represents the estimate to decommission Wolf Creek as of the site study year. The actual nuclear decommissioning costs may vary from the estimates because of changes in regulations, technology and changes in costs for labor, materials and equipment.

Electric rates charged to customers provide for recovery of these nuclear decommissioning costs over the life of Wolf Creek, which, as determined by the KCC for purposes of the funding schedule, will be through 2045. The NRC requires that funds to meet its nuclear decommissioning funding assurance requirement be in our nuclear decommissioning fund by the time our license expires. We believe that the KCC approved funding level will also be sufficient to meet the NRC minimum financial assurance requirement. Our consolidated results of operations would be materially adversely affected if we are not allowed to recover in utility rates the full amount of the funding requirement.

We recovered in rates and deposited in an external trust fund approximately $2.9 million for nuclear decommissioning in 2007 and $3.9 million in 2006 and 2005. We record our investment in the nuclear decommissioning fund at fair value. The fair value approximated $122.3 million as of December 31, 2007, and $111.1 million as of December 31, 2006.

Storage of Spent Nuclear Fuel

Under the Nuclear Waste Policy Act of 1982, the Department of Energy (DOE) is responsible for the permanent disposal of spent nuclear fuel. As required by federal law, the Wolf Creek co-owners entered into a standard contract with the DOE in 1984 in which the DOE promised to begin accepting from commercial nuclear power plants their used nuclear fuel for disposal beginning in early 1998. In return, Wolf Creek pays into a federal Nuclear Waste Fund administered by the DOE a quarterly fee for the future disposal of spent nuclear fuel. Our share of the fee was $4.4 million in 2007, $4.1 million in 2006 and $3.8 million in 2005 and is calculated as one-tenth of a cent for each kilowatt-hour of net nuclear generation delivered to customers. We include these disposal costs in fuel and purchased power expenses.

In 2002, the Yucca Mountain site in Nevada was approved for the development of a nuclear waste repository for the disposal of spent nuclear fuel and high level nuclear waste from the nation's defense activities. This action allows the DOE to apply to the NRC to license the project. The DOE announced in December 2007, that it planned to submit a license application to the NRC no later than June 30, 2008. However, in January 2008, DOE officials announced that that filing date was in jeopardy because of fiscal year 2008 budget allocation reductions. The opening of the Yucca Mountain site has been delayed many times and could be delayed further due to litigation and other issues related to the site as a permanent repository for spent nuclear fuel. Wolf Creek has on-site temporary storage for spent nuclear fuel expected to be generated by Wolf Creek through 2025.

Nuclear Insurance

We maintain nuclear insurance for Wolf Creek in four areas: liability, worker radiation, property and accidental outage. These policies contain certain industry standard exclusions, including, but not limited to, ordinary wear and tear and war. Both the nuclear liability and property insurance programs subscribed to by members of the nuclear power generating industry include industry aggregate limits for non-certified acts, as defined by the Terrorism Risk Insurance Act, of terrorism-related losses, including replacement power costs. An industry aggregate limit of

$300.0 million exists for liability claims, regardless of the number of non-certified acts affecting Wolf Creek or any other nuclear energy liability policy or the number of policies in place. An industry aggregate limit of $3.2 billion plus any reinsurance recoverable by Nuclear Electric Insurance Limited (NEIL), our insurance provider, exists for property claims, including accidental outage power costs for acts of terrorism affecting Wolf Creek or any other nuclear energy facility property policy within twelve months from the date of the first act. These limits are the maximum amount to be paid to members who sustain losses or damages from these types of terrorist acts. For certified acts of terrorism, the individual policy limits apply. In addition, industry-wide retrospective assessment programs (discussed below) can apply once these insurance programs have been exhausted.

Nuclear Liability Insurance

Pursuant to the Price-Anderson Act, which was reauthorized through December 31, 2025, by the Energy Policy Act of 2005, we are required to insure against public liability claims resulting from nuclear incidents to the full limit of public liability, which is currently approximately $10.8 billion. This limit of liability consists of the maximum available commercial insurance of $300.0 million, and the remaining $10.5 billion is provided through mandatory participation in an industry-wide retrospective assessment program. Under this retrospective assessment program, the owners of Wolf Creek Nuclear Operating Corporation (WCNOC) can be assessed a total of $100.6 million (our share is $47.3 million), payable at no more than $15.0 million (our share is $7.1 million) per incident per year, per reactor. Both the total and yearly assessment are subject to an inflation adjustment based on the Consumer Price Index and applicable premium taxes. This assessment also applies in excess of our worker radiation claims insurance. The next scheduled inflation adjustment is scheduled for July 1, 2008. In addition, Congress could impose additional revenue-raising measures to pay claims.

Nuclear Property Insurance

The owners of Wolf Creek carry decontamination liability, premature nuclear decommissioning liability and property damage insurance for Wolf Creek totaling approximately $2.8 billion (our share is $1.3 billion). This insurance is provided by NEIL. In the event of an accident, insurance proceeds must first be used for reactor stabilization and site decontamination in accordance with a plan mandated by the NRC. Our share of any remaining proceeds can be used to pay for property damage or decontamination expenses or, if certain requirements are met, including nuclear decommissioning the plant, toward a shortfall in the nuclear decommissioning trust fund.

Accidental Nuclear Outage Insurance

The owners also carry additional insurance with NEIL to cover costs of replacement power and other extra expenses incurred during a prolonged outage resulting from accidental property damage at Wolf Creek. If significant losses were incurred at any of the nuclear plants insured under the NEIL policies, we may be subject to retrospective assessments under the current policies of approximately $25.7 million (our share is $12.1 million).

Although we maintain various insurance policies to provide coverage for potential losses and liabilities resulting from an accident or an extended outage, our insurance coverage may not be adequate to cover the costs that could result from a catastrophic accident or extended outage at Wolf Creek. Any substantial losses not covered by insurance, to the extent not recoverable through rates, would have a material adverse effect on our consolidated financial condition and results of operations.

Purchased Power and Fuel Commitments

To supply a portion of the fuel requirements for our generating plants, we have entered into various commitments to obtain nuclear fuel and coal. Some of these contracts contain provisions for price escalation and minimum purchase commitments. As of December 31, 2007, our share of Wolf Creek's nuclear fuel commitments were approximately $61.1 million for uranium concentrates expiring in 2016, $9.3 million for conversion expiring in 2016, $153.4 million for enrichment expiring at various times through 2024 and $50.0 million for fabrication in 2024.

As of December 31, 2007, our coal and coal transportation contract commitments in 2007 dollars under the remaining terms of the contracts were approximately $1.4 billion. The largest contract expires in 2020, with the remaining contracts expiring at various times through 2013.

As of December 31, 2007, our natural gas transportation commitments in 2007 dollars under the remaining terms of the contracts were approximately $166.8 million. The natural gas transportation contracts provide firm service to several of our natural gas burning facilities and expire at various times through 2028.

We have entered into power purchase agreements with the owners of two separate wind powered electric generating facilities located in Kansas with a combined capacity of 146 MW. The agreements have a term of 20 years and provide for our receipt and purchase of the energy produced at a fixed price per unit of output. We estimate that our annual cost for energy purchased from these wind farms will be approximately $21.0 million. We expect the facilities to be in service by the end of 2008.

15. ASSET RETIREMENT OBLIGATIONS

Legal Liability

In accordance with SFAS No. 143, "Accounting for Asset Retirement Obligations" and FIN 47, "Accounting for Conditional Asset Retirement Obligations", we have recognized legal obligations associated with the disposal of long-lived assets that result from the acquisition, construction, development or normal operation of such assets. Concurrent with the recognition of the liability, the estimated cost of an asset retirement obligation is capitalized and depreciated over the remaining life of the asset.

We initially recorded asset retirement obligations at fair value for the estimated cost to decommission Wolf Creek (our 47% share). dispose of asbestos insulating material at our power plants, remediate ash disposal ponds and dispose of polychlorinated biphenyl (PCB) contaminated oil.

The following table summarizes our legal asset retirement obligations included on our consolidated balance sheets in long-term liabilities.

As of December 31,	2007	2006
	(In Thousands)	
Beginning asset retirement obligations	$ 84,192	$ 129,888
Liabilities incurred	85	218
Liabilities settled	(987)	(737)
Accretion expense	5,421	8,327
Revision to nuclear decommissioning ARO Liability	—	(53,504)
Ending asset retirement obligations	$ 88,711	$ 84,192

In September 2006, WCNOC, the operating company for Wolf Creek, filed a request for a 20 year extension of Wolf Creek's operating license with the NRC. Currently, the operating license will expire in 2025. The NRC's milestone schedule for its review of this request projects a decision by late 2008. The NRC may impose conditions as part of any approval. Based on the experience of other nuclear plant operators, we believe that the NRC will ultimately approve the request. Therefore, we decreased our asset retirement obligation by $53.5 million to reflect the revision in our estimate of the timing of the cash flows that we will incur to satisfy this obligation.

In March 2005, the FASB issued FIN 47. The interpretation clarified the term "conditional asset retirement obligation" as used in SFAS No. 143. Conditional asset retirement obligation refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. We determined the conditional asset retirement obligations that are within the scope of FIN 47 to include disposal of asbestos insulating material at our power plants, remediation of ash disposal ponds and the disposal of PCB-contaminated oil. We adopted the provisions of FIN 47 for the year ended December 31, 2005.

The amount of the retirement obligation related to asbestos disposal was recorded as of 1990, the date when the Environmental Protection Agency published the "National Emission Standards for Hazardous Air Pollutants: Asbestos NESHAP Revision; Final Rule."

We operate, as permitted by the state of Kansas, ash landfills at several of our power plants. The ash landfills retirement obligation was determined based upon the date each landfill was originally placed in service.

PCB-contaminated oil is contained within company electrical equipment, primarily transformers. The PCB retirement obligation was determined based upon the PCB regulations that originally became effective in 1978.

The recording of the obligation for regulated operations has no income statement impact due to the deferral of the adjustments through the establishment of a regulatory asset pursuant to SFAS No. 71.

Non-Legal Liability — Cost of Removal

We recover in rates, as a component of depreciation, the costs to dispose of utility plant assets that do not represent legal retirement obligations. As of December 31, 2007 and 2006, we had $25.2 million and $13.4 million, respectively, in amounts collected, but unspent, for removal costs classified as a regulatory liability. The net amount related to non-legal retirement costs can fluctuate based on amounts recovered in rates compared to removal costs incurred.

16. LEGAL PROCEEDINGS

We and our subsidiaries are involved in various legal, environmental and regulatory proceedings. We believe that adequate provisions have been made and accordingly believe that the ultimate disposition of such matters will not have a material adverse effect on our consolidated financial statements.

See also Notes 14 and 17 for discussion of alleged violations of the Clean Air Act, and potential liabilities to David C. Wittig and Douglas T. Lake.

17. POTENTIAL LIABILITIES TO DAVID C. WITTIG AND DOUGLAS T. LAKE

David C. Wittig, our former chairman of the board, president and chief executive officer, resigned from all of his positions with us and our affiliates on November 22, 2002. On May 7, 2003, our board of directors determined that the employment of Mr. Wittig was terminated as of November 22, 2002, for cause. Douglas T. Lake, our former executive vice president, chief strategic officer and member of the board, was placed on administrative leave from all of his positions with us and our affiliates on December 6, 2002. On June 12, 2003, our board of directors terminated the employment of Mr. Lake for cause.

On June 13, 2003, we filed a demand for arbitration with the American Arbitration Association asserting claims against Mr. Wittig and Mr. Lake arising out of their previous employment with us. Mr. Wittig and Mr. Lake filed counterclaims against us in the arbitration alleging substantial damages related to the termination of their employment and the publication of the report of a special committee of our board of directors. We intend to vigorously defend against these claims. The arbitration has been stayed pending final resolution of criminal charges filed by the United States Attorney's Office against Mr. Wittig and Mr. Lake in U.S. District Court in the District of Kansas. On September 12, 2005, a jury convicted Mr. Wittig and Mr. Lake on the charges relevant to each of them. On January 5, 2007, these convictions were overturned by U.S. Tenth Circuit Court of Appeals following appeals by Mr. Wittig and Mr. Lake. On April 30, 2007, the government announced that it had decided to retry certain charges against Mr. Wittig and Mr. Lake and the retrial is currently scheduled to commence on September 9, 2008. We are unable to predict the ultimate impact of this matter on our consolidated financial statements.

As of December 31, 2007, we had accrued liabilities totaling $76.0 million for compensation not yet paid to Mr. Wittig and Mr. Lake under various agreements and plans. The compensation includes RSU awards, deferred vested shares, deferred RSU awards, deferred vested stock for compensation, executive salary continuation plan benefits, potential obligations related to the cash received for Guardian International, Inc. (Guardian) preferred stock, and, in the case of Mr. Wittig, benefits arising from a split dollar life insurance agreement. The amount of our obligation to Mr. Wittig related to a split dollar life insurance agreement is subject to adjustment at the end of each quarter based on the total return to our shareholders from the date of that agreement. The total return considers the change in our stock price and accumulated dividends. These compensation-related accruals are included in long-term liabilities on the consolidated balance sheets with a portion recorded as a component of paid in capital. The amount accrued will increase annually for future dividends on deferred RSU awards and increases in amounts that may be due under the executive salary continuation plan.

In addition, through December 31, 2007, we have accrued $7.3 million for legal fees and expenses incurred by Mr. Wittig and Mr. Lake that are recorded in accounts payable on our consolidated balance sheets. These legal fees and expenses were incurred by Mr. Wittig and Mr. Lake in the defense of the criminal charges filed by the United States Attorney's Office and the subsequent appeal of convictions on these charges. We have filed lawsuits against Mr. Wittig and Mr. Lake claiming that the legal fees and expenses they have incurred are unreasonable and excessive and we have asked the courts to determine the amount of the legal fees and expenses that were reasonably incurred and which we have an obligation to pay, as well as the amount of the legal fees and expenses that we have an obligation to advance in the future. The U.S. District Court in the lawsuit against Mr. Lake ordered us to pay approximately $3.2 million of the past unpaid fees and expenses and directed us to advance future fees and expenses related to the retrial on a current basis at counsel's customary hourly rates. We appealed this order to the U.S. Tenth Circuit Court of Appeals and asked for a stay of the portion of the order related to the payment of past unpaid fees and expenses. On October 18, 2007, the U.S. Tenth Circuit Court of Appeals denied our request for a stay of the portion of the order related to the payment of past unpaid fees and expenses. Pursuant to the District Court's order, we have paid approximately $3.2 million of Mr. Lake's past unpaid fees and expenses and we have paid approximately $0.9 million for fees and expenses incurred by Mr. Lake in 2007. The issues on appeal other than our request for a stay remain pending before the U.S. Tenth Circuit Court of Appeals. The lawsuit against Mr. Wittig is pending in Shawnee County, Kansas District Court. A special master appointed by the District Court submitted a report in November 2007 finding that $2.5 million of the legal fees and expenses incurred by Mr. Wittig were reasonable and should be paid by us. We submitted objections to the report and the matter is now being reviewed by the District Court. We expect to incur substantial additional expenses for legal fees and expenses that will be incurred by Mr. Wittig and Mr. Lake, but are unable to estimate the amount for which we may ultimately be responsible.

18. GUARDIAN INTERNATIONAL PREFERRED STOCK

On March 6, 2006, Guardian was acquired by Devcon International Corporation in a merger. In connection with this merger, we received approximately $23.2 million for 15,214 shares of Guardian Series D preferred stock and 8,000 shares of Guardian Series E preferred stock held of record by us. We beneficially owned 354.4 shares of the Guardian Series D preferred stock and 312.9 shares of the Guardian Series E preferred stock. We recognized a gain of approximately $0.3 million as a result of this transaction. Certain current and former officers beneficially owned the remaining shares. Of these shares, 14,094 shares of Guardian Series D preferred stock and 7,276 shares of Guardian Series E preferred stock were beneficially owned by Mr. Wittig and Mr. Lake. The ownership of the shares beneficially owned by either Mr. Wittig or Mr. Lake, as well as related dividends, and now the cash received for the shares, is disputed and is the subject of the arbitration proceeding with Mr. Wittig and Mr. Lake discussed in Note 17, "Potential Liabilities to David C. Wittig and Douglas T. Lake." As a result of this transaction, we no longer hold any Guardian securities.

19. COMMON AND PREFERRED STOCK

Activity in Westar Energy's stock accounts for each of the three years ended December 31 is as follows:

	Cumulative preferred stock shares	Common stock shares
Balance at December 31, 2004	214,363	86,029,721
Issuance of common stock	—	805,650
Balance at December 31, 2005	214,363	86,835,371
Issuance of common stock	—	559,515
Balance at December 31, 2006	214,363	87,394,886
Issuance of common stock	—	8,068,294
Balance at December 31, 2007	214,363	95,463,180

Westar Energy's articles of incorporation, as amended, provide for 150,000,000 authorized shares of common stock. As of December 31, 2007, we had 95,463,180 shares issued and outstanding.

Westar Energy has a direct stock purchase plan (DSPP). Shares sold pursuant to the DSPP may be either original issue shares or shares purchased in the open market. During 2007, a total of 482,981 shares were issued by Westar Energy through the DSPP and other stock based plans operated under the 1996 LTISA Plan. As of December 31, 2007, a total of 4,339,963 shares were available under the DSPP registration statement.

Common Stock Issuance

On April 12, 2007, we entered into a Sales Agency Financing Agreement with BNY Capital Markets, Inc. (BNYCMI). As of July 12, 2007, we had sold $100.0 million of common stock (3,701,568 shares) through BNYCMI, as agent, pursuant to the agreement. We received $99.0 million in proceeds net of a commission paid to BNYCMI equal to 1% of the sales price of all shares it sold under the agreement. We used the proceeds to repay borrowings under our revolving credit facility, which is the primary liquidity facility for acquiring capital equipment, and any remainder was used for working capital and general corporate purposes.

On August 24, 2007, we entered into a subsequent Sales Agency Financing Agreement with BNYCMI. Under the terms of the agreement, we may offer and sell shares of our common stock from time to time through BNYCMI, as agent, up to an aggregate of $200.0 million for a period of no more than three years. We will pay BNYCMI a commission equal to 1% of the sales price of all shares sold under the agreement. As of December 31, 2007, we had sold $20.0 million of common stock (783,745 shares) through BNYCMI. We received $19.8 million in proceeds net of commission paid to BNYCMI. We used the proceeds to repay borrowings under our revolving credit facility, which is the primary liquidity facility for acquiring capital equipment, and any remainder was used for working capital and general corporate purposes. Pursuant to the same program, in the period January 1, 2008, through February 19, 2008, we sold an additional 75,177 shares for $1.9 million, net of commission.

On November 15, 2007, we entered into a forward equity sale agreement (forward sale agreement) with UBS AG, London Branch (UBS), as forward purchaser, relating to 8.2 million shares of our common stock. The forward sale agreement provides for the sale of our common stock within approximately twelve months at a stated settlement price. In connection with the forward sale agreement, UBS borrowed an equal number of shares of our common stock from stock lenders and sold the borrowed shares to J.P. Morgan Securities, Inc. (JPM) under an underwriting agreement among Westar Energy, JPM and UBS Securities, LLC, as co-managers for the underwriters. The underwriters subsequently offered the borrowed shares to the public at a price per share of $25.25.

The use of a forward sale agreement allows us to avoid equity market uncertainty by pricing a stock offering under then existing market conditions, while mitigating share dilution by postponing the issuance of stock until funds are needed. Except in specified circumstances or events that would require physical share settlement, we are able to elect to settle the forward sale agreement by means of a physical share, cash or net share settlement and are also able to elect to settle the agreement in whole, or in part, earlier than the stated maturity date at fixed settlement prices. Under a physical share or net share settlement, the maximum number of shares that are deliverable under the terms of the forward sale agreement is limited to 8.2 million shares.

On December 28, 2007, we delivered 3.1 million newly issued shares of our common stock to UBS, and received proceeds of $75.0 million as partial settlement of the forward sale agreement. Additionally, on February 7, 2008, we delivered 2.1 million shares and received proceeds of $50.0 million as partial settlement of the forward sale agreement. Assuming gross share settlement of all remaining shares under the forward sale agreement, we could receive additional aggregate proceeds of approximately $75.0 million, based on a forward price of $24.25 per share for 3.0 million shares. Proceeds from these offerings were used to repay borrowings under our revolving credit facility, which is the primary liquidity facility for acquiring capital equipment, and any remainder was used for working capital and general corporate purposes.

Preferred Stock Not Subject to Mandatory Redemption

Westar Energy's cumulative preferred stock is redeemable in whole or in part on 30 to 60 days' notice at our option. The table below shows our redemption amount for all series of preferred stock not subject to mandatory redemption as of December 31, 2007.

Rate	Shares	Principal Outstanding	Call Price	Premium	Total Cost to Redeem
		(Dollars in Thousands)			
4.500%	121,613	$ 12,161	108.00%	$ 973	$ 13,134
4.250%	54,970	5,497	101.50%	82	5,579
5.000%	37,780	3,778	102.00%	76	3,854
		$ 21,436		$ 1,131	$ 22,567

The provisions of Westar Energy's articles of incorporation, as amended, contain restrictions on the payment of dividends or the making of other distributions on its common stock while any preferred shares remain outstanding unless certain capitalization ratios and other conditions are met. If the ratio of the capital represented by Westar Energy's common stock, including premiums on its capital stock and its surplus accounts, to its total capital and its surplus accounts at the end of the second month immediately preceding the date of the proposed payment of dividends, adjusted to reflect the proposed payment (capitalization ratio), will be less than 20%, then the payment of the dividends on its common stock shall not exceed 50% of its net income available for dividends for the 12-month period ending with and including the second month immediately preceding the date of the proposed payment. If the capitalization ratio is 20% or more but less than 25%, then the payment of dividends on its common stock, including the proposed payment, shall not exceed 75% of its net income available for dividends for such 12-month period. Except to the extent permitted above, no payment or other distribution may be made that would reduce the capitalization ratio to less than 25%. The capitalization ratio is determined based on the unconsolidated balance sheet for Westar Energy. As of December 31, 2007, the capitalization ratio was greater than 25%.

So long as there are any outstanding shares of Westar Energy preferred stock, Westar Energy shall not without the consent of a majority of the shares of preferred stock or if more than one-third of the outstanding shares of preferred stock vote negatively and without the consent of a percentage of any and all classes required by law and Westar Energy's articles of incorporation, declare or pay any dividends (other than stock dividends or dividends applied by the recipient to the purchase of additional shares) or make any other distribution upon common stock unless, immediately after such distribution or payment the sum of Westar Energy's capital represented by its outstanding common stock and its earned and any capital surplus shall not be less than $10.5 million plus an amount equal to twice the annual dividend requirement on all the then outstanding shares of preferred stock.

20. LEASES

Operating Leases

We lease office buildings, computer equipment, vehicles, rail cars, a generating facility and other property and equipment. These leases have various terms and expiration dates ranging from 1 to 22 years.

In determining lease expense, we recognize the effects of scheduled rent increases on a straight-line basis over the minimum lease term. The rental expense associated with the La Cygne unit 2 operating lease includes an offset for the amortization of the deferred gain on the sale-leaseback. The rental expense and estimated commitments are as follows for the La Cygne unit 2 lease and other operating leases.

Year Ended December 31,	La Cygne Unit 2 Lease[(a)]	Total Operating Leases
	(In Thousands)	
Rental expense:		
2005	$ 23,481	$ 34,239
2006	18,069	32,107
2007	18,069	35,267
Future commitments:		
2008	$ 32,892	$ 48,067
2009	32,964	47,176
2010	33,041	45,870
2011	33,122	43,800
2012	33,209	47,165
Thereafter	289,475	335,470
Total future commitments	$ 454,703	$567,548

[(a)] *The La Cygne unit 2 lease amounts are included in the total operating leases column.*

On June 30, 2005, KGE and the owner of La Cygne unit 2 amended certain terms of the agreement relating to KGE's lease of La Cygne unit 2, including an extension of the lease term. The lease was entered into in 1987 with an initial term ending in September 2016. With the June 30, 2005, extension, the term of the lease will expire in September 2029. Upon expiration of the lease term in 2029, KGE has a fixed price option to purchase La Cygne unit 2 for a price that is estimated to be the fair market value of the facility in 2029. KGE can also elect to renew the lease at the expiration of the lease term in 2029. However, any renewal period, when added to the initial lease term, cannot exceed 80% of the estimated useful life of La Cygne unit 2.

On June 30, 2005, KGE caused the owner of La Cygne unit 2 to refinance the debt used by the owner to finance the purchase of the facility. The savings resulting from extending the term of the lease and refinancing the debt will reduce KGE's annual lease expense by approximately $10.8 million.

Capital Leases

We identify capital leases based on criteria in SFAS No. 13, "Accounting for Leases." For both vehicles and computer equipment, new leases are signed each month based on the terms of master lease agreements. The lease term for vehicles is from 5 to 14 years depending on the type of vehicle. Computer equipment has either a two- or four-year term.

On April 1, 2007, we completed the purchase of Aquila, Inc.'s (Aquila) 8% leasehold interest in Jeffrey Energy Center for $25.8 million and assumed the related lease obligation. This lease expires on January 3, 2019, and has a purchase option at the end of the lease term. Based on current economic and other conditions, we expect to exercise the purchase option. Based upon these expectations, we recorded a capital lease of $118.5 million.

Assets recorded under capital leases are listed below.

December 31,	2007	2006
	(In Thousands)	
Vehicles	$ 27,132	$ 30,009
Computer equipment and software	5,212	4,950
Jeffrey Energy Center 8% interest	118,538	—
Accumulated amortization	(20,576)	(18,115)
Total capital leases	$130,306	$ 16,844

Capital lease payments are currently treated as operating leases for rate making purposes. Minimum annual rental payments, excluding administrative costs such as property taxes, insurance and maintenance, under capital leases are listed below.

Year Ended December 31,	Total Capital Leases
	(In Thousands)
2008	$ 17,637
2009	16,757
2010	15,578
2011	15,489
2012	11,378
Thereafter	124,391
	201,230
Amounts representing imputed interest	(69,076)
Present value of net minimum lease payments under capital leases	132,154
Less current portion	(8,300)
Total long-term obligation under capital leases	$123,854

21. DISCONTINUED OPERATIONS — Sale of Protection One and Protection One Europe

In 2006, we received proceeds of $1.2 million that was released from an escrow account arising from the sale of Protection One Europe, a security business we sold on June 30, 2003. In 2005, we recorded approximately $0.7 million in income in our results of discontinued operations due to the resolution of indemnification issues with the sale of the Protection One Europe security business.

Results of discontinued operations are presented in the table below.

Year Ended December 31,	2005[(a)]
	(In Thousands, Except Per Share Amounts)
Sales	$ —
Costs and expenses	—
Earnings from discontinued operations before income taxes	—
Estimated gain on disposal	1,232
Income tax expense	490
Results of discontinued operations	$ 742
Basic results of discontinued operations per share	$ 0.01
Diluted results of discontinued operations per share	$ 0.01

[(a)] *Amounts are related to the resolution of indemnification issues associated with the sale of Protection One Europe.*

22. QUARTERLY RESULTS (UNAUDITED)

Our electric business is seasonal in nature and, in our opinion, comparisons between the quarters of a year do not give a true indication of overall trends and changes in operations.

2007	First	Second	Third	Fourth
	(In Thousands, Except Per Share Amounts)			
Sales	$370,306	$415,178	$ 548,496	$392,854
Net income	30,175	32,708	91,706	13,765
Earnings available for common stock	29,933	32,466	91,464	13,523
Per Share Data[(a)]:				
Basic:				
Earnings available	$ 0.34	$ 0.36	$ 0.99	$ 0.15
Diluted:				
Earnings available	$ 0.34	$ 0.36	$ 0.99	$ 0.14
Cash dividend declared per common share	$ 0.27	$ 0.27	$ 0.27	$ 0.27
Market price per common share:				
High	$ 28.54	$ 28.57	$ 26.44	$ 26.83
Low	$ 25.23	$ 23.81	$ 22.84	$ 24.29

[(a)] *Items are computed independently for each of the periods presented and the sum of the quarterly amounts may not equal the total for the year.*

2006	First	Second	Third	Fourth
	(In Thousands, Except Per Share Amounts)			
Sales	$340,023	$406,622	$ 515,947	$343,152
Net income	26,838	35,365	90,034	13,073
Earnings available for common stock	26,596	35,123	89,792	12,831
Per Share Data[(a)]:				
Basic:				
Earnings available	$ 0.30	$ 0.40	$ 1.03	$ 0.15
Diluted:				
Earnings available	$ 0.30	$ 0.40	$ 1.02	$ 0.15
Cash dividend declared per common share	$ 0.25	$ 0.25	$ 0.25	$ 0.25
Market price per common share:				
High	$ 22.05	$ 22.39	$ 24.60	$ 27.24
Low	$ 20.09	$ 20.40	$ 21.50	$ 23.20

[(a)] *Items are computed independently for each of the periods presented and the sum of the quarterly amounts may not equal the total for the year.*

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Under the supervision and with the participation of our management, including our chief executive officer and our chief financial officer, we have evaluated the effectiveness of the design and operation of our disclosure controls and procedures as defined in Rule 13a-15(e) of the Securities Exchange Act of 1934. These controls and procedures are designed to ensure that material information relating to the company and its subsidiaries is communicated to the chief executive officer and the chief financial officer. Based on that evaluation, our chief executive officer and our chief financial officer concluded that, as of December 31, 2007, our disclosure controls and procedures are effective to ensure that information required to be disclosed by us in reports that we file or submit under the Securities Exchange Act of 1934 is accumulated and communicated to the chief executive officer and the chief financial officer, and recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by an issuer in the reports that it files or submits under the Act is accumulated and communicated to the issuer's management, including its principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

There were no changes in our internal control over financial reporting during the fourth quarter ended December 31, 2007, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

See "Item 8. Financial Statements and Supplementary Data" for Management's Annual Report On Internal Control Over Financial Reporting and the Independent Registered Public Accounting Firm's report with respect to management's assessment of the effectiveness of internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The information concerning directors required by Item 401 of Regulation S-K will be included under the caption "Election of Directors" in our definitive Proxy Statement for our 2008 Annual Meeting of Shareholders to be filed pursuant to Regulation 14A (the 2008 Proxy Statement), and that information is incorporated by reference in this Form 10-K. Information concerning executive officers required by Item 401 of Regulation S-K is located under Part I, Item 1 of this Form 10-K. The information required by Item 405 of Regulation S-K concerning compliance with Section 16(a) of the Exchange Act will be included under the caption "Section 16(a) Beneficial Ownership Reporting Compliance" in our 2008 Proxy Statement, and that information is incorporated by reference in this Form 10-K. The information required by Item 406, 407(c)(3), (d)(4) and (d)(5) of Regulation S-K will be included under the caption "Corporate Governance Matters" in our 2008 Proxy Statement, and that information is incorporated by reference in this Form 10-K.

ITEM 11. EXECUTIVE COMPENSATION

The information required by Item 11 will be set forth in our 2008 Proxy Statement under the captions "Compensation Discussion and Analysis," "Compensation Committee Report," "Compensation of Executive Officers and Directors," and "Compensation Committee Interlocks and Insider Participation" and that information is incorporated by reference in this Form 10-K.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The information required by Item 12 will be set forth in our 2008 Proxy Statement under the captions "Beneficial Ownership of Voting Securities" and "Shares Authorized For Issuance Under Equity Compensation Plans," and that information is incorporated by reference in this Form 10-K.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Not applicable.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by Item 14 will be set forth in our 2008 Proxy Statement under the captions "Independent Registered Accounting Firm Fees" and "Audit Committee Pre-Approval Policies and Procedures," and that information is incorporated by reference in this Form 10-K.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

FINANCIAL STATEMENTS INCLUDED HEREIN

Westar Energy, Inc.

Management's Report on Internal Control Over Financial Reporting
Reports of Independent Registered Public Accounting Firm
Consolidated Balance Sheets, as of December 31, 2007 and 2006
Consolidated Statements of Income for the years ended December 31, 2007, 2006 and 2005
Consolidated Statements of Comprehensive Income for the years ended December 31, 2007, 2006 and 2005
Consolidated Statements of Cash Flows for the years ended December 31, 2007, 2006 and 2005
Consolidated Statements of Shareholders' Equity for the years ended December 31, 2007, 2006 and 2005
Notes to Consolidated Financial Statements

SCHEDULES

Schedule II —Valuation and Qualifying Accounts

Schedules omitted as not applicable or not required under the Rules of Regulation S-X: I, III, IV, and V

EXHIBIT INDEX

All exhibits marked "I" are incorporated herein by reference. All exhibits marked by an asterisk are management contracts or compensatory plans or arrangements required to be identified by Item 15(a)(3) of Form 10-K. All exhibits marked "#" are filed with this Form 10-K.

Description

1(a)	—	Underwriting Agreement between Westar Energy, Inc., and Citigroup Global Markets Inc. and Lehman Brothers Inc., as representatives of the several underwriters, dated January 12, 2005 (filed as Exhibit 1.1 to the Form 8-K filed on January 18, 2005)	I
1(b)	—	Underwriting Agreement between Westar Energy, Inc. and Barclays Capital and Citigroup Global Markets, Inc., as representatives of the several underwriters, dated June 27, 2005 (filed as Exhibit 1.1 to the Form 8-K filed on July 1, 2005)	I
1(c)	—	Sales Agency Financing Agreement, dated as of April 12, 2007, between Westar Energy, Inc. and BNY Capital Markets, Inc. (filed as Exhibit 1.1 to the Form 8-K filed on April 12, 2007)	I
1(d)	—	Sales Agency Financing Agreement, dated as of August 24, 2007, between Westar Energy, Inc. and BNY Capital Markets, Inc. (filed as Exhibit 1.1 to the Form 8-K filed on August 27, 2007)	I
1(e)	—	Underwriting Agreement, dated November 15, 2007, among UBS Securities LLC and J.P. Morgan Securities Inc., as representatives of the underwriters named therein, UBS Securities LLC, in its capacity as agent for UBS AG, London Branch, and Westar Energy, Inc. (filed as Exhibit 1.1 to the Form 8-K filed on November 16, 2007)	I
3(a)	—	By-laws of Westar Energy, Inc., as amended April 28, 2004 (filed as Exhibit 3(a) to the Form 10-Q for the period ended June 30, 2004 filed on August 4, 2004)	I
3(b)	—	Restated Articles of Incorporation of Westar Energy, Inc., as amended through May 25, 1988 (filed as Exhibit 4 to the Form S-8 Registration Statement, SEC File No. 33-23022 filed on July 15, 1988)	I
3(c)	—	Certificate of Amendment to Restated Articles of Incorporation of Westar Energy, Inc. (filed as Exhibit 3 to the Form 10-K405 for the period ended December 31, 1998 filed on April 14, 1999)	I
3(d)	—	Certificate of Designations for Preference Stock, 8.5% Series (filed as Exhibit 3(d) to the Form 10-K for the period ended December 31, 1993 filed on March 22, 1994)	I
3(e)	—	Certificate of Correction to Restated Articles of Incorporation of Westar Energy, Inc. (filed as Exhibit 3(b) to the Form 10-K for the period ended December 31, 1991 filed on March 30, 1992)	I
3(f)	—	Certificate of Designations for Preference Stock, 7.58% Series (filed as Exhibit 3(e) to the Form 10-K for the period ended December 31, 1993 filed on March 22, 1994)	I
3(g)	—	Certificate of Amendment to Restated Articles of Incorporation of Westar Energy, Inc. (filed as Exhibit 3(c) to the Form 10-K for the period ended December 31, 1994 filed on March 30, 1995)	I
3(h)	—	Certificate of Amendment to Restated Articles of Incorporation of Westar Energy, Inc. (filed as Exhibit 3 to the Form 10-Q for the period ended June 30, 1994 filed on August 11, 1994)	I
3(i)	—	Certificate of Amendment to Restated Articles of Incorporation of Westar Energy, Inc. (filed as Exhibit 3(a) to the Form 10-Q for the period ended June 30, 1996 filed on August 14, 1996)	I
3(j)	—	Certificate of Amendment to Restated Articles of Incorporation of Westar Energy, Inc. (filed as Exhibit 3 to the Form 10-Q for the period ended March 31, 1998 filed on May 12, 1998)	I
3(k)	—	Form of Certificate of Designations for 7.5% Convertible Preference Stock (filed as Exhibit 99.4 to the Form 8-K filed on November 17, 2000)	I
3(l)	—	Certificate of Amendment to Restated Articles of Incorporation of Westar Energy, Inc. (filed as Exhibit 3(l) to the Form 10-K for the period ended December 31, 2002 filed on April 11, 2003)	I
3(m)	—	Certificate of Amendment to Restated Articles of Incorporation of Westar Energy, Inc. (filed as Exhibit 3(m) to the Form 10-K for the period ended December 31, 2002 filed on April 11, 2003)	I
3(n)	—	Certificate of Amendment to Restated Articles of Incorporation of Westar Energy, Inc. (filed as Exhibit 3(m) to the Form S-3 Registration Statement No. 333-125828 filed on June 15, 2005)	I
4(a)	—	Mortgage and Deed of Trust dated July 1, 1939 between Westar Energy, Inc. and Harris Trust and Savings Bank, Trustee (filed as Exhibit 4(a) to Registration Statement No. 33-21739)	I
4(b)	—	First and Second Supplemental Indentures dated July 1, 1939 and April 1, 1949, respectively (filed as Exhibit 4(b) to Registration Statement No. 33-21739)	I
4(c)	—	Sixth Supplemental Indenture dated October 4, 1951 (filed as Exhibit 4(b) to Registration Statement No. 33-21739)	I

4(d)	—	Fourteenth Supplemental Indenture dated May 1, 1976 (filed as Exhibit 4(b) to Registration Statement No. 33-21739)	I
4(e)	—	Twenty-Eighth Supplemental Indenture dated July 1, 1992 (filed as Exhibit 4(o) to the Form 10-K for the period ended December 31, 1992 filed on March 30, 1993)	I
4(f)	—	Twenty-Ninth Supplemental Indenture dated August 20, 1992 (filed as Exhibit 4(p) to the Form 10-K for the period ended December 31, 1992 filed on March 30, 1993)	I
4(g)	—	Thirtieth Supplemental Indenture dated February 1, 1993 (filed as Exhibit 4(q) to the Form 10-K for the period ended December 31, 1992 filed on March 30, 1993)	I
4(h)	—	Thirty-First Supplemental Indenture dated April 15, 1993 (filed as Exhibit 4(r) to the Form S-3 Registration Statement No. 33-50069 filed on August 24, 1993)	I
4(i)	—	Thirty-Second Supplemental Indenture dated April 15, 1994 (filed as Exhibit 4(s) to the Form 10-K for the period ended December 31, 1994 filed on March 30, 1995)	I
4(j)	—	Thirty-Fourth Supplemental Indenture dated June 28, 2000 (filed as Exhibit 4(v) to the Form 10-K for the period ended December 31, 2000 filed on April 2, 2001)	I
4(k)	—	Thirty-Fifth Supplemental Indenture dated May 10, 2002 between Westar Energy, Inc. and BNY Midwest Trust Company, as Trustee (filed as Exhibit 4.1 to the Form 10-Q for the period ended March 31, 2002 filed on May 15, 2002)	I
4(l)	—	Thirty-Sixth Supplemental Indenture dated as of June 1, 2004, between Westar Energy, Inc. and BNY Midwest Trust Company (as successor to Harris Trust and Savings Bank), to its Mortgage and Deed of Trust dated July 1, 1939 (filed as Exhibit 4.1 to the Form 8-K filed on January 18, 2005)	I
4(m)	—	Thirty-Seventh Supplemental Indenture, dated as of June 17, 2004, between Westar Energy, Inc. and BNY Midwest Trust Company (as successor to Harris Trust and Savings Bank), to its Mortgage and Deed of Trust dated July 1, 1939 (filed as Exhibit 4.2 to the Form 8-K filed on January 18, 2005)	I
4(n)	—	Thirty-Eighth Supplemental Indenture, dated as of January 18, 2005, between Westar Energy, Inc. and BNY Midwest Trust Company (as successor to Harris Trust and Savings Bank), to its Mortgage and Deed of Trust dated July 1, 1939 (filed as Exhibit 4.3 to the Form 8-K filed on January 18, 2005)	I
4(o)	—	Thirty-Ninth Supplemental Indenture dated June 30, 2005 between Westar Energy, Inc. and BNY Midwest Trust Company (as successor to Harris Trust and Savings Bank) to its Mortgage and Deed of Trust dated July 1, 1939 (filed as Exhibit 4.1 to the Form 8-K filed on July 1, 2005)	I
4(p)	—	Forty-First Supplemental Indenture dated June 6, 2002 between Kansas Gas and Electric Company and BNY Midwest Trust Company, as Trustee (filed as Exhibit 4.1 to the Form 10-Q for the period ended June 30, 2002 filed on August 14, 2002)	I
4(q)	—	Forty-Second Supplemental Indenture dated March 12, 2004 between Kansas Gas and Electric Company and BNY Midwest Trust Company, as Trustee (filed as Exhibit 4(p) to the Form 10-K for the period ended December 31, 2004 filed on March 16, 2005)	I
4(r)	—	Forty-Fourth Supplemental Indenture dated May 6, 2005 between Kansas Gas and Electric Company and BNY Midwest Trust Company, as Trustee (filed as Exhibit 4 to the Form 10-Q for the period ended March 31, 2005 filed on May 10, 2005)	I
4(s)	—	Debt Securities Indenture dated August 1, 1998 (filed as Exhibit 4.1 to the Form 10-Q for the period ended June 30, 1998 filed on August 12, 1998)	I
4(t)	—	Securities Resolution No. 2 dated as of May 10, 2002 under Indenture dated as of August 1, 1998 between Western Resources, Inc. and Deutsche Bank Trust Company Americas (filed as Exhibit 4.2 to the Form 10-Q for the period ended March 31, 2002 filed on May 15, 2002)	I
4(u)	—	Forty-Fifth Supplemental Indenture dated March 17, 2006 between Kansas Gas and Electric Company and BNY Midwest Trust Company, as Trustee, to the Kansas Gas and Electric Company Mortgage and Deed of Trust dated April 1, 1940 (filed as Exhibit 4.1 to the Form 8-K filed on March 21, 2006)	I
4(v)	—	Forty-Sixth Supplemental Indenture dated June 1, 2006 between Kansas Gas and Electric Company and BNY Midwest Trust Company, as Trustee, to the Kansas Gas and Electric Company Mortgage and Deed of Trust dated April 1, 1940 (filed as Exhibit 4 to the Form 10-Q for the period ended June 30, 2006 filed on August 9, 2006)	I
4(w)	—	Fortieth Supplemental Indenture dated May 15, 2007, between Westar Energy, Inc. and The Bank of New York Trust Company, N.A. (as successor to Harris Trust and Savings Bank) to its Mortgage and Deed of Trust dated July 1, 1939 (filed as Exhibit 4.16 to the Form 8-K filed on May 16, 2007)	I

4(x)	— Forty-Eighth Supplemental Indenture, dated as of July 10, 2007, by and among Kansas Gas and Electric Company, The Bank of New York Trust Company, N.A. and Judith L. Bartolini	#
4(y)	— Bond Purchase Agreement, dated as of August 14, 2007, between Kansas Gas and Electric Company and Nomura International PLC (filed as Exhibit 4.1 to the Form 8-K filed on August 15, 2007)	I
4(z)	— Forty-Ninth Supplemental Indenture, dated as of October 12, 2007, by and among Kansas Gas and Electric Company, The Bank of New York Trust Company, N.A. and Judith L. Bartolini (filed as Exhibit 4.1 to the Form 8-K filed on October 19, 2007)	I
4(aa)	— Form of First Mortgage Bonds, 6.10% Series Due 2047 (contained in Exhibit 4(w)	I
	Instruments defining the rights of holders of other long-term debt not required to be filed as Exhibits will be furnished to the Commission upon request.	
10(a)	— Long-Term Incentive and Share Award Plan (filed as Exhibit 10(a) to the Form 10-Q for the period ended June 30, 1996 filed on August 14, 1996)*	I
10(b)	— Form of Employment Agreements with Messrs. Grennan, Koupal, Terrill, Lake and Wittig and Ms. Sharpe (filed as Exhibit 10(b) to the Form 10-K for the period ended December 31, 2000 filed on April 2, 2001)*	I
10(c)	— A Rail Transportation Agreement among Burlington Northern Railroad Company, the Union Pacific Railroad Company and Westar Energy, Inc. (filed as Exhibit 10 to the Form 10-Q for the period ended June 30, 1994 filed on August 11, 1994)	I
10(d)	— Agreement between Westar Energy, Inc. and AMAX Coal West Inc. effective March 31, 1993 (filed as Exhibit 10(a) to the Form 10-K for the period ended December 31, 1993 filed on March 22, 1994)	I
10(e)	— Agreement between Westar Energy, Inc. and Williams Natural Gas Company dated October 1, 1993 (filed as Exhibit 10(b) to the Form 10-K for the period ended December 31, 1993 filed on March 22, 1994)	I
10(f)	— Short-term Incentive Plan (filed as Exhibit 10(j) to the Form 10-K for the period ended December 31, 1993 filed on March 22, 1994)*	I
10(g)	— Westar Energy, Inc. Non-Employee Director Deferred Compensation Plan, as amended and restated, dated as of October 20, 2004 (filed as Exhibit 10.1 to the Form 8-K filed on October 21, 2004)*	I
10(h)	— Executive Salary Continuation Plan of Western Resources, Inc., as revised, effective September 22, 1995 (filed as Exhibit 10(j) to the Form 10-K for the period ended December 31, 1995 filed on March 27, 1996)*	I
10(i)	— Letter Agreement between Westar Energy, Inc. and David C. Wittig, dated April 27, 1995 (filed as Exhibit 10(m) to the Form 10-K for the period ended December 31, 1995 filed on March 27, 1996)*	I
10(j)	— Form of Split Dollar Insurance Agreement (filed as Exhibit 10.3 to the Form 10-Q for the period ended June 30, 1998 filed on August 12, 1998)*	I
10(k)	— Amendment to Letter Agreement between Westar Energy, Inc. and David C. Wittig, dated April 27, 1995 (filed as Exhibit 10 to the Form 10-Q/A for the period ended June 30, 1998 filed on August 24, 1998)*	I
10(l)	— Letter Agreement between Westar Energy, Inc. and Douglas T. Lake, dated August 17, 1998 (filed as Exhibit 10(n) to the Form 10-K405 for the period ended December 31, 1999 filed on March 29, 2000)*	I
10(m)	— Form of Change of Control Agreement with officers of Westar Energy, Inc. (filed as Exhibit 10(o) to the Form 10-K for the period ended December 31, 2000 filed on April 2, 2001)*	I
10(n)	— Form of loan agreement with officers of Westar Energy, Inc. (filed as Exhibit 10(r) to the Form 10-K for the period ended December 31, 2001 filed on April 1, 2002)*	I
10(o)	— Amendment to Employment Agreement dated April 1, 2002 between Westar Energy, Inc. and David C. Wittig (filed as Exhibit 10.1 to the Form 10-Q for the period ended June 30, 2002 filed on August 14, 2002)*	I
10(p)	— Amendment to Employment Agreement dated April 1, 2002 between Westar Energy and Douglas T. Lake (filed as Exhibit 10.2 to the Form 10-Q for the period ended June 30, 2002 filed on August 14, 2002)*	I
10(q)	— Credit Agreement dated as of June 6, 2002 among Westar Energy, Inc., the lenders from time to time party there to, JPMorgan Chase Bank, as Administrative Agent, Citibank, N.A., as Syndication Agent, and Bank of America, N.A., as Documentation Agent (filed as Exhibit 10.3 to the Form 10-Q for the period ended June 30, 2002 filed on August 14, 2002)	I
10(r)	— Employment Agreement dated September 23, 2002 between Westar Energy, Inc. and David C. Wittig (filed as Exhibit 10.1 to the Form 10-Q for the period ended September 30, 2002 filed on November 15, 2002)*	I
10(s)	— Employment Agreement dated September 23, 2002 between Westar Energy, Inc. and Douglas T. Lake (filed as Exhibit 10.1 to the Form 8-K filed on November 25, 2002)*	I

10(t)	—	Letter Agreement dated November 1, 2003 between Westar Energy, Inc. and James S. Haines, Jr. (filed as Exhibit 10(a) to the Form 10-Q for the period ended September 30, 2003 filed on November 10, 2003)*	I
10(u)	—	Letter Agreement dated November 1, 2003 between Westar Energy, Inc. and William B. Moore (filed as Exhibit 10(b) to the Form 10-Q for the period ended September 30, 2003 filed on November 10, 2003)*	I
10(v)	—	Letter Agreement dated November 1, 2003 between Westar Energy, Inc. and Mark A. Ruelle (filed as Exhibit 10(c) to the Form 10-Q for the period ended September 30, 2003 filed on November 10, 2003)*	I
10(w)	—	Letter Agreement dated November 1, 2003 between Westar Energy, Inc. and Douglas R. Sterbenz (filed as Exhibit 10(d) to the Form 10-Q for the period ended September 30, 2003 filed on November 10, 2003)*	I
10(x)	—	Letter Agreement dated November 1, 2003 between Westar Energy, Inc. and Larry D. Irick (filed as Exhibit 10(e) to the Form 10-Q for the period ended September 30, 2003 filed on November 10, 2003)*	I
10(y)	—	Waiver and Amendment, dated as of November 6, 2003, to the Credit Agreement, dated as of June 6, 2002, among Westar Energy, Inc., the Lenders from time to time party thereto, JPMorgan Chase Bank, as Administrative Agent for the Lenders, Citibank, N.A., as Syndication Agent, and Bank of America, N.A., as Documentation Agent (filed as Exhibit 10(f) to the Form 10-Q for the period ended September 30, 2003 filed on November 10, 2003)	I
10(z)	—	Credit Agreement dated as of March 12, 2004 among Westar Energy, Inc., the several banks and other financial institutions or entities from time to time parties to the Agreement, JPMorgan Chase Bank, as administrative agent, The Bank of New York, as syndication agent, and Citibank, N.A., Union Bank of California, N.A., and Wachovia Bank, National Association, as documentation agents (filed as Exhibit 10(a) to the Form 10-Q for the period ended March 31, 2004 filed on May 10, 2004)	I
10(aa)	—	Supplements and modifications to Credit Agreement dated as of March 12, 2004 among Westar Energy, Inc., as Borrower, the Several Lenders Party Thereto, JPMorgan Chase Bank, as Administrative Agent, The Bank of New York, as Syndication Agent, and Citibank, N.A., Union Bank of California, N.A., and Wachovia Bank, national Association, as Documentation Agents (filed as Exhibit 10(a) to the Form 10-Q for the period ended June 30, 2004 filed on August 4, 2004)	I
10(ab)	—	Purchase Agreement dated as of December 23, 2003 between POI Acquisition, L.L.C., Westar Industries, Inc. and Westar Energy, Inc. (filed as Exhibit 99.2 to the Form 8-K filed on December 24, 2003)	I
10(ac)	—	Settlement Agreement dated November 12, 2004 by and among Westar Energy, Inc., Protection One, Inc., POI Acquisition, L.L.C., and POI Acquisition I, Inc. (filed as Exhibit 10.1 to the Form 8-K filed on November 15, 2004)	I
10(ad)	—	Restricted Share Unit Award Agreement between Westar Energy, Inc. and James S. Haines, Jr. (filed as Exhibit 10.1 to the Form 8-K filed on December 7, 2004)*	I
10(ae)	—	Deferral Election Form of James S. Haines, Jr. (filed as Exhibit 10.2 to the Form 8-K filed on December 7, 2004)*	I
10(af)	—	Resolutions of the Westar Energy, Inc. Board of Directors regarding Non-Employee Director Compensation, approved on September 2, 2004 (filed as Exhibit 10.1 to the Form 8-K filed on December 17, 2004)*	I
10(ag)	—	Restricted Share Unit Award Agreement between Westar Energy, Inc. and William B. Moore (filed as Exhibit 10.1 to the Form 8-K filed on December 29, 2004)*	I
10(ah)	—	Deferral Election Form of William B. Moore (filed as Exhibit 10.2 to the Form 8-K filed on December 29, 2004)*	I
10(ai)	—	Amended and Restated Credit Agreement dated as of May 6, 2005 among Westar Energy, Inc., the several banks and other financial institutions or entities from time to time parties to the Agreement, JPMorgan Chase Bank, N.A., as administrative agent, The Bank of New York, as syndication agent, and Citibank, N.A., Union Bank of California, N.A., and Wachovia Bank, National Association, as documentation agents (filed as Exhibit 10 to the Form 10-Q for the period ended March 31, 2005 filed on May 10, 2005)	I
10(aj)	—	Amended and Restated Westar Energy Restricted Share Units Deferral Election Form for James S. Haines, Jr. (filed as Exhibit 10.1 to the Form 8-K filed on December 22, 2005)*	I
10(ak)	—	Form of Change in Control Agreement (filed as Exhibit 10.1 to the Form 8-K filed on January 26, 2006)*	I
10(al)	—	Form of Amendment to the Employment Letter Agreements for Mr. Ruelle and Mr. Sterbenz (filed as Exhibit 10.2 to the Form 8-K filed on January 26, 2006)*	I
10(am)	—	Form of Amendment to the Employment Letter Agreements for Mr. Irick and One Other Officer (filed as Exhibit 10.3 to the Form 8-K filed on January 26, 2006)*	I
10(an)	—	Second Amended and Restated Credit Agreement, dated as of March 17, 2006, among Westar Energy, Inc., the several banks and other financial institutions or entities from time to time parties to the Agreement (filed as Exhibit 10.1 to the Form 8-K filed on March 21, 2006)	I

10(ao)	—	Amendment to the Employment Letter Agreement for Mr. James S. Haines, Jr. (filed as Exhibit 99.3 to the Form 8-K filed on August 22, 2006)*	I
10(ap)	—	Confirmation of Forward Sale Transaction, dated November 15, 2007, between UBS AG, London Branch and Westar Energy, Inc. (filed as Exhibit 10.1 to the Form 8-K filed on November 16, 2007)	I
10(aq)	—	Third Amended and Restated Credit Agreement dated as of February 22, 2008, among Westar Energy, Inc., and several banks and other financial institutions or entities from time to time parties to the Agreement (filed as Exhibit 10.1 to the Form 8-K filed on February 26, 2008)	I
12(a)	—	Computations of Ratio of Consolidated Earnings to Fixed Charges	#
12(b)	—	Computation of Ratio of Earnings to Fixed Charges for the Three Months Ended March 31, 2007 (filed as Exhibit 12.1 to the Form 8-K filed on May 10,2007)	I
21	—	Subsidiaries of the Registrant	#
23	—	Consent of Independent Registered Public Accounting Firm, Deloitte & Touche LLP	#
31(a)	—	Certification of Principal Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	#
31(b)	—	Certification of Principal Accounting Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	#
32	—	Certifications pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished and not to be considered filed as part of the Form 10-K)	#
99(a)	—	Kansas Corporation Commission Order dated November 8, 2002 (filed as Exhibit 99.2 to the Form 10-Q for the period ended September 30, 2002 filed on November 15, 2002)	I
99(b)	—	Kansas Corporation Commission Order dated December 23, 2002 (filed as Exhibit 99.1 to the Form 8-K filed on December 27, 2002)	I
99(c)	—	Debt Reduction and Restructuring Plan filed with the Kansas Corporation Commission on February 6, 2003 (filed as Exhibit 99.1 to the Form 8-K filed on February 6, 2003)	I
99(d)	—	Kansas Corporation Commission Order dated February 10, 2003 (filed as Exhibit 99.1 to the Form 8-K filed on February 11, 2003)	I
99(e)	—	Kansas Corporation Commission Order dated March 11, 2003 (filed as Exhibit 99(f) to the Form 10-K for the period ended December 31, 2002 filed on April 11, 2003)	I
99(f)	—	Demand for Arbitration (filed as Exhibit 99.1 to the Form 8-K filed on June 13, 2003)	I
99(g)	—	Stipulation and Agreement filed with the Kansas Corporation Commission on July 21, 2003 (filed as Exhibit 99.1 to the Form 8-K filed on July 22, 2003)	I
99(h)	—	Summary of Rate Application dated May 2, 2005 (filed as Exhibit 99.1 to the Form 8-KA filed on May 10, 2005)	I
99(i)	—	Federal Energy Regulatory Commission Order On Proposed Mitigation Measures, Tariff Revisions, and Compliance Filings issued September 6, 2006 (filed as Exhibit 99.1 to the Form 8-K filed on September 12, 2006)	I
99(j)	—	Westar Energy, Inc. Form of Restricted Share Units Award (filed as Exhibit 99.1 to the Form 8-K filed on December 19, 2006)	I

WESTAR ENERGY, INC.

SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS

Description	Balance at Beginning of Period	Charged to Costs and Expenses	Deductions[a]	Balance at End of Period
		(In Thousands)		
Year ended December 31, 2005				
Allowances deducted from assets for doubtful accounts	$5,313	$3,959	$(4,039)	$5,233
Year ended December 31, 2006				
Allowances deducted from assets for doubtful accounts	$5,233	$5,091	$(4,067)	$6,257
Year ended December 31, 2007				
Allowances deducted from assets for doubtful accounts	$6,257	$3,273	$(3,809)	$5,721

[a] *Deductions are the result of write-offs of accounts receivable.*

SIGNATURE

Pursuant to the requirements of Sections 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.

WESTAR ENERGY, INC.

Date: February 29, 2008 By: /s/ Mark A. Ruelle

Mark A. Ruelle,
Executive Vice President and Chief Financial Officer

SIGNATURES

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 dates indicated.

Signature	Title	Date
/s/ WILLIAM B. MOORE (William B. Moore)	President, Director and Chief Executive Officer (Principal Executive Officer)	February 29, 2008
/s/ MARK A. RUELLE (Mark A. Ruelle)	Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	February 29, 2008
/s/ CHARLES Q. CHANDLER IV (Charles Q. Chandler IV)	Chairman of the Board	February 29, 2008
/s/ MOLLIE H. CARTER (Mollie H. Carter)	Director	February 29, 2008
/s/ R. A. EDWARDS III (R. A. Edwards III)	Director	February 29, 2008
/s/ JERRY B. FARLEY (Jerry B. Farley)	Director	February 29, 2008
/s/ B. ANTHONY ISAAC (B. Anthony Isaac)	Director	February 29, 2008
/s/ ARTHUR B. KRAUSE (Arthur B. Krause)	Director	February 29, 2008
/s/ SANDRA A. J. LAWRENCE (Sandra A. J. Lawrence)	Director	February 29, 2008
/s/ MICHAEL F. MORRISSEY (Michael F. Morrissey)	Director	February 29, 2008
/s/ JOHN C. NETTELS, JR. (John C. Nettels, Jr.)	Director	February 29, 2008

Construction on the circulating water line replacement on unit 3 at Jeffrey Energy Center.

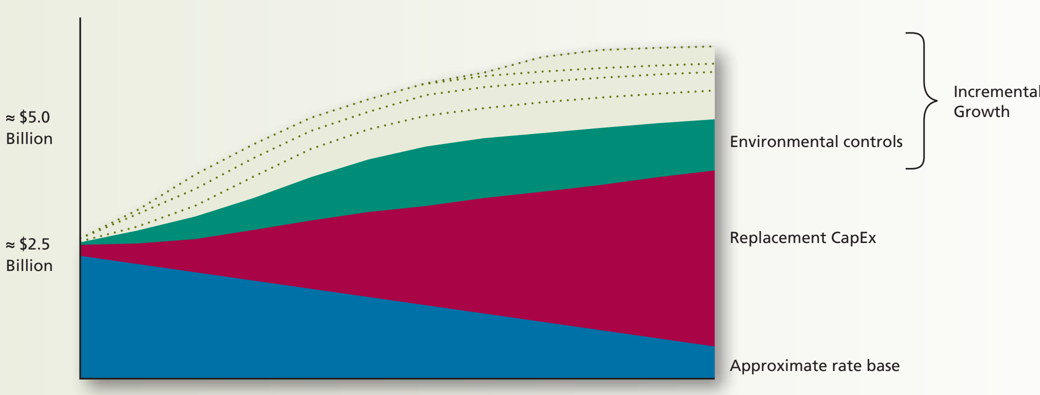
Crews prepare to seal a section of the new water line on unit 3.

We all share the responsibility of being good stewards of the environment.

At Westar Energy, that means doing what it takes to preserve resources and to protect our environment for future generations.

Westar plans to invest about $465 million in environmental projects at Jeffrey Energy Center over the next several years to dramatically decrease air emissions. Projects include rebuilding machinery that removes sulfur dioxide, adding new burners to reduce nitrous oxides and modifying equipment to better capture very small particulate matter. We will also invest to meet new regulations to reduce mercury emissions. We have similar emission control projects lined up at all of our coal plants.

PLANNED CAPITAL EXPANSION



Environmental improvements, represented by the first layer of investment, will reduce the emissions of our existing power plants.

Westar Energy is expanding its transmission network with initiatives that will serve Kansas well into future decades.

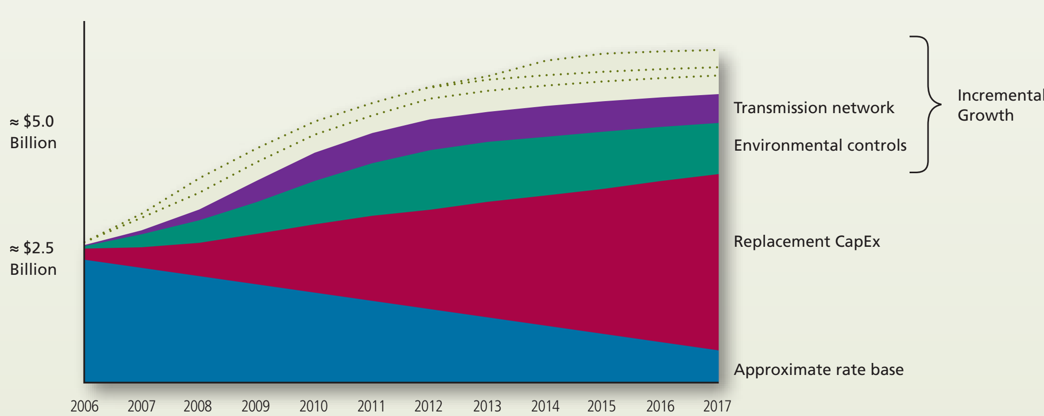
Our planned transmission expansion will also increase the availability of affordable power to Kansans, as well as improve regional reliability. Transmission systems can help ensure the power we have is distributed most efficiently within our state, improve reliability and facilitate the introduction of wind power into our system.

In January 2008 we began constructing the first section of a 345 kilovolt (kV) high-capacity transmission line extending from near Wichita to the Hutchinson area. The remaining section will take the line from Hutchinson to southeast of Salina. We expect to complete construction of this line in late 2009.

We have proposed a 345 kV high-capacity transmission line from near Wichita south to Oklahoma Gas and Electric's system to support current demand, while allowing for growth. We would build the line from south of Wichita to the border of Kansas and Oklahoma. If approved, this project is expected to be serving customers by summer 2011.

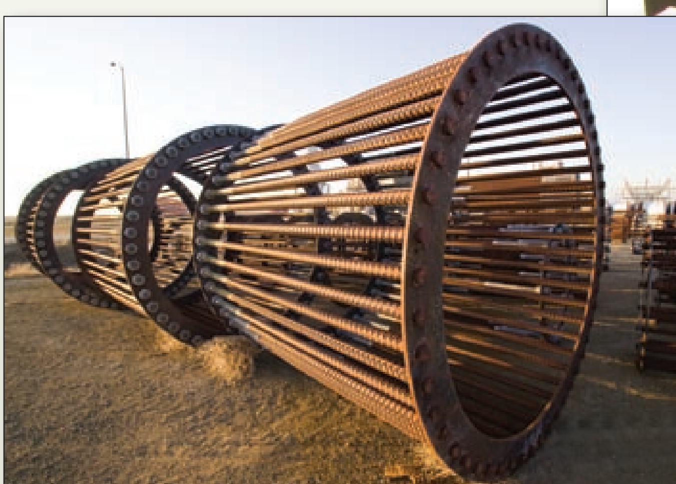
Reels of wire at Gordon Evans Energy Center that will be used for the new 345 kV line from Wichita to Hutchinson, and then to Salina. Construction is expected to be complete by late 2009.

PLANNED CAPITAL EXPANSION



Investment in new transmission lines, represented by the next layer of the graph, will increase the reliability of our system and the availability of affordable power throughout the state.

Contractors pour the concrete foundation for a steel pole for phase one of the 345 kV Wichita to Hutchinson to Salina line. Phase one extends from Wichita to Hutchinson. Phase two continues from Hutchinson to Salina.



Contractors construct the 40 foot long rebar cages that will serve as part of the foundation for hundreds of steel poles.

Westar Energy generates electricity using diverse resources – nuclear, coal, natural gas, and, by the end of 2008, wind.

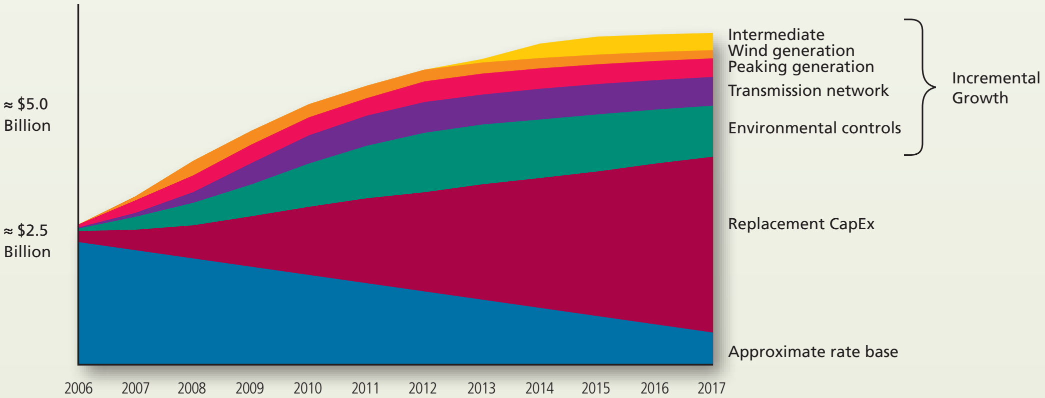
We operate about 6,200 megawatts (MW) of electric generation. We estimate that over the next decade, we will need another 1,100 MW of generation to meet consumer needs. During this time, our nuclear and coal-fueled plants will continue to be important to our generation mix, but we will see natural gas and wind taking larger roles.

Our moderate size makes it important to balance innovation and risk. We have designed our investment plan to provide time for industry developments as technologies mature and regulations evolve. This flexible approach to planning allows us to make better decisions for our customers and shareholders. Our plan allows us to remain nimble and anticipate change.

Water tower at the new Emporia Energy Center.

Overview of Emporia Energy Center construction.

PLANNED CAPITAL EXPANSION



Generation resources account for the remaining layers of our investment plan. Even with successful energy efficiency initiatives, new generation will be needed.

Westar Energy is launching Kansas' largest wind energy program.

By the end of 2008, we will add nearly 300 MW of wind generation to our energy resources, making our program one of the largest utility-sponsored wind programs in the country. Technological advances in recent years have made wind affordable and appealing.

Westar has worked with regulators to ensure recovery of these investments and has signed agreements with developers for three wind farms in different parts of the state. The agreements represent more than a half-billion dollar commitment to wind power in Kansas.

We will bring about 300 MW of wind generation into our generation mix by the end of 2008 with wind farms in Wichita, Barber and Cloud Counties.

Along with energy efficiency and renewable energy, we will need to build additional plants to meet growing needs.

Growth in customers' use of electricity requires us to invest in additional new power plants. We will keep a close eye on market changes, but at this point we expect a highly efficient combined-cycle natural gas plant will be a more cost effective solution than a base load coal plant when it comes time to build more than a peaking plant.

The first phase of our Emporia Energy Center, which is a gas peaking plant, will be available to serve customers this spring and construction of the second phase is scheduled to be complete next spring. This natural gas plant paired with our wind investment will provide reliable electricity for our consumers.

Units at the new Emporia Energy Center.

Larry Graves, Emporia Energy Center plant manager.

Constructive rate mechanisms will benefit shareholders and customers as we grow.

We prepared carefully for this time of growth, working with the Kansas Corporation Commission, our primary regulator, to develop forward-thinking approaches to setting utility rates and to ensure we have the financial capacity to meet growing demands and increasingly uncertain future conditions.

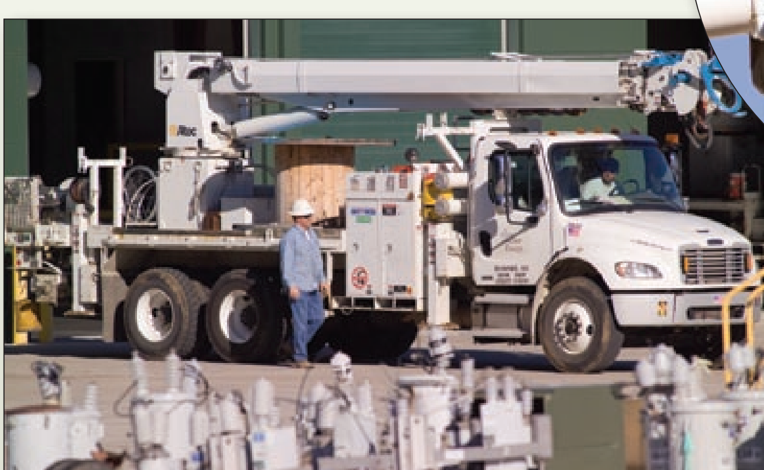
Our Environmental Cost Recovery Rider adjusts each year to reflect investments related to meeting the requirements of the Clean Air Act and other environmental regulations since the prior full review of our rates. Customers benefit because rate changes are more gradual and ultimately lower than they would be without this cost recovery rider. Investors benefit from more timely investment recovery.

Our ability to adjust components of our rates monthly in response to changing fuel prices helps customers understand the cost of their electric service, including the cost of meeting stricter environmental standards, which in turn helps them make better choices to meet their energy needs. In today's volatile fuel markets, it also ensures they are paying the correct price for fuel.

Under a recent state law, Kansas utilities are able to establish with regulators how new generation investment will be recovered in utility rates before a utility makes a substantial commitment to invest. With the rapid changes affecting our industry, this confirms the prudence of these investments and keeps our cost of capital reasonable.

Dustin Spencer, substation apprentice, Topeka Operations Center.

Ryan McCallister, apprentice lineman, and Robert Heath, journeyman lineman, install protective cover up on a line in preparation to provide service to a new commercial customer in DeSoto.



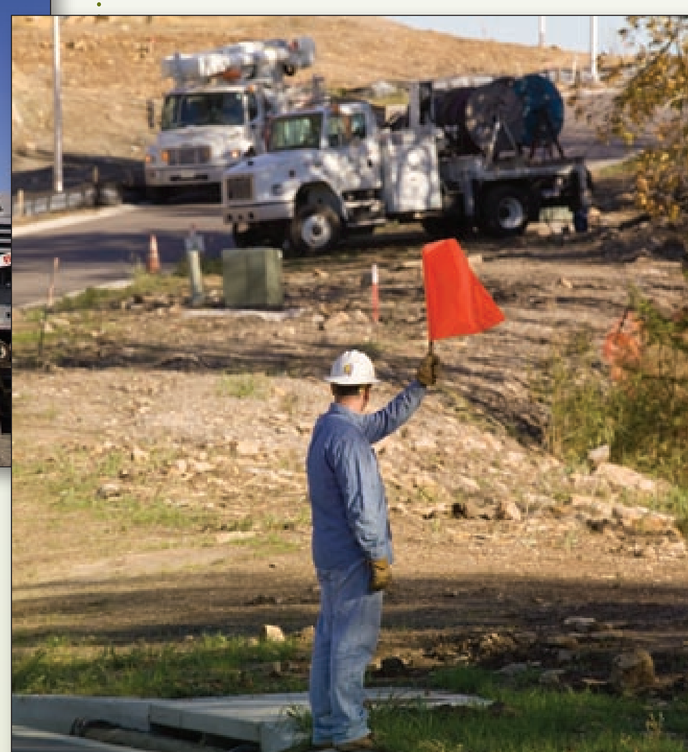
Darrin Hackney, journeyman lineman, loads material at the Shawnee Service Center before heading to the job site.

Construction on the circulating water line replacement on unit 3 at Jeffrey Energy Center.

Transmission lines coming out of Emporia Energy Center.

We are ready for change, but are still steadfast in our mission.

As needs, policies and regulations change, we expect to make adjustments to our investment plan, but our mission and sole business purpose remains the same: Westar Energy provides safe, reliable, high quality electric energy service at a reasonable cost to all customers.



Todd Richardson, apprentice lineman, communicates with crew members as an underground cable is installed for a new residential development in Olathe.

Shareholder Information & Assistance:

Westar Energy's Shareholder Services department offers personalized service to the company's individual shareholders. We are the transfer agent for Westar Energy common and preferred stock. Shareholder Services provides information and assistance to shareholders regarding:

- Dividend payments
  - Historically paid on the first business day of January, April, July and October
- Direct deposit of dividends
- Transfer of shares
- Lost stock certificate assistance
- Direct Stock Purchase Plan assistance
  - Dividend reinvestment
  - Purchase additional shares by making optional cash payments by check or monthly electronic withdrawal from your bank account
  - Deposit your stock certificates into the plan for safekeeping
  - Sell shares

Please contact us in writing to request elimination of duplicate mailings because of stock registered in more than one way. Mailing of annual reports can be eliminated by marking your proxy card to consent to accessing reports electronically on the Internet.

Please visit our Web site at **www.WestarEnergy.com.** Registered shareholders can easily access their shareholder account information online by clicking on the **Go to Shareholder Sign-in button.**

CONTACTING SHAREHOLDER SERVICES

TELEPHONE

Toll-free:	(800) 527-2495
In the Topeka area:	(785) 575-6394
Fax:	(785) 575-1796

ADDRESS

Westar Energy, Inc.
Shareholder Services
P.O. Box 750320
Topeka, KS 66675-0320

E-MAIL ADDRESS

shareholders@WestarEnergy.com

Please include a daytime telephone number in all correspondence.

CO-TRANSFER AGENT

Continental Stock Transfer
& Trust Company
17 Battery Place, 8th Floor
New York, NY 10004

CONTACTING INVESTOR RELATIONS

TELEPHONE (785) 575-8227

ADDRESS

Westar Energy, Inc.
Investor Relations
P.O. Box 889
Topeka, KS 66601-0889

E-MAIL ADDRESS

ir@WestarEnergy.com

Copies of our Annual Report on Form 10-K filed with the Securities and Exchange Commission and other published reports can be obtained without charge by contacting Investor Relations at the above address, by accessing the company's home page on the Internet at www.WestarEnergy.com or by accessing the Securities and Exchange Commission's Internet Web site at www.sec.gov.

TRUSTEE FOR FIRST MORTGAGE BONDS

PRINCIPAL TRUSTEE, PAYING AGENT AND REGISTRAR

The Bank of New York
2 North LaSalle Street, Suite 1020
Chicago, IL 60602-3802
(800) 548-5075

CORPORATE INFORMATION

CORPORATE ADDRESS

Westar Energy, Inc.
818 South Kansas Avenue
Topeka, KS 66612-1203
(785) 575-6300
www.WestarEnergy.com

COMMON STOCK LISTING

Ticker Symbol (NYSE): WR

Daily Stock Table Listing:
WestarEngy

CHIEF EXECUTIVE OFFICER AND CHIEF FINANCIAL OFFICER CERTIFICATIONS

In 2007, our chief executive officer submitted a certificate to the New York Stock Exchange (NYSE) affirming that he is not aware of any violation by the company of the NYSE's corporate governance listing standards. Our chief executive officer's and chief financial officer's certifications pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 for the year ended December 31, 2007, were included as exhibits to Westar Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2007, that was filed with the Securities and Exchange Commission.

Directors:

Westar Energy Board of Directors, from left, is composed of John C. Nettels Jr., Michael F. Morrissey, Sandra A.J. Lawrence, Charles Q. Chandler IV, William B. Moore, Arthur B. Krause, Mollie Hale Carter, Jerry B. Farley, B. Anthony Isaac and R.A. Edwards III.

CHARLES Q. CHANDLER IV (54)
Chairman of the Board
Director since 1999
Chairman since 2002
Chairman of the Board, President
and Chief Executive Officer
INTRUST Bank, NA
Wichita, Kansas

MOLLIE HALE CARTER (45)
Director since 2003
Chairman of the Board, President
and Chief Executive Officer
Sunflower Banks, Inc.
Salina, Kansas
Committees: Compensation, Finance

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Director since 2001
Director, President and
Chief Executive Officer
First National Bank
of Hutchinson
Hutchinson, Kansas
Committees: Audit, Nominating and Corporate Governance

JERRY B. FARLEY (61)
Director since 2004
President
Washburn University
Topeka, Kansas
Committees: Audit, Nominating and Corporate Governance

B. ANTHONY ISAAC (54)
Director since 2003
President
LodgeWorks, LP
Wichita, Kansas
Committees: Compensation, Finance

ARTHUR B. KRAUSE (66)
Director since 2003
Executive Vice President and
Chief Financial Officer (Retired)
Sprint Corporation
Naples, Florida
Committees: Audit, Finance

SANDRA A.J. LAWRENCE (50)
Director since 2004
Executive Vice President and
Chief Financial Officer
Children's Mercy Hospital
Kansas City, Missouri
Committees: Compensation, Nominating and Corporate Governance

WILLIAM B. MOORE (55)
Director since 2007
President and Chief Executive Officer
Westar Energy, Inc.
Topeka, Kansas

MICHAEL F. MORRISSEY (65)
Director since 2003
Managing Partner (Retired)
Ernst & Young LLP
Naples, Florida
Committees: Audit, Compensation

JOHN C. NETTELS, JR. (51)
Director since 2000
Partner
Stinson Morrison Hecker LLP
Overland Park, Kansas
Committee: Finance

Officers:

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27 years of service
President and Chief Executive Officer

DOUGLAS R. STERBENZ (44)
10 years of service
Executive Vice President and
Chief Operating Officer

MARK A. RUELLE (46)
15 years of service
Executive Vice President and
Chief Financial Officer

JAMES J. LUDWIG (49)
17 years of service
Executive Vice President,
Public Affairs and Consumer Services

BRUCE AKIN (43)
20 years of service
Vice President, Operations Strategy
and Support

JEFF BEASLEY (49)
30 years of service
Vice President, Corporate Compliance
and Internal Audit

GREG A. GREENWOOD (42)
14 years of service
Vice President, Generation Construction

KELLY B. HARRISON (49)
26 years of service
Vice President, Transmission Operations
and Environmental Services

LARRY D. IRICK (51)
8 years of service
Vice President, General Counsel and
Corporate Secretary

KENNETH C. JOHNSON (54)
6 years of service
Vice President, Generation

MICHAEL LENNEN (62)
1 year of service
Vice President, Regulatory Affairs

PEGGY S. LOYD (50)
29 years of service
Vice President, Customer Care

ANTHONY D. SOMMA (44)
13 years of service
Treasurer

LEE WAGES (59)
30 years of service
Vice President, Controller

CAROLINE A. WILLIAMS (51)
32 years of service
Vice President,
Distribution Power Delivery

Ages and years of service are as of December 31, 2007.

Westar Energy®

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