



Aquila



# 2005 Annual Report



Providing Energy For Better Living.  
**Providing Energy For Better Living.™**

# Letter to Shareholders

---

Dear Aquila Shareholders,

Before I discuss our progress in 2005 and what lies ahead in 2006, let me begin by saying we would not be on today's path to recovery without the dedication and determination of our employees. Even in the midst of all the adversity, the spirit of our employees has continually improved our utility business. In addition, their tireless commitment to customer satisfaction and volunteerism continues to make Aquila a valuable part of our communities.

In every community we serve, during discussions with regulators, legislators and industry peers, we have answered questions about our ability to fix financial problems without harming the 1.3 million customers who reside in the seven states where we provide energy. In fact, our service metrics have steadily improved. In a recent Gallup Poll survey, more than 50 percent of our customers gave Aquila the highest overall service rating possible.

Let me report on our progress and give you a sense of our future.

## Setting Critical Objectives

During 2005, we made decisions that repositioned Aquila as a multi-state natural gas and electric utility company, ready to realize 3 percent to 5 percent growth within our service territories. An analysis of our business indicated the need to expand our infrastructure – generating plants, gas and electric distribution facilities, transmission lines and environmental upgrades – to enable us to serve the increasing energy demands of our customers. To realize this opportunity, we identified six critical objectives that needed to be accomplished:

- 1) Maintain focus on operating an integrated, multi-state utility,
- 2) Consider the sale of selected utilities and remaining non-core assets,
- 3) Significantly reduce debt levels and strengthen our credit profile,
- 4) Gain access to capital markets,

- 5) Improve operational efficiency and lower earnings variability, and
- 6) Work with regulators and legislators to address rate and fuel-cost issues.

## Improving Business Operations

We continue to develop goals based on our core business principles and measures of operational performance, including safety, service reliability, customer service and environmental stewardship. As a gauge, we compare our results to industry standards and historical performance benchmarks. Each year we consistently raise the bar and implement improvements that enable us to exceed expectations. In 2005, 93 percent of the time Aquila's service personnel responded to emergency situations in less than 60 minutes. Our call centers responded to 2.7 million customer calls – an 8 percent increase over previous levels. The average speed of answer for these calls was 28 seconds for 2005. We maintained a work environment with few lost-time injuries, our electric service had minimal service interruptions, and we had no environmental standard violations.

In the second year of using Six Sigma principles, Aquila's Business Process Improvement Initiative delivered efficiency gains and reduced costs across our utility operations. With more than 35 projects completed in 2005, we achieved over \$9 million in recurring annual EBIT improvement, with about \$1.4 million in cost-of-capital savings.

These efforts to improve our utility business are not simply a one-time attempt to capture "low-hanging fruit." We want the thoughtful analysis, implementation, and monitoring tools we have learned to become part of Aquila's culture at all levels. More than 400 employees have received Six Sigma training, and 30 Black Belts lead teams providing education and coaching to the entire organization.

## Accelerating Debt Reduction

Following considerable analysis of Aquila's asset base and in preparation

for future infrastructure investment, in March 2005, we announced a strategy to accelerate debt reduction by divesting some of our utility properties, as well as certain remaining non-core assets associated with the final exit of our merchant trading division.

Decisions to sell are never easy, and the process takes an immense toll on all employees. As we embarked on this effort, the principles that guided our actions were threefold: the purchasers would be solid businesses offering fair prices, they would have utility expertise, and they would be fair to our people.

This strategy resulted in agreements to sell our gas operations in Michigan, Minnesota and Missouri, and our electric operations in Kansas, for a total base purchase price of \$896.7 million. We expect these utility transactions to close by the end of the third quarter of 2006, along with the sales of two Illinois peaking facilities and our communications company, Everest Connections.

## Building Financial Strength

In 2005, we made strides in building additional financial strength. In July 2005, we successfully converted nearly all of the PIES to shares of Aquila common stock, thus reducing our interest expense and improving our debt-to-equity ratio – a key metric monitored by regulators and credit-rating agencies. In addition, we replaced \$300 million of short-term credit facilities with \$330 million of revolving credit agreements that may be renewed on an annual basis, signaling a return to more normal financing for businesses of our type. Overall, Aquila's debt has been reduced from a high of about \$3.6 billion in 2002 to the current level of \$2 billion.

We expect to begin receiving proceeds from our asset sales in April 2006, and believe all transactions will be closed prior to the end of the third quarter. As the dollars come in, we will continue to implement strategies to reduce debt and further improve our credit metrics and balance sheet. It is our expectation that

by the time we efficiently deploy these proceeds, Aquila's debt will be more appropriate for a utility company of our size. This will put us in a better position to enter into discussions with lenders as opportunities for investments in utility infrastructure arise.

### Addressing Rate and Fuel-Cost Issues

We took significant steps in 2005 to mitigate high fuel-cost impacts on behalf of our customers and shareholders by implementing state-by-state hedging programs. This allowed us to prudently manage the risk associated with the volatility of natural gas prices.

Additionally, new legislation passed in the State of Missouri is expected to benefit both customers and shareholders by providing a means for the recovery of fuel and purchased-power costs without going through a general rate case. Until now, Missouri has been one of only three states that had legal prohibitions against a fuel-adjustment mechanism to ensure that customer rates for fuel reflect in a timely manner the market rates that utilities must pay for fuel to generate electricity.

The Missouri Public Service Commission is currently setting guidelines that will govern the new legislation, and it is expected that rate cases filed in 2006, with rates effective in 2007, will utilize this mechanism. We believe that having a clear understanding of the Commission's expectations and a standardized process pertaining to fuel

procurement and recovery will enable electric utilities to better manage their fuel risks, avoid costly disallowances and keep customer rates in line with current market prices.

### Board of Directors

Aquila has benefited from the expertise of its Board members, and this year we welcomed the addition of Nicholas Singer as a director. Singer is a partner at Cyrus Capital Partners, L.P., an investment manager for a number of funds. He replaced John R. Baker, a long-time director and former Aquila vice chairman, who retired after 34 years of service.

We offer our appreciation and thanks to Gerald L. Shaheen, a group vice president of Caterpillar Inc. in Peoria, Ill., who resigned from the Board at the end of 2005. A member of the Board since August 2001, Shaheen had served as chairman of the Audit Committee since May 2002. He was succeeded as chairman of the Audit Committee by Patrick J. Lynch, a member of the Board and the Audit Committee since 2004.

### Looking Forward

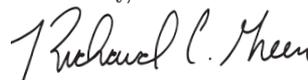
As we move forward into 2006, our asset base will get smaller and so will our organization and my executive leadership team. These decisions continue to be difficult but are necessary to create a stronger company that provides value to our shareholders, a great place to work for our employees and reliable energy to

our customers. This year it is imperative we achieve the following milestones:

- Close the utility and non-core asset sales and effectively transition our people and businesses to the new owners;
- Use the asset sale proceeds to reduce debt and position Aquila to access the capital markets more efficiently;
- Eliminate \$30 million to \$50 million of costs from our remaining business to reflect the appropriate cost structure for a utility of our size;
- Continue to grow and improve our utility operations by expanding economic development initiatives in our service territories, offering additional utility services and introducing new business process improvement initiatives;
- Increase employee engagement through development initiatives that foster collaboration and improve our customer service metrics.

I am confident we will deliver the results outlined above, and I appreciate your support as we continue to gain strength. We will keep working to earn your confidence as Aquila continues to recover.

Sincerely,



Richard C. Green  
Chairman and Chief Executive Officer  
March 2006

### This letter to shareholders contains the following forward-looking statements:

**We expect to complete our pending asset sales by the end of the third quarter of 2006. Some important factors that could cause actual results to differ materially from those anticipated include:**

- Regulatory commissions may refuse to approve certain of our pending divestitures, or it may take longer than expected to obtain the regulatory approvals required to complete the asset sales.
- We or the buyers may not be able to satisfy all of the conditions required to be satisfied in order to complete the pending asset sales.

**We expect to use sale proceeds to reduce debt and improve our credit metrics and balance sheet, which should bring our capitalization**

**structure more in line with a utility company of our size. Some important factors that could cause actual results to differ materially from those anticipated include:**

- We may not be able to retire a sufficient amount of debt and other liabilities with net sale proceeds and, thereby, rationalize our capitalization structure.
- Our inability to pass through fuel, purchased-power and environmental costs to our customers, as well as higher fuel, purchased-power and compliance costs, in general, may impair our ability to rationalize our capitalization structure.

**We expect Missouri electric utilities that file rate cases in 2006, with rates effective in 2007, will benefit from the**

**fuel-adjustment mechanism authorized recently by Missouri legislation. Some important factors that could cause actual results to differ materially from those anticipated include:**

- The Missouri Public Service Commission and its staff may not finalize rules implementing the fuel-adjustment mechanism as soon as anticipated, or at all during 2006.
- Even if the Missouri Public Service Commission approves rules implementing the fuel-adjustment mechanism this year, utilities may not be able to take advantage of the new rules in Missouri electric rate cases filed in 2006.

**We expect to achieve several milestones during 2006, such as positioning our company to access the**

**capital markets more efficiently and eliminating \$30 million to \$50 million of costs from our remaining business. Some important factors that could cause actual results to differ materially from those anticipated include:**

- The capital markets may not be accessible to us, or be accessible on reasonable terms, even if we execute on our debt-reduction plan.
- We may not be able to eliminate the overhead costs in the magnitude described above, and a delay in the anticipated closing date of our pending asset sales would impede our ability to eliminate this magnitude of overhead costs.

# Management and Directors

## Management Team

		Age/Year Joined Company
<b>Richard C. Green</b>	Chairman of the Board, President and Chief Executive Officer	51 / 1976
<b>Keith G. Stamm</b>	Senior Vice President and Chief Operating Officer	45 / 1983
<b>Rick J. Dobson</b>	Senior Vice President and Chief Financial Officer	46 / 1989
<b>Christopher M. Reitz</b>	Senior Vice President, General Counsel and Corporate Secretary	39 / 2000
<b>Jon R. Empson</b>	Senior Vice President, Regulated Operations	60 / 1978
<b>Norma F. Dunn</b>	Senior Vice President, Communications and Stakeholder Outreach	52 / 2005
<b>Leo E. Morton</b>	Senior Vice President and Chief Administrative Officer	60 / 1994
<b>Scott H. Heidtbrink</b>	Vice President, Power Generation and Energy Resources	44 / 1987

## Board of Directors

		Age/Year Joined Company
<b>Richard C. Green</b>	Chairman, President and Chief Executive Officer	51 / 1982
<b>Herman Cain</b>	Chief Independent Director; Chief Executive Officer of T.H.E. New Voice, a leadership consulting company, and former Chairman of the Board of Godfather's Pizza, Inc., Omaha, NE	60 / 1992
<b>Dr. Michael M. Crow</b>	President of Arizona State University, Tempe, AZ	50 / 2003
<b>Irvine O. Hockaday, Jr.</b>	Retired President and Chief Executive Officer of Hallmark Cards, Inc., Kansas City, MO	68 / 1995
<b>Heidi E. Hutter</b>	Managing General Partner, Black Diamond Capital Partners, a merchant bank and advisory company, Austin, TX	47 / 2002
<b>Dr. Stanley O. Ikenberry</b>	Former President of the American Council on Education, Washington, DC	70 / 1993
<b>Patrick J. Lynch</b>	Retired Senior Vice President and Chief Financial Officer, Texaco, Inc., Houston, TX	68 / 2004
<b>Nicholas J. Singer</b>	Senior Partner, Cyrus Capital Partners, L.P.	26 / 2005

## Committees of the Board

*Committee chairmen are underlined.*

### **Executive Committee: Green, Cain and Hockaday.**

Exercises the authority of the Board on matters of an urgent nature that arise when the Board is not in session.

### **Audit Committee: Lynch, Hutter and Singer.**

Retains independent accountants and preapproves their services. Reviews and approves audit plans, accounting policies, financial statements and reporting, and internal audit reports and controls.

### **Business Process Improvement Committee: Crow, Cain and Singer.**

Oversees, monitors, evaluates, and makes recommendations regarding the formation, development, and operation of the company's business process improvement program.

### **Compensation and Benefits Committee: Hockaday, Crow and Ikenberry.**

Evaluates the performance of the chief executive officer and establishes the compensation of the chief executive officer and other senior officers. Establishes and monitors management's administration of the company's retirement and employee benefit plans.

### **Nominating and Corporate Governance Committee: Ikenberry, Cain and Hockaday.**

Identifies, considers and recommends to the Board nominees for director. Develops and recommends to the Board corporate governance principles applicable to Aquila. Oversees the annual evaluation of the Board and its committees.

**UNITED STATES  
SECURITIES AND EXCHANGE COMMISSION  
Washington, D.C. 20549  
FORM 10-K**

(Mark One)

**Annual report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the fiscal year ended December 31, 2005

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: 1-03562

**AQUILA, INC.**

(Exact name of registrant as specified in its charter)

**Delaware**

(State or other jurisdiction of  
incorporation or organization)

**44-0541877**

(I.R.S. Employer  
Identification No.)

**20 West Ninth Street, Kansas City, Missouri 64105**

(Address of principal executive offices)

**Registrant's telephone number, including area code (816) 421-6600**

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

Title of each class	Name of each exchange on which registered
<b>Common Stock, par value \$1.00 per share</b>	<b>New York Stock Exchange</b>
<b>7.875% Quarterly Interest Bonds, due March 1, 2032</b>	<b>New York Stock Exchange</b>
<b>Premium Income Equity Securities, 6.75%, mandatorily convertible to common shares on September 15, 2007</b>	<b>New York Stock Exchange</b>

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

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

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

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

Indicate by check mark 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. See definition of "accelerated filer and large accelerated filer" in Rule 12B-2 of the Exchange Act. (Check one):

Large accelerated filer  Accelerated Filer  Accelerated Filer

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

The aggregate market value of the voting stock held by non-affiliates of the Registrant, based upon the closing sale price of the Common Stock on June 30, 2005 as reported on the New York Stock Exchange, was approximately \$760,002,903. Shares of Common Stock held by each officer and director and by each person who owns 5% or more of the outstanding Common Stock have been excluded in that such persons may be deemed to be affiliates. This determination of affiliate status is not necessarily a conclusive determination for other purposes.

Title	Outstanding at March 1, 2006
<b>Common Stock, par value \$1.00 per share</b>	<b>373,671,736</b>
<b>Documents Incorporated by Reference: Proxy Statement for 2006 Annual Shareholders Meeting</b>	<b>Where Incorporated: Part III</b>

## INDEX

	<u>Page</u>
<b>Part I</b>	
Item 1	Business . . . . . 5
Item 1A	Risk Factors . . . . . 22
Item 1B	Unresolved Staff Comments . . . . . 26
Item 2	Properties . . . . . 26
Item 3	Legal Proceedings . . . . . 27
Item 4	Submission of Matters to a Vote of Security Holders . . . . . 27
<b>Part II</b>	
Item 5	Market for Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities . . . . . 28
Item 6	Selected Financial Data . . . . . 29
Item 7	Management’s Discussion and Analysis of Financial Condition and Results of Operations . . . . . 30
Item 7A	Quantitative and Qualitative Disclosures About Market Risk . . . . . 71
Item 8	Financial Statements and Supplementary Data . . . . . 75
Item 9	Changes in and Disagreements With Accountants on Accounting and Financial Disclosure . . . . . 145
Item 9A	Controls and Procedures . . . . . 145
Item 9B	Other Information . . . . . 145
<b>Part III</b>	
Item 10	Directors and Executive Officers of the Company . . . . . 145
Item 11	Executive Compensation . . . . . 145
Item 12	Security Ownership of Certain Beneficial Owners and Management . . . . . 145
Item 13	Certain Relationships and Related Transactions . . . . . 145
Item 14	Principal Accountant Fees and Services . . . . . 146
<b>Part IV</b>	
Item 15	Exhibits, Financial Statement Schedules . . . . . 147
<b>Index to Exhibits</b> . . . . . 149	
<b>Signatures</b> . . . . . 152	

## **Glossary of Terms and Abbreviations**

APB—Accounting Principles Board.

AFUDC—Allowance for Funds Used During Construction.

Aquila Merchant—Aquila Merchant Services, Inc., our wholly-owned merchant energy subsidiary.

Btu—British Thermal Unit, which is a standard unit for measuring the quantity of heat energy required to raise the temperature of one pound of water by one degree Fahrenheit.

CERCLA (Superfund)—Comprehensive Environmental Response Compensation Liability Act of 1980, which is federal environmental legislation that addresses remediation of contaminated sites.

CFTC—Commodity Futures Trading Commission.

CO<sub>2</sub>—Carbon Dioxide.

Cooling Degree-Days—The summation of positive differences between the mean daily temperatures and the 65° Fahrenheit base. This statistic is useful as an indicator of demand for electricity for summer space cooling for residential and commercial customers.

EBITDA—Earnings before interest, taxes, depreciation and amortization.

EITF—Emerging Issues Task Force, an organization that is designed to assist the FASB in improving financial reporting through the identification, discussion and resolution of financial issues within the framework of existing authoritative literature.

Energy Act—Energy Policy Act of 2005.

EPA—Environmental Protection Agency, a governmental agency of the United States of America.

ERISA—Employee Retirement Income Security Act of 1974, as amended.

Exchange Act—Securities Exchange Act of 1934, as amended.

FASB—Financial Accounting Standards Board, a rulemaking organization that establishes financial accounting and reporting standards in the United States of America.

FERC—Federal Energy Regulatory Commission, a governmental agency of the United States of America that, among other things, regulates interstate transmission and wholesale sales of electricity and gas and related matters.

FIN—FASB Interpretation intended to clarify accounting pronouncements previously issued by the FASB.

Fitch—Fitch Ratings, a leading global rating agency.

FPA—Federal Power Act.

GAAP—Generally Accepted Accounting Principles in the United States of America.

GWh—Gigawatt-hour.

Heat Rate—The measure of efficiency of converting fuel to electricity, expressed as British thermal units (Btu) of fuel per kilowatt-hour. The lower the heat rate, the more efficient the plant.

Heating Degree-Days—The summation of negative differences between the mean daily temperature and the 65° Fahrenheit base. This statistic is useful as an indicator of demand for electricity and natural gas for winter space heating for residential and commercial customers.

KCPL—Kansas City Power & Light Company.

kWh—Kilowatt-hour.

LIBOR—London Inter-Bank Offering Rate.

Mcf—One thousand cubic feet.

MGP—Manufactured Gas Plant.

MMBtu—One Million Btus.

Mmcf—One million cubic feet.

Moody’s—Moody’s Investors Service, Inc., a leading global rating agency.

MW—Megawatt, one thousand kilowatts.

MWh—Megawatt-hour.

NO<sub>x</sub>—Nitrogen oxide.

NSR—New Source Review programs under the federal Clean Air Act.

NYMEX—New York Mercantile Exchange.

NYSE—New York Stock Exchange.

NYSEG—New York State Electric and Gas Corp.

OCI—Other Comprehensive Income (Loss) as defined by GAAP.

PCB—Polychlorinated Biphenyl.

PGA—Purchased Gas Adjustment tariffs, which impact our natural gas utility customers.

PIES—Premium Income Equity Securities, our series of 6.75% mandatorily convertible senior notes.

PUHCA—Public Utility Holding Company Act of 1935, as amended.

RTO—Regional Transmission Organization.

S&P—Standard and Poor’s, a division of The McGraw-Hill Companies, Inc., a leading global rating agency.

SEC—Securities and Exchange Commission, a governmental agency of the United States of America.

SFAS—Statement of Financial Accounting Standards, the accounting and financial reporting rules issued by FASB.

SO<sub>2</sub>—Sulfur dioxide.

## Part I

### Item 1. Business

#### History and Organization

Aquila, Inc. (Aquila or the company, which may be referred to as “we,” “us” or “our”) is primarily an integrated electric and natural gas utility headquartered in Kansas City, Missouri. We began as Missouri Public Service Company in 1917 and reincorporated in Delaware as UtiliCorp United Inc. in 1985. In March 2002, we changed our name to Aquila, Inc. As of December 31, 2005, we had 3,204 employees in the United States. Our business is organized into three business segments: Electric Utilities, Gas Utilities and Merchant Services. Electric Utilities comprises our regulated electric utility operations, Gas Utilities comprises our regulated gas utility operations, and Merchant Services comprises our unregulated energy activities operated by Aquila Merchant. All other operations are included in Corporate and Other, including costs that are not allocated to our operating businesses; our controlling interest in a broadband company operating in Kansas City, Everest Connections, which is “held for sale” and reported in discontinued operations; and our former investments in Australia and the United Kingdom. Substantially all of our revenues are generated by our Electric and Gas Utilities.

We have entered into agreements to sell our Electric Utilities in Kansas and our Gas Utilities in Michigan, Minnesota, and Missouri, which results in these operations being considered “held for sale” and reported as discontinued operations. Excluding discontinued operations, our Electric Utilities include 1,827 MW of generation and 14,723 pole miles of electric transmission and distribution lines, and our Gas Utilities include 516 miles of intrastate gas transmission pipelines and 11,104 miles of gas distribution mains and service lines. Our Electric and Gas Utilities generated revenues from continuing and discontinued operations of \$1,315.8 million and \$816.8 million, respectively, in the year ended December 31, 2005. The continuing and discontinued operations of our Electric and Gas Utilities had total assets of \$2.6 billion and \$0.9 billion, respectively, at December 31, 2005.

Until recently, our operations also included significant international utility investments and Merchant Services was a much larger component of our business. In 2002, we began to reposition our business to concentrate on our Electric and Gas Utilities and reduce our financial obligations. As part of that repositioning, we sold all of our international investments and a substantial portion of our Merchant Services assets. Additionally, we wound down most of our Merchant Services energy trading portfolio. Our remaining Merchant Services group principally owns, operates, and contractually controls non-regulated power generation assets in the United States. We have entered into agreements to sell our Raccoon Creek and Goose Creek merchant power plants, which results in these operations being considered “held for sale” and reported as discontinued operations. See Management’s Discussion and Analysis for further discussion of our strategic and financial repositioning.

#### Access to Company Information and Officer Certifications

The reports we file with the SEC are available free of charge at our website *www.aquila.com* as soon as reasonably practicable after they are filed. In addition, the charters of our Audit, Nominating and Corporate Governance, and Compensation and Benefits Committees are located on our website along with our Code of Business Conduct, Code of Ethics for Senior Financial Officers, and Corporate Governance Principles. The information contained on our website is not part of this document.

Our Chief Executive Officer and Chief Financial Officer have filed with the SEC, as exhibits to our Annual Report on Form 10-K, the certifications required by Section 302 of the Sarbanes Oxley Act regarding the quality of our public disclosure.

Our Chief Executive Officer certified to the NYSE following our 2005 annual shareholder meeting that he was not aware of violations by us of the NYSE corporate governance listing standards.

Each of the foregoing documents is available in print to any of our shareholders upon request by writing to Aquila, Inc. 20 West Ninth Street, Kansas City, Missouri 64105: Attention: Investor Relations.

## **Business Group Summary**

Segment information for the three years ended December 31, 2005 is included in Note 19 to the Consolidated Financial Statements.

### **I. Electric and Gas Utilities**

Electric Utilities generates, transmits and distributes electricity to 391,406 customers in our continuing operations in Colorado and Missouri and to 68,920 customers in our discontinued operations in Kansas. Our electric generating facilities and purchased power contracts supply electricity principally to our own distribution systems. Additionally, we sell excess power to other utilities and marketing companies. Approximately 65% of our electric customers are located in Missouri. Gas Utilities distributes natural gas to 508,543 customers in our continuing operations in Colorado, Iowa, Kansas, and Nebraska and to 414,556 customers in our discontinued operations in Michigan, Minnesota, and Missouri. Approximately 59% of our continuing utility operations, based on the book value of our regulated assets, are located in Missouri.

### **Electric Utilities**

As of December 31, 2005, our owned or leased interests in electric generation plants were as follows:

<b>Unit</b>	<b>Location</b>	<b>Year Installed</b>	<b>Unit Capability (MW)</b>	<b>Fuel</b>
<b>Missouri:</b>				
Sibley #1-3	Sibley	1960, 1962, 1969	502	Coal
Ralph Green #3	Pleasant Hill	1981	69	Gas
Nevada	Nevada	1974	20	Oil
Greenwood #1-4	Greenwood	1975-1979	241	Gas/Oil
KCI #1-2	Kansas City	1970	31	Gas
Lake Road #1, 3	St. Joseph	1951, 1962	30	Gas/Oil
Lake Road #2, 4	St. Joseph	1957, 1967	122	Coal/Gas
Lake Road #5	St. Joseph	1974	62	Gas/Oil
Lake Road #6-7	St. Joseph	1989, 1990	40	Oil
Iatan	Iatan	1980	118	Coal
Jeffrey #1-3	St. Mary's	1978, 1980, 1983	175	Coal
South Harper #1-3	Peculiar	2005	315	Gas
<b>Colorado:</b>				
W.N. Clark #1-2	Canon City	1955, 1959	43	Coal
Pueblo #6	Pueblo	1949	20	Gas
Pueblo #5	Pueblo	1941, 2001	9	Gas
AIP Diesel	Pueblo	2001	10	Oil
Diesel #1-5	Pueblo	1964	10	Oil
Diesel #1-5	Rocky Ford	1964	10	Oil
<b>Total continuing operations</b>			1,827	
<b>Kansas:</b>				
Judson Large #4	Dodge City	1969	142	Gas
Arthur Mullergren #3	Great Bend	1963	96	Gas
Cimarron River #1-2	Liberal	1963, 1967	72	Gas
Clifton #1-2	Clifton	1974	71	Gas/Oil
Jeffrey #1-3	St. Mary's	1978, 1980, 1983	175	Coal
<b>Total discontinued operations</b>			556	
<b>Total capability</b>			2,383	

The following table shows Electric Utilities' overall fuel mix and generation capability for 2005:

<b>Fuel Source—In Megawatts (MW)</b>	<b>Continuing</b>	<b>Discontinued</b>
Coal	838	175
Gas	444	310
Oil	90	—
Coal and gas	122	—
Gas and oil	333	71
<b>Total generation capability</b>	1,827	556

At December 31, 2005, Electric Utilities owned or leased the electric transmission and distribution lines shown below:

<b>Line Type—In Miles</b>	<b>Continuing</b>	<b>Discontinued</b>
Electric transmission	2,141	2,500
Electric distribution	12,582	3,835

The following table summarizes sales, volumes and customers for our Electric Utilities business:

	<b>2005</b>	<b>2004</b>	<b>2003</b>
<b>Sales (in millions)</b>			
Residential	\$ 303.8	\$ 263.3	\$ 250.6
Commercial	190.0	173.0	158.1
Industrial	91.6	84.2	75.7
Other	98.7	73.6	59.7
Total continuing electric operations	684.1	594.1	544.1
Total discontinued electric operations	190.9	165.2	153.4
<b>Total</b>	<b>\$ 875.0</b>	<b>\$ 759.3</b>	<b>\$ 697.5</b>

<b>Volumes Generated and Purchased (GWh)</b>			
Coal	5,248	5,275	5,580
Gas	91	2	38
Coal/Gas	611	686	641
Gas/Oil	61	21	99
Total generated	6,011	5,984	6,358
Purchased	5,860	4,630	3,828
Total generated and purchased	11,871	10,614	10,186
Company use	(15)	(14)	(13)
Line loss	(691)	(668)	(697)
Total continuing electric operations	11,165	9,932	9,476
Total discontinued electric operations	2,311	2,431	2,357
<b>Total</b>	<b>13,476</b>	<b>12,363</b>	<b>11,833</b>

<b>Volumes (GWh)</b>			
Residential	3,961	3,603	3,637
Commercial	3,050	2,893	2,840
Industrial	1,870	1,838	1,775
Other	2,284	1,598	1,224
Total continuing electric operations	11,165	9,932	9,476
Total discontinued electric operations	2,311	2,431	2,357
<b>Total</b>	<b>13,476</b>	<b>12,363</b>	<b>11,833</b>

	2005	2004	2003
<b>Customers at Year End</b>			
Residential	341,589	335,003	328,837
Commercial	46,029	45,084	44,900
Industrial	372	383	383
Other	3,416	3,359	3,397
Total continuing electric operations	391,406	383,829	377,517
Total discontinued electric operations	68,920	68,817	68,373
<b>Total</b>	<b>460,326</b>	<b>452,646</b>	<b>445,890</b>

<b>Continuing Operations Statistics—</b>			
<b>Average annual volume per residential customer (kWh)</b>	11,597	10,755	11,060
<b>Average annual sales per residential customer</b>	\$ 889	\$ 786	\$ 762
<b>Average residential sales per kWh (cents)</b>	7.67	7.31	6.89
<b>Units of Fuel Used in Generation</b>			
Coal—thousand tons	3,569	3,582	3,677
Natural gas—Mmcf	2,120	782	1,903
<b>Average Cost of Fuel</b>			
Coal—per ton	\$ 24.97	\$ 23.34	\$ 21.17
Natural gas—per Mcf	9.85	6.97	4.82

### **Gas Utilities**

At December 31, 2005, Gas Utilities owned the gas transmission and distribution lines shown below:

<b>Line Type—In Miles</b>	<b>Continuing</b>	<b>Discontinued</b>
Intrastate gas transmission pipelines	516	300
Gas distribution mains and service lines	11,104	8,550

The following table summarizes sales, volumes and customers for our Gas Utilities business:

	2005	2004	2003
<b>Sales (in millions)</b>			
Residential	\$ 400.7	\$ 334.6	\$ 314.5
Commercial	156.7	124.5	114.8
Industrial	27.3	25.0	19.7
Other	21.8	22.4	24.9
Total continuing gas operations	606.5	506.5	473.9
Total discontinued gas operations	614.2	525.5	495.6
<b>Total</b>	<b>\$1,220.7</b>	<b>\$1,032.0</b>	<b>\$ 969.5</b>

	<b>2005</b>	<b>2004</b>	<b>2003</b>
<b>Volumes (Mcf)</b>			
Residential	34,922	34,331	37,919
Commercial	14,886	14,230	14,850
Industrial	3,399	3,789	3,248
Transportation	42,465	41,200	44,493
Other	115	141	169
Total continuing gas operations	95,787	93,691	100,679
Total discontinued gas operations	123,136	121,285	127,316
<b>Total</b>	<b>218,923</b>	<b>214,976</b>	<b>227,995</b>

<b>Customers at Year End</b>			
Residential	456,592	448,889	441,263
Commercial	43,213	42,921	42,012
Industrial	1,699	1,691	1,556
Other	7,039	7,306	8,166
Total continuing gas operations	508,543	500,807	492,997
Total discontinued gas operations	414,556	409,309	407,780
<b>Total</b>	<b>923,099</b>	<b>910,116</b>	<b>900,777</b>

### ***Seasonal Variations of Business***

Our electric and gas utility businesses are weather-sensitive. We have both summer- and winter-peaking network assets to reduce dependence on a single peak season. The table below shows normal utility peak seasons.

<b>Operations</b>	<b>Peak</b>
Gas Utilities	November through March
Electric Utilities	July and August

### ***Competition***

We currently have limited competition for the retail distribution of electricity and natural gas in our service areas. While various restructuring and competitive initiatives have been discussed in the states in which our utilities operate, only Michigan has adopted rules for retail competition for residential customers. Residential retail gas customers in Michigan were able to choose their service provider beginning in June 2002, but no competitors have emerged. Although we face competition from independent marketers for the sale of natural gas to our industrial and commercial customers, in instances where independent marketers displace us as the seller of natural gas, we still collect a distribution charge. PGA clauses in place in all states in which we operate gas utilities make the cost of gas sold a pass-through item for utilities.

### ***Regulation and Rates***

#### *State Regulation*

Our utility operations are subject to the jurisdiction of the public service commissions in the states in which they operate. The commissions oversee services and facilities, rates and charges, accounting, valuation of property, depreciation rates and various other matters. Certain

commissions also have jurisdiction over the creation of liens on property located in their state to secure bonds or other securities.

Our regulated businesses produce, purchase and distribute power in three states and purchase and distribute natural gas in seven states. All of our Gas Utilities have PGA provisions that allow them to pass the prudently-incurred cost of gas through to the customer. To the extent that gas prices are higher or lower than amounts in our current billing rates, adjustments are made on a periodic basis to “true-up” billed amounts to match the actual cost we incurred. These adjustments are subject to periodic prudence reviews by the state utility commissions. The Kansas Commission also allows us to recover the gas cost portion of uncollectible accounts through the PGA and has established a weather normalization tariff which provides a pass through mechanism for weather margin variability from the level used to establish base rates to be paid by the customer.

In our continuing regulated electric business in 2005, we generated approximately 51% of the power that we sold and we purchased the remaining 49% through long-term contracts or in the open market. The regulatory provisions for recovering power costs vary by state. In Kansas and Colorado, we have Energy Cost Adjustment (ECA) clauses which serve a purpose similar to the PGAs for our gas utilities. To the extent that our fuel and purchased power energy costs vary from the energy cost built into our tariffs, the difference is passed through to the customer. In Missouri, we currently do not have the ability to adjust the rates we charge for electric service to offset all or part of any increase or decrease in prices we pay for natural gas, coal or other fuel we use in generating electricity (i.e., a fuel adjustment mechanism). As a result, our electric earnings can fluctuate more in Missouri than in our other electric rate jurisdictions. As described more fully below, the Missouri Commission approved a settlement agreement in April 2004 for our electric operations that established our right to recover costs up to \$13.98/Mwh in our St. Joseph Light & Power operations and \$19.71/Mwh in our Missouri Public Service operations for a two-year period. If our actual costs were higher than those allowed costs, we could not recover the excess costs through rates. If our actual costs were less than those allowed costs, we would refund the difference to our customers, except to the extent actual costs were below \$12.64/Mwh for our St. Joseph Light & Power operations and \$16.65/Mwh for our Missouri Public Service operations. Since the rate increase went into effect, our actual costs exceeded the allowed costs for our Missouri Public Service operations. However, in connection with our settlement of the Missouri electric rate case in February 2006, we agreed to refund \$1.0 million to our St. Joseph Light & Power customers and terminate our interim energy charge when new base rates become effective on March 1, 2006.

On July 14, 2005, the governor of the State of Missouri signed into law new legislation establishing a means for recovering prudently incurred fuel and purchased power costs without going through a general rate case. This legislation, which also permits the recovery of government-mandated environmental investments, must first be implemented through the issuance of rules by the Missouri Commission and the initial filing of fuel and environmental tariffs must be made in connection with a general rate proceeding. The Missouri Commission has not established the rules as of the conclusion of our most recent rate case in February 2006. We expect these provisions to be considered in our next electric rate case, which we have agreed in our 2006 rate case settlement not to file with the Missouri Commission before July 2006. We cannot estimate with certainty the impact that implementing these provisions may have on our financial results and financial condition.

On May 7, 2003, the Kansas Commission issued an order in connection with its investigation into the affiliated transactions between our regulated utilities and our other businesses. On June 26, 2003, the Kansas Commission modified that order. The May 7, 2003 and June 26, 2003

orders are filed as exhibits to our 2003 Annual Report on Form 10-K. Among other things, the orders provide that without the approval of the Kansas Commission, we may not:

- pledge for the benefit of our current and prospective lenders any regulated utility assets presently devoted to serving Kansas retail customers;
- invest any money in new non-utility businesses or invest in any existing business except in the ordinary course of business or to fulfill an existing financial, contractual or operational obligation;
- incur any new or modify any existing indebtedness other than routine, short-term borrowings incurred in the ordinary course of business for working capital needs;
- pay any dividends; or
- enter into any contract or agreement that: (1) alienates, conveys or creates an interest in our assets (e.g., through issuing stock or debt or arranging other securitization), including any agreement to modify an existing obligation to alienate, convey or create an interest in our assets, or (2) relates to products or services not required for the provision of continuing utility operations.

The rates that we are allowed to charge for our services are determined by state public service or utility commissions. Decisions are influenced by many factors, including the cost of providing service, capital expenditures, the prudence of our costs, views about appropriate rates of return, the rates of other utilities, general economic conditions and the political environment.

The following summarizes our recent rate case activity:

<i>(In millions)</i>	<b>Type of Service</b>	<b>Date Requested</b>	<b>Date Effective</b>	<b>Amount Requested</b>	<b>Amount Approved</b>
Nebraska (1)	Gas	6/2003	1/2004	\$ 9.9	\$ 6.2
Missouri (2)	Electric	7/2003	4/2004	79.6	36.2
Missouri (2)	Steam	7/2003	4/2004	1.3	1.3
Missouri (3)	Gas	8/2003	5 & 8/2004	6.4	3.4
Colorado (4)	Electric	12/2003	9/2004	11.4	8.2
Kansas (5)	Electric	6/2004	4/2005	16.4	8.0
Kansas (6)	Gas	11/2004	6/2005	6.2	2.7
Iowa (7)	Gas	5/2005	4/2006	4.1	2.9
Missouri (8)	Electric	5/2005	3/2006	78.6	44.8
Missouri (8)	Steam	5/2005	3/2006	5.0	4.5

- (1) We collected interim rates in Nebraska beginning in October 2003 based on an interim rate increase of \$9.9 million. In April 2004, we refunded the difference between the interim rate increase implemented in October 2003 and the final settlement amount to our Nebraska customers.
- (2) The Missouri electric settlement included a two-year interim energy charge that allowed the company to recover variable generation and purchased power costs up to a specified amount per Mwh specific to each Missouri regulatory jurisdiction. The interim energy charge rate per unit sold is \$13.98/Mwh for our St. Joseph Light & Power operations and \$19.71/Mwh for our Missouri Public Service operations. If the amounts collected under the interim energy charge exceeded our average cost incurred for the two-year period, we would refund the excess to the customers, with interest. This fuel and purchased power cost recovery mechanism represents \$18.5 million of the \$36.2 million 2004 rate increase.

- (3) The Missouri gas settlement became effective for our Missouri Public Service operations in May 2004 and for our St. Joseph Light & Power operations in August 2004.
- (4) The Colorado electric settlement included the modification of the ECA to provide for the recovery from customers of 100% of the variability of energy costs, an increase from 75%.
- (5) In connection with the settlement, the ECA was modified to allow the pass through of SO<sub>2</sub> allowance costs to customers.
- (6) The Kansas gas settlement also included \$244,000 per year for three years for a pipe replacement program.
- (7) Under Iowa regulations, we instituted interim rates, subject to refund, totaling approximately \$1.7 million in May 2005. On March 1, 2006, the Iowa Utilities Board issued an order approving a \$2.9 million rate increase, including recovery of rate case costs. The order denied a settlement provision that would have established a recovery mechanism for investments in distribution system integrity. Final rates are expected to be effective in April 2006.
- (8) The Missouri electric settlement terminated the interim energy charge established in our 2003 rate case filing and required a \$1.0 million refund to our St. Joseph Light & Power customers as part of the termination. The settlement also established the value of our South Harper peaking capacity at approximately \$140 million, resulting in an additional \$4.4 million impairment of the plant's turbines. See Note 5 to the Consolidated Financial Statements for further discussion. The settlement was approved by the Missouri Commission on February 23, 2006, and the new rates became effective on March 1, 2006. In addition, in February 2006, we settled the Missouri steam rate case for a \$4.5 million rate increase. This settlement includes a provision for sharing 80% of fuel cost variability from the established base fuel rates. It was approved by the Missouri Commission in February 2006 and the new rates became effective on March 6, 2006.

### *Federal Regulation*

Under the FPA, our wholesale transmission and sale of electricity in interstate commerce and our generation facilities are subject to the jurisdiction of the FERC. That jurisdiction extends to, among other things, rates and charges in connection with such transmission and sale, the issuance of stock and long- and short-term debt, the sale, lease or other disposition of such facilities, and accounting matters.

In December 1999, FERC issued Order 2000 that established the structure of an RTO. The RTO characteristics were independence, scope and configuration, operational authority, and short-term reliability. An RTO has the responsibility to provide tariff administration, regional planning, and scheduling functions, as well as monitor and coordinate the regional grid. Order 2000 strongly encouraged investor-owned utilities to join a FERC approved RTO. We have FERC jurisdictional transmission facilities in Colorado, Kansas, and Missouri.

In Colorado, the only available RTO, WestConnect, has not yet received approval by the FERC. The signatories to the WestConnect RTO include utilities in Arizona, New Mexico, Nevada and Colorado. We will continue to monitor the status of WestConnect.

The 2000 FERC approval of the merger between St. Joseph Light & Power and Aquila included a stipulation to file a plan to join an RTO. At that time, the only FERC approved RTO in the midwest was the Midwest ISO (MISO). Thus, we informed the FERC that we planned to join the MISO for both our Kansas and Missouri facilities subject to obtaining the necessary approvals.

With respect to our Missouri facilities, we submitted to both the FERC and the Missouri Commission an application to join MISO and transfer operational control of our transmission system to MISO in 2001. The FERC application was approved. However, the application to the Missouri Commission was dismissed in early 2002 when the MISO footprint was modified and AmerenUE was no longer a participant. We were relying upon the AmerenUE interconnections to provide the electric connectivity to the MISO footprint. Upon further evolution of the MISO footprint, in June 2003, we submitted another application to the Missouri Commission to join and transfer operational control to MISO. In response to that application, the Missouri Commission asked for additional cost-benefit information from us and MISO. The Missouri Commission dismissed the application pending completion of the additional cost-benefit studies. These studies are being completed and we expect to submit another application in 2006 with the Missouri Commission. At this time, we expect to ultimately participate in an RTO with our Missouri facilities and do not expect a significant impact to our financial statements upon participation.

In Kansas, we submitted an application to both the FERC and the Kansas Commission and were approved to join MISO and transfer operational control of its transmission system in 2001. However, we did not transfer operational control to MISO for our Kansas facilities because we were relying upon our Missouri facilities to provide the electric connectivity to the MISO footprint. In February 2005, the Kansas Commission rescinded the 2001 approval and suggested that we join the Southwest Power Pool (SPP) RTO for our Kansas facilities. The SPP RTO was granted RTO status by FERC on October 1, 2004. We submitted an application to join the SPP RTO in August 2005 along with the other FERC jurisdictional utilities in Kansas. The Kansas Commission order is expected in 2006. We do not expect this order to have a significant impact on our financial statements.

In November 2003, the FERC issued Order 2004 adopting new standards of conduct for transmission-owning utilities. Under the order, a transmission-owning utility must separate its transmission function from its marketing function and from the operations of its affiliates engaged in energy-related activities. Also, every transmission-owning utility must treat all of its transmission customers, whether affiliated or unaffiliated, on a non-discriminatory basis. The new standards became effective on June 1, 2004, and we have modified our operations to comply with the order.

In August 2005, President Bush signed into law the Energy Act. The Energy Act repeals PUHCA, effective as of February 8, 2006, and gives the FERC access to books and records of holding companies and other affiliate companies within a holding company system as the FERC determines it is necessary for the protection of utility customers. The Energy Act also authorizes state regulatory commissions to obtain access to the books and records of holding companies, as well as their affiliates, if access to the books and records is necessary for the effective discharge of the FERC's responsibilities. We do not expect the Energy Act to have a material impact on our operations, as we were not a public utility holding company under PUHCA and we were otherwise subject to extensive "books and records" review by various state and federal regulatory authorities previously.

## ***Environmental Matters***

### *General*

We are subject to a number of federal, state and local requirements relating to:

- the protection of the environment; and
- the safety and health of personnel and the public.

These requirements relate to a broad range of our activities, including:

- the protection of air and water quality;
- the identification, generation, storage, handling, transportation, disposal, record-keeping, labeling, reporting of, and emergency response in connection with hazardous and toxic materials and wastes, including asbestos;
- the protection of plant and animal species and minimization of noise emissions; and
- safety and health standards, practices and procedures that apply to the workplace and to the operation of our facilities.

#### *Water Issues*

The Clean Water Act controls water discharge and intake requirements and generally prohibits the discharge of any pollutants, including heat, into any body of surface water, except in compliance with a discharge permit issued by a state environmental regulatory agency or the EPA.

#### *316(b) Fish Impingement Requirements*

In July 2004, the EPA issued new rules requiring power plants with cooling water intake structures to undertake studies and implement technologies to minimize fish kills resulting from water withdrawal. We have two owned power plants that are affected by these rules. We are currently completing the required studies and working with state and federal agencies involved with the Missouri River regulations to determine compliance options and benefits to Missouri River fish populations.

#### *Missouri River Levels*

Recent attempts have been made to address items such as drought conditions, endangered species, navigation, and recreational interests along the course of the Missouri River through litigation and the revision of plans that manage the level of water flow. The U.S. Army Corps of Engineers has proposed changes for the management of the Missouri River that may, in coming years, lower water levels. Reduced river levels can impact the net capacity of generating facilities along the Missouri River, which may in turn have a material impact on utility operations in the future.

#### *Air Emissions*

Our facilities are subject to the Clean Air Act and many state and local laws and regulations relating to the protection of air quality. These laws and regulations cover, among other pollutants, those contributing to the formation of ground-level ozone, carbon monoxide, SO<sub>2</sub>, NO<sub>x</sub> and particulate matter. In addition, CO<sub>2</sub> is also included as a potential emission that may be regulated. Fossil-fueled power generating facilities emit each of the foregoing pollutants and, accordingly, are subject to substantial regulation and enforcement oversight by various governmental agencies.

#### *Clean Air Act*

Title IV of the Clean Air Act (CAA) created an SO<sub>2</sub> allowance trading program as part of the federal acid rain program. Each allowance gives the owner the right to emit one ton of SO<sub>2</sub>. At the end of each year, each emitting unit must have enough allowances to cover its emissions for that year. Allowances may be traded so that affected units that expect to emit more SO<sub>2</sub> than their allowances may purchase allowances from other affected units that expect to emit less than

their allocated allowances. The allowance allocation is based on historical operating data. Our facilities emit SO<sub>2</sub> in excess of their allocated allowances. Currently, we purchase additional allowances to stay in compliance. Allowance prices have more than doubled in price during 2005 and we are continuing to evaluate the cost of purchasing allowances versus adding pollution control equipment.

#### Multi-pollutant regulations

Approximately 53% of our continuing operations generating capacity is coal-fired. The EPA has issued the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR) regulations with respect to SO<sub>2</sub>, NO<sub>x</sub> and mercury emissions from coal-fired power plants. These new rules would require significant reductions in these emissions from our power plants in phases, beginning as early as 2009. The rules are being challenged in the courts. We are completing a study to determine the best options for compliance with CAIR and CAMR and participating in state work groups that will adopt the final Federal regulations. Federal multi-pollutant legislation is also being considered that would require reductions similar to the EPA rules and some that could add greenhouse gas emission requirements. We anticipate additional capital costs to comply with the CAIR and CAMR rules.

#### New Source Review

The EPA has been conducting enforcement initiatives nationwide to determine whether certain activities conducted at electric generating facilities were subject to its NSR requirements under the CAA. The EPA is interpreting the CAA to require coal-fired power plants to update emission controls at the time of major maintenance or capital activity. Several utility companies have entered into settlement agreements with the EPA that resulted in fines and commitments to install the best available pollution controls at facilities alleged to have violated the EPA's NSR requirements.

In January 2004, Westar Energy, Inc. received a notification from the EPA that it had violated the EPA's NSR requirements and Kansas environmental regulations by making modifications to the Jeffrey Energy Center without obtaining the proper permits. The Jeffrey Energy Center is a large coal-fired power plant located in Kansas that is 84% owned by Westar and operated exclusively by Westar. We have a 16% interest in the Jeffrey Energy Center and are generally responsible for this portion of its operating costs and capital expenditures. The electric generation plants we own or lease are described in the table at Item 1, page 7. At this time, no settlement has been reached with the EPA, however, it is possible that Westar could be subject to an enforcement action by the EPA and be required to make significant capital expenditures to install additional pollution controls at the Jeffrey Energy Center. Irrespective of the NSR case, the recent high cost of SO<sub>2</sub> allowances may make it economical to install SO<sub>2</sub> technology. In either case, we could potentially be responsible for up to 16% of those costs, including the 8% lease interest held by our Kansas electric utility which is included in discontinued operations.

On January 31, 2006, KCPL was issued an air permit for Iatan 2 that included additional air pollution control equipment for Iatan 1. As an 18% owner of Iatan 1, we expect to be responsible for 18% of the costs of the additional air pollution control equipment for Iatan 1.

Our capital expenditure budgets include \$73.4 million over the next three years for these types of environmental improvements. These estimates are subject to change based upon the timing and extent of the upgrades.

## *Global Climate Change*

We utilize a diversified energy portfolio that includes a fuel mix of coal, natural gas, biomass, wind, and nuclear sources. Of these fuel mixes, coal-fired power plants are the most significant sources of CO<sub>2</sub> emissions. We believe that it is possible that greenhouse gases may be regulated within the next five years. There are no specifics on how greenhouse gases will be regulated but, any mandated federal greenhouse gas reductions or caps on CO<sub>2</sub> emissions could have a material impact.

We currently have a multi-disciplinary team taking a comprehensive review of all our greenhouse gas impacts. We are quantifying our major sources of greenhouse gas emissions and plan to incorporate potential greenhouse gas impacts into our decision making process. We also plan to meet with regulators to discuss future impacts that greenhouse gas legislative proposals may have on our operations.

## *Solid Waste*

Various materials used at our facilities are subject to disposal regulations. Our coal facilities generate ash that is sent to a permitted landfill or is utilized either in roofing material, road construction or as flowable fill. The useful life of the permitted landfill at our Sibley location is set to expire in 2006. Therefore, we have begun permitting of a new landfill for this waste disposal and beneficial utilization of additional fly ash. We estimate that we will incur approximately \$3 million of capital expenditures in 2006 to close the current landfill and open the new landfill.

## *Past Operations*

Some federal and state laws authorize the EPA and other agencies to issue orders compelling potentially responsible parties to clean up sites that are determined to present an actual or potential threat to human health or the environment. We are named as a potentially responsible party at two disposal sites for PCBs. In addition, we retain some environmental liability for several operations and investments that we no longer own.

We also own or have acquired liabilities from companies that once owned or operated former MGP sites, which are subject to the supervision of the EPA and various state environmental agencies.

As of December 31, 2005, we estimate probable costs of future investigation and remediation on our identified MGP sites, PCB sites and retained liabilities to be \$8.2 million, of which \$5.4 million relates to sites which will be assumed by the buyers of our Michigan and Missouri gas utilities. This estimate was based upon a comprehensive review of the potential costs associated with conducting investigative and remedial actions at our identified sites, as well as the likelihood of whether such actions will be necessary. There are also additional costs that we consider to be less likely but still "reasonably possible" to be incurred at these sites. Based upon the results of studies at these sites and our knowledge and review of potential remedial actions, it is reasonably possible that these additional costs could exceed our estimate by approximately \$13.0 million, of which \$8.8 million relates to sites which will be assumed by the buyers of our Michigan and Missouri gas utilities. This estimate could change materially after further investigation. It could also be affected by the actions of environmental agencies and the financial viability of other responsible parties.

We have received favorable rate orders that enable us to recover environmental cleanup costs in certain jurisdictions. In other jurisdictions, there are favorable regulatory precedents for recovery of these costs. We are also pursuing recovery from insurance carriers and other potentially responsible parties.

## II. Merchant Services

Merchant Services consists principally of our interests in gas-fired merchant power plants and our remaining wholesale energy trading business. Our merchant power plants do not have dedicated customers and are designed to operate only during periods of peak demand in the geographic area in which the plant is located.

The table below shows information about our Merchant Services power plants as of December 31, 2005:

Plant & Location	Location	Type of Investment	Capacity (MW)	Heat Rates	Date in Service
Elwood Energy L.L.C.	Illinois	Toll Contracts	609	10.7	July 2001
Crossroads Energy Center	Mississippi	Contractually Controlled	340	11.9	September 2002
Raccoon Creek Energy Center (a)	Illinois	Owned	340	11.9	November 2002
Goose Creek Energy Center (a)	Illinois	Owned	510	12.0	June 2003
<b>Total Capacity (MW)</b>			<b>1,799</b>		

(a) On December 16, 2005, two of our subsidiaries entered into agreements to sell our Raccoon Creek power plant and Goose Creek power plant to AmerenUE for approximately \$70 million and \$105 million, respectively. These plants have been reclassified to discontinued operations. The sale is expected to be completed in the first half of 2006.

During the summer of 2005, we sold capacity and energy off the three owned or contractually controlled merchant peaking facilities contributing \$8.9 million of gross profit. These plants did not generate enough profit to cover their annual investment carrying cost and operating and maintenance costs. In addition, we make annual capacity payments of approximately \$37.3 million on our Elwood tolling contracts through 2017.

Although we have exited the wholesale energy trading business, in the late 1990s and early 2000s we were one of the largest marketers and traders of wholesale natural gas, electricity and other commodities in North America and Western Europe. We stopped wholesale energy trading during the third quarter of 2002, and subsequent activity has focused on limiting our credit risk to counterparties and liquidating our trading positions. However, we still have certain contracts that remain in the trading portfolio because we were unable to liquidate or terminate them under economically feasible terms. Most, but not all, of our positions have been hedged to limit our exposure to price movements, and these contracts will continue to be our assets and liabilities until the contracts are settled or assigned.

### **Competition**

Our merchant power plants compete with other non-utility generators, regulated utilities, unregulated subsidiaries of regulated utilities, and other energy service companies in the development and operation of energy-producing projects. There is an oversupply of power in the geographic areas in which our merchant power generation plants are located, resulting in strong price competition for electric power. Often our marginal cost of producing power exceeds the marginal costs of other generators or normal market prices. Our merchant power plants, which are peaking plants, are generally dependent on outages and transmission difficulties occurring at generation facilities and distribution networks of others or short-term spikes in demand for power resulting from extreme weather. Those events, if they occur, can create short-term opportunities for our merchant power plants to produce and sell power at very favorable prices. Although we continue to work in the marketplace to mitigate our costs, if such events do not occur, or the spread between the cost of gas and the price of power does not increase, we will incur significant losses related to these plants, including the capacity payments on our Elwood tolling contracts and continued operating and maintenance costs on our Crossroads power plant.

## **Regulation**

### *Natural Gas Marketing Regulation*

Our natural gas purchases and sales are generally not regulated by the FERC or other regulatory authorities. However, we depend on natural gas transportation and storage services offered by companies that are regulated by the FERC and state regulatory authorities to transport natural gas we purchase or sell.

### *Power Generation and Marketing Regulation*

The FPA and rules of the FERC regulate the generation and transmission of electricity in interstate commerce and sales for resale of electric power. As a result, portions of our operations are under the jurisdiction of the FPA and the FERC.

The FPA grants the FERC exclusive rate-making jurisdiction over wholesale sales of electricity in interstate commerce. The FPA provides the FERC with ongoing as well as initial jurisdiction, enabling the FERC to modify previously approved rates. Such rates may be based on a cost-of-service approach or through competitive bidding or negotiation on a market basis. Independent power projects must obtain FERC acceptance of their rates under FPA Section 205. Our owned and contractually controlled merchant power plants have been granted market-based rate authority and comply with the FPA requirements governing the approval of wholesale rates.

## Our Executive Team

<u>Name</u>	<u>Age at December 31, 2005</u>	<u>Position</u>
Richard C. Green (Rick) . . . . .	51	President, Chief Executive Officer and Chairman
Keith G. Stamm . . . . .	45	Senior Vice President and Chief Operating Officer
Rick J. Dobson . . . . .	46	Senior Vice President and Chief Financial Officer
Leo E. Morton . . . . .	60	Senior Vice President and Chief Administrative Officer
Christopher M. Reitz (Chris) . . .	39	Senior Vice President, General Counsel and Corporate Secretary
Norma F. Dunn . . . . .	52	Senior Vice President, Communications and Stakeholder Outreach
Jon R. Empson . . . . .	60	Senior Vice President, Regulated Operations
Scott H. Heidtbrink . . . . .	44	Vice President, Power Generation and Energy Resources

### **Richard C. Green (B.S., Business, Southern Methodist University)**

Rick joined our company in 1976 and held various financial and operating positions between 1976 and 1982. In 1982, he was appointed Executive Vice President at Missouri Public Service Company, the predecessor to Aquila, Inc. Rick served as President and Chief Executive Officer from 1985 to 1996 and has been Chairman of the Board of the Company since 1989. He was also Chief Executive Officer from 1996 through 2001. In October 2002, Rick resumed the roles of President and Chief Executive Officer.

### **Keith G. Stamm (B.S., Mechanical Engineering, University of Missouri at Columbia; M.B.A., Rockhurst University)**

Keith joined our company in 1983 as a staff engineer at the Sibley Generating Station. Between 1985 and 1995, he held various operating positions. In 1995, Keith was promoted to Vice President, Energy Trading and in 1996, to Vice President and General Manager, Regulated Power. In 1997, he became the Chief Executive Officer of United Energy Limited, an affiliated electric distribution company that was listed on the Australian Stock Exchange in 1998. From January 2000 to November 2001, he served as Chief Executive Officer of what is now Aquila Merchant. In November 2001, he was appointed President and Chief Operating Officer of what is now our Electric and Gas Utilities. In October 2002, Keith became Chief Operating Officer of Aquila, Inc.

### **Rick J. Dobson (B.B.A., Accounting, University of Wisconsin at Madison; M.B.A., University of Nebraska at Omaha)**

Rick joined Aquila Merchant in 1989 as Vice President and Controller. In 1995, he left Aquila to serve as Vice President and Controller for ProEnergy in Houston, Texas. He rejoined Aquila Merchant in 1997 and served as Vice President Financial Management until November 2002, when he was appointed Interim Chief Financial Officer of Aquila, Inc. In May 2003, Rick was

appointed Senior Vice President and Chief Financial Officer of Aquila. Prior to joining our company, Rick served in a management position with Arthur Andersen LLP.

**Leo E. Morton (B.S., Mechanical Engineering, Tuskegee University; M.S., Management, Massachusetts Institute of Technology)**

Leo joined our company in 1994 as Vice President, Performance Management. He was appointed Senior Vice President in 1995 and Senior Vice President, Human Resources and Operations Support in 1997. In 2000, he was named Senior Vice President and Chief Administrative Officer. Prior to working for us, Leo held executive and management positions in manufacturing and engineering for AT&T beginning in 1973.

**Christopher M. Reitz (B.S., Accounting and Business, University of Kansas; J.D., University of Kansas Law School)**

Chris joined our company in July 2000 in our General Counsel's office, serving most recently as Assistant General Counsel. In February 2005, he was appointed Interim General Counsel and Corporate Secretary of Aquila, Inc. In May 2005, Chris was appointed Senior Vice President, General Counsel and Corporate Secretary of Aquila, Inc. Prior to joining our company, Chris held corporate counsel positions with Cerner Corporation, Sprint Corporation and the law firm of Blackwell Sanders Peper Martin LLP.

**Norma F. Dunn (B.S., Business, University of Texas-El Paso)**

Norma joined our company in April 2005 as Senior Vice President, Communications and Stakeholder Outreach. Prior to joining the Company, she worked 17 years in a variety of roles of increasing responsibility for El Paso Corporation in Houston, Texas, including Vice-President Investor and Public Relations and most recently Senior Vice President, Corporate Communications and Government Affairs.

**Jon R. Empson (B.A., Economics, Carleton College; M.B.A., Economics, University of Nebraska at Omaha)**

Jon joined our company in 1986 as Vice President, Regulation, Finance and Administration of one of our major utility divisions. In 1993, Jon was appointed Aquila's Senior Vice President, Gas Supply and Regulatory Services and in 1996 he was appointed Senior Vice President, Regulatory, Legislative and Environmental Services. In December 2003, Jon was appointed Senior Vice President, Regulated Operations. Prior to joining the company, Jon worked for a predecessor company in various executive and management positions for seven years, held executive management positions at the Omaha Chamber of Commerce and Omaha Economic Development Council and worked as an economist with the U.S. Department of Housing and Urban Development.

**Scott H. Heidtbrink (B.S., Electrical Engineering, Kansas State University)**

Scott joined our company in 1987 as a field engineer at our Lee's Summit, Missouri service center. He has held various engineering, field and customer operations management positions involving both gas and electric utility operations. Prior roles with the company include State President and General Manager—Kansas from 1994 to 1997; Vice President, Network Management from 1998 to 2000; Vice President, Aquila Gas Operations in 2001; and Vice President, Kansas/Colorado Gas from 2002 to 2004. Over the past two years Scott led the deployment of Six Sigma into our utility operations and is a certified Six Sigma Black Belt. In January 2006, Scott was appointed Vice President, Power Generation and Energy Resources.

## **Item 1A. Risk Factors**

***Our strategic repositioning plan depends on our ability to raise adequate proceeds from asset sales and retire a sufficient amount of debt and other long-term liabilities with the net sale proceeds.***

In March 2005, we announced our strategic repositioning plan. Asset divestitures, including the sale of certain regulated utility properties and our merchant peaking power plants, are a key element of our plan. We have signed definitive agreements to sell (i) our electric utility operations in Kansas and our gas utility operations in Michigan, Minnesota and Missouri for an aggregate base purchase price of \$896.7 million, (ii) our Goose Creek and Raccoon Creek merchant peaking plants located in Illinois for an aggregate purchase price of \$175 million and (iii) Everest Connections for a base purchase price of \$85.7 million. We anticipate using the net proceeds generated by these divestitures to retire debt and other obligations, and to fund capital expenditures, including rate-base investments required to satisfy our long-term power generation and transmission needs and comply with environmental rules and regulation.

If we cannot complete these asset sales, or if we are not able to retire a principal amount of debt sufficient to reduce our interest expense to a level that can be satisfied by the cash flow generated by our remaining utility operations, we will continue to have a cash flow shortfall. We may also need to explore alternatives with respect to financing the significant capital expenditures anticipated in connection with environmental upgrades and compliance, as well as capital expenditures generally required to continue to provide safe and reliable service to our remaining utility customers.

***We must substantially reduce our overhead costs.***

Certain costs allocated to our utility divisions held for sale cannot be eliminated immediately upon the completion of our utility sales. In 2005, we allocated \$42.3 million of operating costs, comprised of corporate overhead and central services, to our utility divisions held for sale. We are developing a comprehensive plan to eliminate the majority of these costs when these support services are no longer required, and we expect that a portion of these allocated costs could be reallocated to our remaining utilities (and therefore recovered in rates). However, there can be no assurances that we will be successful in our efforts to eliminate these costs and/or reallocate them to our remaining utilities.

***We expect to continue to incur net losses.***

Except for the quarter ended March 31, 2005 during which we earned nominal net income, we have not earned net income since the quarter ended March 31, 2002. During the three-year period ending December 31, 2005, we have recorded cumulative net losses of approximately \$858.9 million.

We may incur material impairment charges if we decide to sell our interest in our Crossroads merchant peaking power plant, and if we are able to exit or otherwise terminate our Elwood tolling contract. In addition, we expect to continue to incur operating losses from our remaining Merchant Services business.

Our fuel and purchased power costs for our Missouri electric utilities are expected to significantly exceed the costs we are able to pass through to customers during 2006. We expect to file a rate case in July 2006 to implement a mechanism that will allow us to fully recover these costs; however, even if we are successful, we will not realize any rate relief until mid 2007 at the earliest. Until the Missouri Commission establishes rules to implement the legislation adopted in July 2005 that provides a means for the recovery of prudently incurred fuel and purchased power costs without going through a general rate case, our ability to recover fuel and purchased power

costs for our Missouri electric operations will continue to be limited due to the time lag associated with filing rate cases. Our inability to pass through fuel and purchased power costs to our Missouri electric customers may also adversely affect our ability to satisfy the financial covenants in our credit agreements, which if breached could cross default our other debt instruments.

***Due to our substantial leverage, our cash flows are constrained.***

As of December 31, 2005, we had, on a consolidated basis, \$3.3 billion of total liabilities, including almost \$2 billion of long-term debt. This substantial leverage has important consequences for us, including a substantial portion of our cash flow available from operations will be dedicated to the payment of principal and interest.

***Our non-investment grade credit ratings have an adverse effect on our liquidity and borrowing costs.***

Our long-term senior unsecured debt is presently rated “B2” (Positive Outlook) by Moody’s, and our long-term senior unsecured debt is presently rated “B-” (Positive Outlook) by S&P. Our non-investment grade ratings have increased our borrowing costs. These increases in our borrowing costs are not recoverable in our utility rates. In addition, our non-investment grade ratings generally require us to prepay our commodity purchases or post collateral to obtain trade credit. As of December 31, 2005, we had posted \$461.5 million of collateral (in the form of cash or letters of credit) with counterparties.

The most significant activity impacting working capital is the purchase of natural gas for our gas utility customers. We could experience significant working capital requirements during peak winter heating months due to higher natural gas consumption, potential periods of high natural gas prices and the fact that we are currently required to prepay certain of our gas commodity suppliers and pipeline companies. Our revolving credit and letter of credit lines are currently limited to \$590 million of capacity, as of February 2006.

***Our ability to further reposition our company as a regulated utility could be restricted by the terms of our finance agreements and our regulatory orders.***

Our credit facilities and regulatory orders contain restrictive covenants that could negatively impact our ability to continue to implement our strategic plan. For example, we must generally obtain the approval of the Kansas Commission prior to selling assets, and certain negative covenants contained in our credit facilities limit our ability to sell assets (or use the sale proceeds for various purposes) unless certain conditions are satisfied. Even if we were to repay our credit facilities, we would still generally be required to obtain the approval of the Kansas Commission for any asset sales. Accordingly, our ability to sell assets, such as our Crossroads peaking power plant and Everest Connections, may be limited.

The terms of our credit facilities and regulatory orders also limit the amount of additional indebtedness that we can incur. For example, our ability to incur indebtedness is restricted unless the additional indebtedness satisfies certain conditions (including use of proceeds restrictions), and prior to issuing long-term debt securities we must obtain the approval of the FERC and certain state commissions. Even if we were to repay our credit facilities, we would still be required to seek regulatory approvals to issue long-term debt. Thus, our ability to raise capital quickly (if at all) on favorable market terms could be limited.

In addition, the Kansas Commission staff recently proposed rules that would require utilities (including us) to “ring fence” their Kansas utility operations. As currently written, the proposal would require us to, among other things, transfer our Kansas utility assets to one or more separate wholly-owned subsidiaries, create a money pool that may only be used by our utility

operations, create a separate subsidiary that would provide operating and administrative services to the ring-fencing utility subsidiary, and finance our Kansas utility operations with capital raised by the ring-fenced Kansas utility subsidiary or a finance subsidiary that issues debt on behalf of our Kansas utility subsidiary. Because numerous of our contracts, indentures and loan agreements restrict or prohibit the transfer of utility assets from our company to one or more subsidiaries, compliance with any such proposal adopted by the Kansas Commission could have a material adverse effect on us.

***Stockholder approval is required to issue additional common stock.***

Our Restated Certificate of Incorporation currently authorizes us to issue up to 400 million shares of common stock. Taking into account the shares of our common stock that have been reserved for issuance under our existing stock option plans, we have less than 14 million shares of our common stock available for future issuance. We must seek the approval of our stockholders to increase the number of shares of common stock we may issue. To the extent our ability to satisfy our current and future obligations rests on our future ability to raise funds by issuing common stock or securities convertible into common stock, we will be dependent upon our stockholders for this approval.

***Our utility operations are subject to risks associated with higher fuel and purchased power prices, and we may not be able to recover costs of fuel and purchased power.***

Our regulated utilities produce, purchase and distribute power in three states and purchase and distribute natural gas in seven states. Generally, the regulations of the states in which we operate allow us to pass through changes in the costs of natural gas to our natural gas utility customers through purchased gas adjustment provisions in the applicable tariffs. All of our Gas Utilities have PGA provisions that allow them to pass the prudently-incurred cost of the gas to the customer. To the extent that gas prices are higher or lower than amounts in our current billing rates, adjustments are made on a periodic basis to “true-up” billed amounts to match the actual cost we incurred. There is, however, a timing difference between our purchases of natural gas and the ultimate recovery of these costs.

In our continuing regulated electric business, we generated approximately 51% of the power utilized by our utility customers and we purchased the remaining 49% through long-term contracts or in the open market in 2005. The regulatory provisions for recovering energy costs vary by state. In Kansas and Colorado, we have ECAs that serve a purpose similar to the PGAs for our gas utilities. To the extent that our fuel and purchased power costs vary from the energy cost built into our tariffs, the difference is passed through to the customer. In Missouri, which is our largest service area, we currently do not have the ability to adjust the rates we charge for electric service to offset all or part of any increase or decrease in prices we pay for fuel we use in generating electricity or for purchased power (i.e., a fuel adjustment mechanism). These costs could substantially reduce our operating results.

We are experiencing a 15-20% rail curtailment in our contracted coal deliveries from the Southern Powder River Basin, due in part to weather and other track problems that have caused Union Pacific and Burlington Northern to curtail rail shipments. This curtailment affects coal deliveries to our owned coal-fired power plants, and our jointly-owned investments, Iatan and Jeffrey Energy Center. Because substitute coal supplies are typically of higher sulfur content, we are required to purchase additional SO<sub>2</sub> emission allowances at a time when the cost of such allowances is substantially higher than historical levels. The continuation of either or both of these events for any extended period of time could have a material effect on our operations and cash flows if we are not allowed to pass these costs through to our customers.

***Regulatory commissions may refuse to approve some or all of the utility rate increases we may request in the future.***

Our regulated electricity and natural gas operations are subject to cost-of-service regulation and annual earnings oversight. This regulatory treatment does not provide any assurance as to achievement of earnings levels. Our rates are regulated on a state-by-state basis by the relevant state regulatory authorities based on an analysis of our costs, as reviewed and approved in a regulatory proceeding. The rates that we are allowed to charge may or may not match our related costs and allowed return on invested capital at any given time. While rate regulation is premised on the full recovery of prudently incurred costs and a reasonable rate of return on invested capital, there can be no assurance that the state public utility commissions will judge all of our costs to have been prudently incurred or that the regulatory process in which rates are determined will always result in rates that will produce a full recovery of our costs and the return on invested capital allowed by the applicable state public utility commission.

***Our operating results can be adversely affected by milder weather.***

Our utility businesses are seasonal businesses and weather patterns can have a material impact on our operating performance. Demand for electricity is typically greater in the summer and winter months associated with cooling and heating, and demand for natural gas is extremely sensitive to winter weather effects on space heating requirements. Because natural gas is heavily used for residential and commercial heating, the demand for this product depends heavily upon weather patterns throughout our service territory and a significant amount of natural gas revenues are recognized in the first and fourth quarters related to the heating seasons. Accordingly, our operations have historically generated less revenues and income when weather conditions are cooler in the summer and warmer in the winter. We expect that unusually mild summers and winters would have an adverse effect on our financial condition and results of operations.

***Our utility business is subject to complex government regulations and changes in these regulations or in their implementation may affect the costs of operating our businesses, which may negatively impact our results of operations.***

Our natural gas and electric utilities operate in a highly regulated environment. Retail operations, including the prices charged, are regulated by the state public utility commissions for our service areas as well as by the FERC. Changes in regulatory requirements or adverse regulatory actions could have an adverse effect on our performance by, for example, increasing competition or costs, threatening investment recovery or impacting rate structure.

In addition, our operations are subject to extensive federal, state and local statutes, rules and regulations relating to environmental protection. To comply with these legal requirements, we must spend significant sums on environmental monitoring, pollution control and emission fees.

New environmental laws and regulations affecting our operations, and new interpretations of existing laws and regulations, may be adopted or become applicable to us. For example, the laws governing air emissions from coal-burning plants have recently been revised by federal and state authorities. These changes will result in the imposition of substantially more stringent limitations on these emissions than those currently in effect.

We may not be able to obtain or maintain all environmental regulatory approvals necessary to our business. If there is a delay in obtaining any required environmental regulatory approval or if we fail to obtain, maintain or comply with any such approval, operations at our affected facilities could be halted or subjected to additional costs.

***The outcome of legal proceedings cannot be predicted. An adverse finding could have a material adverse effect on our financial condition.***

We are from time to time party to various material litigation matters and regulatory matters arising out of our business operations. The ultimate outcome of these matters cannot presently be determined, nor can the liability that could potentially result from a negative outcome in each case presently be reasonably estimated. The liability we may ultimately incur with respect to any of these cases in the event of a negative outcome may be in excess of amounts currently reserved and insured against with respect to such matters and, as a result, these matters may have a material adverse effect on our consolidated financial position.

In addition, on December 20, 2005, the Missouri Court of Appeals for the Western District of Missouri affirmed an order of the Circuit Court of Cass County, Missouri, which held that we lacked the requisite approvals to construct our South Harper power peaking facility and related transmission substation. In affirming the trial court's decision, however, the appellate court opined that we could obtain the requisite approval either from Cass County (in the form of zoning approval) or the Missouri Commission (in the form of specific authority). We decided not to appeal the order of the Court of Appeals and instead filed an application for approval with the Missouri Commission on January 24, 2006. On January 27, 2006, the trial court granted our request to stay the permanent injunction until May 31, 2006, and ordered us to post a \$20 million bond to secure the cost of removing the project. Given that the remedy sought is the removal of the plant and substation, an adverse outcome could have a material impact on our financial condition, results of operations and cash flows. If we are not successful in obtaining the required approvals, we currently estimate the cost to dismantle the plant and substation to be approximately \$20 million based on an engineering study. Significant additional costs would be incurred to store the equipment, secure replacement power and build the plant at a new site. We cannot estimate with certainty the total amount of these incremental costs that could be incurred, or the potential impairment of the carrying value of our investment in the plant we could suffer to the extent the cost exceeds the amount allowed for recovery in rates.

***We have several matters pending before the Internal Revenue Service, the negative outcome of which could materially impact our financial condition.***

As a large corporate taxpayer all of our federal income tax returns are examined by the IRS. Currently, our federal income tax returns for the years 1998-2002 are under audit and we expect an audit of the 2003 and 2004 tax years to begin soon. In addition, our returns for the taxable years 1996 and 1997 are before the Appeals division of the IRS. As of December 31, 2005, we had approximately \$287.6 million of cumulative tax provisions for tax deduction or income positions that we believe are proper but for which it is reasonably likely that these deductions or income positions will be challenged upon audit by the IRS. The timing of the resolution of these issues is uncertain. If our positions are not sustained, we may be required to utilize our capital loss and net operating loss or alternative minimum tax credit carryforwards and/or make cash payments plus interest.

#### **Item 1B. Unresolved Staff Comments**

None.

#### **Item 2. Properties**

Our corporate offices are located in 225,000 square feet of owned office space in Kansas City, Missouri. We also occupy other owned and leased office space for various operating offices.

In addition, we lease or own various real property and facilities relating to our regulated and non-regulated electricity generation assets. Our principal assets are generally described under

“Electric and Gas Utilities” and “Merchant Services.” Certain of these properties are encumbered by liens securing loans made to us. See Note 12 to the Consolidated Financial Statements for a description of the liens.

**Item 3. Legal Proceedings**

See Note 20 to the Consolidated Financial Statements.

**Item 4. Submission of Matters to a Vote of Security Holders**

There were no matters submitted to a vote of security holders in the fourth quarter of 2005.

## Part II

### Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Our common stock (par \$1) is listed on the NYSE under the symbol ILA. At March 1, 2006, we had approximately 28,000 common shareholders of record. Information relating to market prices of common stock on the NYSE and cash dividends on common stock is set forth below. On March 1, 2006, the reported last sale price of the common stock on the NYSE was \$3.94 per share.

#### Market Price Per Share

	<b>High</b>	<b>Low</b>	<b>Cash Dividends</b>
<b>2005 Quarters</b>			
Fourth	\$4.07	\$3.29	—
Third	4.14	3.50	—
Second	3.87	2.90	—
First	4.24	3.24	—
<b>2004 Quarters</b>			
Fourth	\$3.80	\$3.00	—
Third	3.87	2.25	—
Second	4.86	3.05	—
First	4.75	3.41	—

As part of our repositioning plan, our board of directors in the third quarter of 2002 suspended the payment of dividends on our common stock. Our board of directors regularly evaluates our common stock dividend policy. The determination whether we will pay dividends is influenced by many factors, including, among other things, our overall financial condition and cash flows, legal and contractual restrictions on the payment of dividends, and general economic and competitive conditions. We are bound by certain agreements and orders that limit our ability to pay dividends. For example, our \$220 million five-year unsecured term loan, \$110 million five-year unsecured revolving credit facility, Iatan construction facility, and \$100 million secured six-month revolving credit facility prohibit us from paying dividends if our senior unsecured debt is not rated at least Ba2 by Moody's and BB by S&P. In addition, an order of the Kansas Commission prohibits us from paying any dividends without its approval. We can make no determination at this time as to whether, or when, we will begin to pay dividends in the future.

## Item 6. Selected Financial Data

*In millions, except per share amounts*

	2005	2004	2003	2002	2001
Sales	\$1,314.2	\$ 971.0	\$ 983.1	\$ 1,496.0	\$ 2,743.0
Gross profit	450.5	249.8	303.6	329.9	1,188.5
Earnings (loss) from continuing operations (a)	(158.0)(b)	(348.3)(c)	(356.5)(d)	(1,597.5)(e)	180.5 (f)
Basic earnings (loss) per common share—					
Continuing operations	(.40)	(1.35)	(1.83)	(9.88)	1.61
Diluted earnings (loss) per common share—					
Continuing operations	(.40)	(1.35)	(1.83)	(9.88)	1.56
Cash dividends per common share	—	—	—	.775	1.20
Total assets	4,630.7	4,777.3	7,719.1	9,319.1	11,966.5
Short-term debt	12.0	—	—	287.8	445.0
Long-term debt (including current maturities)	1,979.5	2,366.4	2,706.0	2,624.8	2,432.9
Common shareholders' equity	1,309.9	1,130.5	1,359.3	1,607.9	2,551.6

The following notes reflect the pretax effect of items affecting the comparability of the Selected Financial Data above:

(a) Depreciation and amortization expense included \$13.1 million of goodwill amortization for the year ended December 31, 2001. Goodwill amortization was not recorded in the years ended December 31, 2005, 2004, 2003 and 2002 as a result of the implementation of a new accounting standard that discontinued the amortization of goodwill beginning January 1, 2002. Additionally, included in earnings from equity method investments for the year ended December 31, 2001 was approximately \$17.6 million of goodwill amortization.

(b) Included in loss from continuing operations for the year ended December 31, 2005, is a \$82.3 million loss on the early termination of the PIES; offset in part by \$31.3 million of net gains primarily related to the termination of our power sales contract and assignment of our rights under the Batesville tolling contract and the sale of our interests in the IntercontinentalExchange, Inc. (ICE), which owns a web-based commodity exchange platform, and Red Lake gas storage development project.

(c) Included in loss from continuing operations for the year ended December 31, 2004, is a \$46.6 million loss on the transfer of our interest in the Aries power project and termination of our 20-year tolling agreement with that project, a \$156.2 million loss on the termination of four long-term gas contracts, \$63.9 million of losses related to derivatives cancelled and replacement gas purchased for these four contracts, and \$19.5 million of other impairment charges; offset in part by \$34.0 million of gains including the sale of our interests in 12 equity method independent power plants, the sale of a power development project in the United Kingdom and a distribution from our interest in the BAF power partnership that sold its cogeneration facility.

(d) Included in loss from continuing operations for the year ended December 31, 2003, are (a) a \$105.5 million termination payment regarding our 20-year tolling agreement for the Acadia power plant; (b) an \$87.9 million impairment charge on our equity method investments in 12 independent power plants; and (c) \$26.1 million of restructuring charges from exit from interest rate swaps related to our Raccoon Creek and Goose Creek construction financing arrangements and additional severance and retention payments related to the continued wind-down of our energy trading operations.

(e) Included in loss from continuing operations for the year ended December 31, 2002, are (a) a \$696.1 million impairment charge on our investment in Quanta Services; (b) a \$247.5 million impairment charge on our investment in Midlands Electricity; (c) a \$127.2 million impairment charge on our investment in Multinet Gas and AlintaGas; (d) a \$29.8 million impairment charge related to our investments in Everest Connections and various communications projects; (e) a \$181.2 million write-down of Merchant Services' goodwill; (f) other

impairment charges and losses on sale of assets of \$91.9 million; and (g) \$210.2 million of restructuring charges from our exit from the wholesale energy trading business and the restructuring of our utility business. We also recorded a \$130.5 million gain on the sale of our shares of UnitedNetworks.

(f) In the year ended December 31, 2001, we (a) recorded a \$110.8 million gain on the sale of 5.75 million shares of Aquila Merchant Services, Inc. Class A common stock (net income reflects our 80% ownership of Aquila Merchant from April 27, 2001 to December 31, 2001); (b) wrote off exposure related to the Enron bankruptcy of \$35.0 million in Merchant Services and \$31.8 million in our Gas Utilities; (c) recorded charges of \$4.0 million in our communications business; and (d) recorded charges of \$11.5 million in our Australian networks related to valuation allowances on certain deferred taxes and collectibility of certain receivables.

## **Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations**

See Forward-Looking Information beginning on page 68 and Risk Factors beginning on page 22.

### **Strategic and Financial Repositioning Overview**

#### **Overview**

Our repositioning plan is based on improving operational results of our integrated electric and gas utility operations and strengthening our credit profile. The key elements of our plan are to:

- Maintain synergies of an integrated, multi-state utility.
- Complete our pending sale of regulated utility assets, merchant peaking power plants, and Everest Connections.
- Efficiently exit our Elwood tolling obligation.
- Significantly reduce our debt levels.
- Actively work with regulators and legislators to address capital investment and fuel recovery issues in Missouri.
- Continue to improve operational efficiency and lower earnings variability.
- Gain access to the capital markets on improved terms, allowing the company to more cost-effectively fund investments in its rate base to meet customer needs.

This repositioning plan was developed to focus on building and maintaining the generation, transmission and distribution infrastructure necessary to provide our utility customers with safe and reliable service, while increasing the returns on invested capital in jurisdictions that lag behind those of our peers. We intend to focus on improving our returns through future rate activities and process improvements.

#### **Asset Divestures and Strengthen Credit Profile**

With a stronger credit profile we will have the opportunity to invest in power generation, transmission and distribution capacity, as well as undertake environmental upgrades over the next decade. We believe these normal course investments will not only improve the reliability and quality of our utility service, but also provide a platform for additional growth in our earnings and enhanced shareholder value.

Following an extensive review and discussion with outside advisors on our stand-alone regulated utility strategy, we retained investment bankers to conduct a competitive sale process for certain assets. This auction process resulted in our execution of agreements to sell (a) four of our Utilities (including our Kansas electric operations and our gas operations in Michigan, Minnesota, and Missouri) to three buyers for an aggregate base purchase price of \$896.7 million, (b) two of our merchant peaking power plants, the Goose Creek and Raccoon Creek facilities located in Illinois, to AmerenUE for a total purchase price of \$175 million, and (c) Everest Connections for a total purchase price of \$85.7 million. The utility asset sales are expected to occur at different times throughout 2006, and the sale of the two peaking facilities is expected to be completed in the first half of 2006.

We expect to use the proceeds from the sale of regulated utility assets and the non-regulated assets to retire debt and other liabilities. We have not made a final determination of which debt will be retired. Although we have debt that is callable or maturing over the next 18 months, it may be more advantageous to pursue the retirement of other debt instruments through open market purchases, tenders or exchanges. The particular debt instruments to be retired will depend upon market conditions, the market price of the particular debt instrument, the call provisions (or lack thereof), the remaining life of the instrument, our near term capital needs and the timing of the receipt of the sales proceeds. We intend to apply the sales proceeds in a manner which maximizes the improvement to our credit profile and cash flow.

### **Historical Review of Repositioning Efforts**

In response to significant changes in the energy industry during the past few years, we undertook a strategic review of our business in the second quarter of 2002 and announced a change in our strategic direction. Our revised strategy features a concentrated focus on our utility operations, which preceded our diversification into merchant and international arenas in the 1990s.

As part of this repositioning, we took the following actions in 2002:

- Began the wind-down of our Merchant Services trading portfolio in North America and Europe;
- Sold our natural gas storage facilities in both North America and the United Kingdom;
- Sold substantially all of our merchant loan portfolio;
- Sold our gas gathering and processing business located primarily in Texas and Oklahoma;
- Reduced our investment in Quanta Services, Inc. (which builds and maintains networks that carry energy and telecommunications) from 38% to 10.2%;
- Sold our equity investment in regulated utility operations in New Zealand; and
- Eliminated our quarterly dividend.

Separately, we restructured our Electric and Gas Utilities in 2002 to more closely align them with their regulatory service areas. Due to our ongoing restructuring efforts since March 2002, we reduced staff by approximately 1,800 employees, including those transferred with the sale of various businesses. Of these, 496 were Corporate or Utilities employees.

In 2003, we continued to execute on our transition plan through the following actions:

- Sold our remaining 10.2% investment in Quanta Services, Inc.;
- Sold our Australian investments;

- Signed an agreement to sell our United Kingdom utility investment, which we completed in January 2004;
- Entered into a \$430 million three-year secured term loan;
- Terminated our capacity payment obligations under our Acadia tolling agreement;
- Signed agreements to sell our Canadian utility businesses, which we completed in the second quarter of 2004;
- Signed agreements to sell our equity investment in 13 independent power plants, which we completed in the first half of 2004;
- Pursued rate increases for certain of our gas and electric operations; and
- Continued the wind-down of our wholesale energy trading businesses in North America and Europe.

In 2004, we continued to implement our restructuring plan through the following actions, among others:

- Sold our investment in a merchant power plant development project in the United Kingdom;
- Settled rate cases relating to our Missouri and Colorado electric and Missouri and Nebraska gas utility operations and pursued rate relief for our Kansas electric and gas utility operations;
- Terminated our capacity payment obligations under our Aries tolling agreement and exited our investment in the Aries merchant power plant;
- Received a distribution on our investment in the BAF Energy cogeneration project;
- Renewed our 364-day letter of credit facility;
- Sold a non-strategic natural gas system located in eastern Missouri;
- Terminated four long-term natural gas supply contracts;
- Issued 46.0 million shares of common stock and \$345 million of PIES, raising \$446.6 million in net proceeds;
- Retired the \$430 million three-year secured term loan due in April 2006;
- Entered into a \$220 million five-year unsecured term loan and a \$110 million five-year revolving credit facility; and
- Entered into a \$150 million six-month revolving credit facility secured by the accounts receivable of our regulated operations.

Proceeds from these asset sales were used to pay down debt, fund restructuring charges and support our continuing operations.

In 2005, we further implemented our repositioning plan through the following actions, among others:

- Exited merchant obligations and sold merchant assets, including the Batesville tolling contract, the PacifiCorp stream flow contract, our 4.5% ownership interest in ICE, and the Red Lake gas storage development project;

- Settled rate cases relating to our Kansas electric and gas utility operations and pursued rate relief for our Iowa gas utility operations and our Missouri electric and steam operations, which were approved in early 2006;
- Completed an exchange offer that converted approximately 98.9% of our PIES units into our common stock earlier than the PIES mandatory conversion date (September 15, 2007), thereby reducing our interest expense;
- Entered into a \$150 million four-year revolving credit facility secured by certain of our Gas and Electric Utilities accounts receivables; and
- Entered into a \$180 million five-year unsecured credit and letter of credit facility, under which we may have letters of credit issued without having to cash collateralize the letters of credit.
- Entered into a \$300 million five-year secured credit facility, which provides the funding required for our investment in the Iatan 2 power plant and our share of certain environmental improvements required by the Iatan 1 power plant.
- Entered into agreements to sell our Kansas electric operations and our gas operations in Michigan, Minnesota and Missouri to three buyers for a total base purchase price of \$896.7 million;
- Entered into agreements to sell our two Illinois merchant peaking power plants to AmerenUE for a total purchase price of \$175 million; and
- Initiated an auction process to sell Everest Connections, our telecommunication business serving the greater Kansas City area. On March 3, 2006, we agreed to sell Everest Connections for a base purchase price of \$85.7 million.

## LIQUIDITY AND CAPITAL RESOURCES

### Working Capital Requirements

The most significant activity impacting working capital is the purchase of natural gas for our gas utility customers. We could experience significant working capital requirements during peak months of the winter heating season due to higher natural gas consumption, during potential periods of high natural gas prices and due to our current requirement to prepay certain gas commodity suppliers and pipeline transportation companies. Under a stressed weather and commodity price environment, such as the spike in 2005 commodity prices following the recent hurricanes, we estimate this working capital peak to be up to \$400 million. We anticipate using the combination of revolving credit and letter of credit facilities listed below and cash on hand to meet our peak winter working capital requirements.

<b>Credit Facility</b>	<b>Expiration</b>	<b>Maximum Capacity</b>	<b>Borrowings or Letters of Credit Issued at December 31, 2005</b>
			<i>In millions</i>
Four-Year Secured Revolving Credit Facility	April 22, 2009 (1)	\$150.0	\$12.0
Five-Year Unsecured Revolving Credit Facility	September 19, 2009	110.0	—
\$180 Million Unsecured Revolving Credit and Letter of Credit Facility	April 13, 2010 (1)(2)	180.0	150.9
\$100 Million Secured Revolving Credit Facility	April 19, 2006 (options to extend to July 19, 2006)	100.0	—
\$50 Million Unsecured Revolving Credit and Letter of Credit Facility	December 20, 2006	50.0	—

(1) *Borrowings under these facilities must be repaid within 364 days unless we obtain regulatory approval to incur long-term indebtedness under these facilities.*

(2) *Issuances above \$150 million are currently cash collateralized.*

The sale of our Michigan, Minnesota and Missouri gas operations is expected to reduce our peak working capital requirements by approximately 50%.

### Cash Flows

Our Statement of Cash Flows for the three years ended December 31, 2005 includes the cash flows related to our discontinued operations. Included in our cash provided from operating activities in 2005 is approximately \$76.7 million of cash flows associated with our discontinued operations. Our cash used for investing activities in 2005 includes approximately \$46.9 million of additions to utility plant and \$11.4 million of investments in communication services which are associated with our discontinued operations. Our cash flows from financing activities for 2005 includes \$2.0 million of issuance of long-term debt related to our discontinued operations.

### Cash Flows from Operating Activities

Our positive 2005 operating cash flows were driven primarily by the return of \$88.2 million of funds on deposit as a result of the replacement of cash deposits with letters of credit. The

increase in natural gas prices required our merchant and utilities counterparties to post an additional \$54.6 million of collateral with us. Offsetting these increases were the use of \$33.3 million of cash to inject higher cost natural gas into storage for the winter heating season, a 2005 income tax payment of \$30.9 million related to the sale of our Canadian utilities business in 2004, and the \$28.0 million settlement with Enron in connection with the netting of amounts owed under various contracts at the time of Enron's bankruptcy filing in 2001.

Our 2004 cash flows from operations were negative due to significant cash impacts resulting primarily from our 2004 operating net loss, the exiting of our non-core businesses including the termination of four long-term gas contracts, and the continued wind-down of our Merchant Services business. Our negative 2004 cash flows were driven by the following events and factors:

- We had a net loss from continuing operations of \$562.5 million before income tax benefits, including a \$156.2 million loss related to the termination of four long-term gas contracts.
- During 2004, we paid a \$26.5 million civil penalty settlement to the CFTC related to the reporting of natural gas trading information to publications and we paid \$38.0 million to settle an appraisal rights lawsuit.
- Higher gas prices in 2004 resulted in increased cash payments for the purchase of gas inventory, collateral deposits and gas purchase prepayments for our Gas Utilities business.
- We made \$25.6 million of net tax payments related to the sale of our consolidated Canadian utility operations and other international investments.
- Offsetting cash outflows in 2004 were collateral returns resulting from the continued wind-down of our wholesale energy trading positions and contract exits, and depreciation.

Our Elwood tolling contracts will have a material negative impact on our operating cash flows for the foreseeable future. We are attempting to restructure or terminate the Elwood tolling contracts. Any cash payment made to exit this obligation would have a negative impact on operating cash flows in the year the payment is made, but would improve operating cash flows in future periods.

Our significant debt load relative to our overall capitalization and the 14.875% interest rate we pay on \$500 million of our long-term debt has substantially increased our interest costs and will continue to negatively impact our operating cash flows. It will be important for us to substantially improve our operating cash flows. We are attempting to do this by improving the efficiency of our remaining businesses, increasing sales through utility rates, retiring debt and completing the wind-down of our Merchant Services business.

### ***Cash Flows from Investing Activities***

The decrease in cash provided from (used for) investing activities in 2005 compared to 2004 was primarily the result of the 2004 receipt of cash proceeds on the sale of our former investments in independent power plants and Canadian utility businesses.

Cash flows provided from investing activities increased in 2004 compared to 2003, primarily due to an increase in net proceeds received from the 2004 sales of our Canadian utility businesses, independent power plants, and Midlands Electricity. In 2003, we received proceeds from the sale of our merchant loan portfolio, our investments in Australian network companies and Quanta Services, and our gas gathering and pipeline assets. In addition, we had lower merchant capital expenditures and investments in unconsolidated merchant subsidiaries in 2004 compared to 2003, due to the completion of construction of a merchant power plant in June 2003, and the sale of our Aries power project in March 2004. Our utility capital expenditures decreased in 2004 due to the sale of our Canadian utility businesses in May 2004.

### **Cash Flows from Financing Activities**

Cash flows used for financing activities decreased in 2005 compared to 2004, primarily due to funds used in 2004 to terminate four of our long-term gas contracts, and retire debt associated with our acquisition of Midlands Electricity, our 7.00% and 6.875% senior notes, our three-year secured term loan and debt related to our Canadian utility operations. Partially offsetting this decrease was the issuance of common stock and the PIES which generated approximately \$446.6 million in August 2004.

Cash flows from financing activities decreased in 2004 compared to 2003. Our 2004 net cash used for financing activities consisted primarily of cash we paid to retire our short and long-term debt obligations and to terminate four of our long-term gas contracts, offset in part by the issuance of our common stock, mandatorily convertible PIES and our five-year unsecured term loan. In 2004, we retired the Midlands Electricity acquisition note, our three-year secured term loan, our 7.0% and 6.875% senior notes, and debt related to our Canadian utility operations. In 2003, we retired the debt associated with our investment in Australia and the construction of our merchant power plants. Additionally, we paid \$556.7 million for the termination of our obligations under four long-term gas contracts in 2004. The funds used to retire debt and terminate our long-term gas contracts were provided by investing activities, and the proceeds from our issuance of 46.0 million shares of common stock, our mandatorily convertible PIES and our \$220 million five-year unsecured term loan.

### **Current Credit Ratings**

Credit ratings impact our ability to obtain short- and long-term financing, the cost of such financing and vendor payment terms, including collateral and prepayment requirements. Our financial flexibility is limited because of restrictive covenants and other terms that are typically imposed on non-investment grade borrowers. As of December 31, 2005, our senior unsecured long-term debt ratings, as assessed by the three major credit rating agencies, were as follows:

<b>Agency</b>	<b>Rating</b>	<b>Commentary</b>
Moody's	B2	Positive Outlook
S&P	B-	Positive Outlook
Fitch	B-	Positive Outlook

Debt ratings by the various rating agencies reflect each agency's opinion of the ability of the issuers to repay debt obligations as they come due. In general, lower ratings result in higher borrowing costs and/or impaired ability to borrow. A security rating is not a recommendation to buy, sell, or hold securities and may be subject to revision or withdrawal at any time by the assigning rating organization.

Any rating below BBB-, for S&P and Fitch, or Baa3, for Moody's, is considered to be non-investment grade and indicates that the security is speculative in nature. A BB rating, for S&P and Fitch, or a Ba rating, for Moody's, indicates that the issuer currently has the capacity to meet its financial commitment on the obligation; however, it faces major ongoing uncertainties or exposure to adverse business, financial or economic conditions, which could lead to the obligor's inadequate capacity to meet its financial commitment on the obligation. An obligation rated B is more vulnerable to nonpayment than obligations rated BB or Ba, but the obligor currently has capacity to meet its financial commitment on the obligation. Adverse business, financial, or economic conditions will likely impair the obligor's capacity or willingness to meet its financial commitment on the obligation. The plus and minus symbols, for S&P and Fitch, and the "1,2,3"

modifiers, for Moody's, show relative standing within the major categories, 1 being the highest, or best, modifier in terms of credit quality.

We do not have any trigger events (i.e., an acceleration of repayment of outstanding indebtedness, an increase in interest costs or the posting of additional cash collateral) tied to our stock price and have not executed any transactions that require us to issue equity based on our credit ratings or other trigger events. If our credit ratings improve to certain levels, the interest rates on \$970 million of our long-term debt obligations will be lowered.

### **Collateral Positions**

As of December 31, 2005, we had posted collateral for the following in the form of cash or cash collateralized letters of credit:

*In millions*

---

Trading positions	\$ 86.7
Utility cash collateral requirements	118.4
Elwood tolling contract	38.7
Insurance and other	21.1
Total Funds on Deposit	\$264.9

---

Collateral requirements for our remaining trading positions will fluctuate based on the movement in commodity prices and our credit rating. Changes in collateral requirements will vary depending on the magnitude of the price movement and the current position of our trading portfolio. As these trading positions settle in the future, the collateral will be returned.

We are required to post collateral with certain commodity and pipeline transportation vendors. This amount will fluctuate depending on gas prices and projected volumetric deliveries. The ultimate return of this collateral is dependent on the strengthening of our credit profile.

We have been required to post collateral related to our Elwood tolling contract until we either successfully restructure the contract or obtain investment-grade credit ratings from certain major rating agencies. We will not be required to post any additional collateral related to this contract.

We are required to post collateral with certain insurance providers representing an amount equal to our estimated claim reserves for our multiple year policies. The return of this collateral is dependent on various factors including the improvement of our credit rating, the ultimate payout of claims over time and the sale of our electric and gas utilities.

### **Contractual Obligations**

Our contractual cash obligations include maturities of short-term and long-term debt, cash payments for our two remaining long-term gas contracts, minimum payments on operating leases and regulated power, gas and coal purchase contracts, as well as the Elwood tolling contracts and merchant gas transportation obligations. See Notes 11, 12, 13 and 20 to the Consolidated Financial Statements for further discussion of these obligations.

The amounts of total continuing and discontinued operations contractual cash obligations maturing in each of the next five years and thereafter are shown below:

<i>In millions</i>	2006	2007	2008	2009	2010	Thereafter	Total
<b>Continuing Operations—</b>							
Short-term and long-term debt obligations (a)	\$100.3	\$ 39.4	\$ 2.5	\$421.5	\$ 1.9	\$1,423.3	\$1,988.9
Interest on long-term debt (b)	197.2	189.5	189.1	180.6	151.7	1,064.0	1,972.1
Long-term gas contracts	23.4	23.9	2.0	—	—	—	49.3
Lease and other obligations	12.6	10.7	9.8	6.7	5.2	15.1	60.1
Elwood tolling contracts	37.3	37.3	37.3	37.4	37.4	230.3	417.0
Merchant gas transportation obligations	8.5	5.5	5.4	5.4	5.4	18.1	48.3
Non-qualified pension and other post-retirement benefits (c)	10.2	8.5	9.0	9.5	9.8	48.8	95.8
Regulated purchase obligations	251.2	214.7	178.7	153.1	155.6	355.0	1,308.3
<b>Total Continuing Operations</b>	<b>640.7</b>	<b>529.5</b>	<b>433.8</b>	<b>814.2</b>	<b>367.0</b>	<b>3,154.6</b>	<b>5,939.8</b>
<b>Discontinued Operations—</b>							
Long-term debt obligations	1.3	6.2	—	—	—	—	7.5
Interest on long-term debt (b)	.6	.5	—	—	—	—	1.1
Lease and other obligations	13.6	12.9	13.7	14.2	13.8	62.9	131.1
Regulated purchase obligations	73.5	68.4	64.5	48.4	38.1	238.5	531.4
<b>Total Discontinued Operations</b>	<b>89.0</b>	<b>88.0</b>	<b>78.2</b>	<b>62.6</b>	<b>51.9</b>	<b>301.4</b>	<b>671.1</b>
<b>Total</b>	<b>\$729.7</b>	<b>\$617.5</b>	<b>\$512.0</b>	<b>\$876.8</b>	<b>\$418.9</b>	<b>\$3,456.0</b>	<b>\$6,610.9</b>

(a) Long-term debt obligations maturing in 2007 does not include the non-cash, mandatory conversion of \$2.6 million of PIES to common stock on September 15, 2007.

(b) Interest on long-term debt is estimated based on scheduled maturity dates of debt outstanding at December 31, 2005 and does not reflect anticipated early redemptions, tenders or exchanges. Variable rate interest obligations are estimated based on rates as of December 31, 2005.

(c) Includes total estimated contributions for non-qualified pension benefits and other post-retirement benefits continuing and discontinued operations as described in Note 18 to Consolidated Financial Statements.

### **Regulated business purchase obligations**

In 2005, our continuing electric utility operations generated 51% of the power delivered to their customers. Our electric utility operations purchase coal and natural gas, including transportation capacity, as fuel for its generating power plants under long-term contracts with the longest extending through 2020. We also purchase power and gas to meet customer needs under short-term and long-term purchase contracts.

### **Long-Term Gas Contracts**

We accounted for the advance cash payments we received under these contracts as liabilities. We reduce our obligation for these long-term gas contracts as the gas is delivered to the customer under the units of revenue method. If we were to default on these obligations, or were unable to

perform on them, we would be required to pay the issuers of the surety bonds or the counterparties on these arrangements approximately \$49.2 million. This amount is greater than the long-term gas contract balance on our Consolidated Balance Sheet due to our use of the units of revenue method versus a present value method applied under the default provisions of the contractual agreements. We do not intend to terminate these remaining contracts.

### ***Elwood Tolling Contracts***

Because it is generally expected that the fuel and start-up costs of operating the Elwood power plant will exceed the revenues that would be generated from the power sales, during the foreseeable future, we believe that our capacity to generate power from the Elwood power plant will largely be unutilized. Before including existing forward sales contracts, we expect to incur pretax losses and negative operating cash flows of approximately \$37.3 million in 2006 related to these contracts. We are attempting to terminate or restructure this obligation.

### **Off-Balance Sheet Arrangements**

The term “off-balance sheet arrangement” generally means any transaction, agreement or other contractual arrangement to which an entity that we do not consolidate is a party, under which we have (i) any obligation arising under a guarantee contract, derivative instrument or variable interest; or (ii) a retained or contingent interest in assets transferred to such entity or similar arrangement that serves as credit, liquidity or market risk support for such assets. As of December 31, 2005, we have obligations under certain off-balance sheet arrangements that have or are reasonably likely to have a current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that may be material to investors. These are discussed below.

### ***Equity Put Rights***

Certain minority owners of Everest Connections had the option to sell their ownership units to us if Everest Connections did not meet certain financial and operational performance measures as of December 31, 2004 (target-based put rights). If the target-based put rights were exercised, we would have been obligated to purchase up to 4.0 million and 4.75 million ownership units at a price of \$1.00 and \$1.10 per unit, respectively, for a total potential cost of \$9.2 million. As a result of our reduced funding of this business, management assessed the likelihood of achieving these metrics and during 2002 recorded a probability-weighted expense of \$7.1 million. In 2004, we achieved the operating targets related to 4.0 million and 1.5 million of ownership units at a price of \$1.00 and \$1.10 per unit, respectively. Therefore, we reversed \$4.5 million of this reserve. The holders of these ownership units are disputing our conclusion that we have achieved these operating targets and are attempting to exercise these target-based put rights. We do not believe we have any obligation with regard to these target-based put rights. We did not achieve the targets related to 3.25 million of ownership units at a price of \$1.10 per unit. The holders of these target-based put rights exercised their options and were paid \$3.6 million for their ownership units in February 2005.

The minority owners of 9.5 million ownership units have also notified us that they intend to exercise their option to sell their ownership units to us at fair market value (market-based put rights). We have not provided for this potential obligation as the exercise would represent an equity transaction at fair value. We do not believe based on current estimates of fair value that these market-based put rights are a material contingent obligation.

## Capital Expenditures

We estimate future cash requirements for capital expenditures for property, plant and equipment additions will be as follows:

<i>In millions</i>	Actual	Estimated Future Cash Requirements		
	2005	2006	2007	2008
Electric Utilities	\$151.2	\$176.4	\$222.6	\$212.0
Gas Utilities	30.8	32.9	34.4	33.1
Corporate and Other	7.5	8.4	7.2	4.9
Total Continuing Operations	189.5	217.7	264.2	250.0
Discontinued Operations	58.3	22.0	—	—
<b>Total capital expenditures</b>	<b>\$247.8</b>	<b>\$239.7</b>	<b>\$264.2</b>	<b>\$250.0</b>

## Iatan 2

Our 2005 power supply plan indicates the need for additional base-load capacity in Missouri after 2009. There is generally a five- to seven-year lead time required between the decision to proceed with a coal-fired generating project and the completion of development, permitting, construction and performance testing of such a project. KCPL has received approval of its long-term energy plan from the Missouri Commission that includes the construction of up to 800 - 900 MW of coal-fired generating capacity at the existing Iatan site in Weston, Missouri. The additional generating capacity is presently planned for commercial operation in 2010. On January 31, 2006, the Missouri Department of Natural Resources issued a Permit to Construct (air permit) to KCPL for construction of Iatan 2 and air pollution control additions for Iatan 1. We were chosen by KCPL to participate in the construction of the Iatan 2 plant, and we will have an 18% ownership share (commensurate with our existing 18% ownership of Iatan 1). We are currently negotiating participation documents which are expected to be executed during the first half of 2006. The capital requirements included in the table above for this participation, including capitalized interest, are estimated as follows: 2006—\$78.4 million, 2007—\$97.1 million, 2008—\$68.4 million and 2009-2010—\$60.1 million.

## Regulatory Approvals Required for Financing

We are required to obtain the prior approval of the FERC, Kansas Commission and Colorado Commission prior to issuing long-term debt or stock. We have not requested approvals to incur additional long-term debt.

We are also required to obtain the prior approval of the FERC to issue short-term debt. We have obtained their approval to have outstanding up to \$500 million of additional secured or unsecured short-term debt. Our authority to issue short-term debt expires in April 2006, and, on February 2, 2006, we filed an application with the FERC requesting authority to issue up to \$500 million of short-term debt from time to time over the next two years. We must also obtain the prior approval of the Kansas Commission to issue short-term debt except as required to meet our working capital requirements.

The use of our utility assets as collateral generally requires the prior approval of the FERC and the regulatory commission in the state in which the utility assets are located.

## **Restriction on Ability to Issue Common Stock**

Our certificate of incorporation authorizes us to issue up to 400 million shares of common stock, 20 million shares of Class A Common Stock and 20 million shares of preferred stock. Of the 400 million shares of common stock authorized to be issued, 386 million shares have either been issued or reserved for issuance in connection with the conversion of our PIES or pursuant to employee compensation plans. Accordingly, unless our certificate of incorporation is amended with the approval of our shareholders, our ability to raise capital through the sale of common stock is severely restricted.

## **FINANCIAL REVIEW**

This review of performance is organized by business segment, reflecting the way we managed our business during the periods covered by this report. Each business group leader is responsible for operating results down to earnings before interest, taxes, depreciation and amortization (EBITDA). We use EBITDA as a performance measure as it captures the income and expenses within the management control of our segment business leaders. Because financing for the various business segments is generally completed at the parent company level, EBITDA provides our management and third parties an indication of how well individual business segments are performing. Therefore, each segment discussion focuses on the factors affecting EBITDA, while financing and income taxes are separately discussed at the corporate level.

As further discussed in Note 6 to the Consolidated Financial Statements, we have reported the results of operations of the following assets in discontinued operations in the Consolidated Statements of Income: (i) our Kansas electric utility operations and our Michigan, Minnesota, and Missouri gas utility operations, (ii) our Goose Creek and Raccoon Creek peaking power plants in Illinois, (iii) our communications business, Everest Connections, (iv) our Canadian utility businesses that we sold in May 2004, and (v) our consolidated independent power plants, Lake Cogen and Onondaga, that we sold in March 2004. Therefore, the operating results of these assets are discussed separately from the reporting segments to which they relate under the caption "Discontinued Operations."

As described in Note 6 to the Consolidated Financial Statements, only direct operating costs associated with the utility divisions currently held for sale have been reclassified to discontinued operations. The costs related to executive management and centralized services that have been allocated to these divisions remain in continuing operations. We are developing a comprehensive plan to eliminate the majority of these costs when these support services are no longer required. We expect that a portion of these costs could be reallocated to the remaining utilities.

The use of EBITDA as a performance measure is not meant to be considered an alternative to net income or cash flows from operating activities, which are determined in accordance with

GAAP. In addition, our use of EBITDA may not be comparable to similarly titled measures used by other entities.

<i>In millions, except per share amounts</i>	<b>Year Ended December 31,</b>		
	<b>2005</b>	<b>2004</b>	<b>2003</b>
<b>Earnings (Loss) Before Interest, Taxes, Depreciation and Amortization:</b>			
Electric Utilities	\$ 147.7	\$ 130.3	\$ 128.0
Gas Utilities	33.6	34.9	46.8
<b>Total Utilities</b>	<b>181.3</b>	<b>165.2</b>	<b>174.8</b>
Merchant Services	(22.6)	(416.7)	(378.4)
Corporate and Other	(103.2)	(23.8)	19.0
<b>Total EBITDA</b>	<b>55.5</b>	<b>(275.3)</b>	<b>(184.6)</b>
Depreciation and amortization expense	106.4	102.8	120.1
Interest expense	150.2	184.5	198.8
Income tax benefit	(43.1)	(214.3)	(147.0)
<b>Loss from continuing operations</b>	<b>(158.0)</b>	<b>(348.3)</b>	<b>(356.5)</b>
<b>Earnings (loss) from discontinued operations, net of tax</b>	<b>(72.0)</b>	<b>55.8</b>	<b>20.1</b>
<b>Net loss</b>	<b>\$(230.0)</b>	<b>\$(292.5)</b>	<b>\$(336.4)</b>
<b>Diluted earnings (loss) per share:</b>			
Continuing operations	\$ (.40)	\$ (1.35)	\$ (1.83)
Discontinued operations	(.20)	.22	.10
<b>Net loss</b>	<b>\$ (.60)</b>	<b>\$ (1.13)</b>	<b>\$ (1.73)</b>

### **Key Factors Impacting Continuing Operating Results**

Our total EBITDA increased significantly in 2005 compared to 2004. Key factors affecting 2005 results were as follows:

- Total Utilities EBITDA increased \$16.1 million primarily due to favorable weather for our electric utilities, and rate increases in Missouri, Colorado and Kansas and customer growth, offset in part by higher costs for natural gas used for fuel and increased labor and compensation costs.
- The continued wind-down of our energy trading businesses in 2005, including \$31.3 million of net gains related to the sale of our investment in ICE and the Red Lake gas storage development project and the termination of our Batesville tolling agreement and associated forward sale contract, resulted in a \$394.1 million increase in EBITDA compared to 2004. Merchant Services' EBITDA in 2004 included \$185.5 million of net losses on sale of assets and other charges, and \$166.1 million of margin losses primarily associated with our former long-term gas contracts, alternative risk contracts, and other trading activities.
- Corporate and other loss before EBITDA decreased \$79.4 million in 2005 compared to 2004, primarily due to the non-cash loss on the early conversion of the PIES.

## Restructuring Charges

As further discussed in Note 4 to the Consolidated Financial Statements, we recorded the following restructuring charges:

	<b>Year Ended December 31</b>		
	<b>2005</b>	<b>2004</b>	<b>2003</b>
Merchant Services:			
Interest rate swap reductions	\$ —	\$ —	\$ 23.1
Severance costs	—	.7	—
Retention payments	—	—	2.2
Lease agreements	6.6	—	(.2)
Other	—	—	(.4)
<b>Total Merchant Services</b>	<b>6.6</b>	<b>.7</b>	<b>24.7</b>
Corporate and Other severance costs	—	.2	1.4
<b>Total restructuring charges</b>	<b>\$ 6.6</b>	<b>\$ .9</b>	<b>\$ 26.1</b>

## Net Loss on Sale of Assets and Other Charges

As further discussed in Note 5 to the Consolidated Financial Statements, we recorded the following net loss (gain) on sale of assets and other charges:

<i>In millions</i>	<b>Year Ended December 31,</b>		
	<b>2005</b>	<b>2004</b>	<b>2003</b>
Gas Utilities:			
Other	\$ —	\$ —	\$ (2.2)
Total Gas Utilities	—	—	(2.2)
Merchant Services:			
Batesville tolling agreement	(16.3)	—	—
ICE sale	(9.3)	—	—
Aries power project and tolling agreement	—	46.6	—
Termination of long-term gas contracts	—	156.2	—
Red Lake gas storage development project	(6.2)	8.9	—
Acadia tolling agreement	—	—	105.5
Turbine contracts	—	—	(5.1)
Independent power plants	—	(6.1)	87.9
Investment in BAF Energy	(.7)	(9.1)	—
Enron bankruptcy	—	(6.0)	—
Marchwood development project	—	(5.0)	—
Other	1.2	—	.8
Total Merchant Services	(31.3)	185.5	189.1
Corporate and Other:			
Early conversion of the PIES	82.3	—	—
Everest Connections target-based put rights	—	(4.5)	—
Midlands	—	(3.3)	4.0
Australia	—	—	1.8
Turbines impairment	4.4	10.6	—
Total Corporate and Other	86.7	2.8	5.8
Total net loss on sale of assets and other charges	\$ 55.4	\$188.3	\$192.7

During 2005, 2004 and 2003, we also incurred net (gains) losses on asset sales and other charges of \$159.5 million, \$(74.0) million, and \$49.5 million, respectively, that are reflected in discontinued operations and are not included in the table above.

### Three-Year Review—Electric Utilities

The table below summarizes the operations of our Missouri and Colorado Electric Utilities:

<i>Dollars in millions</i>	<b>Year Ended December 31,</b>		
	<b>2005</b>	<b>2004</b>	<b>2003</b>
Sales:			
Electricity—regulated	\$ 684.1	\$ 594.1	\$ 544.1
Other—non-regulated	.6	.8	1.0
Total sales	684.7	594.9	545.1
Cost of sales:			
Electricity—regulated	355.4	295.8	254.2
Other—non-regulated	.3	.3	.6
Total cost of sales	355.7	296.1	254.8
Gross profit	329.0	298.8	290.3
Operating expense	186.5	171.3	162.4
Other income	5.2	2.8	.1
EBITDA	\$ 147.7	\$ 130.3	\$ 128.0
Depreciation and amortization expense	\$ 64.0	\$ 60.1	\$ 62.0
Electric sales and transportation volumes (GWh)	11,165	9,932	9,476
Electric customers	391,406	383,829	377,517

#### **2005 versus 2004**

##### *Sales, Cost of Sales and Gross Profit*

Sales, cost of sales and gross profit for the Electric Utilities business increased \$89.8 million, \$59.6 million, and \$30.2 million, respectively, in 2005 compared to 2004. These changes were primarily due to the following factors:

- Sales and gross profit increased by \$15.7 million due to rate increases in Colorado effective in September 2004 and in Missouri effective in April 2004, plus \$8.8 million of additional margin from an increase in customers.
- Favorable weather-related volume and other variances increased gross profit by \$9.1 million in 2005.
- The favorable impacts above were offset in part by higher costs of fuel, purchased power, transmission and emission allowances, net of offsetting derivative settlements and off-system sales which reduced margins by approximately \$3.1 million as compared to 2004.

### *Operating Expense*

Operating expenses consisted of the following:

<i>In millions</i>	<b>Year Ended December 31,</b>		
	<b>2005</b>	<b>2004</b>	<b>2003</b>
Operating expenses of Colorado and Missouri electric	\$175.5	\$161.2	\$153.5
Allocated expenses of Kansas electric	11.0	10.1	8.9
Total operating expenses	\$186.5	\$171.3	\$162.4

Operating expense increased \$15.2 million from 2004 primarily due to approximately \$9.7 million of higher labor and benefit costs and \$3.5 million of increased outside service costs associated with storm-related outages in 2005.

### *Other Income*

Other income increased \$2.4 million in 2005 compared to 2004 primarily due to increased AFUDC associated with the construction of our South Harper peaking facility, which began in late 2004. AFUDC represents the cost of both debt and equity funds used to finance utility plant additions during the construction period. AFUDC is capitalized as a part of the cost of utility plant and is credited to other income.

### *Depreciation and Amortization Expense*

Depreciation and amortization expense increased \$3.9 million in 2005 compared to 2004 due to additional plant placed in service, primarily the South Harper peaking facility.

### **2004 versus 2003**

#### *Sales, Cost of Sales and Gross Profit*

Sales and cost of sales for the Electric Utilities businesses increased \$49.8 million and \$41.3 million, respectively, resulting in a gross profit increase of \$8.5 million in 2004 compared to 2003. These changes were primarily due to the following factors:

- Sales and gross profit increased by \$36.3 million due to rate increases in Colorado effective in July 2003 and in Missouri effective in April 2004, plus \$5.3 million of additional margin from an increase in customers.
- These were partially offset by a \$24.1 million increase in cost of sales due to the higher cost of fuel and purchased power, net of offsetting derivative hedge positions in 2004 and 2003.
- Unfavorable weather decreased gross profit by \$4.8 million.
- In addition, 2003 electric cost of sales included \$3.8 million of favorable adjustments that did not recur in 2004, such as settlement of purchased power pricing disputes and the Greenwood Energy Center damage claim.

### *Operating Expense*

Operating expense increased \$8.9 million in 2004 compared to 2003, as a result of a number of cost increases. The most significant of these was outside services and materials costs, which increased \$6.0 million, and labor and other compensation costs, which increased \$3.3 million due

to additional customer service representatives, apprentice linemen, increased pension costs and compliance costs in 2004 compared to 2003.

#### *Other Income*

Other income increased \$2.7 million in 2004 compared to 2003 primarily due to increased AFUDC associated with the construction of our South Harper peaking facility, which began in late 2004.

#### *Depreciation and Amortization Expense*

Depreciation and amortization expense decreased \$1.9 million in 2004 compared to 2003, primarily due to the adjustments to depreciation rates resulting from recent rate cases.

#### ***Earnings Trend***

The February 2006 settlement of our electric rate case in Missouri is expected to increase annual sales by approximately \$26.3 million, net of the former interim energy charge. To the extent that our costs of natural gas used for fuel and purchased power or other operating expenses increase or decrease from the level of costs recovered in the current rate case settlement, the impact of the change will affect our operating results. The \$4.5 million settlement of our Missouri steam case includes an 80% sharing of fuel cost changes from the base fuel rate.

On July 6, 2005, Union Pacific railroad notified us and other utilities receiving coal shipments from the Southern Powder River Basin that a force majeure event requiring maintenance on rail lines resulted in a 15-20% reduction in contracted deliveries through November 2005. Other weather and track problems have continued to limit coal deliveries and are expected to continue into 2006. We have analyzed the potential effects of these reductions in deliveries on our owned coal-fired power plants and believe that our coal inventory levels are sufficient, assuming continued deliveries at these levels, to carry us through the spring and early summer without significantly reducing utilization of these plants below current levels. We continue to hold discussions with KCPL and Westar regarding our jointly-owned plants, Iatan and Jeffrey, respectively, and have agreed to coal conservation measures at both plants. If the deliveries are returned to normal levels before the 2006 summer cooling season, this event is not expected to have a direct material effect on our operations. There is no assurance that deliveries will return to normal levels at this time.

As discussed in Note 6 to the Consolidated Financial Statements, certain allocated executive management and centralized services costs associated with our electric and gas utility divisions held for sale cannot be immediately eliminated when the pending asset sales close. We intend to eliminate these costs to the greatest extent possible and reallocate any remaining costs to the remaining utility jurisdictions where appropriate. To the extent these costs are not recovered in other jurisdictions or we are unsuccessful in eliminating these costs, our earnings could be adversely affected.

We have entered into a program for our electric utility operations in Missouri to mitigate our exposure to natural gas price volatility in the market. This program extends multiple years and the mark-to-market value of the portfolio of \$20.7 million related to contracts that will settle against actual purchases of natural gas and purchased power in 2006 through 2008. In connection with the recently settled Missouri electric rate case, we agreed that these contracts would be recognized into cost of sales when they settle. A regulatory liability has been recorded under SFAS 71 in the amount of \$20.7 million to reflect the change in the timing of recognition authorized by the Missouri Commission.

As a result of the fuel adjustment clause legislation signed into law in July 2005, the Missouri Commission will set forth rules regarding the implementation and definition of costs to be recovered in the fuel adjustment clause for our Missouri electric operations. The value of our NYMEX financial contracts may be a part of the defined costs to be recovered through the fuel adjustment clause. If so, the settlement of the contracts, as well as the cost of the physical fuel and purchased power from the marketplace, will flow through to the customer.

### **Three-Year Review—Gas Utilities**

The table below summarizes the operations of our Colorado, Iowa, Kansas and Nebraska Gas Utilities:

<i>Dollars in millions</i>	<b>Year Ended December 31,</b>		
	<b>2005</b>	<b>2004</b>	<b>2003</b>
Sales:			
Natural gas—regulated	\$ 606.5	\$ 506.5	\$ 473.9
Other—non-regulated	24.6	22.5	32.3
Total sales	631.1	529.0	506.2
Cost of sales:			
Natural gas—regulated	452.1	356.3	320.9
Other—non-regulated	14.7	12.8	18.9
Total cost of sales	466.8	369.1	339.8
Gross profit	164.3	159.9	166.4
Operating expense	133.0	125.8	123.1
Net loss (gain) on sale of assets and other charges	—	—	(2.2)
Other income	2.3	.8	1.3
<b>EBITDA</b>	<b>\$ 33.6</b>	<b>\$ 34.9</b>	<b>\$ 46.8</b>
Depreciation and amortization expense	\$ 35.8	\$ 35.0	\$ 35.0
Gas sales and transportation volumes (Mcf)	95,787	93,691	100,679
Gas customers	508,543	500,807	492,997

### **2005 versus 2004**

#### *Sales, Cost of Sales and Gross Profit*

Sales, cost of sales and gross profit for the Gas Utilities business increased \$102.1 million, \$97.7 million and \$4.4 million, respectively, in 2005 compared to 2004. These changes were primarily due to the following factors:

- Sales and cost of sales increased approximately \$88.6 million due to a 25% increase in natural gas prices since December 31, 2004. However, because gas purchase costs for our gas utility operations are passed through to our customers, the change in gas prices did not have a corresponding impact on gross profit.
- Gross profit increased by approximately \$2.9 million due to a rate increases in Kansas effective in June 2005 and an interim rate increase in Iowa effective in May 2005, as well as \$1.5 million of additional margins from customer growth in 2005. Final Iowa rates will be effective in April 2006.

- The impact of warmer 2005 weather decreasing gross profit was mitigated by a weather hedge and the Kansas weather normalization adjustment.

#### *Operating Expense*

Operating expenses consisted of the following:

<i>In millions</i>	<b>Year Ended December 31,</b>		
	<b>2005</b>	<b>2004</b>	<b>2003</b>
Operating expenses of Colorado, Iowa, Kansas and Nebraska gas	\$101.7	\$ 96.3	\$ 94.9
Allocated expenses of Michigan, Minnesota and Missouri gas	31.3	29.5	28.2
<b>Total operating expenses</b>	<b>\$133.0</b>	<b>\$125.8</b>	<b>\$123.1</b>

Operating expense for 2005 increased \$7.2 million from 2004 primarily as a result of increased labor and benefit costs.

#### **2004 versus 2003**

##### *Sales, Cost of Sales and Gross Profit*

Sales and cost of sales for the Gas Utilities business increased \$22.8 million and \$29.3 million, respectively, resulting in a gross profit decrease of \$6.5 million in 2004 compared to 2003. These changes were primarily due to the following factors:

- Regulated gas sales and cost of sales increased \$32.6 million and \$35.4 million, respectively, in 2004 compared to 2003, for a net decrease in gross profit of \$2.8 million. Sales and cost of sales increased due to an 18% increase in natural gas prices. However, because gas purchase costs for our gas utility operations are passed through to our customers, the change in gas prices did not have a corresponding impact on gross profit. Regulated gas margins decreased \$7.0 million due to unfavorable weather and lower usage per customer in 2004 compared to 2003. Regulated gas margins in 2003 included a \$2.5 million favorable change in reserved funds released upon conclusion of multi-year gas cost recovery filings that did not recur in 2004. The overall decline in gas margins due to volume and weather was partially offset by \$5.0 million in rate increases in Nebraska and Iowa and \$1.1 million of increased margins from customer growth.
- Non-regulated gas sales, cost of sales and gross profit decreased \$8.3 million, \$6.8 million and \$1.5 million, respectively, in 2004 compared to 2003, primarily as the result of the sale of certain non-regulated gas pipeline and gathering operations in August 2003.
- Non-regulated other sales decreased \$1.5 million and cost of sales increased \$.7 million for a net decrease in gross profit of \$2.2 million, primarily as a result of a decrease in appliance service contracts and increased costs of servicing existing contracts.

#### *Operating Expense*

Operating expense for 2004 increased \$2.7 million from 2003 primarily as a result of increased labor and benefit costs.

#### *Net Loss (Gain) on Sale of Assets and Other Charges*

The 2003 net gain on sale of assets was a result of the sale of our off-system appliance repair business.

## Merchant Services

We conduct our Merchant Services business through Aquila Merchant, which primarily owns, operates and contractually controls our non-regulated power generation assets. Merchant Services also includes our former North American and European energy trading businesses.

### Three-Year Review—Merchant Services

<i>In millions</i>	<b>Year Ended December 31,</b>		
	<b>2005</b>	<b>2004</b>	<b>2003</b>
Sales	\$ (1.6)	\$(152.9)	\$ (70.1)
Cost of sales	41.2	56.0	84.6
Gross loss	(42.8)	(208.9)	(154.7)
Operating expenses:			
Operating expense	10.6	28.7	91.3
Restructuring charges	6.6	.7	24.7
Net loss (gain) on sale of assets and other charges	(31.3)	185.5	189.1
Total operating expenses	(14.1)	214.9	305.1
Other income:			
Equity in earnings of investments	—	1.9	53.7
Other income	6.1	5.2	27.7
Earnings (loss) before interest, taxes, depreciation and amortization	\$(22.6)	\$(416.7)	\$(378.4)
Depreciation and amortization expense	\$ 6.3	\$ 7.3	\$ 24.3

Due to EITF 02-3, we report our gains and losses from energy trading contracts on a net basis. To the extent losses exceeded gains, sales are shown as a negative number.

### **2005 versus 2004**

#### *Sales, Cost of Sales and Gross Loss*

Gross loss for our Merchant Services operations for 2005 was \$42.8 million, primarily due to the following factors:

- In 2005, we recorded a net margin loss of \$32.4 million associated with our Elwood tolling agreement. We make fixed capacity payments evenly throughout the year that entitle us to generate power at the Elwood plant. The cost to purchase natural gas to fuel this power plant generally exceeded the value of the power that could be generated. Accordingly, we did not generate material revenues.
- As part of the continued wind-down of our wholesale energy trading operations, we assigned the final year of our obligation under a stream flow contract to a third party in the second quarter of 2005. Included in our gross loss for 2005 were mark-to-market losses and settlements of approximately \$7.4 million, related to our stream flow transaction.
- We recorded a margin loss of \$4.5 million on the 2005 write-off of certain balances retained in our previous sale of gas pipeline investments.

- We also incurred margin losses of \$7.1 million resulting from the difference between revenue recognized on our two remaining long-term gas delivery contracts compared to the net cost of gas delivered under these contracts.
- Partially offsetting the gross loss for 2005 was the termination of certain commodity and interest rate hedges. The termination of the hedges and the release of our contingent obligation to the buyer of our former merchant loan portfolio resulted in the reversal of the related liability of \$7.1 million associated with these contracts.

Gross loss for our Merchant Services operations for 2004 was \$208.9 million, primarily due to the following factors:

- Approximately \$22.6 million was a non-cash loss related to the discounting of our trading portfolio, primarily driven by our long-term gas contracts. After updating the future cash flow stream based on the new forward natural gas prices, we discount the future cash flows of our price risk management assets based on our counterparties' credit standing, versus our future cash flows of our price risk management liabilities that are discounted based on our current credit standing. In prior periods, primarily in 2002, when our credit standing deteriorated compared to our counterparties' that make up the vast majority of our price risk management assets, we recorded non-cash earnings related to the discounting of our price risk management assets and liabilities. During 2004, the benchmark indices we used to determine the discount rate appropriate for our credit standing decreased, resulting in the partial reversal of the previous earnings and assets recorded. Due to the settlement of four of our long-term gas contracts, the future impact of non-cash mark-to-market movements described above will be significantly reduced.
- In 2004, we incurred margin losses of \$30.3 million resulting from the difference between revenue recognized on our long-term gas contracts and the net cost of gas delivered under these contracts.
- During 2004, we made fixed capacity payments evenly throughout the year that entitled us to generate power at merchant power plants owned by others. For 2004, we recorded net margin loss associated with these agreements of \$36.9 million. The cost to purchase natural gas to fuel these power plants generally exceeded the value of the power that could be generated. Accordingly, we did not generate material revenues.
- The settlement of our price risk management assets and liabilities associated with four of our long-term gas contracts resulted in non-cash, mark-to-market losses of approximately \$40.3 million related to the discounting of our trading portfolio. We discount the future cash flows of our price risk management assets based on our counterparties' credit standing, versus our future cash flows of our price risk management liabilities that are discounted based on our current credit standing. This resulted in the recording of a net asset related to these four long-term contracts and their corresponding commodity hedges of approximately \$40.3 million prior to our settlement. Additionally, we recorded a margin loss of approximately \$16.5 million for margin recorded on these long-term contracts and approximately \$7.1 million related to replacement gas payments we made under the termination provisions of these contracts.
- We incurred approximately \$23.9 million of costs to manage our remaining natural gas hedge positions related to the Onondaga swap derivative sold in connection with the sale of our independent power plants, cash flow hedge option premium expirations, the exit of other hedges related to previous contracts and settlements of various open positions during 2004.

- Our remaining gross loss for 2004 mainly stems from mark-to-market losses and unfavorable settlements of approximately \$32.4 million, related to a long-term power supply transaction with NYSEG and our stream flow transaction. In May 2004, we settled our obligation under the long-term power supply contract with NYSEG by making a cash payment of \$37.7 million to a third party that assumed our obligations under this contract.

#### *Operating Expense*

Operating expense decreased \$18.1 million primarily due to the refund of approximately \$7.2 million of value-added taxes previously paid and expensed by our European merchant trading business, the reduction of our allowance for bad debts by \$7.1 million, \$5.4 million of reduced surety payments due to the settlement of four long-term gas contracts in 2004, and \$5.3 million of reduced costs for staffing needed to manage our remaining trading positions and non-regulated power generation assets. These cost reductions were offset in part by the provision of \$9.0 million in 2005 relating to certain price reporting litigation.

#### *Restructuring Charges*

Restructuring charges increased \$5.9 million in 2005 compared to 2004, primarily due to the termination of the majority of the remaining leases associated with our former Merchant Services headquarters in March 2005 for \$13.0 million which exceeded the reserve obligation by \$6.6 million.

#### *Net (Gain) Loss on Sale of Assets and Other Charges*

Net gain on sale of assets and other charges in 2005 consists primarily of pretax gains of \$16.3 million on the termination of the Batesville tolling agreement and related forward sale contract and \$9.3 million on the sale of our stock investment in ICE and \$6.2 million on the sale of our Red Lake gas storage development project.

During 2004, net loss on sale of assets and other charges consisted of a \$156.2 million loss on the termination of four long-term gas contracts, a \$46.6 million loss on the transfer of our equity interest in the Aries power project and termination of our tolling obligation and an \$8.9 million impairment charge on our investment in the Red Lake gas storage project, offset by a \$6.1 million gain related to the sale of our equity method investments in independent power plants, a \$5.0 million gain on the sale of our Marchwood development project in the United Kingdom, a \$9.1 million gain related to a distribution from BAF Energy and a \$6.0 million reduction of our reserve for the anticipated settlement of our outstanding liabilities to Enron.

#### **2004 versus 2003**

##### *Sales, Cost of Sales and Gross Loss*

The significant factors causing our \$208.9 million gross loss for 2004 are described above.

Gross loss for our Merchant Services operations for 2003 was \$154.7 million, primarily due to the following factors:

- Partially offsetting the losses discussed below were approximately \$54.9 million of non-cash earnings related to the discounting of our trading portfolios, primarily driven by long-term gas contracts. During 2003, average gas prices rose over the life of our price risk management assets and liabilities by \$.73 per MMBtu.

- In 2003, we incurred margin losses of \$45.9 million, resulting from the difference between revenue recognized on our long-term gas contracts and the net cost of gas delivered under these contracts.
- During 2003, we made fixed capacity payments evenly throughout the year that entitled us to generate power at merchant power plants owned by others. For 2003, we recorded net margin loss associated with these agreements of \$56.3 million. The cost to purchase natural gas to fuel these power plants generally exceeded the value of the power that could be generated. Accordingly, we did not generate material revenues.
- In 2003, we incurred approximately \$47.9 million of unfavorable settlements of our highly structured stream flow and long-term power supply transactions and our continued wind-down of our European trading operations.
- We recorded a \$25.6 million non-cash loss related to the sale of our capacity under certain long-term gas transportation agreements at substantially less than our future commitments. Although the loss was recognized for accounting purposes, the cash associated with the loss will be paid out over the term of the contracts.
- We recognized approximately \$29.3 million of net mark-to-market losses on natural gas hedge positions related to the Onondaga swap derivative and other hedges related to previous contracts.
- The remaining \$4.6 million of gross loss primarily relates to mark-to-market losses on alternative risk contracts and settlements of various open positions during 2003.

#### *Operating Expense*

Operating expense decreased \$62.6 million primarily due to \$26.5 million of expense accrued in 2003 related to our January 2004 settlement with the CFTC, and lower labor and other costs related to continued reductions in staff as part of the wind-down of our Merchant operations.

#### *Restructuring Charges*

Restructuring charges decreased \$24.0 million in 2004 compared to 2003. This decrease stemmed primarily from restructuring charges of \$23.1 million during 2003 relating to the termination of our remaining interest rate swaps associated with the construction financings for our Raccoon Creek and Goose Creek power plants. As debt related to these facilities was retired earlier than anticipated, our swaps exceeded our outstanding debt. As a result, we reduced our swap position and realized the loss associated with the cancelled portion of the swaps.

#### *Net Loss on Sale of Assets and Other Charges*

During 2004, net loss on sale of assets and other charges totaled \$185.5 million as discussed above.

During 2003, we recorded \$189.1 million of net loss on sale of assets and other charges. These charges consisted of \$87.9 million related to the write-down of our equity method investments in independent power plants. In the third quarter of 2003, we decided to sell our interest in these plants and therefore wrote our investments down to estimated fair value, which was less than their carrying value. Also included was a \$105.5 million payment for the termination of our 20-year tolling contract for the Acadia power plant, partially offset by a \$5.1 million gain related to the contract termination and sale of certain turbines that we had previously written down to estimated fair value.

### *Depreciation and Amortization Expense*

Depreciation and amortization expense decreased \$17.0 million in 2004 compared to 2003, primarily due to the elimination of the amortization of premiums associated with our equity method investments in independent power plants, resulting from the impairment of our investments in these plants in September 2003.

### *Equity in Earnings of Investments*

Equity in earnings of investments decreased \$51.8 million due to the sale of our independent power plant investments in the first quarter of 2004.

### *Other Income*

Other income decreased \$22.5 million in 2004 primarily due to two items recorded in 2003 that did not recur in 2004. On January 12, 2004, the Eighth Circuit Court of Appeals overturned a prior adverse decision of the United States Tax Court regarding the proper depreciable life of certain of our natural gas gathering and pipeline assets. As a result of the appeals court's decision, we reversed the accrual of \$7.7 million of interest expense in 2003 that would have been payable had the Internal Revenue Service prevailed in the dispute. We also realized foreign currency translation gains of \$12.5 million on the wind-down of our European merchant operations in 2003.

### ***Earnings Trend and Impact of Changing Business Environment***

The merchant energy sector has been negatively impacted by the increase in generation capacity that became operational in 2002 and 2003. This increase in supply has placed downward pressure on power prices and subsequently the value of unsold merchant generation capacity. Although weather and market conditions enabled us to generate \$2.3 million of gross profit in 2005, it is generally expected that the fuel and start-up costs of operating our Crossroads peaking power plant will exceed the revenues that would be generated from the power sold, we believe that during the foreseeable future we will have limited assurance of our ability to generate power at a gross profit. We will continue to have operating and maintenance costs associated with our Crossroads peaking power plant, whether the facility is being utilized to generate power or is idle. We continue to look for viable solutions to the utilization of our unsold merchant generation capacity. Additionally, we will be required to make capacity payments related to our Elwood tolling agreements and expect to incur pretax losses and negative operating cash flows of approximately \$37.3 million in 2006 related to this arrangement. We are attempting to restructure our Elwood obligation, and will incur a significant charge to the extent that we are able to exit or restructure that obligation. As a result of the above factors and our change in strategy, we do not expect Merchant Services to be profitable in the next two to three years.

We recently evaluated the carrying value of our Crossroads merchant peaking power plant. As of December 31, 2005, the carrying value of this plant was \$122.6 million. We performed this evaluation due to reduced spark spreads and an oversupply of generation that we expect will continue for the foreseeable future. This situation has prevented the plant from producing significant margins and, in turn, has created losses for us. It is forecasted that these losses will continue for the next few years. We separately tested the cash flows for the plant based on estimated margin contributions and forecasted operating expenses over its remaining plant life. The peaking plant was placed into service in 2002 and we depreciate the facility over 35 years. In evaluating future estimated margin contributions, we used external price curves based on four different future price environments. In each environment, we calculated an average margin contribution based on a multi-simulation scenario analysis and then equally weighted each price

environment. Based on this analysis and the level of probability we would sell the asset, the undiscounted probability weighted cash flows for the plant exceeded its current book value. Therefore, under SFAS 144 no impairment was required as of December 31, 2005. We have evaluated this asset as held and used. If at some future date we determine this asset is held for sale, based on current market values, we would likely record a material impairment charge.

## Corporate Matters

### Three-Year Review—Corporate and Other

The table below summarizes EBITDA for Corporate and Other, which includes the retained costs of the company that are not allocated to our operating businesses, and our former equity method investments in Australia and the United Kingdom, each of which has been sold. Our Australian investments included a 33.8% interest in United Energy Limited (UEL), an electric distribution company in the Melbourne area; a 25.5% interest in Multinet Gas, a gas distribution company in the Melbourne area; and a 45.0% interest, held jointly with UEL, in AlintaGas Limited, a gas distribution company in Western Australia. We sold our Australian investments in May and July 2003. Our United Kingdom investment consisted of an indirect 79.9% interest in Aquila Sterling Limited, the holding company for Midlands Electricity, an electric distribution company in central England. We sold our United Kingdom investment in January 2004.

We sold our former Canadian utility businesses in May 2004 and have classified our 97% owned subsidiary, Everest Connections, a communications provider, as held for sale. The results of Everest Connections and our Canadian utility businesses have been reclassified as discontinued operations and are not included below (see Note 6 to the Consolidated Financial Statements).

<i>In millions</i>	<b>Year Ended December 31,</b>		
	<b>2005</b>	<b>2004</b>	<b>2003</b>
Sales	\$ —	\$ —	\$ 1.9
Cost of sales	—	—	.3
Gross profit	—	—	1.6
Operating expenses:			
Operating expense	20.9	31.4	51.5
Restructuring charges	—	.2	1.4
Net loss on sale of assets and other charges	86.7	2.8	5.8
Total operating expenses	107.6	34.4	58.7
Other income (expense):			
Equity in earnings of investments	—	.2	15.9
Other income	4.4	10.4	60.2
Earnings (loss) before interest and taxes, depreciation and amortization	\$(103.2)	\$(23.8)	\$19.0
Depreciation and amortization expense	\$ .3	\$ .4	\$ (1.2)

### **2005 versus 2004**

#### *Operating Expense*

Operating expense decreased \$10.5 million in 2005 compared to 2004, due to the 2004 settlement of the appraisal rights shareholder lawsuit for \$8.8 million, a \$8.5 million decrease in

costs associated with our former international networks investments in Canada and Australia compared to 2004 and a \$3.3 million decrease in insurance costs in 2005. These decreases were offset in part by \$7.9 million of increased legal fees related to our ERISA litigation and \$4.0 million of increased consulting fees and other costs associated with the process of selling certain of our Gas and Electric Utilities in 2005.

#### *Net Loss on Sale of Assets and Other Charges*

The \$86.7 million loss on sale of assets and other charges in 2005 was primarily the result of the \$82.3 million loss on the early conversion of the PIES. In addition, we recognized an additional \$4.4 million loss on three natural gas combustion turbines that were held by one of our non-regulated subsidiaries and were transferred to our Missouri electric operations at their current fair value. In connection with the settlement of our recent Missouri electric rate case, we agreed with the Missouri Commission staff and other interveners that fair value was approximately \$4.4 million lower than that estimated in 2004. The 2004 loss on sale of assets and other charges of \$2.8 million is mainly due to the \$10.6 million impairment on three natural gas combustion turbines that were held by one of our non-regulated subsidiaries and were transferred to our Missouri electric operations in 2004 at their estimated current fair value. The impairment was partially offset by the reversal of a \$4.5 million liability we recorded at Corporate related to our Everest Connections target-based put rights due to the meeting of certain financial and operational performance measures, and the \$3.3 million gain we recorded in connection with the sale of our interest in Midlands Electricity in January 2004. The Midlands Electricity investment was written down to its estimated fair value in 2002 and again in September 2003. However, due to strengthening of the British pound exchange rate in the fourth quarter of 2003 and in early 2004, we realized a gain on the closing of the sale.

#### *Other Income*

Other income decreased \$6.0 million in 2005 compared to 2004, primarily due to \$3.4 million of fees on the \$180 million facility supporting our unsecured letter of credit in 2005, and \$3.3 million of net gains in 2004 discussed below that did not recur in 2005.

### **2004 versus 2003**

#### *Operating Expense*

Operating expense decreased \$20.1 million in 2004 compared to 2003, primarily due to a \$14.2 million decrease in insurance and other costs associated with having non-investment grade credit ratings. Consulting fees decreased \$8.2 million in 2004 due to the completion of our restructuring efforts in 2003. In addition, the sale of our international investments in Australia and the United Kingdom decreased operating expenses \$12.5 million. These decreases were partially offset by an \$8.8 million increase in costs associated with the settlement of the appraisal rights shareholder lawsuit in 2004 and \$4.9 million of additional costs related to the exit of our international networks investment in 2004.

#### *Net Loss (Gain) on Sale of Assets and Other Charges*

The 2004 net loss on sale of assets and other charges of \$2.8 million is mainly due to the \$10.6 million impairment on three natural gas combustion turbines that were held by one of our non-regulated subsidiaries and have now been transferred to our Missouri electric operations at their current fair value. The impairment was partially offset by the reversal of our Everest Connections target-based put rights liability of \$4.5 million due to the meeting of certain financial and operational performance measures, and the \$3.3 million gain we recorded in

connection with the sale of our interest in Midlands Electricity in January 2004. The Midlands Electricity investment was written down to its estimated fair value in 2002 and again in September 2003. However, due to strengthening of the British pound exchange rate in the fourth quarter of 2003 and in early 2004, we realized a gain on the closing of the sale. The 2003 loss on sale of assets of \$5.8 million was related to the impairment charge taken on our investment in Midlands Electricity in September 2003 and the net loss on the sale of our interests in AlintaGas, UEL and Multinet Gas in Australia in May and July 2003.

#### *Equity in Earnings of Investments*

Equity in earnings of investments decreased \$15.7 million in 2004 compared to 2003 due to the sale of our investments in Australia in May and July 2003.

#### *Other Income*

Other income decreased \$49.8 million in 2004 compared to 2003, mainly due to \$42.1 million of foreign currency gains recognized in 2003 related to favorable movements in the Australian and New Zealand dollar against the U.S. dollar, and \$12.3 million of foreign currency gains recognized in the second quarter of 2003 due to the strengthening of the Canadian dollar on U.S. dollar obligations at a former Canadian finance subsidiary not included in discontinued operations. We had an \$11.9 million gain on foreign currency related to the wind-down of our Canadian merchant subsidiaries in 2004. Additionally in 2004, we realized a \$1.9 million gain on the early redemption of the note payable issued in connection with our acquisition of Midlands, which was offset by \$1.8 million in fees paid to lenders in connection with the waiver and amendment of financial covenants under our retired secured term loan. These gains in 2004 were partially offset by \$8.7 million of prepayment penalties and fees we paid in association with the retirement of the secured term loan.

#### **Interest Expense and Income Tax Benefit**

The table below summarizes our consolidated interest expense and income tax benefit:

<i>In millions</i>	<b>Year Ended December 31,</b>		
	<b>2005</b>	<b>2004</b>	<b>2003</b>
Interest expense	\$150.2	\$ 184.5	\$ 198.8
Income tax benefit	\$(43.1)	\$(214.3)	\$(147.0)

#### ***2005 versus 2004***

##### *Interest Expense*

Interest expense decreased \$34.3 million in 2005 compared to 2004. The decrease was primarily the result of the following:

- Lower interest costs of \$18.5 million related to the scheduled retirements of senior notes in 2004 and 2005;
- A \$24.9 million decrease in interest expense related to our former \$430.0 million secured term loan which was repaid in September 2004; and
- The repayment of our \$430.0 million secured term loan also resulted in the expensing of \$10.3 million of unamortized debt issuance costs in 2004.

These decreases were partially offset by the following increases in interest expense:

- Interest expense increased approximately \$15.1 million related to our \$220 million unsecured term loan borrowing in September 2004; and
- Interest expense increased approximately \$3.4 million related to the PIES issued in August 2004.

#### *Income Tax Benefit*

The income tax benefit decreased \$171.2 million in 2005 compared to 2004, primarily due to decreased pretax losses and non-deductible expenses in 2005 related to the \$82.3 million loss on the PIES exchange. In addition, in 2005 a \$53.2 million decrease in valuation allowances related to capital losses was substantially offset by an increase in the reserve for contingent liabilities.

#### **2004 versus 2003**

##### *Interest Expense*

Interest expense decreased \$14.3 million in 2004 compared to 2003. The decrease was primarily the result of the following:

- Lower interest costs of \$8.3 million related to the retirement of debt associated with our international utility investments and power generation;
- Decreased interest expense and fees on short-term borrowings and letter of credit facilities of approximately \$6.8 million; and
- Decreased amortization of debt issuance costs of \$9.3 million mainly associated with the 364-day secured credit facility and the three-year secured term loan in 2003.

These decreases were partially offset by the following increase in interest expense:

- The repayment in the third quarter of 2004 of \$430.0 million under our three-year secured term loan resulted in the expensing of \$10.3 million of unamortized debt issuance costs.

##### *Income Tax Benefit*

The income tax benefit increased \$67.3 million in 2004 compared to 2003, primarily due to increased pretax losses, the decrease in net valuation allowances provided on capital losses and the accrual of non-deductible fines and penalties in 2003.

## Discontinued Operations

Operating results of discontinued operations are as follows:

<i>In millions</i>	<b>Year Ended December 31,</b>		
	<b>2005</b>	<b>2004</b>	<b>2003</b>
Sales	\$ 879.8	\$870.9	\$1,013.3
Cost of sales	608.0	518.1	508.8
Gross profit	271.8	352.8	504.5
Operating expenses:			
Operating expense	112.1	183.0	263.0
Restructuring charges	—	—	2.1
Net loss (gain) on sale of assets and other charges	159.5	(74.0)	49.5
Total operating expenses	271.6	109.0	314.6
Other income (expense):			
Other income (expense)	.5	3.5	(15.6)
EBITDA	.7	247.3	174.3
Depreciation and amortization expense	42.5	47.5	53.2
Interest expense	71.2	88.6	98.2
Earnings (loss) before income taxes	(113.0)	111.2	22.9
Income tax expense (benefit)	(41.0)	55.4	2.8
Earnings (loss) from discontinued operations	\$ (72.0)	\$ 55.8	\$ 20.1

### **2005 versus 2004**

#### *Sales, Cost of Sales and Gross Profit*

##### Electric Utilities

Sales, cost of sales and gross profit for our Kansas electric utility increased \$25.7 million, \$15.7 million, and \$10.0 million, respectively, in 2005 compared to 2004. Sales and gross profit increased by \$6.2 million due to a rate increase in Kansas effective in April 2005. The favorable impacts of weather on electricity usage increased 2005 gross profit by an additional \$2.2 million over 2004, and electric wheeling revenue increased by \$2.5 million in 2005.

##### Gas Utilities

Sales, cost of sales, and gross profit for Michigan, Minnesota, and Missouri gas utilities increased \$89.5 million, \$88.2 million, and \$1.3 million, respectively. Sales and cost of sales increased approximately \$80.9 million due to a 25% increase in natural gas prices since December 31, 2004. However, because gas purchase costs for our gas utility operations are passed through to our customers, the change in gas prices did not have a corresponding impact on gross profit. Sales and gross profit increased by \$1.4 million due to rate increases in Missouri effective in May and July 2004. Sales and gross profit increases of \$1.9 million due to the pipeline supplier metering adjustments in 2005 associated with prior periods were offset by the impacts of milder winter weather and other volume variances in 2005 as compared to 2004.

##### Other

Other sales, cost of sales and gross profit decreased \$106.3 million, \$14.0 million, and \$92.3 million, respectively, in 2005 compared to 2004. Our Canadian utilities and independent

power plants, which had 2004 gross profit of \$105.7 million, were sold in the first half of 2004. Slightly offsetting this lost profit was a \$5.8 million increase in Everest Connections 2005 gross profit as compared to 2004 due to an increase in customers served and a \$7.7 million increase in gross profit earned by the Illinois peaking power plants related to increased demand for peaking power and short-term capacity contracts in 2005.

#### *Operating Expense*

Operating expense decreased \$70.6 million in 2005 compared to 2004 primarily due to the sale of our consolidated independent power plants and our Canadian utility businesses in the first half of 2004. Both the electric and gas utility operations also experienced operating expense decreases in 2005, related primarily to property tax settlements in Michigan and Minnesota, lower property tax expenses in all states, and reductions in the reserves needed for bad debt and general claims.

#### *Net Loss (Gain) on Sale of Assets and Other Charges*

In 2005, net loss on sales of assets and other charges of \$159.5 million was the result of an impairment of the Illinois peaking power plants to reduce their book value to current fair market value. In 2004, net gain on sale of assets and other charges of \$74.0 million consisted of a \$65.6 million gain on the sale of our Canadian utility businesses in May 2004 and an \$8.4 million gain on the sale of our consolidated independent power plants, Lake Cogen and Onondaga, in March 2004.

#### *Other Income (Expense)*

Other income decreased \$3.0 million in 2005 compared to 2004, primarily due to 2004 interest income earned by our Canadian subsidiaries that were sold in 2004.

#### *Depreciation and Amortization Expense*

Depreciation and amortization expense decreased \$5.0 million in 2005 compared to 2004. The elimination of depreciation from our Kansas electric and Michigan, Minnesota, and Missouri gas utility businesses in the fourth quarter of 2005, due to their classification as held for sale in accordance with SFAS 144, decreased depreciation expense by \$7.5 million. SFAS 144 requires that depreciation expense no longer be recorded for those assets classified for accounting purposes as held for sale. The decrease was partially offset by increased depreciation expense related to the expansion of Everest Connections' communication network to accommodate customer growth.

#### *Interest Expense*

Interest expense decreased \$17.4 million in 2005 compared to 2004, primarily due to the repayment or assumption of debt associated with our Canadian utility businesses that were sold in May 2004.

#### *Income Tax Expense (Benefit)*

Income tax expense decreased \$96.4 million in 2005 compared to 2004, primarily due to the pretax loss in 2005 related to the impairment of our investments in Illinois peaking power plants in 2005. The 2005 income tax benefit on a pretax loss from discontinued operations was primarily the result of the impairment of our Illinois peaking facilities, while the 2004 income tax expense on pretax income from discontinued operations resulted from the pretax gain on the sale of our Canadian utility businesses. The tax expense on that 2004 gain was substantially higher than the

statutory federal tax rate due to the following factors. The U.S. taxes reflect the partial deduction of Canadian taxes, including withholding taxes, from the U.S. taxable income instead of the full utilization of foreign tax credits. Taxes on the sale also reflect our inability to fully utilize the tax loss on the sale of the Alberta business against the tax gain on the sale of the British Columbia business.

### ***2004 versus 2003***

#### *Sales, Cost of Sales and Gross Profit*

##### Electric Utilities

Sales, cost of sales and gross profit for our Kansas electric utility increased \$11.7 million, \$11.5 million, and \$.2 million, respectively, in 2004 compared to 2003. Higher off-system sales activity in 2004 was the primary driver of these increases, resulting in a \$1.0 million rise in gross profit. Offsetting this 2004 increase was the impact of a 2003 sale of “green” credits awarded to us for using environmentally-friendly generation. No similar sale occurred in 2004.

##### Gas Utilities

Sales and cost of sales for Michigan, Minnesota, and Missouri gas utilities increased \$29.4 million and \$35.4 million, respectively, resulting in a \$6.0 million decrease in gross profit. This decrease in gross profit was primarily the result of milder weather in 2004 and a 2003 pipeline supplier metering adjustment in Michigan. The increase in sales and cost of sales in 2004 compared to 2003 was primarily the result of higher natural gas prices which are passed through to our customers.

##### Other

Other sales and cost of sales decreased \$183.5 million and \$37.7 million, respectively, resulting in a gross profit decrease of \$145.8 million in 2004 compared to 2003. Sales, cost of sales and gross profit for our Canadian utility business decreased \$126.0 million, \$21.2 million and \$104.8 million, respectively, primarily due to the sale of these businesses in May 2004. Canadian utility sales, cost of sales and gross profit in June 2003 through December 2003 were \$170.4 million, \$23.3 million and \$147.1 million, respectively. These decreases were partially offset by the March 2003 decision by the Alberta Energy Utilities Board (AEUB) to reduce our 2002 and 2003 customer billing rates. The AEUB decision resulted in an adjustment that reduced our first quarter 2003 sales and gross profit by approximately \$33.7 million. Sales, cost of sales and gross profit for Lake Cogen and Onondaga were lower in 2004 by \$65.2 million, \$17.8 million and \$47.4 million, respectively, due to the sale of these businesses in early March 2004 and a price dispute settlement that increased Lake Cogen’s 2003 sales by \$5.7 million. Everest Connections’ gross profit increased \$5.2 million in 2004 as compared to 2003 due to an increase in customers served; slightly offsetting that increase was a \$1.5 million decrease in gross profit earned by the Illinois peaking power plants.

#### *Operating Expense*

Operating expense decreased \$80.0 million in 2004 compared to 2003 primarily due to the sale of our consolidated independent power plants in March 2004 and our Canadian utility businesses in May 2004, offset in part by increased operating expenses at our Kansas electric and Michigan, Minnesota and Missouri gas utilities.

### *Net Loss (Gain) on Sale of Assets and Other Charges*

In 2004, net gain on sale of assets and other charges of \$74.0 million consisted of a \$65.6 million gain related to the sale of our Canadian utility businesses in May 2004, and an \$8.4 million gain related to the sale of our consolidated independent power plants, Lake Cogen and Onondaga, in March 2004. In 2003, the \$49.5 million net loss and other charges was primarily related to the impairment charge taken on our consolidated independent power plants. In the third quarter of 2003, we decided to proceed with their sale and therefore wrote them down to their estimated fair value less costs to sell, which was less than their carrying value.

### *Other Income (Expense)*

Other income increased \$19.1 million in 2004 compared to 2003, primarily due to 2003 costs including an \$18.5 million charge related to a currency put option purchased to protect us from unfavorable currency movements on the Canadian asset sale proceeds and \$3.2 million of foreign currency losses related to U.S. dollar denominated debt issued by our Canadian subsidiaries.

### *Depreciation and Amortization Expense*

Depreciation and amortization expense decreased \$5.7 million in 2004 compared to 2003. The elimination of depreciation from our Canadian utility businesses, due to their classification as held for sale in accordance with SFAS 144, decreased depreciation expense \$21.4 million. SFAS 144 requires that depreciation expense no longer be recorded for those assets classified for accounting purposes as held for sale. The decrease was offset by the \$15.2 million adjustment in the first quarter of 2003 related to the decision by the AEUB to reduce the depreciation rates on most of our distribution assets in Alberta.

### *Interest Expense*

Interest expense decreased \$9.6 million in 2004 compared to 2003, primarily due to the sale of our Canadian utility businesses in May 2004.

### *Income Tax Expense*

Income tax expense increased \$52.6 million in 2004 compared to 2003. The 2004 income tax expense on pretax income from discontinued operations was primarily the result of taxes associated with the gain on the sale of our Canadian utility businesses. The effective tax rate on the pretax gain on sale of our Canadian utility businesses is substantially higher than the statutory federal tax rate due to the following factors. The U.S. taxes reflect the partial deduction of Canadian taxes, including withholding taxes, from the U.S. taxable income instead of the full utilization of foreign tax credits. Taxes on the sale also reflect our inability to fully utilize the tax loss on the sale of the Alberta business against the tax gain on the sale of the British Columbia business. Offsetting the 2004 income tax expense was the reversal of \$11.1 million of valuation allowances provided in 2003 related to the impairment of our investments in independent power plants. This valuation allowance was reversed in 2004 when the final sale structure was determined and an updated estimate of expected capital losses was completed. In addition, our former Alberta utility recognized income taxes using the flow-through method. As a result, the elimination of depreciation in 2004 and the adjustment of depreciable lives due to the 2003 regulatory decision increased pretax income but had no impact on income tax expense.

## **OTHER ITEMS**

### **Critical Accounting Policies and Estimates**

We have prepared our financial statements in conformity with accounting principles generally accepted in the United States. These statements include some amounts that are based on informed judgments and estimates of management. Our significant accounting policies are discussed in Note 1 to the Consolidated Financial Statements. Our critical accounting policies are subject to judgments and uncertainties that affect the application of such policies. As discussed below, while we believe these financial statements include the most likely outcomes with regard to amounts that are based on our judgments and estimates, our financial position and results of operations may be materially different when reported under different conditions or when using different assumptions in the application of such policies. In the event estimates or assumptions prove to be different from actual amounts, adjustments are made in subsequent periods to reflect more current information. Our critical accounting policies include:

#### ***Energy Trading and Derivative Accounting***

The portion of our trading activities that qualify as derivatives under SFAS 133 is recorded under the mark-to-market method of accounting. The market prices or fair values used in determining the value of our portfolio are our best estimates utilizing information such as closing exchange rates, over-the-counter quotes, historical volatility and the potential impact on market prices of liquidating our positions in an orderly manner over a reasonable amount of time under current market conditions. As additional information becomes available, or actual amounts are determinable, the recorded estimates are revised. As a result, operating results can be affected by revisions to prior accounting estimates. Operating results can also be affected by changes in underlying factors used in the determination of fair value of our portfolio such as the following:

- We have variability in our mark-to-market earnings due to changes in the market price for gas and/or power. Our portfolio is valued from current and expected future gas and power prices. Changes in these prices can cause fluctuations in our earnings.
- We discount our price risk management assets and liabilities using risk-free interest rates adjusted for our credit standing and the credit standings of our counterparties in accordance with SFAS 133 which is more fully described in Statement of Financial Accounting Concepts No. 7, "Using Cash Flow Information and Present Value in Accounting Measurement". Because our price risk management liabilities are discounted using our credit standing, versus the receivable side of these transactions which are discounted based on our counterparties' credit standings (which on average are higher than ours), non-cash mark-to-market earnings or losses are created. As these spreads narrow, we record mark-to-market losses; as they widen, we record mark-to-market gains. These gains and losses can fluctuate if our credit or the credit of a group of our counterparties deteriorates or improves significantly.

We also have other activities in our utility operations that are accounted for under SFAS 133. The majority of these activities consist of the purchasing of gas, power and coal for our utility operations, which fall under the normal purchases and sales exception. These activities require that management make certain judgments regarding the election of the normal purchases and sales exceptions. In addition, as allowed by state regulatory commissions, we have entered into certain financial instruments to reduce our customers' underlying exposure to fluctuations in gas prices. These financial instruments are considered derivatives under SFAS 133 and are marked-to-market and recorded in our PGA accounts as they are collectible under the provisions of the PGA upon settlement. We also have entered into a program for our electric utility operations in Missouri to mitigate our exposure to natural gas price volatility in the market. This

program extends multiple years and the mark-to-market value of the portfolio of \$20.7 million related to contracts that will settle against actual purchases of natural gas and purchased power in 2006 through 2008. In connection with the recently settled Missouri electric rate case, we agreed that these contracts would be recognized into cost of sales when they settle. A regulatory liability has been recorded under SFAS 71 in the amount of \$20.7 million to reflect the change in the timing of recognition authorized by the Missouri Commission.

### ***Unbilled Utility Revenues***

Sales related to the delivery of energy are generally recorded when service is rendered or energy is delivered to customers. However, the determination of sales is based on reading customers' meters, which occurs systematically throughout the month. At the end of each month, an estimate is made of the amount of energy delivered to customers after the date of the last meter reading. The unbilled revenue is calculated each month based on estimated customer usage, weather factors, line losses and applicable customer rates. Total unbilled revenues for continuing operations at December 31, 2005 were \$101.2 million.

### ***Impairment of Long-Lived Assets***

We review the carrying value of long-lived assets whenever events or changes in circumstances indicate that such carrying values may not be recoverable in accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-lived Assets." Unforeseen events and changes in conditions could indicate that these carrying values may not be recoverable and may therefore result in impairment charges. An impairment loss is recognized only if the carrying amount of the long-lived asset is not recoverable and exceeds its fair value. The carrying amount of a long-lived asset is not recoverable if it exceeds its future undiscounted cash flows. Once deemed impaired, the long-lived asset is written down to its fair value. The determination of future cash flows, and, if required, fair value of a long-lived asset is by its nature a highly subjective judgment. Fair value is determined by calculating the discounted future cash flows using a discount rate based upon our weighted average cost of capital, third party contracted bids or appraisals performed by a qualified party. Significant judgments and assumptions are required in the forecast of future operating results used in the preparation of the long-term estimated cash flows, including long-term forecasts of the amounts and timing of overall market growth. Changes in these estimates could have a material effect on the assessment of our long-lived assets.

We have evaluated the carrying value of the Crossroads peaking power plant we contractually control and which is classified as held and used. As of December 31, 2005, the carrying value of this plant was \$122.6 million. We performed this evaluation due to reduced spark spreads and an oversupply of generation that we expect will continue for the foreseeable future. This situation has prevented this plant from firing and, in turn, has created losses for us. It is forecasted that this loss will continue for the next few years. We tested the cash flows for the plant based on estimated margin contributions and forecasted operating expenses over its remaining plant life. This peaking plant was placed into service in 2002 and we depreciate this facility over 35 years. In evaluating future estimated margin contributions, we used external price curves based on four different future price environments. In each environment, we calculated an average margin contribution based on a multi-simulation scenario analysis and then equally weighted each price environment. Based on this analysis and the level of probability we would sell this asset, the undiscounted probability weighted cash flows for this plant exceeded its current book value. Therefore, under SFAS 144 no impairment was required as of December 31, 2005. We have evaluated this asset as held and used. If at some future date we determine this asset is held for sale, based on current market values, we would likely record a material impairment charge.

### ***Goodwill and Other Intangible Assets***

On January 1, 2002, we adopted SFAS No. 142, “Goodwill and Other Intangible Assets” (SFAS 142). Under SFAS 142 we no longer amortize goodwill, but instead test it for impairment each year on November 30, and if impaired, write it off against earnings at that time. Goodwill is tested for impairment by comparing the fair value of a reporting unit, determined on a discounted cash flow basis or other fair market value methods, with its carrying amount, including goodwill. If the fair value of the reporting unit exceeds its carrying amount, goodwill of the reporting unit is not considered impaired. If the carrying amount of a reporting unit exceeds its fair value, then an impairment loss is measured by comparing the implied goodwill (excess of the fair value of the reporting unit over the fair value assigned to its assets and liabilities) with the carrying amount of that goodwill.

We believe that the accounting estimate related to determining the fair value of goodwill, and thus any impairment, is a critical accounting estimate because: (1) it is susceptible to change from period to period because it requires us to make cash flow assumptions about future sales, operating costs and discount rates over an indefinite life; and (2) the impact of recognizing an impairment could be material. Management’s assumptions about future sales margins and volumes require significant judgment because actual margins and volumes have fluctuated in the past and are expected to continue to do so. In estimating future margins and expenses, we use our internal budgets. We develop our budgets based on anticipated customer growth, rate cases, inflation and weather trends. Total goodwill at December 31, 2005 was \$111.0 million.

### ***Regulatory Accounting Implications***

We currently record the economic effects of regulation in accordance with the provisions of SFAS No. 71 “Accounting for the Effects of Certain Types of Regulation” (SFAS 71). Accordingly, our balance sheet reflects certain costs as regulatory assets. We are required to periodically assess the probable recovery of our regulatory assets. We expect our rates will continue to be based on historical costs for the foreseeable future. However, if we no longer qualified for treatment under SFAS 71, we would make adjustments to the carrying value of our regulatory assets and liabilities and would be required to recognize them in current period earnings. Total regulatory assets and liabilities at December 31, 2005 were \$110.7 million and \$115.6 million, respectively. See Note 10 to the Consolidated Financial Statements for further details.

### ***Valuation of Deferred Tax Assets***

We are required to assess the ultimate realization of deferred tax assets generated from net operating losses and capital losses incurred on the sale of assets using a “more likely than not” assessment of realization. This assessment takes into consideration tax planning strategies within our control, including assumptions regarding the availability and character of future taxable income. As of December 31, 2005, we have recorded \$248.9 million of valuation allowances against deferred tax assets for which the ultimate realization of the tax asset is mainly dependent on the availability of future capital gains and taxable income in certain states. The ultimate amount of deferred tax assets realized could be materially different from that recorded, as impacted by changes in federal income tax laws and upon the generation of future capital gains or state taxable income to enable us to realize the related tax assets.

As of December 31, 2005, we had approximately \$454.5 million of federal net operating loss carryforwards originating in 2003, \$579.0 million of estimated federal net operating losses originating in 2004 and an estimated \$85.9 million of federal net operating losses originating in 2005. The 2003 federal net operating loss carryforward expires in 2023 and can be carried back to 2001 to offset potential IRS audit adjustments. The 2004 and 2005 federal net operating loss

carryforwards expire in 2024 and 2025, respectively, and cannot be carried back due to losses in the carryback years. We did not record valuation allowances against the deferred tax assets related to federal net operating losses. This determination was based on our assessment that it is more likely than not that we will realize these deferred assets during the carryforward period. This assessment considered the forecasted reversal of existing temporary differences and taxable income expected to be generated in the carryforward period and potential IRS audit adjustments in 2001.

### ***Reserve for Contingent Tax Liabilities***

As of December 31, 2005, we have recorded liabilities of \$287.6 million for cumulative tax provisions for tax deduction or income positions taken in prior tax returns that we believe were properly treated on such tax returns but for which it is reasonably likely that these deductions or income positions will be challenged when the returns are audited. The tax returns containing these tax deductions or income positions are currently under audit or will likely be audited. The reserve is included in deferred tax liabilities because the timing of the resolution of these audits is uncertain and if the positions taken on the tax returns are not ultimately sustained, we may be required to utilize our net operating loss carryforwards, alternative minimum tax credit carryforwards, and/or general business credit carryforwards and/or make cash payments plus interest. We use significant judgment in both the determination of probability and the determination as to whether a contingent tax liability is reasonably estimable. Because of uncertainties related to these matters, reserves are based only on the best information at that time. As additional information becomes available, we reassess the potential liability related to our tax deductions or income positions and may revise our estimates. Such revisions in the estimates of contingent tax liabilities could have a material impact on our financial position and results of operations.

### ***Pension Plans***

Our reported costs of providing non-contributory defined pension benefits (described in Note 18 to the Consolidated Financial Statements) are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience.

Pension costs, for example, are impacted by actual employee demographics (including age, compensation levels and employment periods), the level of contributions we make to the plan and earnings on plan assets. Changes made to the provisions of the plan may also impact current and future pension costs. Pension costs may also be significantly affected by changes in key actuarial assumptions, including anticipated rates of return on plan assets and the discount rates used in determining the projected benefit obligation and pension costs. Pension plan assets are primarily made up of equity and fixed income investments. Fluctuations in actual equity market returns as well as changes in general interest rates may result in increased or decreased pension costs in future periods. Likewise, changes in assumptions regarding current discount rates and expected rates of return on plan assets could also increase or decrease recorded pension costs. As of September 30, 2005, our average assumed discount rate was 5.80% and our average expected return on plan assets was 8.50%.

The following chart reflects the sensitivities associated with a change in certain actuarial assumptions by the indicated percentage. While the chart below reflects an increase in the percentage for each assumption, we and our actuaries expect that the inverse of this change would impact the projected benefit obligation (PBO) at December 31, 2005, and our estimated annual pension cost (APC) on the income statement for 2006 by a similar amount in the opposite

direction. Each sensitivity below reflects an evaluation of the change based solely on a change in that assumption.

<i>Dollars in millions</i>	<b>Change in Assumption</b> Incr.(decr.)	<b>Impact on PBO</b> Incr.(decr.)	<b>Impact on APC</b> Incr.(decr.)
Discount rate	.25%	\$(13.7)	\$(1.4)
Rate of return on plan assets	.25%	—	(.9)

### ***Legal Contingencies***

We are currently involved in various claims and legal proceedings. We periodically review the status of each significant matter and assess our potential financial exposure. If the potential loss from any claim or legal proceeding is considered probable and the amount can be reasonably estimated, we accrue a liability for the estimated loss. We use significant judgment in both the determination of probability and the determination as to whether an exposure is reasonably estimable. Because of uncertainties related to these matters, accruals are based only on the best information at that time. As additional information becomes available, we reassess the potential liability related to our pending claims and litigation and may revise our estimates. Such revisions in the estimates of potential liabilities could have a material impact on our financial position and results of operations. We expense legal fees as incurred.

### **Significant Balance Sheet Movements**

Total assets decreased by \$146.6 million since December 31, 2004. This decrease is primarily due to the following:

- Cash decreased \$204.3 million. See our Consolidated Statement of Cash Flows for analysis of this decrease.
- Funds on deposit decreased \$88.2 million, primarily due to the return of margin deposits paid to counterparties in connection with the continued wind-down of our wholesale energy-trading portfolio and the replacement of cash collateral with uncollateralized letters of credit, offset in part by additional requirements by our suppliers of natural gas that we post additional margin deposits as a result of our non-investment grade credit rating and increased natural gas prices.
- Accounts receivable increased \$57.7 million, primarily due to increased natural gas prices since December 31, 2004, offset in part by lower volumes of natural gas and electricity delivered due to the continued wind-down of wholesale energy trading business.
- Price risk management assets increased \$116.7 million, primarily due to an increase in natural gas prices since December 31, 2004.
- Property, plant and equipment, net, increased \$67.3 million primarily due to the construction of our South Harper peaking facility in 2005.
- Current and non-current assets of discontinued operations decreased \$82.3 million, primarily due to the impairment of our Illinois peaking power plants in 2005, offset in part by increased accounts receivables in the gas states due to higher natural gas prices.

Total liabilities decreased by \$326.0 million and common shareholders' equity increased by \$179.4 million since December 31, 2004. These changes are primarily attributable to the following:

- Price risk management liabilities increased \$65.4 million, primarily due to an increase in natural gas prices since December 31, 2004.
- Customer funds on deposit increased \$53.6 million, primarily due to increased margin deposits received from counterparties on "in-the-money" derivative contracts for natural gas resulting from increased natural gas prices.
- Short-term and long-term debt, including current maturities of long-term debt, together decreased by \$374.9 million, primarily due to the early exchange of the PIES for shares of common stock.
- Deferred income taxes and credits decreased \$76.5 million primarily as the result of deferred tax benefits on 2005 net operating losses.
- Common shareholders' equity increased \$179.4 million, primarily as a result of the early PIES exchange transaction, offset in part by the \$230.0 million net loss in 2005.

### **New Accounting Standards**

In 2004 and 2005, the FASB issued a number of interpretation, staff positions and new accounting standards that had potential impacts on our financial results. In 2004, the FASB issued SFAS No. 123R, "Share-Based Payments," and FASB Staff Position No. 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003." In 2005, the FASB issued Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations," SFAS 153, "Accounting for Nonmonetary Exchanges" and SFAS 154, "Accounting Changes and Error Corrections." See Notes 2, 8 and 18 to the Consolidated Financial Statements for further discussion.

### **Effects of Inflation**

In the next few years, we anticipate that the level of inflation, if moderate, will not have a significant effect on operations.

### **Forward-Looking Information**

This report contains forward-looking information. Forward-looking information involves risks and uncertainties, and certain important factors can cause actual results to differ materially from those anticipated. The forward-looking statements contained in this report include:

- We expect to improve our returns through future rate activities and process improvements. Some important factors that could cause actual results to differ materially from those anticipated include:
  - Regulatory commissions may refuse to approve some or all of the utility rate increases we may request, and we may not be allowed by regulatory commission to keep any or all of the savings generated by our process improvements for our shareholders' benefit.
  - The timing of utility rate increases approved by regulatory commissions is often beyond our control and, until final approval is received, our earnings will continue to be impacted.
  - We may not be able to improve operational efficiencies in a magnitude that would help improve our credit profile.

- We expect to use the net proceeds from asset sales to retire debt and other liabilities and fund our anticipated capital expenditures, in a manner that maximizes the improvement of our credit profile. Some important factors that could cause actual results to differ materially from those anticipated include:
  - We may not be able to retire a sufficient principal amount of debt and other liabilities in a manner that maximizes our net sale proceeds or improves our credit sufficiently.
  - We may receive less net sale proceeds than anticipated due to purchase price adjustments or changes required to satisfy the conditions of regulatory orders pertaining to the asset sales.
  - The counterparty to the Elwood tolling contract may be unwilling to terminate or restructure this contract, or we may not find a third party willing to assume this obligation upon acceptable terms.
- We are developing a comprehensive plan to eliminate the majority of the allocated costs related to the utilities that are being sold when the support services are no longer required, and we expect that a portion of these costs will be reallocated to our remaining utility operations for recovery in future rate cases. Some important factors that could cause actual results to differ materially from those anticipated include:
  - We may not be able to eliminate a majority, or even a material amount, of the overhead costs allocated to the held-for-sale utility divisions.
  - Regulatory commissions may not approve some or all of any cost reallocations in future rate cases.
- We anticipate significant additional capital expenditures in order to satisfy our long-term power generation and transmission needs and comply with environmental rules and regulations. Some important factors that could cause actual results to differ materially from those anticipated include:
  - We may not receive the approvals required to participate in the planned construction of additional generating capacity at the Iatan 2 facility near Weston, Missouri, and a lengthy delay in the construction of the Iatan 2 facility may require us to satisfy our baseload capacity requirements through spot-market purchases.
  - Environmental rules and regulations could change such that we are not required to make anticipated capital expenditures for environmental compliance, or such that the cost of environmental compliance is greater than anticipated.
  - We may not receive shareholder approval to issue additional shares of our common stock, which may be required to fund part of our anticipated future capital expenditures.
- We believe that the anticipated capital costs of environmental compliance will be allowed for recovery in future rate cases. Some important factors that could cause actual results to differ materially from those anticipated include:
  - Regulatory commissions may refuse to allow us to recover in rates part or all of the capital costs related to environmental compliance.
  - Changes in applicable law or regulation may prohibit us from recovering in rates part or all of the capital costs related to environmental compliance.
- We expect the Missouri Commission to issue, prior to the filing of our next electric rate case in Missouri, rules implementing the fuel clause adjustment legislation recently

adopted by the State of Missouri. Some important factors that could cause actual results to differ materially from those anticipated include:

- If the rules implementing the adopted fuel clause adjustment legislation are delayed, we may incur significant losses if we are not otherwise permitted to pass through to ratepayers costs associated with fuel purchases for our Missouri electric operations.
- Even if the Missouri Commission implements the fuel clause adjustment rules prior to our next electric rate case in Missouri, the Missouri Commission may subsequently determine that certain fuel costs were not prudently incurred and, therefore, refuse to allow such costs to be recovered in rates.
- We anticipate that our current revolving credit capacity and available cash will be sufficient to fund our winter needs and working capital requirements. Some important factors that could cause actual results to differ materially from those anticipated include:
  - Our access to revolving credit capacity depends on maintaining compliance with loan covenants. If we violate these covenants, we may lose revolving credit capacity and not have sufficient cash available for our winter needs and working capital requirements.
  - Unanticipated increases in the price of natural gas that we purchase for our utility customers could exhaust our liquidity in the winter months.
  - Counterparties may default on their obligations to supply commodities or return collateral to us or to meet their obligations under commercial contracts, including those designed to hedge against movements in commodity prices.
- We believe that we have strong defenses to litigation pending against us. Some important factors that could cause actual results to differ materially from those anticipated include:
  - Judges and juries can be difficult to predict and may, in fact, rule against us.
  - Our positions may be weakened by adverse developments in the law or the discovery of facts that hurt our cases.
- We do not expect that the annual limitations on net operating losses would cause any of our net operating losses to expire unutilized for purposes of reducing our taxes. Some important factors that could cause actual results to differ materially from those anticipated include:
  - Changes in the tax law could result in our tax net operating losses going unutilized.
  - The failure to generate sufficient income (including income from asset sales) could result in our tax net operating losses going unutilized.

## **Item 7A. Quantitative and Qualitative Disclosures About Market Risk**

### **Market Risk—Utility Operations**

Our regulated businesses produce, purchase and distribute power in three states and purchase and distribute natural gas in seven states. All of our gas distribution utilities have PGA provisions that allow them to pass the prudently-incurred cost of gas through to the customer. To the extent that gas prices are higher or lower than amounts in our current billing rates, adjustments are made on a periodic basis to “true-up” billed amounts to match the actual cost we incurred. These adjustments are subject to periodic prudence reviews by the state utility commissions.

In our continuing regulated electric business in 2005, we generated approximately 51% of the power that we sold and we purchased the remaining 49% through long-term contracts or in the open market. The regulatory provisions for recovering power costs vary by state. In Kansas and Colorado, we have ECAs that serve a purpose similar to the PGAs for our gas utilities. To the extent that our fuel and purchased power energy costs vary from the energy cost built into our tariffs, the difference is passed through to the customer. In Missouri, we currently do not have the ability to adjust the rates we charge for electric service to offset all or part of any increase or decrease in prices we pay for natural gas, coal or other fuel we use in generating electricity (i.e., a fuel adjustment mechanism). As a result, our exposure to commodity price changes has historically been concentrated in the Missouri electric operations, resulting in greater earnings volatility from year to year there than in our other electric rate jurisdictions.

In July 2005, legislation was adopted establishing a means for the recovery of prudently incurred fuel, purchased power costs and government-mandated environmental investments without going through a general rate case. The Missouri Commission staff has held a number of workshops with utility companies, industry groups and consumer advocates to develop rulemaking proposals. At least one further workshop is expected in the first quarter of 2006 before final rules are issued later in the year.

We have taken several measures to mitigate the commodity price risk exposure in our Missouri electric operations. One of these measures is contracting for a diverse supply of coal to meet 99.8% of our native load fuel requirements of coal-fired generation in 2006 and 94.0% in 2007, respectively. We are currently receiving reduced volumes on one of these coal contracts because of a declared partial force majeure that occurred in 2004. The price risk associated with our natural gas and on-peak spot market purchased power requirements is also mitigated through a dollar-cost averaging hedging plan using NYMEX futures contracts and options. This is a multi-year hedging plan. As of December 31, 2005, we had financial contracts in place to hedge approximately 57% of our expected on-peak natural gas and natural gas equivalent purchased power price exposure for 2006.

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 the availability, price and deliverability of a given fuel type as well as planned and scheduled outages at our facilities that use fossil fuels. Our customers' electricity usage could also vary from year to year based on the weather or other factors.

### **Market Risk—Trading**

We are exposed to market risk, including changes in commodity prices, interest rates and currency exchange rates. To manage the volatility relating to these exposures, we enter into various derivative transactions in accordance with our policy approved by the Board of Directors.

Our trading portfolios consist primarily of natural gas, electricity and interest rate contracts that are settled by the delivery of the commodity or cash. These contracts take many forms, including futures, forwards, swaps and options. As we are winding down our trading portfolio, most of our positions have been hedged to limit our exposure to the above risks.

We measure the risk in our trading portfolio using a value-at-risk methodology. The value-at-risk calculation utilizes statistics to determine the relationship between the size of a potential loss and the probability of its occurrence, from holding an individual instrument or portfolio of instruments for a given period of time. The quantification of market risk using value-at-risk methodologies provides a consistent measure of risk across diverse energy markets and products and is considered a “best practice” standard for this application. The use of this methodology requires a number of key assumptions, including:

- Selection of a confidence level (we use 95%);
- Holding period (this is the time needed to liquidate a position—we use one day); and
- Use of historical volatility and correlations with the most recent activity weighted more heavily.

The average value-at-risk for all commodities during 2005 was \$2.1 million. Our Board of Directors sets our value-at-risk limit. We are currently limited to \$3.0 million for the remaining commodity trading portfolio and a \$5.0 million target for the aggregate book that includes the first 18 months of Merchant Services asset positions. In addition to value-at-risk, we also apply other risk control measures that incorporate volumetric limits by commodity, loss limits, durational limits and application of stress testing to our various risk portfolios.

All merchant interest and foreign currency risks are monitored within the commodity portfolios and value-at-risk calculation. The merchant commodity portfolios are valued on a mark-to-market basis that requires that the trading book be discounted on a net present value basis utilizing risk adjusted current interest rates based on our credit standing and those of our counterparties. Because interest rate movements impact the value of our trading portfolio, we have used interest rate derivatives to hedge this risk and may do so in the future as the portfolio continues to wind down.

### **Certain Trading Activities**

We engage in price risk management activities for both trading and non-trading activities. Transactions carried out in connection with trading activities that are derivatives under SFAS 133 are accounted for under the mark-to-market method of accounting. Under SFAS 133, our energy commodity trading contracts, including physical transactions (mainly gas and power) and financial instruments, are recorded at fair value. As part of the valuation of our portfolio, we value the credit risks associated with the financial condition of counterparties and the time value of money. We primarily use quoted market prices from published sources or comparable transactions in liquid markets to value our contracts. If actively quoted market prices are not available, we contact brokers and other external sources or use comparable transactions to obtain current values of our contracts. In addition, the market prices or fair values used in determining the value of the portfolio are our best estimates utilizing information such as historical volatility, time value, counterparty credit and the potential impact on market prices of liquidating our positions in an orderly manner over a reasonable period of time under current market conditions. When market prices are not readily available or determinable, certain contracts are recorded at fair value using an alternative approach such as model pricing.

The changes in fair value of our Utilities and Merchant Services derivative contracts for 2005 are summarized below:

<i>In millions</i>	<b>Utilities</b>	<b>Merchant Services</b>	<b>Total</b>
Fair value at December 31, 2004	\$ (3.3)	\$25.9	\$ 22.6
Increase (decrease) in fair value during the year	77.6	(5.5)	72.1
Contracts realized or cash settled	(32.0)	11.2	(20.8)
Fair value at December 31, 2005	\$ 42.3	\$31.6	\$ 73.9

The fair value of contracts maturing in each of the next four years and thereafter are shown below:

<i>In millions</i>	<b>2006</b>	<b>2007</b>	<b>2008</b>	<b>2009</b>	<b>Thereafter</b>	<b>Total</b>
Prices actively quoted	\$ 35.1	\$25.4	\$ .8	\$—	\$—	\$61.3
Prices provided by other external sources	—	—	7.0	—	—	7.0
Priced based on models and other valuation methods	—	—	—	.7	4.9	5.6
Net price risk management assets	\$ 35.1	\$25.4	\$ 7.8	\$ .7	\$ 4.9	\$73.9

### **Credit Risk**

In conducting our operations, we regularly transact business with a broad range of entities and a wide variety of end users, energy merchants, producers and financial institutions. Credit risk is measured by the loss we would record if our counterparties failed to perform pursuant to the terms of their contractual obligations less the value of any collateral held.

We have established policies, systems and controls to manage our exposure to credit risk. This infrastructure allows us to assess counterparty creditworthiness, monitor credit exposures, stress test the portfolio to quantify future potential credit exposures and catalogue collateral received by the company. In addition, to enhance the ongoing management of credit exposure, we have used master netting agreements whenever possible. Master netting agreements enable us to net certain assets and liabilities by counterparty. In situations where the credit quality of counterparties has deteriorated to certain levels, we will assert our contractual rights to minimize our exposures by requesting collateral against these obligations.

A natural result of our prior business strategy is the concentration of energy sector credit risk. Factors affecting this industry segment will affect the general credit quality of our portfolio both positively and negatively. The result of energy industry downgrades of certain companies with significant energy merchant activity has reduced the overall credit quality of our exposures in general.

The following table details our credit exposures at December 31, 2005, associated with our forward positions within our trading portfolio and our billed receivables (excluding tariff customers), netted by counterparty where master netting agreements exist and by collateral to the extent any is held.

<i>In millions</i>	<b>Investment Grade</b>	<b>Non-investment Grade</b>	<b>Total</b>
Utilities and merchants	\$ 52.9	\$ 90.2	\$143.1
Financial institutions	187.7	—	187.7
Oil and gas producers	.2	—	.2
Commercial and industrial	—	.1	.1
<b>Total</b>	<b>\$240.8</b>	<b>\$ 90.3</b>	<b>\$331.1</b>

A majority of the customers in our continuing Electric and Gas Utilities businesses are billed under jurisdictional tariffs in the states in which we operate. We are obligated to provide service to all of our electric and gas customers within their respective franchised territories. Credit risk is managed by credit and collection policies that are consistent with state regulatory requirements. See pages 8 and 10 under Business for a breakout of our utility customers by type.

### **Currency Rate Exposure**

We have substantially wound down our United Kingdom and Canadian merchant trading businesses, which are included in our Merchant Services segment, and have sold our international utility businesses in Canada, Australia, New Zealand and the United Kingdom. Our remaining currency rate exposure relates only to approximately \$3.0 million of cash held in foreign countries, a limited trading portfolio in Canada and the resolution of outstanding tax obligations and receivables.

### **Interest Rate Exposure**

We have approximately \$251.8 million in unhedged variable rate financial obligations. A 100-basis-point change in the variable rate financial instruments would affect net income by approximately \$1.5 million.

## Item 8. Financial Statements and Supplementary Data

	<b>Page No.</b>
Consolidated Statements of Income for the three years ended December 31, 2005 . . .	76
Consolidated Balance Sheets at December 31, 2005 and 2004 . . . . .	77
Consolidated Statements of Common Shareholders' Equity for the three years ended December 31, 2005 . . . . .	78
Consolidated Statements of Comprehensive Income for the three years ended December 31, 2005 . . . . .	79
Consolidated Statements of Cash Flows for the three years ended December 31, 2005 . . . .	80
Notes to Consolidated Financial Statements: . . . . .	82
Summary of Significant Accounting Policies . . . . .	82
New Accounting Standards . . . . .	87
Risk Management . . . . .	88
Restructuring Charges . . . . .	92
Net Loss on Sale of Assets and Other Charges . . . . .	93
Discontinued Operations . . . . .	98
Accounts Receivable . . . . .	103
Property, Plant and Equipment . . . . .	104
Investments in Unconsolidated Subsidiaries . . . . .	106
Regulatory Assets . . . . .	109
Short-Term Debt . . . . .	111
Long-Term Debt . . . . .	113
Long-Term Gas Contracts . . . . .	117
Capital Stock and Stock Compensation . . . . .	118
Accumulated Other Comprehensive Income (Loss) . . . . .	122
Earnings (Loss) Per Share . . . . .	122
Income Taxes . . . . .	123
Employee Benefits . . . . .	126
Segment Information . . . . .	132
Commitments and Contingencies . . . . .	135
Quarterly Financial Data (Unaudited) . . . . .	141
Report of Independent Registered Public Accounting Firm . . . . .	142
Report of Independent Registered Public Accounting Firm . . . . .	143

**Aquila, Inc.**  
**Consolidated Statements of Income**

<i>In millions, except per share amounts</i>	<b>Year Ended December 31,</b>		
	<b>2005</b>	<b>2004</b>	<b>2003</b>
<b>Sales:</b>			
Electricity—regulated	\$ 684.1	\$ 594.1	\$ 544.1
Natural gas—regulated	606.5	506.5	473.9
Other—non-regulated	23.6	(129.6)	(34.9)
<b>Total sales</b>	<b>1,314.2</b>	<b>971.0</b>	<b>983.1</b>
<b>Cost of sales:</b>			
Electricity—regulated	355.4	295.8	254.2
Natural gas—regulated	452.1	356.3	320.9
Other—non-regulated	56.2	69.1	104.4
<b>Total cost of sales</b>	<b>863.7</b>	<b>721.2</b>	<b>679.5</b>
<b>Gross profit</b>	<b>450.5</b>	<b>249.8</b>	<b>303.6</b>
<b>Operating expenses:</b>			
Operating expense	351.0	357.2	428.3
Restructuring charges	6.6	.9	26.1
Net loss on sale of assets and other charges	55.4	188.3	192.7
Depreciation and amortization expense	106.4	102.8	120.1
<b>Total operating expenses</b>	<b>519.4</b>	<b>649.2</b>	<b>767.2</b>
<b>Other income (expense):</b>			
Equity in earnings of investments	—	2.1	69.6
Other income	18.0	19.2	89.3
<b>Total other income</b>	<b>18.0</b>	<b>21.3</b>	<b>158.9</b>
Interest expense	150.2	184.5	198.8
<b>Loss from continuing operations before income taxes</b>	<b>(201.1)</b>	<b>(562.6)</b>	<b>(503.5)</b>
Income tax benefit	(43.1)	(214.3)	(147.0)
<b>Loss from continuing operations</b>	<b>(158.0)</b>	<b>(348.3)</b>	<b>(356.5)</b>
<b>Earnings (loss) from discontinued operations, net of tax</b>	<b>(72.0)</b>	<b>55.8</b>	<b>20.1</b>
<b>Net Loss</b>	<b>\$ (230.0)</b>	<b>\$(292.5)</b>	<b>\$(336.4)</b>
<b>Basic and diluted earnings (loss) per common share:</b>			
Continuing operations	\$ (.40)	\$ (1.35)	\$ (1.83)
Discontinued operations	(.20)	.22	.10
<b>Net loss</b>	<b>\$ (.60)</b>	<b>\$ (1.13)</b>	<b>\$ (1.73)</b>

See accompanying notes to consolidated financial statements.

**Aquila, Inc.**  
**Consolidated Balance Sheets**

<i>In millions</i>	<b>December 31,</b>	
	<b>2005</b>	<b>2004</b>
<b>Assets</b>		
<b>Current assets:</b>		
Cash and cash equivalents	\$ 14.2	\$ 218.5
Restricted cash	10.9	22.8
Funds on deposit	264.9	353.1
Accounts receivable, net	399.5	341.8
Inventories and supplies	107.3	88.0
Price risk management assets	200.0	124.9
Other current assets	78.3	80.3
Current assets of discontinued operations	269.0	220.7
<b>Total current assets</b>	<b>1,344.1</b>	<b>1,450.1</b>
Property, plant and equipment, net	1,877.3	1,810.0
Price risk management assets	177.7	136.1
Goodwill, net	111.0	111.0
Prepaid pension	68.3	67.5
Deferred charges and other assets	154.4	174.1
Non-current assets of discontinued operations	897.9	1,028.5
<b>Total Assets</b>	<b>\$4,630.7</b>	<b>\$4,777.3</b>
<b>Liabilities and Shareholders' Equity</b>		
Current liabilities:		
Current maturities of long-term debt	\$ 88.3	\$ 41.4
Short-term debt	12.0	—
Accounts payable	356.2	366.2
Accrued interest	64.6	66.3
Other accrued liabilities	187.8	175.5
Price risk management liabilities	164.9	136.1
Current portion of long-term gas contracts	15.7	15.0
Customer funds on deposit	74.0	20.4
Current liabilities of discontinued operations	31.1	33.5
<b>Total current liabilities</b>	<b>994.6</b>	<b>854.4</b>
<b>Long-term liabilities:</b>		
Long-term debt, net	1,891.2	2,325.0
Deferred income taxes and credits	71.5	148.0
Price risk management liabilities	138.9	102.3
Long-term gas contracts	17.2	32.9
Deferred credits	144.4	130.4
Non-current liabilities of discontinued operations	63.0	53.8
<b>Total long-term liabilities</b>	<b>2,326.2</b>	<b>2,792.4</b>
<b>Common shareholders' equity</b>	<b>1,309.9</b>	<b>1,130.5</b>
<b>Total Liabilities and Shareholders' Equity</b>	<b>\$4,630.7</b>	<b>\$4,777.3</b>

See accompanying notes to consolidated financial statements.

**Aquila, Inc.**  
**Consolidated Statements of Common Shareholders' Equity**

<i>In millions, except per share amounts</i>	<b>Year Ended December 31,</b>		
	<b>2005</b>	<b>2004</b>	<b>2003</b>
<b>Common stock:</b> authorized 400,000,000 at December 31, 2005, 2004 and 2003, par value \$1 per share, 373,603,277 shares issued at December 31, 2005 (241,739,573 at December 31, 2004 and 195,252,630 at December 31, 2003); authorized 20,000,000 shares of Class A common stock, par value \$1 per share, none issued			
Balance beginning of year	\$ 241.7	\$ 195.3	\$ 193.8
Issuance of shares in public offerings	—	46.0	—
Issuance of shares through PIES exchange	131.4	—	—
Issuance of shares under compensation arrangements	.5	.4	1.5
<b>Balance end of year</b>	<b>373.6</b>	<b>241.7</b>	<b>193.3</b>
<b>Premium on capital stock:</b>			
Balance beginning of year	3,228.6	3,161.3	3,158.6
Issuance of shares in public offerings	—	66.3	—
Issuance of shares through PIES exchange	280.2	—	—
Issuance of shares under compensation arrangements	(1.8)	1.0	2.7
<b>Balance end of year</b>	<b>3,507.0</b>	<b>3,228.6</b>	<b>3,161.3</b>
<b>Retained deficit:</b>			
Balance beginning of year	(2,340.6)	(2,047.9)	(1,711.5)
Net loss	(230.0)	(292.5)	(336.4)
Other	—	(.2)	—
<b>Balance end of year</b>	<b>(2,570.6)</b>	<b>(2,340.6)</b>	<b>(2,047.9)</b>
<b>Treasury stock,</b> at cost, 7 shares at December 31, 2005 (251 shares at December 31, 2004 and 129 shares at December 31, 2003)	—	—	—
<b>Accumulated other comprehensive income (loss)</b>	<b>(.1)</b>	<b>.8</b>	<b>50.6</b>
<b>Total Common Shareholders' Equity</b>	<b>\$ 1,309.9</b>	<b>\$ 1,130.5</b>	<b>\$ 1,359.3</b>

See accompanying notes to consolidated financial statements.

**Aquila, Inc.**  
**Consolidated Statements of Comprehensive Income**

<i>In millions</i>	<b>Year Ended December 31,</b>		
	<b>2005</b>	<b>2004</b>	<b>2003</b>
<b>Net loss</b>	\$(230.0)	\$(292.5)	\$ (336.4)
<b>Other comprehensive income (loss), net of related tax:</b>			
Foreign currency adjustments:			
Foreign currency translation adjustments, net of deferred tax expense (benefit) of \$(.2) million, \$(14.5) million and \$50.3 million for 2005, 2004 and 2003, respectively	(.3)	(22.0)	96.2
Reclassification of foreign currency (gains) losses to income due to sale of businesses and other, net of deferred tax (expense) benefit of \$(.4) million, \$(26.2) million and \$(9.5) million for 2005, 2004 and 2003, respectively	(.6)	(41.0)	(14.9)
Total foreign currency adjustments	(.9)	(63.0)	81.3
Cash flow hedges:			
Unrealized gains (losses) on hedging instruments during the period, net of deferred tax expense (benefit) of \$(1.0) million and \$(.4) million for 2004 and 2003, respectively	—	(1.6)	(1.6)
Unrealized gains (losses) on hedging instruments of equity method investments, net of deferred tax expense (benefit) of \$(5.6) million for 2003	—	—	(7.6)
Reclassification of net losses (gains) on hedging instruments to net income, net of deferred tax benefit (expense) of \$.8 million and \$9.1 million for 2004 and 2003, respectively	—	1.3	15.0
Reclassification of net losses to income on cash flow hedges in equity method investments due to sale, net of deferred tax benefit (expense) of \$5.5 million and \$1.8 million for 2004 and 2003, respectively	—	9.1	3.4
Total cash flow hedges	—	8.8	9.2
Held for sale securities:			
Reclassification of net losses (gains) on sales of securities to income	—	—	(7.3)
Total held for sale securities	—	—	(7.3)
Decrease (increase) in minimum pension liability, net of deferred tax (benefit) expense of \$2.7 million and \$(2.7) million for 2004 and 2003, respectively	—	4.4	.4
Other comprehensive income (loss)	(.9)	(49.8)	83.6
<b>Total Comprehensive Loss</b>	<b>\$(230.9)</b>	<b>\$(342.3)</b>	<b>\$ (252.8)</b>

See accompanying notes to consolidated financial statements.

**Aquila, Inc.**  
**Consolidated Statements of Cash Flows**

<i>In millions</i>	<b>Year Ended December 31,</b>		
	<b>2005</b>	<b>2004</b>	<b>2003</b>
<b>Cash Flows From Operating Activities:</b>			
Net loss	\$ (230.0)	\$(292.5)	\$ (336.4)
Adjustments to reconcile net loss to net cash used for operating activities:			
Depreciation and amortization expense	148.9	150.3	173.3
Restructuring charges	6.6	.9	28.2
Cash paid for restructuring and other charges	(2.3)	(171.2)	(166.8)
Net loss on sale of assets and other charges	214.9	114.3	242.2
Foreign currency gains	(.9)	(13.0)	(53.7)
Net changes in price risk management assets and liabilities	(61.2)	107.9	52.8
Deferred income taxes and investment tax credits	(81.5)	(194.7)	(126.7)
Equity in earnings of investments	—	(2.1)	(69.6)
Dividends and fees from investments	.5	1.5	48.6
Changes in certain assets and liabilities, net of effects of acquisitions and divestitures:			
Restricted cash	11.8	232.9	(99.6)
Funds on deposit	88.2	43.7	(118.5)
Accounts receivable/payable, net	(102.3)	27.4	(100.4)
Inventories and supplies	(33.3)	(10.4)	(14.8)
Prepaid pension and other current assets	17.4	(13.1)	248.4
Deferred charges and other assets	(17.7)	20.8	22.1
Accrued interest and other accrued liabilities	16.8	(107.8)	106.7
Customer funds on deposit	54.6	(235.9)	35.7
Deferred credits	18.8	(8.0)	7.4
Other	(.8)	7.5	(11.2)
<b>Cash provided from (used for) operating activities</b>	<b>48.5</b>	<b>(341.5)</b>	<b>(132.3)</b>
<b>Cash Flows From Investing Activities:</b>			
Additions to utility plant	(228.9)	(219.4)	(247.2)
Merchant capital expenditures	—	—	(20.5)
Investments in communication services	(11.4)	(14.0)	(12.2)
Cash proceeds on sale of assets and subsidiary stock	36.0	1,267.9	905.7
Merchant investment in unconsolidated subsidiary	—	—	(44.5)
Other	(4.4)	(8.2)	(16.6)
<b>Cash provided from (used for) investing activities</b>	<b>(208.7)</b>	<b>1,026.3</b>	<b>564.7</b>

**Aquila, Inc.**  
**Consolidated Statements of Cash Flows (continued)**

<i>In millions</i>	<b>Year Ended December 31,</b>		
	<b>2005</b>	<b>2004</b>	<b>2003</b>
<b>Cash Flows From Financing Activities:</b>			
Issuance of common stock	—	112.3	—
Issuance of long-term debt	2.0	551.2	412.0
Retirement of long-term debt	(45.9)	(943.9)	(492.8)
Short-term borrowings (repayments), net	12.0	(215.0)	(57.9)
Cash paid on long-term gas contracts	(15.0)	(623.1)	(81.6)
Other	1.0	1.3	3.7
<b>Cash used for financing activities</b>	<b>(45.9)</b>	<b>(1,117.2)</b>	<b>(216.6)</b>
Increase (decrease) in cash and cash equivalents	(206.1)	(432.4)	215.8
Cash and cash equivalents at beginning of year (includes \$6.6 million, \$60.9 million and \$76.0 million of cash included in current assets of discontinued operations in 2005, 2004 and 2003, respectively)	225.1	657.5	441.7
<b>Cash and Cash Equivalents at End of Year (includes \$4.8 million, \$6.6 million and \$60.9 million of cash included in current assets of discontinued operations in 2005, 2004 and 2003, respectively)</b>	<b>\$ 19.0</b>	<b>\$ 225.1</b>	<b>\$ 657.5</b>
<b>Supplemental cash flow information:</b>			
Interest paid, net of amount capitalized	\$ 223.1	\$ 299.7	\$ 276.9
Income taxes paid (refunded), net	28.8	21.1	(241.0)

See accompanying notes to consolidated financial statements.

**Aquila, Inc.**  
**Notes to Consolidated Financial Statements**

**Note 1: Summary of Significant Accounting Policies**

**Description of Business**

Aquila, Inc. (Aquila) is an energy provider headquartered in Kansas City, Missouri. We operate in three business segments, Electric Utilities, Gas Utilities and Merchant Services.

Electric Utilities operates in the distribution and transmission of electricity to retail and wholesale customers in Colorado, Kansas and Missouri. Our electric generation facilities and purchase power contracts supply electricity to our own distribution systems in these three states. We also sell a small amount of excess power to wholesale customers outside our service areas. During peak periods, we buy energy in the wholesale market for our utility load. Our Kansas electric utility is currently held for sale and has been reclassified as discontinued operations.

Gas Utilities operates in the distribution of natural gas to retail and wholesale customers in Colorado, Iowa, Kansas, Michigan, Minnesota, Missouri and Nebraska. Our Michigan, Minnesota and Missouri gas operations are currently held for sale and have been reclassified as discontinued operations.

Our Merchant Services business operates as Aquila Merchant Services, Inc. (Aquila Merchant), which, until we began to wind down these operations during the second quarter of 2002, marketed natural gas, electricity and other commodities throughout North America and Western Europe. Aquila Merchant currently owns or contractually controls non-regulated merchant power plants. Two of our merchant peaking plants are currently held for sale and have been reclassified as discontinued operations. Our former investments in 13 independent power plants were sold in the first quarter of 2004. Two of these plants that were consolidated are also reported in discontinued operations.

Corporate and Other includes the costs of the company that are not allocated to our operating businesses. We also formerly had investments in Australia and the United Kingdom. We sold our investments in Australia in the second and third quarters of 2003, and our investment in the United Kingdom in January 2004. Our communications business, Everest Connections, which provides local and long-distance telephone, cable television and high-speed Internet service to areas of greater Kansas City, is currently held for sale and is reported in discontinued operations.

We also owned and operated electric utilities in two Canadian provinces, which were sold in May 2004 and are reported in discontinued operations.

**Use of Estimates**

The preparation of these financial statements in conformity with accounting principles generally accepted in the United States required that we make certain estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of December 31, 2005 and 2004, and the reported amounts of sales and expenses during the three years ended December 31, 2005. Significant items subject to such estimates and assumptions include the carrying value of property, plant and equipment and goodwill; the valuation of derivative instruments; unbilled utility revenues; valuation allowances for receivables and deferred income taxes; and assets and liabilities related to employee benefits. Actual results could differ materially from those estimates and assumptions.

## **Principles of Consolidation**

Our consolidated financial statements include all of our operating divisions and majority-owned subsidiaries for which we maintain controlling interests. We eliminate inter-company accounts and transactions. We use equity accounting for investments in which we have significant influence but do not control. We did not control certain formerly owned investments in which our partners had substantive participating and protective rights. This did not allow us to consolidate those investments.

We evaluated the carrying value of our equity method investments periodically or when there were specific indications of potential impairment, such as continuing operating losses or a substantial decline in market price if publicly traded. In assessing these investments, we considered the following factors, among others, relating to the investment: financial performance and near-term prospects of the company, condition and prospects of the industry and our investment intent.

## **Property, Plant and Equipment**

We initially record property, plant and equipment at cost. Repairs of property and replacements of items not considered to be units of property are expensed as incurred, except for certain major repairs at our generating facilities that are accrued in advance as allowed by regulatory authorities. Depreciation is provided on a straight-line basis over the estimated lives of the assets. When regulated property, plant and equipment is replaced, removed or abandoned, its cost, less salvage, is charged to accumulated depreciation. See Note 8 for further information.

## **Impairment of Long-Lived Assets**

In accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," (SFAS 144), long-lived assets, such as property, plant, and equipment are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to estimated undiscounted future cash flows expected to be generated by the asset. If the carrying amount of an asset exceeds its estimated future cash flows, an impairment charge is recognized by the amount by which the carrying amount of the asset exceeds the fair value of the asset. Assets to be disposed of would be separately presented in the balance sheet and reported at the lower of the carrying amount or fair value less costs to sell, and are no longer depreciated. The assets and liabilities of a disposal group classified as held for sale would be presented separately as discontinued operations in the appropriate asset and liability sections of the balance sheet.

Goodwill is tested annually for impairment, and is tested for impairment more frequently if events and circumstances indicate that the asset might be impaired. Our annual assessment date is November 30. An impairment loss is recognized to the extent that the carrying amount exceeds the goodwill's fair value. For goodwill, the impairment determination is made at the reporting unit level and consists of two steps. First, we determine the fair value of a reporting unit and compare it to its carrying amount. Second, if the carrying amount of a reporting unit exceeds its fair value, an impairment loss is recognized for any excess of the carrying amount of the reporting unit's goodwill over the implied fair value of that goodwill. The implied fair value of goodwill is determined by allocating the fair value of the reporting unit in a manner similar to a purchase price allocation, in accordance with SFAS No. 141, "Business Combinations". The residual fair value after this allocation is the implied fair value of the reporting unit goodwill.

## Goodwill

We have recorded goodwill, representing the excess of the cost of acquisitions over the fair value of the related net assets at the dates of acquisition. Currently the only significant goodwill we have recorded has been allocated to our Electric Utilities segment. As the result of the announced sale of our Kansas electric utility, we performed an assessment of the realizability of this goodwill. This test was performed at the Missouri electric reporting unit level as of September 2005. We concluded that the goodwill was not impaired. At December 31, 2005, we had goodwill in continuing operations of \$113.6 million, less accumulated amortization of \$2.6 million.

Our goodwill was allocated to each segment as follows:

<i>In millions</i>	<b>Total Continuing Operations— Electric Utilities</b>	<b>Total Discontinued Operations</b>
<b>Balance, December 31, 2002</b>	\$111.0	\$ 188.6
Exchange rate change and other	—	40.9
<b>Balance, December 31, 2003</b>	111.0	229.5
Sales of businesses	—	(218.2)
Exchange rate change	—	(11.3)
<b>Balance, December 31, 2004</b>	111.0	—
Other	—	.3
<b>Balance, December 31, 2005</b>	\$111.0	\$ .3

## Sales Recognition

### *Utility Activities*

Sales related to the delivery of gas or electricity are generally recorded when service is rendered or energy is delivered to customers. However, the determination of sales is based on reading customers' meters, which occurs systematically throughout the month. At the end of each month, an estimate is made of the amount delivered to customers after the date of the last meter reading. The unbilled revenue is calculated each month based on estimated customer usage, weather factors, line losses and applicable customer rates.

### *Trading Activities*

Transactions carried out in connection with trading activities that meet the definition of a derivative under SFAS No. 133, "Accounting for Derivative and Hedging Activities" (SFAS 133), are accounted for under the mark-to-market method of accounting. Under SFAS 133, our energy commodity trading contracts, including both physical transactions and financial instruments, are recorded net in sales at fair value and shown on our Consolidated Balance Sheets as price risk management assets and price risk management liabilities. As part of the valuation of our portfolio, we value our credit risks associated with the financial condition of counterparties and the time value of money. We use quoted market prices from published sources or comparable transactions in liquid markets to value our contracts. If actively quoted market prices are not readily available, we contact brokers or other external sources or use comparable transactions to obtain current values of our contracts. When market prices are not readily available or determinable, certain contracts are valued at fair value using an alternate approach such as model pricing. In addition, the market prices or fair values used in determining the value of our

portfolio are our best estimates utilizing information such as historical volatility and the potential impact on market prices of liquidating our positions in an orderly manner over a reasonable period of time under current market conditions. When the market value of the portfolio changes (primarily due to the effect of price changes, newly originated transactions and the settlement of existing transactions), the change is immediately recognized as a gain or loss. We record the resulting unrealized gains or losses as price risk management assets or price risk management liabilities, respectively.

### **Weather Derivatives**

Our utility business also uses weather derivatives to offset inherent weather risks, but not for trading or speculative purposes. EITF No. 99-2, "Accounting for Weather Derivatives," requires that we account for these weather derivatives by recording an asset or liability for the difference between the actual and contracted threshold cooling or heating degree-days in the period multiplied by the contract price.

### **Funds on Deposit**

Funds on deposit consists primarily of cash we have provided with counterparties in support of margin requirements related to commodity purchases, commodity swaps and futures contracts. Pursuant to individual contract terms with counterparties, deposit amounts required vary with changes in market prices, credit provisions and various other factors. Certain letters of credit are required to be secured with cash deposits. See Note 11 for further discussion. These are also identified as funds on deposit in our Consolidated Balance Sheets. Interest is earned on most funds on deposit. We also hold funds on deposit from counterparties in the same manner. These are identified as customer funds on deposit in our Consolidated Balance Sheets.

### **Inventories**

Our inventories consist primarily of natural gas in storage, coal, purchased emission allowances, materials and supplies that are valued at weighted average cost. Coal and emission allowances are charged to fuel expense in cost of sales as they are used in operations. Natural gas in storage is charged to the PGA account as it is withdrawn and is included in cost of sales as it is recovered from ratepayers.

### **Pension and Other Postretirement Plans**

We have a defined benefit pension plan covering substantially all of our employees. We also provide post-retirement health care and life insurance benefits for certain retired employees. See Note 18 for further discussion.

### **Regulatory Matters**

Our regulated utility operations are subject to the provisions of SFAS 71. Therefore our regulated utility operations recognize the effects of rate regulation and accordingly have recorded regulated assets and liabilities to reflect the impact of regulatory orders or precedent. See Note 10 for further discussion.

### **Long-Term Gas Contracts**

We were paid in advance on certain long-term gas contracts for the future delivery of gas to municipal utilities over the subsequent 10 to 12 years. We accounted for these contracts as long-term obligations. We recognize the reduction of our obligations on these long-term gas contracts as gas is delivered to the customer under the units of revenue method, which matches

the revenue recognized with the forecasted volumes of gas to be delivered. See Note 13 for further discussion.

### Income Taxes

We use the liability method to reflect income taxes on our financial statements. We recognize deferred tax assets and liabilities by applying enacted tax rates and regulations to the differences between the carrying value of existing assets and liabilities and their respective tax basis and capital loss and tax credit carryforwards. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that the change is enacted. We amortize deferred investment tax credits over the lives of the related properties. We assess the realizability of deferred tax assets for capital and operating loss carryforwards and provide valuation allowances when we determine it is more likely than not that such losses will not be realized within the applicable carryforward period. See Note 17 for further discussion.

### Environmental Matters

We accrue environmental costs on an undiscounted basis when it is probable that a liability has been incurred and the liability can be reasonably estimated. Such accruals are adjusted as further information develops or circumstances change. If it is probable that we will receive regulatory recovery, we record these costs in a regulatory asset.

### Stock Based Compensation

We issue stock options to employees from time to time and account for these options under APB Opinion No. 25, "Accounting for Stock Issued to Employees" (APB 25). All stock options issued are granted at the common stock's then current market price. This means we record no compensation expense related to stock options. We historically offered employees a stock purchase plan that enabled them to purchase our common stock at a 15% discount from the market price. This program was suspended during the second quarter of 2003 when all authorized shares in the plan were issued. Shareholder approval is required to authorize additional shares for this program to continue. See Note 14 for details of options granted each year.

Because we record options and discounts under APB 25, we must disclose pro forma net income and earnings per share as if we reflected the estimated fair value of options and discounts as compensation expense, as follows:

<i>In millions, except per share amounts</i>	<b>Year Ended December 31,</b>		
	<b>2005</b>	<b>2004</b>	<b>2003</b>
<b>Net loss:</b>			
As reported	\$(230.0)	\$(292.5)	\$(336.4)
PIES adjustment (Note 12)	12.6	9.4	—
Loss available for common shares	(217.4)	(283.1)	(336.4)
Total stock-based employee compensation expense determined under fair value method, net of related tax	(1.9)	(9.3)	(5.4)
Pro forma net loss	\$(219.3)	\$(292.4)	\$(341.8)
<b>Basic and diluted loss per share:</b>			
As reported	\$ (.60)	\$ (1.13)	\$ (1.73)
Pro forma	(.60)	(1.16)	(1.76)

The fair value of stock options granted was estimated on the date of grant using the Black-Scholes option-pricing model. The weighted average fair values and assumptions were as follows:

	<b>Year Ended December 31,</b>		
	<b>2005</b>	<b>2004</b>	<b>2003</b>
Weighted average fair value per share	\$ 2.08	\$ 2.25	\$ .85
Expected volatility	83%	83%	55%
Risk-free interest rate	3.82%	3.40%	3.53%
Expected lives	3.7 years	3.7 years	7 years
Dividend yield	—	—	—

Stock options granted in 2001 by Aquila Merchant had a weighted average fair value of \$22.75 per share on the grant date. This value is included in the total stock-based employee compensation expense determined under the fair value method, net of related tax, in the pro forma table above.

### **Cash and Cash Equivalents**

Cash and cash equivalents includes cash in banks and temporary investments with an original maturity of three months or less. As of December 31, 2005 and 2004, our cash held in foreign countries was \$3.0 million and \$58.5 million, respectively.

### **Currency Adjustments**

For income statement items, we translate the financial statements of our foreign subsidiaries and operations into U.S. dollars using the average exchange rate during the period. For balance sheet items, we use the year-end exchange rate. When translating foreign currency-based assets and liabilities to U.S. dollars, we show any differences between accounts as unrealized translation adjustments in common shareholders' equity. Currency transaction gains or losses on transactions executed in a currency other than the functional currency are recorded in the Consolidated Statements of Income.

### **Reclassifications**

Certain prior year amounts in the consolidated financial statements have been reclassified where necessary to conform to the 2005 presentation. In particular, as discussed in Note 6, certain assets that have been classified as held for sale and the results of operations from those assets have been reclassified as discontinued operations in the accompanying balance sheets and statements of income for all periods presented.

### **Note 2: New Accounting Standards**

#### **Conditional Asset Retirement Obligations**

In March 2005, the FASB issued Interpretation (FIN) No. 47, "Accounting for Conditional Asset Retirement Obligations—An Interpretation of SFAS No. 143" (FIN 47), which clarifies the term "conditional asset retirement obligation" used in SFAS No. 143, "Accounting for Asset Retirement Obligations", and specifically when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. We adopted FIN 47 effective December 31, 2005. As further discussed in Note 8, the adoption of FIN 47 had no impact on our results of operations but did result in the recognition of \$.2 million of additional property, plant and equipment, \$8.4 million of asset retirement obligations and an offsetting regulatory asset of \$8.2 million.

## **Share-Based Payments**

In December 2004, the FASB issued SFAS No. 123R (SFAS 123R), “Share-Based Payments,” that requires all companies to expense the value of employee stock options in periods beginning after June 15, 2005. In April 2005, the SEC approved a rule that delayed the effective date of SFAS 123R for public companies. As a result, SFAS 123R was effective for us as of January 1, 2006, and applied to all outstanding unvested share-based awards on that date and all prospective awards. We have elected to use the modified prospective method to adopt SFAS 123R. The estimated 2006 impact of the adoption of SFAS 123R on January 1, 2006 is immaterial.

## **Exchanges of Nonmonetary Assets**

In December 2004, the FASB issued SFAS No. 153, “Exchanges of Nonmonetary Assets,” (SFAS 153) which eliminates an exception in APB 29 for recognizing nonmonetary exchanges of similar productive assets at fair value and replaces it with an exception for recognizing exchanges of nonmonetary assets at fair value that do not have commercial substance. SFAS 153 was effective for us for nonmonetary asset exchanges occurring on or after January 1, 2006. The adoption of SFAS 153 will not have a significant effect on our financial statements.

## **Accounting Changes and Error Corrections**

In May 2005, the FASB issued SFAS No. 154, “Accounting Changes and Error Corrections” (SFAS 154), which replaces APB Opinion No. 20, “Accounting Changes” and SFAS No. 3 “Reporting Accounting Changes in Interim Financial Statements.” SFAS 154 provides guidance on the accounting for and reporting of accounting changes and error corrections. It establishes retrospective application, or the latest practicable date, as the required method for reporting a change in accounting principle and the reporting of a correction of an error. SFAS 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. We do not expect that the adoption of SFAS No. 154 will have an impact on our financial statements.

## **Note 3: Risk Management**

### **Overview**

We use derivative financial instruments to reduce our exposure to adverse fluctuations in interest rates, foreign currency exchange rates, commodity prices and other market risks. We also enter into derivative instruments in our energy trading business. Below we discuss these various types of instruments and our objectives for holding them.

### **Merchant Trading Activities**

During the second half of 2002, Aquila Merchant began exiting from the wholesale energy trading business. Because of this decision, it liquidated many of its energy trading contracts in the market. However, it was not able to liquidate all of its contracts. Aquila Merchant is no longer a market maker and no longer trades to take advantage of market trends and arbitrage opportunities. Trading activities now consist of optimizing assets it owns or contractually controls.

Prior to the decision to exit this business, Aquila Merchant traded energy commodity contracts daily. The trading activities attempted to match the portfolio of physical and financial contracts to current or anticipated market conditions. Within the trading portfolio, Aquila Merchant took certain positions to hedge physical sale or purchase contracts and to take advantage of market trends and conditions. Aquila Merchant continues to use all forms of financial instruments, including futures, forwards, swaps and options, to help hedge its remaining

portfolio. Each type of financial instrument involves different risks. We believe financial instruments help Aquila Merchant manage its remaining contractual commitments and reduce its exposure to changes in market prices.

We record most trading energy contracts—both physical and financial—at fair value in accordance with SFAS 133. Changes in value are reflected in the Consolidated Statements of Income in sales and on the Consolidated Balance Sheets in price risk management assets or liabilities. We refer to these transactions as price risk management activities.

### **Market Risk**

Our price risk management activities involve commitments to purchase or sell financial instruments or commodities at fixed prices at future dates. The contractual amounts and terms of these Merchant and Utilities financial instruments at December 31, 2005 are below:

<i>Dollars in millions</i>	<b>December 31, 2005</b>		
	<b>Fixed Price Payor</b>	<b>Fixed Price Receiver</b>	<b>Maximum Term in Years</b>
<b>Energy Commodities:</b>			
Natural gas ( <i>trillion Btu's</i> )	191	164	4
Electricity ( <i>megawatt-hours</i> )	234,800	234,800	1
Heating oil ( <i>barrels</i> )	119,000	21,000	2
<b>Financial Products:</b>			
Interest rate instruments	\$1.2	\$.7	15

We have attempted to balance our remaining physical and financial contracts in terms of quantities, commodities and contract performance as our remaining trading portfolio winds down. To the extent we are not hedged, we are exposed to fluctuating market prices that may adversely impact our financial position or results from operations.

### **Market Valuation**

The prices we use to value price risk management activities reflect our best 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. The prices also 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. The values of all forward and future contracts are discounted to December 31, 2005, using market interest rates for the contract term adjusted for our credit rating for liabilities or the credit rating of the counterparty for assets. We continuously monitor the portfolio and value it daily based on present market conditions. The following table

displays the fair values of Merchant and Utilities price risk management assets and liabilities at December 31, 2005, and the average value for the year ended December 31, 2005:

<i>In millions</i>	<b>Price Risk Management Assets</b>		<b>Price Risk Management Liabilities</b>	
	<b>Average Value</b>	<b>December 31, 2005</b>	<b>Average Value</b>	<b>December 31, 2005</b>
Natural gas	\$326.0	\$363.0	\$265.7	\$288.6
Electricity	28.4	8.9	27.5	7.1
Coal	5.4	3.6	—	—
Other	1.9	2.2	12.6	8.1
<b>Total</b>	<b>\$361.7</b>	<b>\$377.7</b>	<b>\$305.8</b>	<b>\$303.8</b>

Our price risk management assets are concentrated with six counterparties representing 77% of the total asset value of the portfolio. This concentration of customers may impact our overall exposure to credit risk, either positively or negatively, as the counterparties may be similarly affected by changes in economic, regulatory or other conditions.

### **Hedging Activities**

When we enter into financial instruments for hedging purposes, we formally designate and document the instrument as a hedge of a specific underlying exposure, as well as the risk management objectives and strategies for undertaking the hedge transaction. Because of the high degree of correlation between the hedging instrument and the underlying exposure being hedged, fluctuations in the value of the derivative instruments are generally offset by changes in the value or cash flows of the underlying exposures being hedged. The fair values of derivatives used to hedge or modify our risks fluctuate over time. These fair value amounts should not be viewed in isolation, but rather in relation to the fair values or cash flows of the underlying hedged transactions and the overall reduction in our risk relating to adverse fluctuations in foreign exchange rates, interest rates, commodity prices and other market factors. We also formally assess, both at the inception and at least quarterly thereafter, whether the financial instruments that are used in hedging transactions are effective at offsetting changes in either the fair value or cash flows of the related underlying exposures. Any ineffective portion of a financial instrument's change in fair value is recognized in other income (expense) on the Consolidated Statements of Income. We discontinue hedge accounting prospectively when we determine that a derivative is no longer effective in offsetting changes in the fair value or cash flows of a hedged item, if the derivative or hedged item is sold, expires, is terminated or is exercised, or when management determines that designating the item as a hedging instrument is no longer appropriate.

In all cases, when hedge accounting is discontinued and the derivative remains outstanding, the derivative is carried at fair value on our balance sheet and changes in fair value from that point forward are included in current period earnings. When we discontinue hedge accounting because the hedged item has been terminated or sold, the accumulated gain or loss in OCI is reclassified into current-period earnings.

### **Cash Flow Hedges**

Changes in the fair value of a derivative that is highly effective, that is designated and qualifies as a cash flow hedge are recorded in OCI to the extent that the derivative is effective as a hedge. We recorded a \$8.8 million decrease in OCI related to cash flow hedges in 2004, net of both taxes and reclassifications to earnings. As of December 31, 2005, we did not have any outstanding cash flow hedges.

### ***Normal Purchases and Sales Exception***

As part of our utility business, we enter into contracts to purchase or sell electricity, gas and coal using contracts that are considered derivatives under SFAS 133. The majority of these contracts, however, qualify for normal purchases and sales treatment under SFAS 133. These contracts are exempt from mark-to-market accounting treatment as they are for the purchase and sale of fuel and energy to meet the requirements of our customers. At the initiation of the contract, we make a determination as to whether or not the contract meets the criteria as a normal purchase or normal sale. These contracts include short-term and long-term commitments to purchase and sell energy and energy-related products in the retail and wholesale markets with the intent and ability to deliver or take delivery in quantities we expect to use over a reasonable period in the normal course of business. Derivatives qualifying as normal purchases or sales are recorded and recognized in income using accrual accounting.

### **Regulated Commodity Management**

Our utility businesses produce, purchase and distribute power in three states and purchase and distribute gas in seven states. All of our Gas Utilities have PGA provisions that allow them to pass the prudently-incurred cost of the commodity to the customer. To the extent that gas prices are higher or lower than amounts in our current billing rates, adjustments are made on a periodic basis to “true-up” billed amounts to actual cost incurred. These adjustments are subject to periodic prudence reviews by the state utility commissions. In addition, as allowed by state regulatory commissions, we have entered into certain financial instruments to reduce our customers’ underlying exposure to fluctuations in gas prices. These financial instruments are considered derivatives under SFAS 133 and are marked-to-market and recorded in our PGA accounts as they are collectible under the provisions of the PGA upon settlement.

In 2005, our continuing regulated electric business generated approximately 51% of the power that we sold and purchased the remaining 49% through long-term contracts or in the open market. The regulatory provisions for recovering power costs vary by state. In Kansas and Colorado, we have ECAs that serve a purpose similar to that of the PGAs for the gas utilities. To the extent that our fuel and purchased power energy costs vary from the energy cost built into our tariffs, the difference is passed through to the customer. In Missouri, there is no provision to pass through changes in costs except through a rate case filing. We were, however, operating in 2004 and 2005 under a two-year interim energy charge as part of a rate case settlement agreement that allowed us to recover such costs up to a specified amount per Mwh specific to each of our Missouri service territories. The settlement rate per unit sold is \$13.98/Mwh for our St. Joseph Light & Power operations and \$19.71/Mwh for our Missouri Public Service operations. Our actual costs since the rate increase went into effect pursuant to the settlement agreement on April 22, 2004 exceeded the amount allowed under the settlement for our Missouri Public Service operations through December 31, 2005. Variability in the cost of natural gas and coal used for the production of electricity and the price of power purchased in the open market can impact the stability of utility earnings. We manage this commodity risk through a purchasing strategy designed to minimize the effect of variability in energy costs on earnings.

We have entered into a program for our electric utility operations in Missouri to mitigate our exposure to natural gas price volatility in the market. This program extends multiple years and the mark-to-market value of the portfolio of \$20.7 million related to contracts that will settle against actual purchases of natural gas and purchased power in 2006 through 2008. In connection with the recently settled Missouri electric rate case, we agreed that these contracts would be recognized into cost of sales when they settle. A regulatory liability has been recorded under SFAS 71 in the amount of \$20.7 million to reflect the change in the timing of recognition authorized by the Missouri Commission.

To the extent that recovery of actual costs incurred is allowed, amounts will not impact earnings, but will impact cash flows due to the timing of the recovery mechanism.

#### **Note 4: Restructuring Charges**

In connection with our continued exit from Merchant Services and the sale of our investments in international networks, we have recorded the following restructuring charges:

	<b>Year Ended December 31,</b>		
	<b>2005</b>	<b>2004</b>	<b>2003</b>
Merchant Services:			
Interest rate swap reductions	\$ —	\$ —	\$ 23.1
Severance costs	—	.7	—
Retention payments	—	—	2.2
Lease agreements	6.6	—	(.2)
Other	—	—	(.4)
<b>Total Merchant Services</b>	<b>6.6</b>	<b>.7</b>	<b>24.7</b>
Corporate and Other severance costs	—	.2	1.4
<b>Total restructuring charges</b>	<b>\$ 6.6</b>	<b>\$ .9</b>	<b>\$ 26.1</b>

#### **Lease Agreements**

In the first quarter of 2005, we terminated the majority of the remaining leases, with terms through 2010, associated with our former Merchant Services headquarters. In connection with this termination we made a lump-sum payment of \$13.0 million which exceeded our restructuring reserve obligation as of the termination date. This resulted in an additional lease restructuring charge of \$6.6 million.

#### **Interest Rate Swap Reductions**

We incurred \$23.1 million of restructuring charges in 2003 to exit interest rate swaps related to our Raccoon Creek and Goose Creek construction financing arrangements. As debt related to these facilities was paid down, the notional amount of our interest rate swaps exceeded the outstanding debt. As a result, we reduced our swap position and realized the loss associated with the cancelled portion of the swaps.

#### **Severance Costs and Retention Payments**

We incurred severance and other related costs of \$.9 million in 2004 related to the continued exit from our Merchant Services business and the sale of our investments in international networks.

We incurred \$2.2 million of retention payments in 2003 related to the continued wind-down of our domestic and international energy trading operations in Merchant Services, and \$1.4 million of Corporate and Other severance costs related to our continued exit from Merchant Services and the sale of our investments in international networks. We also incurred severance and other related costs of \$2.1 million for the year ended December 31, 2003 in connection with the restructuring of Everest Connections, our communications business which has been reclassified to discontinued operations. This resulted from the termination of approximately 160 employees.

## Restructuring Reserve Activity

The following is a summary of the activity for accrued restructuring charges:

<i>In millions</i>	<b>Year Ended December 31,</b>		
	<b>2005</b>	<b>2004</b>	<b>2003</b>
<b>Severance and Retention Costs:</b>			
Accrued severance and retention costs at beginning of period	\$ .8	\$ .9	\$ 16.6
Additional expense during the period	—	.9	3.6
Cash payments during the period	(.7)	(1.0)	(19.3)
Accrued severance and retention costs at end of period	\$ .1	\$ .8	\$ .9
<b>Other Restructuring Costs:</b>			
Accrued other restructuring costs at beginning of period	\$ 7.0	\$16.0	\$ 32.6
Additional expense during the period	6.6	—	22.5
Cash payments during the period	(13.6)	(9.0)	(39.1)
Accrued other restructuring costs at end of period	\$ —	\$ 7.0	\$ 16.0

### **Note 5: Net Loss on Sale of Assets and Other Charges**

Pretax net loss (gain) on sale of assets and other charges we recorded for the years ended December 31, 2005, 2004 and 2003 are shown below. After-tax losses in the following paragraphs are reported after giving consideration to the effects of capital loss carryback and carryforward limitations. As a result, the net tax effect may differ substantially from our expected statutory tax rates. The after-tax losses (gains) discussed below are based on current estimates of the tax

treatment of these transactions and may be adjusted after detailed allocation of the purchase price for tax purposes and the filing of tax returns including these sales.

<i>In millions</i>	<b>Year Ended December 31,</b>		
	<b>2005</b>	<b>2004</b>	<b>2003</b>
<b>Gas Utilities:</b>			
Other	\$ —	\$ —	\$ (2.2)
<b>Total Gas Utilities</b>	<b>—</b>	<b>—</b>	<b>(2.2)</b>
<b>Merchant Services:</b>			
Batesville tolling agreement	(16.3)	—	—
ICE sale	(9.3)	—	—
Aries power project and tolling agreement	—	46.6	—
Termination of long-term gas contracts	—	156.2	—
Red Lake gas storage development project	(6.2)	8.9	—
Acadia tolling agreement	—	—	105.5
Turbine contracts	—	—	(5.1)
Independent power plants	—	(6.1)	87.9
Investment in BAF Energy	(.7)	(9.1)	—
Enron bankruptcy	—	(6.0)	—
Marchwood development project	—	(5.0)	—
Other	1.2	—	.8
<b>Total Merchant Services</b>	<b>(31.3)</b>	<b>185.5</b>	<b>189.1</b>
<b>Corporate and Other:</b>			
Early conversion of the PIES	82.3	—	—
Everest Connections target-based put rights	—	(4.5)	—
Midlands	—	(3.3)	4.0
Australia	—	—	1.8
Turbines impairment	4.4	10.6	—
<b>Total Corporate and Other</b>	<b>86.7</b>	<b>2.8</b>	<b>5.8</b>
<b>Total net loss on sale of assets and other charges</b>	<b>\$ 55.4</b>	<b>\$188.3</b>	<b>\$192.7</b>

During 2005, 2004 and 2003, we also incurred net loss (gain) on sale of assets and other charges of \$159.5 million, \$(74.0) million and \$49.5 million, respectively, relating to our discontinued operations. These charges are reflected in discontinued operations and are not included in the table above. See Note 6 for further discussion.

### **Batesville Tolling Contract**

In February 2005, we terminated our power sales contract and assigned our rights and obligations under the tolling contract in exchange for approximately \$16.3 million. This transaction resulted in a pretax gain of approximately \$16.3 million, or \$10.2 million after tax.

### **ICE Sale**

In February 2005, we sold our 4.5% interest in ICE to other shareholders for approximately \$13.8 million. ICE owns a web-based commodity exchange platform. This transaction resulted in a pretax and after-tax gain of approximately \$9.3 million. The gain was realized as a capital gain for income tax purposes resulting in the reversal of previously provided valuation allowances on capital loss carryforwards.

### **Aries Power Project and Tolling Agreement**

In March 2004, we transferred to Calpine Corp., our joint venture partner in the Aries power project, our 50% ownership interest in this project, \$5.0 million cash and certain transmission and ancillary contract rights in exchange for the termination of our remaining aggregate undiscounted payment obligation of approximately \$397.3 million under our 20-year tolling agreement with the Aries facility. At the same time, Calpine returned approximately \$12.5 million of collateral we had posted in support of ongoing energy trading contracts. We recorded a pretax loss of \$46.6 million, or \$35.4 million after tax, in connection with this transaction.

### **Termination of Long-Term Gas Contracts**

As discussed in more detail in Note 13, we terminated four of our long-term gas supply contracts resulting in payments of \$712.9 million and pretax losses of \$156.2 million, or \$97.6 million after tax in 2004.

### **Red Lake Storage Development Project**

In January 2002, we acquired the Red Lake property, consisting of 33,700 acres of land in Mohave County, Arizona, for development of two salt cavern natural gas storage facilities with a combined working capacity of 12 Bcf. In December 2004, we recorded a pretax impairment charge of \$8.9 million, or \$5.6 million after tax, to write this investment down to its estimated fair value. On August 31, 2005, we executed an agreement to sell the land to a real estate development company for \$21.2 million. The transaction was approved by the Kansas Commission in October 2005 and closed in November 2005. We recorded a pretax gain on this transaction of \$6.2 million, or \$3.9 million after tax, in the fourth quarter of 2005.

### **Acadia Tolling Agreement**

In May 2003, we terminated our 20-year tolling agreement for the Acadia power plant located in Louisiana. After making a termination payment of \$105.5 million, resulting in a \$63.8 million after-tax loss, we were released from the remaining aggregate payment obligation of \$833.9 million, or approximately \$43.5 million on an annual basis.

### **Turbine Contracts**

We had a contract to acquire four General Electric turbines. Our intent was to place these turbines into future power plant development projects. However, due to the restructuring of our business and change in our business strategy, we made the decision in the fourth quarter of 2002 to cease these development projects and to sell these turbines or return them to the manufacturer. As a result, we incurred a \$42.1 million pretax charge, or \$25.5 million after tax, related to the expected loss on sale or contract termination related to these turbines.

During the second quarter of 2003, we completed the contract termination and sale of certain turbines which had been written down to an estimated realizable value at December 31, 2002. In connection with the disposition, we recorded a pretax gain of \$5.1 million, or \$3.2 million after tax.

### **Independent Power Plants**

In November 2003, we agreed to sell our interests in 12 independent power plants. Two of the power plants were consolidated on our balance sheet. Therefore, in accordance with SFAS 144, we have reported the results of operations and assets of these two plants in discontinued operations. See Note 6 for further explanation.

The remaining plants were equity method investments that did not qualify for reporting as discontinued operations under SFAS 144 and were therefore included in continuing operations. In the third quarter of 2003, we evaluated the carrying value of these equity method investments based on the bids received and other internal valuations. The results of this assessment indicated that these investments were impaired. Therefore, we recorded a pretax impairment charge of \$87.9 million, or \$69.9 million after tax, to reduce the carrying value of our investments to their estimated fair value. This sale closed in March 2004. We received adjusted proceeds of approximately \$256.9 million and paid approximately \$4.1 million in transaction fees. As the actual proceeds were greater than estimated when we recorded the 2003 impairment charge, we recorded a pretax gain of \$6.1 million, or \$22.6 million after tax in 2004. The after-tax gain was greater than the pretax gain because an income tax benefit of \$16.2 million was recognized for the reversal of a valuation allowance provided in 2003. The 2003 valuation allowance was provided as it was expected that a substantial portion of the loss would be treated as a capital loss, the benefit from which more likely than not would not be realized. However, the form of the final sale and detailed allocation of the purchase price for tax purposes based on an independent appraisal resulted in a portion of these losses being realized as ordinary losses. The related valuation allowance was therefore reversed in 2004.

### **Investment in BAF Energy**

We own a 23.11% non-voting limited partnership interest in BAF Energy, a California limited partnership that formerly owned a 120 MW natural gas-fired combined cycle cogeneration facility in King City, California. In May 2004, Calpine King City Cogen, LLC purchased 100% of the King City cogeneration facility from BAF Energy. Our share of the proceeds, approximately \$24.3 million, was received as a distribution from the partnership in June 2004. As a result of the distribution, we recorded a pretax gain of \$9.1 million, or \$5.7 million after tax, in the second quarter of 2004. In 2005, we received a final distribution which resulted in a pretax gain of \$.7 million, or \$.4 million after tax.

### **Enron Bankruptcy**

On March 7, 2005, we reached an agreement with Enron Corp. and certain of its affiliates (Enron). Under this agreement, we paid \$28 million to Enron to settle all outstanding claims between Enron and Aquila associated with the various bankruptcy filings of Enron in December 2001 and two lawsuits filed by Enron Canada Corp. in January 2003. In 2001, we reserved for substantially all of our then outstanding receivables from Enron, which resulted in a charge of \$66.8 million. This charge did not reflect potential gains we would record in the event we were successful in netting certain obligations to Enron against these receivables. Approximately \$33.5 million of liabilities remained on our books related to contracts with Enron after the 2001 charge. As a result of the settlement, we reduced our net liability to Enron by approximately \$6.0 million, or \$3.7 million after tax.

### **Marchwood Development Project**

In January 2004, we sold undeveloped land and site licenses for a proposed merchant power plant development project in the United Kingdom for approximately \$5.0 million. As a final decision to proceed with construction of this project had not been made, all project development costs had been expensed as incurred. As a result, the pretax gain on the sale was equal to the net proceeds of \$5.0 million, or \$3.1 million after tax.

### **Early Conversion of the PIES**

As discussed in more detail in Note 12, we completed an exchange offer that resulted in the early conversion of approximately 98.9% of our PIES in July 2005. We recorded a pretax and

after-tax early conversion loss of \$82.3 million in connection with this transaction. We did not record a tax benefit from this transaction as the premium paid to complete the conversion is not deductible for tax purposes.

### **Everest Connections Target-Based Put Rights**

Certain minority owners of Everest Connections had the option to sell their ownership units to us if Everest Connections did not meet certain financial and operational performance measures as of December 31, 2004 (target-based put rights). If the put rights were exercised, we would have been obligated to purchase up to 4.0 million and 4.75 million ownership units at a price of \$1.00 and \$1.10 per unit, respectively, for a total potential cost of \$9.2 million. As a result of our reduced funding of this business, management assessed the likelihood of achieving these metrics and during 2002 recorded a probability-weighted expense of \$7.1 million. In 2004, we achieved the operating targets related to 4.0 million and 1.5 million of ownership units at a price of \$1.00 and \$1.10 per unit, respectively. Therefore, we reversed \$4.5 million pretax and after tax of this liability. We did not achieve the targets related to 3.25 million of ownership units at a price of \$1.10 per unit. The holders of these target-based put rights exercised their option and were paid \$3.6 million for their ownership units in February 2005. We had fully reserved for this payment as of December 31, 2004.

### **Midlands**

In October 2003, we and FirstEnergy Corp. agreed to sell 100% of the shares in Aquila Sterling Limited (ASL), the owner of Midlands Electricity plc, to a subsidiary of Powergen UK plc for approximately £36 million. As a result of this agreement and our analysis of fair value surrounding this investment, in the third quarter of 2003 we recorded a \$4.0 million pretax and after-tax impairment charge to write this investment down to its estimated fair value. We completed the sale of ASL in January 2004, received proceeds of \$55.5 million and paid approximately \$7.6 million in transaction fees. We recorded a pretax and after-tax gain from this sale of approximately \$3.3 million in 2004 due to strengthening in the British pound exchange rate in the fourth quarter of 2003 and early 2004.

### **Australia**

In 2003, we sold our interests in Multinet Gas, UEL and AlintaGas Limited to a consortium consisting of AlintaGas, AMP Henderson and their affiliates. We received approximately \$622 million in cash proceeds from this sale before transaction costs and taxes. We retired our \$200.0 million, 364-day secured credit facility with these proceeds. In 2003, we recorded a pretax loss of \$1.8 million, or \$1.3 million after tax, in connection with this sale.

### **Turbines Impairment**

In December 2004, we determined that the carrying value of three Westinghouse Siemens natural gas combustion turbines held by one of our non-regulated subsidiaries was impaired. These turbines were transferred from the non-regulated subsidiary to our Missouri regulated electric division for the construction of our South Harper peaking facility. Missouri affiliate transaction rules require that such transfers be made at the lower of fair market value or fully distributed cost. We obtained an appraisal of the fair value of the turbines, which was less than the carrying value of the turbines and related costs. As a result, we recorded a pretax impairment charge of approximately \$10.6 million, or \$6.5 million after tax. The transfer was subject to the final determination of the Missouri Commission. In connection with our rate case filed in July 2005 and settled in February 2006, we agreed to lower the turbines fair value an additional \$4.4 million, and recorded a pretax impairment charge of \$4.4 million, or \$2.7 million after tax.

## **Note 6: Discontinued Operations**

We have sold, or are in the process of selling, the assets discussed below, which are considered discontinued operations in accordance with SFAS 144.

After-tax losses discussed below are reported after giving consideration to the effect of capital loss carryback and carryforward limitations. As a result, the net tax effect may differ substantially from our expected statutory tax rates.

### **Electric and Gas Utilities**

On September 21, 2005, we entered into asset purchase agreements to sell our electric distribution business that serves customers in central and western Kansas, our natural gas distribution business serving customers in southern and eastern Michigan, our natural gas distribution business serving Minnesota customers (including a non-regulated appliance repair business in that state) and our natural gas distribution business serving customers in central and northwest Missouri. Additional information on these sales includes:

<b>Utility</b>	<b>Buyer</b>	<b>Base Price (in millions)</b>
Kansas Electric	Mid-Kansas Electric Company	\$255.2
Michigan Gas	WPS Resources Corporation	269.5
Minnesota Gas	WPS Resources Corporation	288.0
Missouri Gas	The Empire District Electric Company	84.0

The base price in each sale will be increased by working capital and capital expenditures net of depreciation. Completion of each of the sale transactions depends on several conditions being satisfied by September 21, 2006 (subject to extension in limited circumstances), including: (i) the non-occurrence of a material adverse event, as described in the asset purchase agreements; (ii) the approval of the applicable state regulatory commissions and, in the case of the Kansas electric business, the approval of the FERC; (iii) the expiration or early termination of any waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended; and (iv) the other closing conditions set forth in the asset purchase agreements. Our employees in each business are expected to be transferred to the buyers upon completion of the sales, upon the terms and conditions contained in the asset purchase agreements. We expect each of the utility asset sales to result in pretax gains upon closing.

The operating results of the utility divisions held for sale, as summarized below, include the direct operating costs associated with those businesses but do not include the allocated operating costs of central services and corporate overhead in accordance with Emerging Issues Task Force Consensus 87-24 (EITF 87-24), "Allocation of Interest to Discontinued Operations." We provide executive management and centralized support services to all of our utility divisions, including customer care, billing, collections, information technology, accounting, tax and treasury services, regulatory services, gas supply services, human resources, safety and other services. The operating costs related to these functions are allocated to the utility divisions, including those held for sale, based on various allocation methods. These allocated costs are not included in the reclassification to earnings from discontinued operations because these support services are necessary to maintain operations until the sales are final and cannot be eliminated immediately upon closing of the asset sales. We are developing a comprehensive plan to eliminate the majority of these costs when these support services are no longer required. We expect that a portion of

these costs could be reallocated to the remaining utilities. The allocated operating costs related to the utility divisions held for sale are as follows:

<i>In millions</i>	<b>Year Ended December 31,</b>		
	<b>2005</b>	<b>2004</b>	<b>2003</b>
Allocated expenses of Kansas electric and Michigan, Minnesota and Missouri gas retained in continuing operations	\$42.3	\$39.6	\$37.2

The discontinued utility operations participate in our single qualified pension plan, single non-qualified Supplemental Executive Retirement Plan (SERP) and single other post-retirement benefit plan. Under the asset purchase agreements, the buyers will assume the accrued pension obligations owed to the current and former employees of the operations they are acquiring upon closing. After closing, benefit plan assets will be transferred to comparable plans established by the buyers in accordance with applicable ERISA requirements and the terms of the asset purchase agreements.

### **Merchant Peaking Power Plants**

On December 16, 2005, our wholly-owned subsidiary, Aquila Piatt County Power, L.L.C. (Aquila Piatt), entered into an asset purchase and sale agreement with Union Electric Company d/b/a AmerenUE (AmerenUE), under which Aquila Piatt has agreed to sell to AmerenUE the Goose Creek Energy Facility for \$105 million. The Goose Creek Energy Facility is a 510 MW natural gas-fired, simple-cycle peaking power plant located in Piatt County, Illinois.

On December 16, 2005, our wholly-owned subsidiary, MEP Flora Power, LLC (MEP), entered into an asset purchase and sale agreement with AmerenUE, under which MEP has agreed to sell to AmerenUE the Raccoon Creek Energy Facility for \$70 million. The Raccoon Creek Energy Facility is a 340 MW natural gas-fired, simple-cycle peaking power plant located in Clay County, Illinois.

Each agreement contains various provisions customary for transactions of this size and type, including representations, warranties and covenants with respect to the facilities that are subject to customary limitations. Completion of the sale transaction depends on several conditions being satisfied by June 1, 2006 (subject to extension for up to an additional 90 days in limited circumstances), including: (i) the non-occurrence of a material adverse event, as described in the asset purchase and sale agreement; (ii) the approval of the Kansas Commission and the FERC; (iii) the expiration or early termination of any waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended; (iv) the closing of the other asset sale transaction with AmerenUE; and (v) the other closing conditions set forth in each asset purchase and sale agreement.

In connection with the sale of these facilities, we determined that the Goose Creek Energy Facility and the Raccoon Creek Energy Facility should be classified as “held for sale” and included in discontinued operations, rather than “held and used” as they had previously been classified. As a result, we reassessed the realizability of the carrying value of our investments in these facilities and concluded that they were impaired. We based this conclusion on the anticipated net sale proceeds of the sale transactions described above. Based on the expected net sale proceeds and transaction-related costs, we recorded a pre-tax non-cash impairment charge of approximately \$93.6 million and \$65.9 million for the Goose Creek Energy Facility and the Raccoon Creek Energy Facility, respectively, or an after-tax loss of approximately \$58.5 million and \$41.2 million on the Goose Creek Energy Facility and the Raccoon Creek Energy Facility, respectively. We expect to receive an aggregate book tax benefit on the asset sales of

approximately \$59.8 million (tax calculation on the pre-tax loss of approximately \$159.5 million), although there will be no immediate cash tax receivable on the asset sales due to our loss carryovers.

### **Everest Connections**

In the fourth quarter of 2005, we began the sales process for our Everest Connections communications company. Competitive bids were solicited and received, and are currently being evaluated by management. Based on the level of bidder participation and the bid evaluations, we expect that the sale of this business will be completed by the end of 2006, and have determined that the business should be classified as “held for sale” and included in discontinued operations. In connection with this reclassification, we reassessed the realizability of the carrying value of our investment in Everest. A comparison of the carrying value to the range of bid valuations mentioned above indicated that no impairment of the investment existed.

On March 3, 2006, our subsidiary, Everest Global Technologies Group, LLC (EGTG), entered into a unit purchase agreement with Everest Connections Holdings, Inc., an acquisition subsidiary of Seaport Capital Partners III, L.P., under which EGTG has agreed to sell certain subsidiaries to the buyer. We own over 97% of the membership interests of EGTG and have guaranteed its obligations under the unit purchase agreement.

The unit purchase agreement provides for the payment in cash of a base purchase price of \$85.7 million, subject to a working capital adjustment. Our proceeds will be reduced by the interests of minority owners, the payment of EGTG debt and other retained liabilities. The agreement contains various provisions customary for transactions of this size and type, including representations, warranties, and covenants with respect to the business that are subject to customary limitations. Completion of the sale transaction depends on several conditions being satisfied by September 3, 2006, including: (i) the non-occurrence of a material adverse event, as described in the unit purchase agreement; (ii) the consent of certain municipalities where Everest Connections operates; (iii) the expiration or early termination of any waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended; (iv) the approval of the Federal Communications Commission; (v) the receipt of third-party acquisition financing by the buyer; and (vi) the other closing conditions set forth in the unit purchase agreement. We expect this sale to result in a pretax gain upon closing.

### **Interest Allocation to Discontinued Operations**

The buyers of our utility divisions and peaking facilities will not assume any of our long-term debt and none of our long-term debt is required to be repaid with the proceeds of the sales. The direct debt and related interest of Everest Connections has been included in discontinued operations as it is expected to be assumed by the buyer or repaid. The lenders in our \$220 million unsecured five-year term loan (see Note 12) and \$100 million secured revolving credit facility (see Note 11) will have the opportunity to elect prepayment without premium, in whole or in part, from the proceeds of the asset sales. We allocated a portion of consolidated interest expense to discontinued operations based on the ratio of net assets of discontinued operations to consolidated net assets plus consolidated debt in accordance with EITF 87-24. The amount of interest expense allocated to discontinued operations may not be representative of the actual interest reductions we may achieve from future debt retirements using the proceeds of the asset sales.

### **Canada**

On May 31, 2004, we completed the sale of our Canadian utility operations in Alberta and British Columbia to two wholly-owned subsidiaries of Fortis Inc., a Canadian energy company, for approximately \$1.08 billion (CDN\$1.476 billion), including the assumption of debt of \$113 million

(CDN\$155 million) by the purchasers. The closing proceeds included \$85 million (CDN\$116 million) of adjustments for working capital and capital expenditures as provided under the sales agreements. We recorded a pretax gain from this sale of \$65.6 million, or \$9.1 million after tax, including final working capital and capital expenditure adjustments.

The effective tax rate on the pretax gain on sale of our Canadian utility businesses is substantially higher than the statutory federal tax rate due to the following factors. The U.S. taxes reflect the partial deduction of Canadian taxes, including withholding taxes, from the U.S. taxable income instead of the full utilization of foreign tax credits. Taxes on the sale also reflect our inability to fully utilize the tax loss on the sale of the Alberta business against the tax gain on the sale of the British Columbia business.

Prior to the closing of the sale, we retired debt related to our Canadian utility operations including \$215 million under a 364-day credit facility and \$15 million (CDN\$20 million) under a revolving bank credit facility. In addition, we were released at the closing of the sale from our guarantor obligations with respect to our former British Columbia utility's debentures and second mortgage loan totaling \$113.0 million (CDN\$155.0 million).

### **Independent Power Plants**

In November 2003, we agreed to sell our interests in 12 independent power plants. Two of the power plants were consolidated on our balance sheet. We have reported the results of operations and assets of these two plants in discontinued operations. In the third quarter of 2003, we evaluated the carrying value of these assets based on the bids received and other internal valuations. The results of this assessment indicated these assets were impaired. We recorded a pretax impairment charge of \$47.5 million, or \$39.8 million after tax, to reduce the carrying value of these assets to their estimated fair value less costs to sell. We closed the sale of these plants in March 2004. Because the actual proceeds realized were greater than estimated when we recorded the 2003 impairment charge, we recorded a pretax gain of \$8.4 million, or \$16.2 million after tax, in the first quarter of 2004. The after-tax gain was greater than the pretax gain because an income tax benefit of \$11.1 million was recognized for the partial reversal of a valuation allowance provided in 2003. The 2003 valuation allowance was provided as it was expected that a substantial portion of the loss would be treated as a capital loss, the benefit from which more likely than not would not be realized. However, the form of the final sale and a detailed allocation of the purchase price for tax purposes based on an independent appraisal resulted in a portion of these losses being realized as ordinary losses. The related valuation allowance was therefore reversed in 2004.

### **Summary**

We have reported the results of operations from these assets in discontinued operations for the three years ended December 31, 2005 in the Consolidated Statements of Income. The related assets and liabilities included in the sale of these businesses, as detailed below, have been

reclassified as current and non-current assets and liabilities of discontinued operations on the December 31, 2005 and 2004 Consolidated Balance Sheets as follows:

<i>In millions</i>	<b>December 31,</b>	
	<b>2005</b>	<b>2004</b>
<b>Current assets of discontinued operations:</b>		
Cash and cash equivalents	\$ 4.8	\$ 6.6
Accounts receivable, net	160.5	121.6
Inventories and supplies	81.0	67.0
Other current assets	22.7	25.5
<b>Total current assets of discontinued operations</b>	<b>\$269.0</b>	<b>\$ 220.7</b>
<b>Non-current assets of discontinued operations:</b>		
Property, plant and equipment, net	\$831.4	\$ 967.4
Prepaid pension	26.6	31.2
Other non-current assets	39.9	29.9
<b>Total non-current assets of discontinued operations</b>	<b>\$897.9</b>	<b>\$1,028.5</b>
<b>Current liabilities of discontinued operations:</b>		
Current maturities of long-term debt	\$ 1.3	\$ .6
Other current liabilities	29.8	32.9
<b>Total current liabilities of discontinued operations</b>	<b>\$ 31.1</b>	<b>\$ 33.5</b>
<b>Non-current liabilities of discontinued operations:</b>		
Long-term debt, net	\$ 6.2	\$ 4.9
Deferred credits	56.8	48.9
<b>Total non-current liabilities of discontinued operations</b>	<b>\$ 63.0</b>	<b>\$ 53.8</b>

Operating results of discontinued operations are as follows:

<i>In millions</i>	<b>Year Ended December 31,</b>		
	<b>2005</b>	<b>2004</b>	<b>2003</b>
Sales	\$ 879.8	\$870.9	\$1,013.3
Cost of sales	608.0	518.1	508.8
Gross profit	271.8	352.8	504.5
Operating expenses:			
Operating expense	112.1	183.0	263.0
Restructuring charges	—	—	2.1
Net loss (gain) on sale of assets and other charges	159.5	(74.0)	49.5
Depreciation and amortization expense	42.5	47.5	53.2
Total operating expenses	314.1	156.5	367.8
Other income (expense):			
Other income (expense)	.5	3.5	(15.6)
Interest expense	71.2	88.6	98.2
Earnings (loss) before income taxes	(113.0)	111.2	22.9
Income tax expense (benefit)	(41.0)	55.4	2.8
Earnings (loss) from discontinued operations	\$ (72.0)	\$ 55.8	\$ 20.1

#### **Note 7: Accounts Receivable**

Our accounts receivable on the Consolidated Balance Sheets are as follows:

<i>In millions</i>	<b>December 31,</b>	
	<b>2005</b>	<b>2004</b>
Merchant Services accounts receivable	\$173.5	\$193.1
Utilities billed accounts receivable	131.4	97.8
Unbilled utility revenue	101.2	77.4
Other accounts receivable	2.7	1.2
Allowance for doubtful accounts	(9.3)	(27.7)
<b>Total</b>	<b>\$399.5</b>	<b>\$341.8</b>

In 2005, we entered into a \$150 million four-year secured revolving credit facility. Borrowings under this facility are secured by the accounts receivable generated by our regulated utility operations in Colorado, Kansas, Michigan, Missouri and Nebraska. We had borrowed \$12 million under this facility as of December 31, 2005. See Note 11 for further discussion.

In October 2003, we pledged receivables from certain of our merchant gas customers as collateral support for a margining agreement with one of our significant gas suppliers. The total of these pledged receivables was \$41.8 million at December 31, 2005.

The allowance for doubtful accounts is our best estimate of the amount of probable credit losses in our accounts receivable. We determine the allowance based on historical write-off experience and detailed reviews of our accounts receivable agings.

## Note 8: Property, Plant and Equipment

The components of property, plant and equipment from continuing operations are listed below:

<i>In millions</i>	<b>December 31,</b>	
	<b>2005</b>	<b>2004</b>
Electric utility	\$ 2,084.0	\$ 1,871.0
Gas utility	633.7	615.6
Non-regulated electric power generation	135.2	135.5
Corporate and other	287.6	286.4
Electric and gas utility plant—construction in process	35.0	124.4
	3,175.5	3,032.9
Less—accumulated depreciation and amortization	(1,298.2)	(1,222.9)
<b>Total property, plant and equipment, net</b>	<b>\$ 1,877.3</b>	<b>\$ 1,810.0</b>

Our property, plant and equipment from continuing operations includes acquisition-related adjustments that are being amortized over useful lives not exceeding 40 years. Net amounts from continuing operations included in electric utility and gas utility that are not included in our rate base were \$17.7 million and \$22.2 million at December 31, 2005 and 2004, respectively.

	<b>Composite Depreciation Rates</b>		
	<b>2005</b>	<b>2004</b>	<b>2003</b>
<b>Continuing Operations—</b>			
Electric utility	2.6%	2.7%	3.2%
Gas utility	3.2%	3.3%	3.5%
Non-regulated electric power generation	2.8%	2.8%	2.8%
Corporate and other	11.3%	11.6%	11.7%
<b>Discontinued Operations—</b>			
Electric utility	3.3%	3.0%	3.0%
Gas utility	2.7%	2.6%	2.5%
Non-regulated electric power generation	2.8%	2.8%	2.8%
Communications	9.2%	9.0%	8.5%

### Jointly Owned Electric Utility Plant

We own an 8% interest and lease another 8% interest in a coal-fired plant (Jeffrey Energy Center) with generating capacity of approximately 2,190 megawatts, operated by Westar Energy, Inc. We also own an 18% interest in a 654-megawatt coal-fired plant (Iatan) operated by KCPL. At December 31, 2005, our investments in the Jeffrey and Iatan plants totaled \$198.1 million and related accumulated depreciation was \$123.2 million. Upon the sale of our Kansas electric utility, our 8% leased interest in the Jeffrey Energy Center will transfer to the buyer, which represents approximately \$17.6 million of our total net investment in the Jeffrey plant as of December 31, 2005. Our pro rata share of Jeffrey Energy Center's and Iatan's operating costs are included in our Consolidated Statements of Income.

## **Allowance for Funds Used During Construction**

AFUDC represents the capitalized cost of debt and equity funds used to finance construction projects for our regulated utilities. For the years ended December 31, 2005, 2004 and 2003, our continuing Electric and Gas Utilities recorded approximately \$5.3 million, \$3.0 million and \$2.8 million, respectively, of additional income and construction work in progress related to AFUDC. The non-cash earnings are classified as other income (expense) in our Consolidated Statements of Income. The increase in AFUDC in 2005 primarily relates to the construction of our South Harper peaking facility.

Under accepted rate making practices, we are allowed cash recovery of AFUDC, as well as other capitalized construction costs, once completed construction projects are placed into service and reflected in customer rates. The rates used for capitalizing AFUDC are computed using agreed upon methods prescribed by the FERC.

## **Asset Retirement Obligations**

In August 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS 143). SFAS 143 requires us to record the fair value of an asset retirement obligation as a liability in the period in which a legal obligation associated with the retirement of tangible long-lived assets is incurred. When the liability is initially recorded, we capitalize the estimated cost by increasing the carrying amount of the related long-lived asset. The liability will be accreted to its present value each subsequent period. The capitalized cost will be depreciated over the life of the related asset. Upon satisfaction of the liability, we will record a gain or loss for the difference between the actual cost incurred and the recorded liability. This standard became effective for us on January 1, 2003.

SFAS 143 requires our regulated utility business to recognize, where it is possible to estimate, the future costs to settle legal liabilities. These legal liabilities include the removal of water intake structures on rivers, capping/filling of piping at levees following steam power plant closures, capping/closure of ash ponds, capping/closure of coal pile bases, and removal and disposal of storage tanks and transformers containing PCB's. We measured these liabilities based on internal engineering estimates of third party costs to remove the assets in satisfaction of legal obligations, discounted using our credit adjusted risk free borrowing rates depending on the anticipated settlement date.

In connection with the adoption of SFAS 143 in January 2003, our regulated business recorded an asset retirement obligation of \$.8 million and increased property, plant and equipment, net of accumulated depreciation, by an immaterial amount. Because this business is a regulated utility subject to the provisions of SFAS 71, the \$.8 million cumulative effect of adoption of SFAS 143 was recorded as a regulatory asset and therefore had no impact on net income.

In March 2005, the FASB issued Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations—An Interpretation of SFAS No. 143" (FIN 47), which clarifies the term "conditional asset retirement obligation" used in SFAS 143, and specified when an entity has sufficient information to reasonably estimate the fair value of an asset retirement obligation. The adoption of FIN 47 on December 31, 2005, required us to update an existing inventory of identified legal obligations, originally created under FAS 143, for conditional asset retirement obligations.

We identified asbestos abatement costs associated with the closure of certain owned power plants and other structures as conditional asset retirement obligations. The ability to reasonable estimate when the obligation would occur was a matter of judgment, based upon our ability to estimate the dates and methods of asbestos abatement. We considered historical practices,

industry practices, our management's intent and the estimated useful lives of our assets in determining settlement dates and methods. Based on our estimates, we measured the fair value of our obligations using the present value of future abatement costs discounted at our credit adjusted risk free borrowing rates.

Our continuing Electric and Gas Utilities recorded an asset retirement obligation of \$8.4 million and increased property, plant and equipment, net of accumulated depreciation, by \$.2 million. Because this business is a regulated utility subject to the provisions of SFAS 71, the \$8.2 million cumulative effect of adoption of FIN 47 was recorded as a regulatory asset and therefore had no impact on net income. In addition, our discontinued utility operations recognized an asset retirement obligation of \$4.4 million, increased net property, plant and equipment by \$.1 million, and recorded an offsetting regulatory asset of \$4.3 million. These liabilities will be adjusted on an ongoing basis due to the passage of time, new laws and regulations and revisions to either the timing or amount of our original cost estimates.

We also have legal asset retirement obligations for certain other assets. It is not possible to estimate the time period when these obligations will be settled. As a result, the retirement obligations cannot be measured at this time. These assets include certain assets within our electric and gas transmission and distribution systems that, pursuant to an easement or franchise agreement, are required to be removed if we discontinue our utility service under such easement or franchise agreement.

Our liability for asset retirement obligations was approximately \$9.2 million and \$.8 million as of December 31, 2005 and 2004, respectively.

Depreciation rates approved by regulatory commissions in certain states include a provision for the cost of future removal of assets for which there is no legal removal obligation. Concurrent with the adoption of SFAS 143, the net provision for these "non-legal" removal costs has been reclassified from accumulated depreciation, where it has been recorded previously, to a regulatory liability. See Note 10 for further discussion.

#### **Note 9: Investments in Unconsolidated Subsidiaries**

Our Consolidated Balance Sheets contain various equity investments, including shareholder loans. The table below summarizes our investments and related equity earnings:

<i>In millions</i>	Effective Ownership at 12/31/05	Country	Investment at December 31,		Equity Earnings— Year Ended December 31,		
			2005	2004	2005	2004	2003
Independent power plant partnerships	Sold	U.S. & Jamaica	\$—	\$ —	\$—	\$ 1.9	\$ 56.4
Midlands Electricity plc	Sold	United Kingdom	—	—	—	—	—
United Energy Limited	Sold	Australia	—	—	—	—	10.9
Multinet Gas	Sold	Australia	—	—	—	—	5.0
AlintaGas Limited	Sold	Australia	—	—	—	—	.2
Other	Various%	United States	.7	1.5	—	.2	(2.9)
<b>Total</b>			\$ .7	\$ 1.5	\$—	\$ 2.1	\$ 69.6

## **Independent Power Plant Partnerships**

As of December 31, 2003, we owned interests in 14 independent power plants located in eight states and Jamaica. In 2003, we decided to proceed with the sale of our remaining investments in independent power plants and evaluated the carrying value of these equity method investments based on the bids received and other internal valuations. The results of this assessment indicated that these investments were impaired. Therefore, we recorded a pretax impairment charge of \$87.9 million, or \$69.9 million after tax, to reduce the carrying value of our investments to their estimated fair value. In January 2004, we sold our interest in one of these plants. In March 2004, we closed the sale of our interests in 12 plants for approximately \$256.9 million and paid approximately \$4.1 million in transaction costs. As the actual proceeds realized were greater than estimated when we recorded the 2003 impairment charges, we recorded a pretax gain of \$6.1 million, or \$22.6 million after tax, in 2004. Two of the power plants, Lake Cogen Ltd. (Lake Cogen) and Onondaga Cogen Ltd. Partnership (Onondaga), were consolidated on our balance sheet. The remaining 10 plants were equity method investments that did not qualify for reporting as discontinued operations under SFAS 144 and were therefore included in continuing operations and in the investment table above.

In May 2004, BAF Energy, in which we own a 23.11% interest, sold the cogeneration facility it owned and distributed to us our share of the proceeds, approximately \$24.3 million. As a result of the distribution, we recorded a pretax gain of \$9.1 million, or \$5.7 million after tax, in 2004. In 2005, we received a final distribution which resulted in a pretax gain of \$.7 million, or \$.4 million after tax.

## **Midlands Electricity plc**

In May 2002, we purchased from FirstEnergy Corp. a 79.9% economic interest in Aquila Sterling Limited (ASL), the holding company for Midlands Electricity, a United Kingdom electricity network. FirstEnergy retained the remaining 20.1% of ASL. The gross purchase price was valued at approximately \$262 million.

In connection with the acquisition, FirstEnergy retained substantive participating and protective rights as the minority partner. We and FirstEnergy each had 50% voting power and an equal number of representatives on the ASL board of directors. Although we had the majority economic interest, FirstEnergy's participation in day-to-day business decisions was significant, including approval of executive compensation, additional capital contributions, budgets, and the dissolution of the company. We were therefore required to account for this acquisition using the equity method of accounting.

Downgrades in credit ratings assigned to the public debt in the Midlands ownership chain called into question the ability of Midlands to pay us management fees and dividends. Additionally, the local regulatory body, the Office of Gas and Electricity Markets, required pre-approval of cash payments to the owners in the form of management fees or dividends. Accordingly, in 2003 we did not record equity earnings as no cash was received.

In August 2002, we and FirstEnergy initiated a bid process for the sale of Midlands. We received offers in early December and were in negotiations with prospective buyers at December 31, 2002. As a result of those offers, our own internal analysis and the corresponding impairment charge at the investment level, we recorded a \$247.5 million pretax and after-tax impairment charge to write this investment down to its estimated fair value.

In October 2003, we and FirstEnergy Corp. agreed to sell 100% of the shares in ASL, the owner of Midlands Electricity plc, to a subsidiary of Powergen UK plc for approximately £36 million. As a result of this agreement and our analysis of fair value surrounding this investment, in the third quarter of 2003 we recorded a \$4.0 million pretax and after-tax impairment charge to write this investment down to its estimated fair value. We completed the

sale of ASL in January 2004, received proceeds of \$55.5 million and paid approximately \$7.6 million in transaction fees. We recorded a pretax and after-tax gain from this sale of approximately \$3.3 million in the first quarter of 2004 due to strengthening in the British pound exchange rate in the fourth quarter of 2003 and early 2004.

Following is the summarized financial information for Midlands Electricity plc. The balance sheets as of December 31, 2005 and 2004 and the income statement for the 2005 and 2004 periods are not included because we sold our investment in January 2004:

<i>In millions</i>	<b>Year Ended December 31, 2003</b>
<b>Operating Results:</b>	
Sales	\$623.3
Costs and expenses	543.2
<b>Net income</b>	<b>\$ 80.1</b>

### **United Energy Limited, Multinet Gas and AlintaGas Limited**

We acquired our initial investment in Australia in 1995. Our ownership interest in United Energy Limited (UEL), a publicly owned electric distribution company in Melbourne, Australia, was 33.8%. UEL owned a 66% interest in Uecomm Limited, a communications business, and a 22.5% interest in AlintaGas Limited, a gas utility in Western Australia.

In March 1999, we acquired a 25.5% interest in Multinet Gas and Ikon Energy Pty Ltd (Ikon), a natural gas retail and distribution network in Melbourne. In December 2001, we advanced an additional \$81.9 million in the form of a loan to enable Multinet to repay certain external debt.

In October 2000, we closed on our \$166 million joint acquisition with UEL of a 45% cornerstone interest in AlintaGas Limited, a gas distribution utility in Western Australia. The remaining 55% of the shares of AlintaGas were sold to the Australian public in an initial public offering in October 2000. Our 22.5% interest was reflected as an equity investment with the remaining 22.5% reflected as part of our interest in UEL.

In 2003, we sold our interests in Multinet Gas, UEL and AlintaGas Limited to a consortium consisting of AlintaGas, AMP Henderson and their affiliates. We received approximately \$622 million in cash proceeds before transaction costs and taxes from this sale. We recorded a pretax loss of \$1.8 million, or \$1.3 million after tax, in 2003 in connection with this sale.

Following is the summarized financial information for UEL. The balance sheet as of December 31, 2005 and 2004 and the income statement for the 2005 and 2004 periods are not included because we sold our investment in 2003:

<i>In millions</i>	<b>Seven Months Ended July 31, 2003</b>
<b>Operating Results:</b>	
Sales	\$157.3
Costs and expenses	126.4
<b>Net income</b>	<b>\$ 30.9</b>

## Aries Power Project and Tolling Agreement

In March 2004, we transferred to Calpine Corp., our joint venture partner in the Aries power project, our 50% ownership interest in this project, \$5.0 million cash and certain transmission and ancillary contract rights in exchange for the termination of our remaining aggregate undiscounted payment obligation of approximately \$397.3 million under our 20-year tolling agreement with the Aries facility. At the same time, Calpine returned approximately \$12.5 million of collateral we had posted in support of ongoing energy trading contracts. We recorded a pretax loss of \$46.6 million, or \$35.4 million after tax, in connection with this transaction.

Following is the summarized financial information for our other unconsolidated equity investments. These investments consist of Multinet, AlintaGas and our independent power project partnerships for the applicable years in which they were equity investments. As mentioned above, we sold our interests in Multinet and AlintaGas in 2003 and our interest in independent power plants and Aries in March 2004. Therefore, the balance sheet as of December 31, 2005 and 2004 and the 2005 and 2004 income statement are not included. The results of operations for 2003 includes each investment only for the periods in which we owned them.

<i>In millions</i>	<b>Year Ended December 31, 2003</b>
<b>Operating Results:</b>	
Sales	\$912.6
Costs and expenses	750.2
<b>Net income</b>	<b>\$162.4</b>

### **Note 10: Regulatory Assets**

Federal, state or local authorities regulate certain of our utility operations. Our financial statements therefore include the economic effects of rate regulation in accordance with SFAS 71. This means our Consolidated Balance Sheets show some assets and liabilities that would not be found on the balance sheets of a non-regulated company.

The following table lists our regulatory assets and liabilities. We primarily show these as deferred charges and other assets and deferred credits on our Consolidated Balance Sheets.

<i>In millions</i>	<b>December 31,</b>	
	<b>2005</b>	<b>2004</b>
<b>Regulatory Assets:</b>		
Under-recovered gas costs	\$ 27.7	\$16.3
Income taxes	59.3	58.1
Environmental	2.2	2.2
Regulatory accounting orders	5.8	7.7
Asset retirement obligations	9.2	.8
Other	6.5	5.3
<b>Total regulatory assets</b>	<b>\$110.7</b>	<b>\$90.4</b>
<b>Regulatory Liabilities:</b>		
Cost of removal	48.4	48.5
Income taxes	5.3	5.9
Revenue subject to refund	1.5	.4
Over-recovered gas costs	28.8	—
Gas price derivatives	20.7	—
Pensions	9.9	5.9
Other	1.0	.6
<b>Total regulatory liabilities</b>	<b>115.6</b>	<b>61.3</b>
<b>Net regulatory (liabilities) assets</b>	<b>\$ (4.9)</b>	<b>\$29.1</b>

Regulatory assets are either currently being collected in rates or are expected to be collected through rates in a future period, as described below:

- Under-recovered gas costs represent the cost of gas delivered to our gas utility customers in excess of that allowed in current rates. We do not earn a return on these costs which are collected from customers in future periods of less than one year as rates are periodically adjusted.
- Income taxes represent amounts of accelerated tax benefits previously flowed through to customers and expected to be collected from customers over the remaining life of the utility plant as accelerated tax benefits reverse. We do not earn a return on these items.
- Environmental costs include certain site clean-up costs that are deferred and expected to be collected from customers in future periods when authorized by regulatory authorities. Prudent costs such as these have traditionally been allowed for recovery by our regulatory jurisdictions over periods of five to 10 years. We do not earn a return on these items.
- Regulatory accounting orders include costs such as ice storm recovery and others that have been specifically approved for recovery over future periods, generally five years or less. We do not earn a return on these items.
- Asset retirement obligations represents the estimated recoverable costs for legally required removal obligations. See Note 8 for further discussion. We do not earn a return on these items.
- Other primarily includes costs related to energy efficiency, demand side management and regulatory proceedings that are deferred and expected to be recovered from customers in future periods when authorized by regulatory authorities. Prudent costs such as these have

traditionally been allowed for recovery by our regulatory jurisdictions over various periods. We do not earn a return on these items.

Regulatory liabilities represent items we expect to pay to customers through billing reductions in future periods or use for the purpose for which they were collected from customers, as described below:

- Cost of removal represents the estimated cumulative net provision for future removal costs included in depreciation expense for which there is no legal removal obligation. See Note 8 for further discussion.
- Income taxes generally represent taxes previously collected at tax rates that were greater than the rates we expect to pay. We expect to refund this amount to customers in future periods.
- Revenue subject to refund represents revenues collected from customers under interim rate orders that we expect to return to customers. This amount is estimated by management based on the particular facts and circumstances of the cases and the historical actions of the regulatory jurisdictions.
- Over-recovered gas costs represent the cost of gas paid by gas utility customers in allowed rates in excess of actual costs incurred. These costs will be returned to customers in future periods as rates are periodically adjusted.
- Gas price derivatives represents the mark-to-market value of the portfolio of natural gas financial contracts that will settle against actual purchases of natural gas and purchased power in 2006 through 2008. In connection with the recently settled Missouri electric rate case, we agreed that these contracts would be recognized into cost of sales when they settle. A regulatory liability has been recorded under SFAS 71 to reflect the change in the timing of recognition authorized by the Missouri Commission.
- Pensions represent the cumulative excess of pension costs recovered in rates over pension expense recorded under SFAS 87. We expect to refund this amount to customers in future periods.

In addition, our discontinued Electric and Gas Utilities had recognized \$29.6 million of regulatory assets and \$37.8 million of regulatory liabilities as of December 31, 2005.

If all or a separable portion of our operations were deregulated and no longer subject to the provisions of SFAS 71, we would be required to write off our related regulatory assets and liabilities, net of the related income tax effect, unless some form of transition cost recovery (refund) was established.

#### **Note 11: Short-Term Debt**

We had \$12.0 million in short-term borrowings outstanding under our four-year secured revolving credit facility on December 31, 2005. No short-term borrowings were outstanding on December 31, 2004.

#### **364-Day Letter of Credit Facility**

In April 2004, we extended our 364-day Letter of Credit Agreement with a commercial bank for an additional 364 days. Under the terms of the agreement, the bank committed to issue letters of credit under the facility subject to a limit of \$100.0 million outstanding at any one time. All letters of credit issued are fully secured by cash deposits with the bank. This facility expired April 22, 2005, however, letters of credit issued under this facility will remain outstanding until their scheduled expiration dates through April 2006. As of December 31, 2005, \$39.2 million of letters of credit remained outstanding under this facility.

### **\$180 Million Unsecured Revolving Credit and Letter of Credit Facility**

On April 13, 2005, we entered into a five-year credit agreement with a commercial lender. Subject to the satisfaction of certain conditions, the facility provides for up to \$180 million of cash advances and letters of credit for working capital purposes. The facility will become available in amounts and at prevailing market rates to be agreed with the lender prior to usage. Cash advances must be repaid within 364 days unless we obtain the necessary regulatory approvals to incur long-term indebtedness under the facility. The facility replaces our existing cash-collateralized letter of credit facility, which expired April 22, 2005. As of December 31, 2005, we had \$150.0 million of uncollateralized capacity at an average cost of 3.65% under this agreement. We had issued \$150.9 million of letters of credit and cash collateralized the excess over \$150 million under this facility as of December 31, 2005.

### **Six-Month Secured Revolving Credit Facility**

On October 22, 2004, we completed a \$125 million secured revolving credit facility. On December 1, 2004, we amended this facility to increase the maximum borrowing limit to \$150 million. The facility was secured by the accounts receivable generated by our regulated utility operations in Colorado, Kansas, Michigan, Missouri and Nebraska. The six-month facility expired April 22, 2005. We did not draw on this facility.

### **Four-Year Secured Revolving Credit Facility**

On April 22, 2005, we executed a new four-year \$150 million secured revolving credit facility (the AR Facility). Proceeds from this facility may be used for working capital and other general corporate purposes. Borrowings under this facility are secured by the accounts receivable generated by our regulated utility operations in Colorado, Kansas, Michigan, Missouri and Nebraska. Borrowings under the AR Facility bear interest at LIBOR plus 1.375%, subject to reduction if our credit ratings improve. Borrowings must be repaid within 364 days unless we obtain the necessary regulatory approvals to incur long-term indebtedness under the facility. Among other restrictions, we are required under the AR Facility to maintain the same debt-to-total capital and EBITDA-to-interest expense ratios as those contained in the Five-Year Facilities discussed in Note 12. We had borrowed \$12.0 million under this facility as of December 31, 2005 at a rate of 7.75%.

As we close the sales of our Kansas electric and Michigan and Missouri gas businesses, the accounts receivable generated by these utilities will be released from the AR Facility and the maximum borrowing limit may be reduced.

### **\$100 Million Secured Revolving Credit Facility**

On January 19, 2006, we closed on a \$100 million revolving credit facility with a commercial lender. This facility, which is expected to be used to meet possible working capital requirements, matures on April 19, 2006 but we may extend the final maturity for up to three additional one-month periods. The facility is secured by our ownership interest in the Goose Creek and Raccoon Creek peaking facilities and must be repaid, if any borrowings exist at the time, with the proceeds from the sale of the facilities. This loan facility also contains mandatory repayment provisions related to the utility asset sales proceeds so long as the asset sales proceeds are not used to repay our \$220 million five-year unsecured term loan. The facility contains covenants that restrict certain activities, including, among others, limitation on additional indebtedness, restrictions on acquisitions, sale transactions and investments. In addition, we are prohibited from paying dividends and from making certain other payments if our senior unsecured debt is not rated at least Ba2 by Moody's and BB by Standard & Poor's, or if such payment could cause a default under the facility.

## \$50 Million Revolving Credit and Letter of Credit Facility

On January 13, 2006, we closed on a \$50 million short-term letter of credit facility with a commercial lender. This facility, which terminates on December 20, 2006, allows us to either issue letters of credit or make cash drawings under the facility. Similar to the \$180 million facility that we signed in April 2005, the lender has relied on the credit derivative swap market to establish pricing for this facility. This facility, which bears a 2.50% interest rate, is expected to be nearly fully utilized through letter of credit issuances.

### Note 12: Long-Term Debt

This table summarizes our long-term debt:

<i>In millions</i>	<b>December 31,</b>	
	<b>2005</b>	<b>2004</b>
<b>First Mortgage Bonds:</b>		
9.44% Series, due annually through 2021 (a)	\$ 18.0	\$ 19.1
<b>Unsecured Term Loan:</b>		
LIBOR plus 5.75% (9.9913% at December 31, 2005), due September 19, 2009	220.0	220.0
<b>Senior Notes:</b>		
9.03% Series, due December 1, 2005	—	19.1
6.70% Series, due October 15, 2006	85.9	85.9
8.2% Series, due January 15, 2007	36.9	36.9
7.625% Series, due November 15, 2009	199.0	199.0
9.95% Series, due February 1, 2011	250.0	250.0
7.75% Series, due June 15, 2011	197.0	197.0
14.875% Series, due July 1, 2012	500.0	500.0
8.27% Series, due November 15, 2021	80.9	80.9
9.0% Series, due November 15, 2021	5.0	5.0
8.0% Series, due March 1, 2023	51.5	51.5
7.875% Series, due March 1, 2032	287.5	287.5
<b>Medium Term Notes:</b>		
Various, 7.19%*, due 2013-2023	17.0	40.0
<b>Mandatorily Convertible Notes:</b>		
6.75% Series, mandatorily convertible on September 15, 2007 into common shares at a conversion rate of 8.0386 to 9.8039 shares per \$25 par value convertible note	2.6	345.0
<b>Convertible Subordinated Debentures:</b>		
6.625%, due July 1, 2011 (convertible into 136,697 common shares at \$15.79 per share)	2.1	2.3
<b>Other:</b>		
Other notes and obligations 4.95%*, due 2006-2028 (a)	26.1	27.2
<b>Total long-term debt</b>	<b>1,979.5</b>	<b>2,366.4</b>
Less current maturities	88.3	41.4
<b>Long-term debt, net</b>	<b>\$1,891.2</b>	<b>\$2,325.0</b>
Fair value of long-term debt, including current maturities (b)	\$2,199.1	\$2,752.4

\* Weighted average interest rate.

(a) Approximately \$38.5 million of our long-term debt, including \$20.5 million of other notes, is secured by certain assets of the company as specified in various mortgages, indentures and security agreements.

(b) The fair value of long-term debt is based on current rates at which we could borrow funds with similar remaining maturities.

The amounts of long-term debt maturing in each of the next five years and thereafter are as follows:

<i>In millions</i>	<b>Maturing Amounts</b>
2006	\$ 88.3
2007 (a)	42.0
2008	2.5
2009	421.5
2010	1.9
Thereafter	1,423.3
<b>Total</b>	<b>\$1,979.5</b>

(a) *Includes the non-cash, mandatory conversion of \$2.6 million of PIES to common stock on September 15, 2007.*

### **Mandatorily Convertible Senior Notes**

In August 2004, we issued 13.8 million PIES units at \$25 per PIES unit, including an over-allotment of 1.8 million PIES, representing \$345.0 million of mandatorily convertible senior notes. These unsecured notes bear interest at 6.75% through September 15, 2007. Unless converted earlier by the holder into our common stock, on September 15, 2007, these securities automatically convert into shares of our common stock at a conversion rate ranging from 8.0386 to 9.8039 shares of common stock per PIES unit, based on the average closing price of our common stock for the 20-day trading period prior to the mandatory conversion date. Our net proceeds on the issuance of the PIES were \$334.3 million, after underwriting discounts, commissions and other costs. The proceeds were used to retire long-term debt and other long-term liabilities.

In June 2005, we announced an exchange offer related to the optional conversion of our PIES into shares of our common stock. Pursuant to the offer, holders of the PIES units would receive a conversion premium of 1.5896 shares of common stock in addition to the 8.0386 shares of common stock per PIES unit they would receive upon exercising their conversion option under the existing terms of the PIES. In July 2005, the holders of approximately 98.9% of the PIES units accepted our exchange offer and tendered their PIES units for conversion. As a result, we issued approximately 131.4 million shares of common stock pursuant to the terms of the PIES exchange offer, and recorded a pretax and after-tax early conversion loss of approximately \$82.3 million related to the PIES exchange offer and certain cash repurchases of PIES units. We did not record a tax benefit from these transactions as the premiums paid were not deductible for tax purposes. The completion of these transactions reduced our annual cash interest payments by approximately \$23.1 million through September 2007. In connection with the exchange offer, approximately \$7.7 million of unamortized debt issue costs related to the PIES were reclassified to premium on capital stock.

### **Senior Notes Rating Triggers**

In July 2002, we issued \$500.0 million of 11.875% senior notes due in July 2012. Because Moody's and S&P have downgraded our credit ratings, the interest rate on these notes has been adjusted to a maximum rate of 14.875%.

In February 2001, we issued \$250.0 million of 7.95% senior notes due in February 2011. Because Moody's and S&P have downgraded our credit ratings, the interest rate on these notes has been adjusted to a maximum rate of 9.95%.

If our credit ratings improve to certain levels, the interest rates on these notes and our Five-Year Facilities (discussed below) will be lowered.

### **Three-Year Secured Term Loan**

In April 2003, we closed on a \$430.0 million, three-year secured loan. The initial interest rate on the facility was LIBOR (with a 3% floor) plus 5.75%. This rate was reduced to LIBOR (with a 3% floor) plus 5.00% when additional regulated utility collateral was pledged. In addition, we were required to pay up-front arrangement fees of \$17.8 million. Proceeds from the financing were used to retire debt and support letters of credit.

The \$430.0 million secured term loan became immediately due and payable in September 2004 when we did not complete an exchange offer, tender offer, refinancing or other retirement transaction with regard to 80% of our \$150.0 million, 6.875% senior note series due October 1, 2004, at least two weeks prior to its maturity date. We paid our lenders an early termination fee of 2%, or \$8.7 million, pursuant to this provision. We also wrote off \$10.3 million of unamortized debt issue costs. Certain lenders participating in the term loan are contesting the terms of the prepayment and seeking to require us to pay additional prepayment penalties of approximately \$6.0 million. See Note 20 for discussion of litigation relating to this dispute.

### **Five-Year Unsecured Term Loan and Revolving Credit Facility**

In September 2004, we completed a \$220 million 364-day unsecured term loan and a \$110 million 364-day unsecured revolving credit facility. The facilities automatically extended to September 2009 when we received extension approval from the FERC and various state public utility commissions (the Five-Year Facilities). We borrowed the full amount of the term loan and received \$211.3 million of net proceeds after upfront fees and expenses on the two facilities. There were no borrowings outstanding on the revolving credit facility as of December 31, 2005. The Five-Year Facilities bear interest at the LIBOR plus 5.75%, subject to reduction if our credit rating improves. Among other restrictions, the Five-Year Facilities contain the following financial covenants with which we were in compliance as of December 31, 2005:

- (1) We are required to maintain a ratio of total debt to total capital (expressed as a percentage) of not more than 90% from December 31, 2005 through September 30, 2007; 75% from December 31, 2007 through September 30, 2008; 70% from December 31, 2008 through June 30, 2009; and 65% thereafter.
- (2) We must maintain a trailing 12-month ratio of EBITDA, as defined in the agreement, to interest expense of no less than 1.1 to 1.0 from December 31, 2005 through September 30, 2006; 1.3 to 1.0 from December 31, 2006 through September 30, 2007; 1.4 to 1.0 from December 31, 2007 through September 30, 2008; 1.6 to 1.0 from December 31, 2008 through June 30, 2009; and 1.8 to 1.0 thereafter.
- (3) We must maintain a trailing 12-month ratio of debt outstanding to EBITDA of no more than 8.5 to 1.0 from December 31, 2005 through September 30, 2006; 7.5 to 1.0 from December 31, 2006 through September 30, 2007; 6.0 to 1.0 from December 31, 2007 through September 30, 2008; 5.5 to 1.0 from December 31, 2008 through June 30, 2009; and 5.0 to 1.0 thereafter.

The Five-Year Facilities also contain covenants that restrict certain activities including, among others, limitations on additional indebtedness, restrictions on acquisitions, sale

transactions and investments. In addition, we are prohibited from paying dividends and from making certain other payments if our senior unsecured debt is not rated at least Ba2 by Moody's and BB by S&P, or if such a payment would cause a default under the facility.

### **Iatan 2 Construction Financing**

On August 31, 2005, we entered into a \$300 million credit agreement with a commercial lender and a syndicate of other lenders (the Iatan Facility). The credit agreement allows us to obtain loans and issue letters of credit (limited to \$175 million of letters of credit) in support of our participation in the construction of an approximately 850 MW coal-fired power plant being developed by KCPL near Weston, Missouri, and our obligation to fund pollution controls being installed at an adjacent facility. Extensions of credit under the facility will be due and payable on August 31, 2010. Loans bear interest at LIBOR plus a margin determined by our credit ratings. A fee based on our credit ratings will be paid on the amount of letters of credit outstanding. Obligations under the credit agreement are secured by the assets of our Missouri Public Service electric operations. There were no borrowings or letters of credit outstanding under this facility at December 31, 2005. Among other restrictions, the Iatan Facility contains the following financial covenants with which we were in compliance as of December 31, 2005:

- (1) We are required to maintain a ratio of total debt to total capital (expressed as a percentage) of not more than 75% through September 30, 2008; 70% from October 1, 2008 through September 30, 2009; and 65% thereafter.
- (2) We must maintain a trailing 12-month ratio of EBITDA, as defined in the agreement, to interest expense of no less than 1.2 to 1.0 through September 30, 2006; 1.3 to 1.0 from October 1, 2006 through September 30, 2007; 1.4 to 1.0 from October 1, 2007 through September 30, 2008; 1.6 to 1.0 from October 1, 2008 through September 30, 2009; and 1.8 to 1.0 thereafter.
- (3) We must maintain a trailing 12-month ratio of debt outstanding to EBITDA of no more than 7.75 to 1.0 through September 30, 2006; 7.5 to 1.0 from October 1, 2006 through September 30, 2007; 6.0 to 1.0 from October 1, 2007 through September 30, 2008; 5.5 to 1.0 from October 1, 2008 through September 30, 2009; and 5.0 to 1.0 thereafter.
- (4) We must maintain a ratio of mortgaged property to extensions of credit (borrowings plus outstanding letters of credit) of no less than 2.0 to 1.0 as of the last day of each fiscal quarter.

The Iatan Facility also contains covenants that restrict certain activities including, among others, limitations on additional indebtedness, restrictions on acquisitions, sale transactions and investments. In addition, we are prohibited from paying dividends and from making certain other payments if our senior unsecured debt is not rated at least Ba2 by Moody's and BB by Standard & Poor's, or if such a payment would cause a default under the facility.

### **Credit Ratings**

Our non-investment grade credit ratings impact our ability to obtain short- and long-term financing, the cost of such financing and the execution of our commercial strategies. Our financial flexibility is limited because of restrictive covenants and other terms that are typically imposed on non-investment grade borrowers.

As of December 31, 2005, our senior unsecured long-term debt ratings, as assessed by the three major credit rating agencies, were as follows:

<b>Agency</b>	<b>Rating</b>	<b>Outlook</b>
Moody's	B2	Positive Outlook
S&P	B-	Positive Outlook
Fitch	B-	Positive Outlook

We do not have any debt with repayment provisions linked to our credit ratings.

### **Secured Financing**

We generally are required to obtain the approval of the relevant state public service commission before pledging utility assets located in the state as collateral. We currently do not have approval to pledge those utility operations as collateral.

In addition, we are required to obtain prior approval from the FERC before we can issue long-term or short-term debt. We currently have authority from the FERC to have up to \$500 million of short-term debt outstanding. Our authority to issue short-term debt expires in April 2006, and, on February 2, 2006, we filed an application with the FERC requesting authority to issue up to \$500 million of short-term debt from time to time over the next two years. The FERC recently issued an order in which it announced that any future debt authorization orders would prohibit companies subject to its jurisdiction from using their utility properties as collateral for loans unless the loan proceeds will be used to support their utility operations.

Except in limited circumstances, holders of our senior notes and bonds, which represent the majority of our unsecured obligations, do not have the right to restrict our use of collateral or to be equally or ratably secured if we provide collateral to other creditors. The terms of our Five-Year Facilities, Iatan Facility and \$100 million secured revolving credit facility prohibit us from pledging our assets as collateral except in certain circumstances.

### **Note 13: Long-Term Gas Contracts**

In 1997 through 2000, we were paid in advance on six contracts to deliver gas to municipal utilities over the subsequent 10 to 12 years. These contracts were settled monthly through the physical delivery of gas. We hedged our exposure to changes in gas prices related to these contracts.

In 2004, we terminated four long-term gas contracts, which included the American Public Energy Agency (APEA) contracts for which Chubb Group of Insurance Companies (Chubb) provided surety bonds (APEA III and APEA IV), and our APEA (APEA II) and Municipal Gas Authority of Mississippi (MGAM) contracts, for which St. Paul/Travelers provided surety bonds. As a result, we were required to pay APEA, Chubb, St. Paul/Travelers and MGAM approximately \$712.9 million under the liquidated damages and other provisions of the gas supply contracts and termination agreements. We recorded a pretax charge of \$156.2 million, or \$97.6 million after tax, on the termination of these four contracts.

In addition, the realization of the price risk management assets and liabilities associated with the terminated long-term gas contracts, and the related commodity hedges that were terminated, resulted in non-cash, mark-to-market losses of \$40.3 million primarily related to the discounting of our trading portfolio, \$16.5 million for margin recorded on these contracts and \$7.1 million of net replacement gas payments under the termination provisions of these contracts.

We do not intend to terminate our two remaining long-term gas contracts with the Municipal Gas Authority of Georgia and APEA (APEA I), which have a total obligation and total remaining cash payments as outlined below:

<i>In millions</i>	<b>Long-Term Gas Contract Settlement (a)</b>	<b>Long-Term Gas Contract Margin Loss (b)</b>	<b>Total Long-Term Gas Contract Cash Payments (c)</b>
2006	\$15.7	\$ 7.7	\$23.4
2007	15.8	8.1	23.9
2008	1.4	.6	2.0
<b>Total</b>	<b>\$32.9</b>	<b>\$16.4</b>	<b>\$49.3</b>

(a) *This represents the reduction of the long-term gas contract liability each period.*

(b) *These margin losses represent the cash payments for gas to settle these contracts on a monthly basis, net of the reduction of the long-term gas contract liability.*

(c) *This represents the cash payment obligation to purchase the gas delivered to the municipal utilities each period.*

We accounted for the cash payments in advance related to these contracts as long-term obligations. We reduce our obligation on these long-term gas contracts as gas is delivered to the customer under the units of revenue method. If we were to default on the two remaining contracts, or were unable to perform on them, we would be required to pay the issuers of the surety bonds or the counterparties on these arrangements approximately \$49.2 million. This amount is greater than the long-term gas contract balance on our Consolidated Balance Sheet due to our use of the units of revenue method versus a present value method applied under default provisions based on contractual agreements.

#### **Note 14: Capital Stock and Stock Compensation**

##### **Capital Stock**

We have two types of authorized common stock—unclassified common stock and Class A common stock. No Class A common stock is issued or outstanding. We also have authorized 10,000,000 shares of preference stock, with no par value, none of which is issued or outstanding.

##### ***Equity Offerings***

In August 2004, we sold 46.0 million shares of our common stock to the public, including an over-allotment option of 6.0 million shares, which raised \$112.3 million in net proceeds. We used the proceeds of this offering to retire long-term debt and reduce other long-term liabilities.

##### ***Suspension of Dividend***

In November 2002, the Board of Directors suspended the annual dividend on common stock for an indefinite period. This decision followed a detailed analysis of the company's then current financial condition, its liquidity forecast and its earnings prospects after completion of certain asset sales. Currently four of our loan agreements and a regulatory order prohibit us from paying any dividends. We can make no determination as to whether or when we will pay dividends in the future.

### ***Aquila Merchant Dissenters' Rights***

In January 2002, we completed an exchange offer and merger in which we acquired all the outstanding publicly-held shares of Aquila Merchant in exchange for shares of Aquila common stock. The public shareholders of Aquila Merchant received .6896 shares of Aquila common stock in a tax-free exchange for each outstanding share of Aquila Merchant Class A common stock. Aquila Merchant shareholders holding approximately 1.7 million shares of Aquila Merchant Class A shares exercised dissenters' rights to request an appraisal of the fair value of their shares with respect to the merger. In June 2004, we paid approximately \$38 million, including interest from 2002, to settle this litigation. This resulted in the recognition of additional expense of \$8.8 million including litigation costs in 2004.

### **Stockholder Rights Plan**

Our Board of Directors has adopted a rights plan and declared a dividend distribution of one right for each outstanding share of our common stock. The rights become exercisable if a person acquires beneficial ownership of 15% or more of our outstanding common stock. If the rights were exercised, the value of the shares of our common stock held by the acquiring person would be substantially diluted. The purpose of the rights plan is to encourage a person desiring to acquire 15% or more of our outstanding common stock to negotiate the terms of their acquisition with our Board of Directors.

### **Dividend Reinvestment and Common Stock Purchase Plan**

Our Dividend Reinvestment and Common Stock Purchase Plan (the Stock Plan) has been suspended since 2003 until we obtain authorization of additional shares. Previously we offered current and potential shareholders the option to participate in the Stock Plan. The Stock Plan allowed participants to purchase up to \$10,000 per month of common stock at the average market price on the date of the transaction, with minimal sales commissions. The Stock Plan also allowed members to reinvest dividends into additional common shares at a 5% discount. For the year ended December 31, 2003, 608,074 shares were issued under the Stock Plan.

### **Employee Stock Purchase Plan**

Purchases have been suspended since 2003 under our Employee Stock Purchase Plan until we obtain authorization of additional shares. Participants in this plan had the opportunity to buy shares of common stock at a reduced price through regular payroll deductions and/or lump sum deposits of up to 20% of the employee's base salary, but not more than \$25,000 annually. Contributions were credited to the participant's account throughout an option period. At the end of the option period, the participant's total account balance was applied to the purchase of common stock. The shares were purchased at 85% of the lower of the market price on the first day or the last day of the option period. Participants must have been enrolled in the Plan as of the first day of an option period in order to participate in that option period. For the year ended December 31, 2003, 665,254 shares were purchased under the Employee Stock Purchase Plan.

### **Retirement Investment Plan**

A defined contribution plan, the Retirement Investment Plan (Savings Plan), covers all of our full-time and eligible part-time employees. Participants may generally elect to contribute up to 50% of their annual pay on a before- or after-tax basis subject to certain limitations. The company generally matches contributions up to 6% of pay. Participants may direct their contributions into various investment options. Matching contributions are made in cash and invested as directed by the employee. Company contributions for continuing operations were

\$6.6 million, \$6.7 million and \$6.5 million and for discontinued operations were \$1.6 million, \$1.7 million and \$1.6 million during the years ended December 31, 2005, 2004, and 2003, respectively. The Savings Plan also includes a discretionary contribution fund to which the company historically contributed an additional 3% of base wages for eligible full-time employees. These contributions are made in cash and invested as directed by the employee. Vesting occurs ratably over five years of employment with distribution upon termination of employment. For 2005, 2004 and 2003, compensation expense for continuing operations of \$3.7 million, \$3.4 million and \$4.1 million, respectively, and for discontinued operations of \$1.0 million, \$0.9 million and \$0.8 million, respectively, was recognized. Any Aquila common shares that have been elected by the employee related to this program are classified as outstanding when calculating earnings per share.

### **Long-Term Incentive Plan**

Our Long-Term Incentive Plan (LTIP) enables the company to reward key executives who have an ongoing company-wide impact. Eligible executives are awarded performance units based on experience and responsibilities in the company. Incentives earned are based on a comparison of our total shareholder return over three years to a specific group of companies with operations similar to ours. Incentives have been paid in cash, restricted stock, restricted stock units or deferred compensation agreements funding stock option grants based on the executives' total shareholdings of company common stock and their elections. No new grants have been provided to senior executive officers since the performance cycle beginning in 2002. We currently have only one outstanding grant to junior executives for the 2003 through 2005 performance cycle. Certain recipients of that outstanding grant have since become senior executive officers of our company, and those grants are reported in our 2006 proxy statement. Total compensation expense for the years ended December 31, 2005, 2004 and 2003, was \$(0.1) million, \$0.3 million and \$0.4 million, respectively.

### **Omnibus Incentive Compensation Plan**

In 2002, the Board and our shareholders approved the Omnibus Incentive Compensation Plan. This plan authorizes the issuance of 9,000,000 shares of Aquila common stock as stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance units, stock awards, cash-based awards and annual incentive awards to all eligible employees and directors of the company. All equity-based awards are issued under this plan. Stock options under this plan and preceding plans have generally been granted at market prices with one to three year vesting terms and have been exercisable for seven to 10 years from the date of grant. In December 2004, we granted fully vested stock options for approximately 1.9 million shares to all employees other than senior executive officers of the company. These options are exercisable for seven years from the date of grant. As of December 31, 2005, we have approximately 5.0 million shares of common stock available for grant under this plan and preceding plans.

## Summary of Stock Options

This table summarizes all stock option activity:

	<b>Year Ended December 31,</b>		
	<b>2005</b>	<b>2004</b>	<b>2003</b>
<b>Shares:</b>			
Beginning balance	9,638,099	8,558,048	8,908,508
Granted	30,000	1,900,760	408,300
Exercised	(308,763)	(472,591)	(85,577)
Cancelled	(2,813,729)	(348,118)	(673,183)
<b>Ending balance</b>	<b>6,545,607</b>	<b>9,638,099</b>	<b>8,558,048</b>
<b>Weighted average prices:</b>			
Beginning balance	\$17.73	\$20.22	\$20.75
Granted price	3.44	3.75	1.44
Exercised price	2.28	4.06	3.04
Cancelled price	25.76	21.57	17.15
<b>Ending balance</b>	<b>\$14.92</b>	<b>\$17.73</b>	<b>\$20.22</b>

This table summarizes all outstanding and exercisable stock options as of December 31, 2005:

<b>Exercise Price Range</b>	<b>Outstanding Options</b>			<b>Exercisable Options</b>	
	<b>Number</b>	<b>Weighted Average Remaining Contractual Life in Years</b>	<b>Weighted Average Exercise Price</b>	<b>Number</b>	<b>Weighted Average Exercise Price</b>
\$1.44-1.83	1,165,878	3.98	\$ 1.78	1,091,178	\$ 1.81
\$3.44-3.75	1,797,410	6.00	3.74	1,797,410	3.74
\$18.50-24.90	2,549,402	2.62	21.69	2,549,402	21.69
\$28.42-39.52	1,032,917	5.23	32.51	1,032,917	32.51
<b>Total</b>	<b>6,545,607</b>			<b>6,470,907</b>	

In 2005, 183,823 shares of restricted stock were awarded to certain managers and executives as an incentive to retain their services through this transition time. These awards will vest two years after the award date. No restricted stock awards were granted during 2004 or 2003. As of December 31, 2005, we had 632,210 restricted stock awards outstanding.

**Note 15: Accumulated Other Comprehensive Income (Loss)**

The table below reflects the activity for accumulated other comprehensive income (loss) for 2003, 2004 and 2005:

<i>In millions</i>	<b>Foreign Currency Adjustments</b>	<b>Cash Flow Hedges</b>	<b>Held for Sale Securities</b>	<b>Minimum Pension Liability</b>	<b>Accumulated Other Comprehensive Income (Loss)</b>
Balance December 31, 2002	\$(17.5)	\$(18.0)	\$ 7.3	\$(4.8)	\$(33.0)
2003 change	81.3	9.2	(7.3)	.4	83.6
Balance December 31, 2003	63.8	(8.8)	—	(4.4)	50.6
2004 change	(63.0)	8.8	—	4.4	(49.8)
Balance December 31, 2004	.8	—	—	—	.8
2005 Change	(.9)	—	—	—	(.9)
Balance December 31, 2005	\$ (.1)	\$ —	\$ —	\$ —	\$ (.1)

**Note 16: Earnings (Loss) Per Share**

The table below shows how we calculated diluted earnings (loss) per share and diluted shares outstanding. Basic earnings (loss) per share and basic weighted average shares are the starting point in calculating the dilutive measures. To calculate basic earnings (loss) per share, divide earnings (loss) available for common shares by weighted average shares outstanding, without adjusting for dilutive items. Weighted average shares used in basic earnings per share includes 110.9 million shares issuable on the conversion of our PIES from August 24, 2004, the date of issuance of the PIES. On July 7, 2005, approximately 98.9% of the PIES units were converted to 131.4 million shares of common stock pursuant to an exchange offer. See Note 12 for further discussion. Diluted earnings (loss) per share is calculated by dividing earnings (loss) available for common shares, after assumed conversion of dilutive securities, by weighted average shares outstanding, adjusted for the effect of dilutive securities. As a result of the net losses in 2005, 2004 and 2003, the potential issuances of common stock were anti-dilutive and therefore not included in the calculation of diluted earnings (loss) per share.

<i>In millions, except per share amounts</i>	<b>Year Ended December 31,</b>		
	<b>2005</b>	<b>2004</b>	<b>2003</b>
Loss from continuing operations	\$(158.0)	\$(348.3)	\$ (356.5)
Interest and debt amortization costs associated with the PIES	12.6	9.4	—
Loss available for common shares from continuing operations	(145.4)	(338.9)	(356.5)
Earnings (loss) from discontinued operations	(72.0)	55.8	20.1
Loss available for common shares	\$(217.4)	\$(283.1)	\$ (336.4)

<i>In millions, except per share amounts</i>	<b>Year Ended December 31,</b>		
	<b>2005</b>	<b>2004</b>	<b>2003</b>
<b>Basic and diluted earnings (loss) per share:</b>			
Loss available for common shares from continuing operations	\$ (.40)	\$ (1.35)	\$ (1.83)
Earnings (loss) from discontinued operations	(.20)	.22	.10
Net loss available for common shares	\$ (.60)	\$ (1.13)	\$ (1.73)
<b>Weighted average number of common shares used in basic and diluted earnings (loss) per share</b>			
	363.30	251.35	194.75

#### **Note 17. Income Taxes**

Loss from continuing operations before income taxes consisted of:

<i>In millions</i>	<b>Year Ended December 31,</b>		
	<b>2005</b>	<b>2004</b>	<b>2003</b>
Domestic	\$(183.2)	\$(560.9)	\$(494.3)
Foreign	(17.9)	(1.7)	(9.2)
Total	\$(201.1)	\$(562.6)	\$(503.5)

Our income tax expense (benefit) consisted of the following:

<i>In millions</i>	<b>Year Ended December 31,</b>		
	<b>2005</b>	<b>2004</b>	<b>2003</b>
<b>Current:</b>			
Federal	\$ —	\$ —	\$ (36.1)
Foreign	(2.6)	(.5)	2.5
State	—	—	(6.4)
<b>Deferred:</b>			
Federal	(20.7)	(168.9)	(116.0)
Foreign	(5.1)	—	(.6)
State	(3.7)	(29.9)	(20.6)
Change in valuation allowance	(53.2)	(8.1)	(51.0)
Change in reserve for contingent tax liabilities	43.5	(5.4)	82.9
Investment tax credit amortization	(1.3)	(1.5)	(1.7)
<b>Income tax benefit from continuing operations</b>	<b>(43.1)</b>	<b>(214.3)</b>	<b>(147.0)</b>
<b>Income tax expense (benefit) from discontinued operations:</b>			
Current	—	36.3	22.5
Deferred (net of valuation allowance of \$(11.1) million and \$11.1 million in 2004 and 2003, respectively)	(41.0)	19.1	(19.7)
<b>Income tax expense (benefit) from discontinued operations</b>	<b>(41.0)</b>	<b>55.4</b>	<b>2.8</b>
<b>Total</b>	<b>\$(84.1)</b>	<b>\$(158.9)</b>	<b>\$(144.2)</b>

The principal components of deferred income taxes consist of the following:

<i>In millions</i>	<b>December 31,</b>	
	<b>2005</b>	<b>2004</b>
<b>Deferred Tax Assets:</b>		
Alternative minimum tax credit carryforward	\$ 103.6	\$ 103.6
U.S. net operating loss carryforward	449.9	359.7
Mark-to-market losses	14.9	8.1
Accrued bonuses and deferred compensation	8.4	14.9
Allowance for doubtful accounts	8.0	11.6
Asset impairments	73.4	25.4
Realized capital loss carryforward for income tax purposes	225.7	275.4
Unrealized capital losses	11.3	17.4
Other	2.1	12.4
Less: reserve for contingent tax liabilities	(287.6)	(244.0)
Less: valuation allowance	(248.9)	(304.7)
<b>Total deferred tax assets</b>	<b>360.8</b>	<b>279.8</b>
<b>Deferred Tax Liabilities and Credits:</b>		
Accelerated depreciation and other plant differences:		
Regulated	306.2	301.0
Non-regulated	42.4	35.9
Currency translation adjustment	—	.5
Pension costs	29.7	38.2
Regulatory asset	54.0	52.2
<b>Total deferred tax liabilities and credits</b>	<b>432.3</b>	<b>427.8</b>
<b>Deferred income taxes and credits, net</b>	<b>\$ 71.5</b>	<b>\$ 148.0</b>

Our effective income tax rate from continuing operations differed from the statutory federal income tax rate primarily due to the following:

	<b>Year Ended December 31,</b>		
	<b>2005</b>	<b>2004</b>	<b>2003</b>
<b>Statutory Federal Income Tax Rate</b>	(35.0)%	(35.0)%	(35.0)%
<b>Tax effect of:</b>			
State income taxes, net of federal benefit	(1.7)	(3.8)	(3.4)
Change in valuation allowance	(26.4)	(1.5)	(10.1)
Reserve for contingent tax liabilities	21.6	(.8)	17.1
Non-deductible loss on PIES exchange	14.3	—	—
Non-deductible interest and amortization of PIES	2.2	.6	—
Other	3.6	2.4	2.2
<b>Effective Income Tax Rate</b>	<b>(21.4)%</b>	<b>(38.1)%</b>	<b>(29.2)%</b>

### **Tax Credits**

At December 31, 2005 and 2004, we had alternative minimum tax credit carryforwards of \$103.6 million. These credits do not expire and can be used to decrease future cash tax payments. In addition, at December 31, 2005 and 2004, we had general business tax credit carryforwards of

\$6.7 million. The substantial majority of the general business credits expire in 2018, after which time they become a deduction against taxable income instead of a credit against tax. We did not record valuation allowances against the deferred tax asset related to the general business credits as we believe that more likely than not they will be utilized.

### **Capital Loss Carryforwards**

As of December 31, 2005 and 2004, respectively, we had approximately \$588.1 million and \$716.3 million, respectively, of net realized capital loss carryforwards available for federal income tax purposes that expire in 2007 through 2010 and recognized impairment charges of \$29.4 million and \$45.1 million, respectively, that we expect to realize (for income tax purposes) as capital losses when the assets are sold. The tax benefit of these carryforwards and impairments is reflected on our balance sheets as of December 31, 2005 and 2004, as deferred tax assets of \$237.0 million and \$292.8 million, respectively. The decrease in capital loss carryforwards from 2004 to 2005 is primarily due to capital gains recognized on our 2004 tax return.

We have assessed the likelihood that all or a portion of the deferred tax assets relating to the remaining capital losses would not be realized. This assessment included consideration of positive and negative factors, including our current financial position and results of operations, projected future taxable income, including projected capital gains, and available tax planning strategies. As a result of such assessment, we determined that it was more likely than not that deferred tax assets relating to capital losses would not be realized. Therefore, we have established full valuation allowances of \$237.0 million and \$292.8 million, respectively, against these tax benefits as of December 31, 2005 and 2004, respectively. The decrease in tax expense in 2005 related to the reduction in the valuation allowances was substantially offset by an increase in 2005 in the reserve for contingent tax liabilities.

### **Net Operating Loss Carryforwards**

As of December 31, 2005, we had approximately \$454.5 million of federal net operating loss carryforwards originating in 2003, \$579.0 million originating in 2004 and an estimated \$85.9 million of originating in 2005. The 2003 federal net operating loss carryforward expires in 2023 and can be carried back to 2001 to offset potential IRS audit adjustments. The 2004 and 2005 federal net operating loss carryforwards expire in 2024 and 2025, respectively, and cannot be carried back due to losses in the carryback years. At December 2005 and 2004, we had recorded deferred tax benefits of \$449.9 million and \$359.7 million, respectively, related to our cumulative net operating loss carryforwards. Included in these amounts are deferred tax benefits of \$58.1 million and \$52.0 million, respectively, related to state net operating losses as of December 31, 2005 and 2004, respectively. The state net operating loss carryforwards expire in various years.

We did not record valuation allowances against the deferred tax assets related to the federal net operating losses as we believe it is more likely than not that sufficient taxable income to utilize these losses during the carryforward period will be generated from continuing operations, including the reversal of deferred tax liabilities on our regulated business plus income from the sale of assets. However, as of December 31, 2005 and 2004 we have recorded a valuation allowance related to state net operating losses of \$11.9 million. During 2005, we recorded additional valuation allowance of \$2.6 million related to state tax benefits from net operating losses and an adjustment for 2004 state income tax returns filed in 2005. We also wrote off \$2.6 million of deferred tax assets and related valuation allowance because we no longer operate in certain states. This valuation allowance is necessary because we believe that it is more likely than not that we will not realize the deferred tax assets related to these state net operating

losses during the applicable carryforward periods. This assessment considered the decline in future business activity in certain states and the taxable income we expect to generate in the applicable state carryforward periods.

### **Reserve for Contingent Tax Liabilities**

As of December 31, 2005 and 2004, we have recorded liabilities of \$287.6 million and \$244.0 million, respectively, of cumulative tax provisions for tax deduction or income positions taken in prior tax returns that we believe were properly treated on such tax returns but for which it is reasonably likely that these deductions or income positions will be challenged when the returns are audited. The tax returns containing these tax deductions or income positions are currently under audit or will likely be audited. The reserve is included in deferred taxes because the timing of the resolution of these audits is uncertain and if the positions taken on the tax returns are not ultimately sustained, we may be required to make cash payments plus interest and/or utilize our net operating loss carryforwards, alternative minimum tax credit carryforwards, and/or general business credit carryforwards.

### **Loss on PIES Exchange**

As discussed in Note 12, we recorded a pretax loss of \$82.3 million in 2005 on the early conversion of the PIES. In addition, in 2005 and 2004 we recorded interest and amortization of debt issue costs on our PIES of \$12.6 million and \$9.4 million, respectively. No tax benefits were recorded as these costs were not deductible for income tax purposes.

### **Note 18: Employee Benefits**

We provide defined benefit pension plans for our employees. Benefits under the plans reflect the employees' compensation, years of service and age at retirement. We satisfy the minimum funding requirements under ERISA. In addition to pension benefits, we provide post-retirement health care and life insurance benefits for certain retired employees. We fund the net periodic post-retirement benefit costs to the extent that they are tax-deductible and/or recoverable in our regulated utility rates.

In February 2005, we amended our pension and other post-retirement benefit plans to bring our benefits into line with our regulated utility peers. The effect of these amendments on our projected (pension) benefit obligation and accumulated post-retirement benefit obligation was an increase of \$40.9 million and \$24.8 million, respectively, as of our most recent measurement date, September 30, 2005. This unrecognized prior service cost is recognized prospectively as a component of net periodic benefit cost, amortized on a straight-line basis over the average future service of active plan participants.

On December 8, 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act) became effective. The Act expands Medicare, primarily by offering a prescription drug benefit to Medicare-eligible retirees starting in 2006, as well as a federal subsidy to sponsors of retiree healthcare plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. Our actuaries have determined that the benefits provided under our other post-retirement benefit plans are actuarially equivalent to the Medicare Part D benefits under the Act for current retirees. Therefore, we will qualify for the 28% federal subsidy. We have recognized the effect of the Act on our other post-retirement benefit obligations and costs in our financial statements, beginning July 1, 2004 in accordance with FASB Staff Position No. 106-2. "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003." Based on a remeasurement of the plans at April 1, 2004, the effect of the Act on the accumulated post-retirement benefit obligation was a decrease of \$10.1 million.

The following table shows the funded status of our pension and post-retirement benefit plans and the amounts included in the Consolidated Balance Sheets and Consolidated Statements of Income. For measurement purposes, projected benefit obligations and the fair value of plan assets were determined as of September 30, 2005 and 2004.

<i>Dollars in millions</i>	<b>Pension Benefits</b>		<b>Other Post-retirement Benefits</b>	
	<b>2005</b>	<b>2004</b>	<b>2005</b>	<b>2004</b>
<b>Change in Projected Benefit Obligation:</b>				
Benefit obligation at start of year	\$337.6	\$330.4	\$ 68.2	\$ 81.1
Service cost	8.9	7.8	.6	.2
Interest cost	22.0	19.4	5.0	4.7
Plan participants' contribution	—	—	2.2	2.3
Amendments	40.9	—	24.8	—
Actuarial (gain) loss	15.1	(4.7)	(7.8)	(12.3)
Benefits paid	(15.6)	(15.3)	(7.6)	(7.8)
Projected benefit obligation at end of year	\$408.9	\$337.6	\$ 85.4	\$ 68.2
<b>Change in Plan Assets:</b>				
Fair value of plan assets at start of year	\$313.6	\$288.4	\$ 13.9	\$ 14.3
Actual return on plan assets	46.6	39.7	.6	.2
Employer contribution	8.8	.8	4.0	4.9
Plan participants' contribution	—	—	2.2	2.3
Benefits paid	(15.6)	(15.3)	(7.6)	(7.8)
Fair value of plan assets at end of year	\$353.4	\$313.6	\$ 13.1	\$ 13.9
<b>Funded status:</b>				
Funded status	\$ (55.5)	\$ (24.0)	\$(72.3)	\$(54.3)
4 <sup>th</sup> quarter employer contribution	.2	—	7.0	—
Unrecognized transition amount	(.6)	(1.5)	10.8	12.4
Unrecognized net actuarial loss	82.7	90.9	6.9	14.8
Unrecognized prior service cost	48.7	12.0	26.0	3.3
Accumulated regulatory gain/loss adjustment	7.3	10.6	(2.0)	(1.0)
Net amount recognized before SFAS 71 regulatory liability	82.8	88.0	(23.6)	(24.8)
SFAS 71 regulatory liability	(10.5)	(6.6)	—	—
Net amount recognized	\$ 72.3	\$ 81.4	\$(23.6)	\$(24.8)
<b>Amounts Recognized in the Consolidated Balance Sheets:</b>				
Prepaid benefit cost	\$ 94.8	\$ 98.7	\$ —	\$ —
Accrued benefit liability	(19.5)	(18.1)	(23.6)	(24.8)
SFAS 71 regulatory liability	(10.5)	(6.6)	—	—
Intangible asset	7.5	7.4	—	—
Net amount recognized	\$ 72.3	\$ 81.4	\$(23.6)	\$(24.8)
<b>Reconciliation of Net Amount Recognized:</b>				
Net amount recognized at start of year	\$ 81.4	\$ 96.4	\$(24.8)	\$(21.0)
Net periodic benefit cost before curtailments and regulatory expense adjustments	(10.8)	(11.3)	(8.8)	(7.8)
Contributions	9.0	.8	11.0	4.9
Regulatory gain/loss adjustment	(3.4)	(.2)	(1.0)	(.9)
SFAS 71 regulatory adjustment	(3.9)	(4.3)	—	—
Net amount recognized at end of year	\$ 72.3	\$ 81.4	\$(23.6)	\$(24.8)
<b>Weighted Average Assumptions as of September 30:</b>				
Discount rate for expense	6.00%	6.00%	6.00%	6.00%
Discount rate for disclosure	5.80%	6.00%	5.53%	6.00%
Expected return on plan assets for expense	8.50%	8.50%	7.00%	7.00%
Expected return on plan assets for disclosure	8.50%	8.50%	7.00%	7.00%
Rate of compensation increase	4.40%	4.40%	n/a	n/a

For measurement purposes, to calculate the annual rate of increase in the per capita cost of covered health benefits for each future fiscal year, we used a graded rate for non-prescription drug medical costs starting at 11% in 2006 and decreasing 1% annually until the rate levels out at 5% for years 2012 and thereafter. For prescription drug costs, we used a graded rate starting at 13% in 2006 and decreasing 1% annually until the rate levels out at 5% for years 2014 and thereafter.

<i>In millions</i>	<b>Pension Benefits</b>			<b>Other Post-retirement Benefits</b>		
	<b>2005</b>	<b>2004</b>	<b>2003</b>	<b>2005</b>	<b>2004</b>	<b>2003</b>
<b>Components of Net Periodic Benefit Cost:</b>						
Service cost	\$ 8.9	\$ 7.8	\$ 8.0	\$ .6	\$ .2	\$ .3
Interest cost	22.0	19.4	19.2	5.0	4.7	4.8
Expected return on plan assets	(27.6)	(23.9)	(22.9)	(1.0)	(1.0)	(1.2)
Amortization of transition amount	(.8)	(1.2)	(1.2)	1.5	1.5	1.6
Amortization of prior service cost	4.2	1.1	1.1	2.2	.7	.7
Recognized net actuarial (gain) loss	4.1	8.1	10.3	.5	1.7	1.2
Net periodic benefit cost before curtailments and regulatory expense adjustments	10.8	11.3	14.5	8.8	7.8	7.4
Curtailment (gain) loss	—	—	.3	—	—	(.2)
Regulatory gain/loss adjustment	3.4	.2	(3.5)	1.0	.9	.1
SFAS 71 regulatory adjustment	3.9	4.3	2.3	—	—	—
<b>Net periodic benefit cost after curtailments and regulatory expense adjustments</b>	<b>\$ 18.1</b>	<b>\$ 15.8</b>	<b>\$ 13.6</b>	<b>\$ 9.8</b>	<b>\$ 8.7</b>	<b>\$ 7.3</b>

In a 2004 settlement with the Missouri Commission, we agreed to recover our Missouri-related pension funding at an agreed-upon annual amount for ratemaking purposes. As ordered by the Missouri Commission, the difference between the agreed-upon expense for ratemaking purposes and the amount determined under SFAS 87, “Employers’ Accounting for Pensions,” will be recognized as a regulatory asset or liability in accordance with SFAS 71.

Previously, the Missouri Commission ordered the recognition of actuarial gains/losses for our Missouri-related pension and post-retirement benefit plans to follow an alternative method to the prescribed “corridor” method outlined in SFAS 87 and SFAS 106, “Employers’ Accounting for Postretirement Benefits Other Than Pension.” The difference between the “Missouri” method and the “corridor” method is noted as regulatory gain/loss adjustment or accumulated regulatory gain/loss adjustment in the preceding tables.

The funded status for those individual plans that have obligations in excess of plan assets and the corresponding amounts recognized in the Consolidated Balance Sheets for the plans are summarized below:

<i>In millions</i>	<b>2005</b>	<b>2004</b>
<b>Projected Benefit Obligations in Excess of Plan Assets:</b>		
Fair value of plan assets at end of year	\$353.4	\$313.6
Projected benefit obligation at end of year	408.9	337.6
Funded status	\$ (55.5)	\$ (24.0)
<b>Accumulated Benefit Obligations in Excess of Plan Assets:</b>		
Fair value of plan assets at end of year	\$ —	\$ —
Accumulated benefit obligation at end of year	19.5	18.1
Funded status (a)	\$ (19.5)	\$ (18.1)

(a) *The SERP is reflected as an unfunded accumulated benefit obligation as plan assets are not netted against the obligations for non-qualified plans. We have segregated approximately \$4.2 million of assets for the SERP as of December 31, 2005. We expect to fund estimated future benefit payments from these assets and company contributions as needed.*

The accumulated benefit obligation for all our defined benefit pension plans was \$361.7 million and \$311.2 million at September 30, 2005, and 2004, respectively.

We engaged benefit plan consultants to assist in the development of a statement of pension plan investment objectives and to perform a study modeling expectations of future returns of numerous portfolios using historic rates of return. The rate of return assumption we used was a result of selecting the model portfolio from the study that best fit our pension plan long-term investment objectives.

### **Pension Plan Investment Objectives**

1. We desire to maintain an appropriately funded status of the defined benefit pension plan. This implies an investment posture that is intended to increase the probability of investment performance exceeding the actuarial assumed rate of return over the long-term.
2. The investment objective is intended to be strategic in nature. Over the long-term, it is expected to protect the funded status of the Plan, enhance the real purchasing power of Plan assets, and not threaten the Plan's ability to meet currently committed obligations.
3. Distinct asset classes and investment approaches have unique return and risk characteristics. The combination of asset classes and approaches produces diversification benefits in the form of enhancement of expected return at a given risk level and/or reduction of the risk level associated with a specific expected return.

Our qualified pension plan weighted-average asset allocations by asset category at September 30, 2005 and 2004, along with the long-term targets and target ranges, are as follows:

	Plan Assets at September 30,		Plan Asset Allocation Targets	
	2005	2004	Long-Term	Range
<b>Asset Category:</b>				
Core fixed income	19.8%	14.6%	21.0%	5.0-25.0%
High yield bonds	9.5	8.2	10.0	6.0-10.0
Large cap equities	28.0	32.2	28.5	27.0-37.0
Mid cap equities	10.2	9.9	10.0	8.0-12.0
Small cap equities	3.4	10.2	3.5	0.0-12.0
International equities	14.3	13.0	14.5	10.0-15.0
Emerging markets equities	2.6	2.7	2.5	0.0-5.0
Real estate	8.5	7.8	7.5	5.0-10.0
Private equity	.7	1.3	2.5	0.0-5.0
Cash	3.0	.1	—	—
Total	100.0%	100.0%	100.0%	100.0%

Our other post-retirement benefit plan assets at December 31, 2005 and 2004 were 100% invested in short-term debt instruments and cash equivalents.

Pension costs are impacted by actual employee demographics (including age, compensation levels, and employment periods), the level of contributions we make to the plan, and earnings on plan assets. Changes made to the provisions of the plan may also impact current and future pension costs. Pension costs may also be significantly affected by changes in key actuarial assumptions, including anticipated rates of return on plan assets and the discount rates used in determining the projected benefit obligation and pension costs. Pension plan assets are primarily made up of equity and fixed income investments. Fluctuations in actual equity market returns as well as changes in general interest rates may result in increased or decreased pension costs in future periods. Likewise, changes in assumptions regarding current discount rates and expected rates of return on plan assets could also increase or decrease recorded pension costs.

The following chart reflects the sensitivities associated with a change in certain actuarial assumptions by the indicated percentage. While the chart below reflects an increase in the percentage for each assumption, we and our actuaries expect that the inverse of this change would impact the projected benefit obligation (PBO) at December 31, 2005, and our estimated annual pension cost (APC) on the income statement for 2006 by a similar amount in the opposite direction. Each sensitivity below reflects an evaluation of the change based solely on a change in that assumption.

<i>Dollars in millions</i>	Change in Assumption	Impact on PBO	Impact on APC
	Incr.(decr.)	Incr.(decr.)	Incr.(decr.)
Discount rate	.25%	\$(13.7)	\$(1.4)
Rate of return on plan assets	.25%	—	(.9)

The discount rate is defined as the rate at which plan obligations could effectively be settled. We utilize the Hewitt Yield Curve (HYC) in selecting the discount rate assumption for our pension and other post-retirement benefit plans. The HYC method is to project all benefit

payments (PBO benefit payments) payable over the life of the plan. Then, stripped investment grade coupons (the top quartile of non-callable, Corporate Aa bonds or higher) are matched to the benefit payments and discounted back to the current date. The result is a PBO. Then, a single discount rate is produced that generates the same PBO. This single discount rate is the weighted-average of the discounted benefit payments.

Our health care plans are contributory, with participants' contributions adjusted annually. The life insurance plans are generally non-contributory. In estimating future health care costs, we have assumed future cost-sharing changes. The assumed health care cost trends significantly affect the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects for 2006.

<i>In millions</i>	<b>1 Percentage-Point</b>	
	Increase	Decrease
Effect on total of service and interest cost components	\$ .3	\$ (.3)
Effect on post-retirement benefit obligation	5.1	(4.5)

Based on actuarial projections, we expect to contribute \$.8 million and \$9.4 million to our defined benefit pension plans and other post-retirement benefit plans, respectively, in 2006. No discretionary contributions are planned in 2006.

Following are estimated future benefit payments, which reflect expected future service, as appropriate. Other post-retirement benefits are reflected gross without considering the estimated subsidy to be received under the Medicare Prescription Drug, Improvement and Modernization Act of 2003, while the estimated subsidy is shown separately.

<i>In millions</i>	<b>Pension Benefits</b>	<b>Other Post-retirement Benefits</b>	<b>Medicare Drug Subsidy</b>
<b>Estimated Future Benefit Payments:</b>			
2006	\$ 17.0	\$ 7.0	\$ (.9)
2007	18.1	7.7	(.9)
2008	19.2	8.1	(1.0)
2009	20.6	8.4	(1.1)
2010	22.2	8.6	(1.1)
2011-2015	134.9	42.8	(5.6)

As disclosed in Note 6, the four utility operations being held for sale have been reclassified as discontinued operations. The preceding employee benefits footnote information, including the various tables, has been presented for these plans in total. As of and for the year ended

December 31, 2005, select pension and other post-retirement benefit plan information related to discontinued operations is summarized below.

<i>In millions</i>	<b>Pension Benefits</b>	<b>Other Post-retirement Benefits</b>
<b>Discontinued Operations</b>		
Accumulated benefit obligation at end of year	\$ 85.4	\$31.9
Projected benefit obligation at end of year	96.6	31.9
Net asset (liability) amount recognized in the balance sheet at end of year	25.9	(5.5)
Net periodic benefit cost	3.7	3.3
Estimated future benefit payments for 2006	4.6	2.2

**Note 19: Segment Information**

We have restated our financial reporting segments to reflect the significant changes in our business over the last three years, including the continuing wind-down of our wholesale energy trading operations and the sale of our merchant loan portfolio, our natural gas pipeline, gathering and storage assets, our investments in international utility networks and our investment in Quanta Services, Inc. We now manage our business in three business segments: Electric Utilities, Gas Utilities and Merchant Services. Our Electric and Gas Utilities consist of our regulated electric utility operations in three states and our natural gas utility operations in seven states. We manage our electric and gas utility divisions by state. However, as each of our electric utility divisions and each of our gas utility divisions have similar economic characteristics, we aggregate our three electric utility divisions into the Electric Utilities reporting segment and our seven gas utility divisions into the Gas Utilities reporting segment. The operating results of our Kansas electric division and our Michigan, Minnesota, and Missouri gas divisions, which are in the process of being sold, have been reclassified to discontinued operations. Merchant Services includes our remaining investments in merchant power plants, our commitments under merchant capacity tolling obligations and long-term gas contracts and the remaining contracts from our wholesale energy trading operations. The operating results of our two Illinois merchant power plants, which are in the process of being sold, and two consolidated independent power plants, which were sold in 2004, have been reclassified to discontinued operations. All other operations are included in Corporate and Other, including the costs not allocated to our operating businesses and costs of our investment in Everest Connections and our former investments in Canada, Australia and the United Kingdom. The operating results of Everest Connections, which is currently held for sale, and our former Canadian utility businesses, which were sold in 2004, have been reclassified to discontinued operations.

Each segment is managed based on operating results, expressed as earnings before interest, taxes, depreciation and amortization. Generally, decisions on finance, dividends and taxes are made at the Corporate level. The current and non-current assets of our discontinued operations are included in the segments referenced above.

## Business Lines

<i>In millions</i>	<b>Year Ended December 31,</b>		
	<b>2005</b>	<b>2004</b>	<b>2003</b>
<b>Sales: (a)</b>			
Utilities:			
Electric Utilities	\$ 684.7	\$ 594.9	\$ 545.1
Gas Utilities	631.1	529.0	506.2
<b>Total Utilities</b>	<b>1,315.8</b>	<b>1,123.9</b>	<b>1,051.3</b>
Merchant Services	(1.6)	(152.9)	(70.1)
Corporate and Other	—	—	1.9
<b>Total</b>	<b>\$1,314.2</b>	<b>\$ 971.0</b>	<b>\$ 983.1</b>

(a) For the years ended December 31, 2005, 2004 and 2003, respectively, the following (in millions) have been reclassified to discontinued operations and are not included in the above amounts: Electric Utilities sales of \$191.0, \$165.4 and \$153.6; Gas Utilities sales of \$625.8, \$536.3 and \$506.9; Merchant Services sales of \$17.0, \$8.0 and \$73.7; and Corporate and Other sales related to our former Canadian utility businesses and Everest Connections of \$46.0, \$161.2 and \$279.1.

<i>In millions</i>	<b>Year Ended December 31,</b>		
	<b>2005</b>	<b>2004</b>	<b>2003</b>
<b>Earnings (Loss) Before Interest, Taxes, Depreciation and Amortization (EBITDA): (a)(b)</b>			
Utilities:			
Electric Utilities	\$ 147.7	\$ 130.3	\$ 128.0
Gas Utilities	33.6	34.9	46.8
<b>Total Utilities</b>	<b>181.3</b>	<b>165.2</b>	<b>174.8</b>
Merchant Services	(22.6)	(416.7)	(378.4)
Corporate and Other	(103.2)	(23.8)	19.0
<b>Total EBITDA</b>	<b>55.5</b>	<b>(275.3)</b>	<b>(184.6)</b>
Depreciation and amortization	106.4	102.8	120.1
Interest expense	150.2	184.5	198.8
Loss from continuing operations before income taxes	\$ (201.1)	\$ (562.6)	\$ (503.5)

(a) Included in EBITDA for each segment for the years ended December 31, 2004 and 2003, respectively, is equity in earnings of investments as follows (in millions): Merchant Services, \$1.9 and \$53.7; and Corporate and Other, \$.2 and \$15.9.

(b) For the years ended December 31, 2005, 2004 and 2003, respectively, the following (in millions) have been reclassified to discontinued operations and are not included in the above amounts: Electric Utilities EBITDA of \$47.9, \$31.4 and \$32.6; Gas Utilities EBITDA of \$96.9, \$88.9 and \$96.9; Merchant Services EBITDA of \$(156.1), \$2.4 and \$(34.9); and Corporate and Other EBITDA relating to our former Canadian utility businesses and Everest Connections of \$12.0, \$124.6 and \$79.8.

<i>In millions</i>	<b>Year Ended December 31,</b>		
	<b>2005</b>	<b>2004</b>	<b>2003</b>
<b>Depreciation and Amortization Expense: (a)</b>			
Utilities:			
Electric Utilities	\$ 64.0	\$ 60.1	\$ 62.0
Gas Utilities	35.8	35.0	35.0
<b>Total Utilities</b>	<b>99.8</b>	<b>95.1</b>	<b>97.0</b>
Merchant Services	6.3	7.3	24.3
Corporate and Other	.3	.4	(1.2)
<b>Total</b>	<b>\$ 106.4</b>	<b>\$ 102.8</b>	<b>\$ 120.1</b>

(a) For the years ended December 31, 2005, 2004 and 2003, respectively, the following depreciation and amortization expense (in millions) have been reclassified to discontinued operations and are not included in the above amounts: Electric Utilities \$9.7, \$11.4 and \$11.1; Gas Utilities \$16.1, \$19.9 and \$21.1; Merchant Services \$9.2, \$10.1 and \$8.0; and Corporate and Other relating to our former Canadian utility businesses and Everest Connections \$7.5, \$6.1 and \$13.0.

<i>In millions</i>	<b>December 31,</b>	
	<b>2005</b>	<b>2004</b>
<b>Identifiable Assets: (a)(b)</b>		
Utilities:		
Electric Utilities	\$2,073.8	\$1,862.3
Gas Utilities	1,421.9	1,353.4
<b>Total Utilities</b>	<b>3,495.7</b>	<b>3,215.7</b>
Merchant Services	918.6	1,080.6
Corporate and other	216.4	481.0
<b>Total</b>	<b>\$4,630.7</b>	<b>\$4,777.3</b>

(a) Included in identifiable assets for each segment as of December 31, 2005 and 2004, respectively, are investments in unconsolidated subsidiaries as follows (in millions): Gas Utilities, \$.1 and \$.1; and Corporate and Other, \$.6 and \$1.4.

(b) Included in identifiable assets as of December 31, 2005 and 2004, are current and non-current assets of discontinued operations as follows (in millions): Electric Utilities, \$273.6 and \$250.5; Gas Utilities, \$657.3 and \$598.8; Merchant Services, \$175.0 and \$341.3; and Corporate and Other related to Everest Connections, \$61.0 and \$58.6.

<i>In millions</i>	<b>Year Ended December 31,</b>		
	<b>2005</b>	<b>2004</b>	<b>2003</b>
<b>Capital Expenditures: (a)</b>			
Utilities:			
Electric Utilities	\$ 175.5	\$ 96.3	\$ 79.2
Gas Utilities	53.4	50.3	46.3
<b>Total Utilities</b>	<b>228.9</b>	<b>146.6</b>	<b>125.5</b>
Merchant Services	—	—	20.5
Corporate and other	18.9	95.3	140.5
<b>Total</b>	<b>\$ 247.8</b>	<b>\$ 241.9</b>	<b>\$ 286.5</b>

(a) Included in the years ended December 31, 2005, 2004 and 2003, respectively, are capital expenditures of discontinued operations as follows (in millions): Electric Utilities, \$24.3, \$15.5 and \$11.6; Gas Utilities, \$22.6, \$22.2 and \$20.4; Merchant Services, \$-, \$- and \$26.9 and Corporate and Other relating to our former Canadian utility businesses and Everest Connections, \$11.4, \$86.8 and \$133.9.

### **Geographical Information**

<i>In millions</i>	<b>Year Ended December 31,</b>		
	<b>2005</b>	<b>2004</b>	<b>2003</b>
<b>Sales: (a)</b>			
United States	\$1,304.4	\$ 971.0	\$1,005.1
Canada	.3	1.3	7.0
Other international	9.5	(1.3)	(29.0)
<b>Total</b>	<b>\$1,314.2</b>	<b>\$ 971.0</b>	<b>\$ 983.1</b>

(a) For the years ended December 31, 2005, 2004 and 2003, respectively, the following (in millions) sales have been reclassified to discontinued operations and are not included in the above amounts: United States sales of \$879.8, \$748.0, and \$764.5; Canadian sales of \$-, \$122.9, and \$248.8.

We had no material long-lived assets, including property, plant and equipment, net, or investments in unconsolidated subsidiaries outside of the United States as of December 31, 2005 or 2004.

### **Note 20: Commitments and Contingencies**

#### **Capital Expenditures**

We have made certain construction commitments in connection with our 2006 capital expenditure plan. During 2006, we estimate that our total capital expenditures will be approximately \$217.7 million, plus approximately \$22.0 million for discontinued operations.

## Commitments

We have various commitments of our continuing and discontinued operations relating to power, gas and coal supply commitments and lease commitments as summarized below.

<i>In millions</i>	2006	2007	2008	2009	2010	Thereafter	Total
<b>Future minimum payments</b>							
<b>Continuing Operations—</b>							
Facilities and equipment	\$ 11.4	\$ 9.6	\$ 8.9	\$ 6.7	\$ 5.2	\$ 15.1	\$ 56.9
Other services	1.2	1.1	.9	—	—	—	3.2
Elwood tolling contracts	37.3	37.3	37.3	37.4	37.4	230.3	417.0
Merchant gas transportation obligations	8.5	5.5	5.4	5.4	5.4	18.1	48.3
Regulated business purchase obligations:							
Purchased power obligations	101.8	101.7	104.1	106.7	109.3	150.5	674.1
Purchased gas obligations	56.2	31.0	23.9	21.0	20.0	63.3	215.4
Coal and rail contracts	93.2	82.0	50.7	25.4	26.3	141.2	418.8
<b>Future minimum payments</b>							
<b>Discontinued Operations—</b>							
Facilities and equipment	3.0	2.3	1.6	1.3	.9	4.9	14.0
Jeffrey Energy Center lease	10.6	10.6	12.1	12.9	12.9	58.0	117.1
Regulated business purchase obligations:							
Purchased power obligations	17.7	19.8	19.7	11.7	3.5	7.0	79.4
Purchased gas obligations	37.9	30.0	25.6	16.8	14.0	91.1	215.4
Coal and rail contracts	17.9	18.6	19.2	19.9	20.6	140.4	236.6

### ***Operating Lease Obligations***

Future minimum payments include operating leases of coal rail cars, vehicles and office space over terms of up to 20 years. Rent expense for continuing operations for the years 2005, 2004 and 2003 was (in millions), \$10.9, \$13.1 and \$18.9, respectively, and for discontinued operations was \$3.4, \$6.5 and \$20.1, respectively.

We have an operating lease of an 8% interest in the Jeffrey Energy Center through 2019 which is included in discontinued operations. The lease contains certain fixed price and fair market value purchase and renewal options. The lease payments vary by year but are recognized as lease expense on a straight-line basis of approximately \$10.4 million annually.

### ***Elwood tolling contracts***

In connection with our merchant power generation business, we have entered into two power purchase agreements through 2017 for a portion of the total output of the Elwood power plant owned by others. This agreement is treated as an operating lease for accounting purposes.

### ***Merchant gas transportation obligations***

We have long-term commitments through 2017 for gas transportation capacity remaining from our wholesale energy trading business. We may terminate these commitments and may incur losses in future periods.

### ***Regulated business purchase obligations***

In 2005, our continuing electric utility operations generated 51% of the power delivered to their customers. Our electric utility operations purchase coal and natural gas, including transportation capacity, as fuel for its generating power plants under long-term contracts through 2020. These operations also purchase power and gas to meet customer needs under short-term and long-term purchase contracts.

### **Contingent Obligations**

#### ***Guarantees***

We have entered into contracts that contain guarantees to outside parties that could require performance or payment under certain conditions. These guarantees have been grouped based on similar characteristics and are described below.

We have entered into various agreements that require letters of credit for financial assurance purposes. These letters of credit are available to fund the payment of such obligations. At December 31, 2005, we had \$196.6 million of letters of credit outstanding with expiration dates generally ranging from one month to 24 months.

In the normal course of business, we guarantee certain payment obligations of our wholly-owned subsidiaries.

#### ***Equity Put Rights***

Certain minority owners of Everest Connections had the option to sell their ownership units to us if Everest Connections did not meet certain financial and operational performance measures as of December 31, 2004 (target-based put rights). If the target-based put rights were exercised, we would have been obligated to purchase up to 4.0 million and 4.75 million ownership units at a price of \$1.00 and \$1.10 per unit, respectively, for a total potential cost of \$9.2 million. As a result of our reduced funding of this business, management assessed the likelihood of achieving these metrics and during 2002 recorded a probability-weighted expense of \$7.1 million. In 2004, we achieved the operating targets related to 4.0 million and 1.5 million of ownership units at a price of \$1.00 and \$1.10 per unit, respectively. Therefore, we reversed \$4.5 million of this liability. The holders of these ownership units are disputing our conclusion that we have achieved these operating targets and are attempting to exercise these target-based put rights. We do not believe we have any obligation with regard to these target-based put rights. We did not achieve the targets related to 3.25 million of ownership units at a price of \$1.10 per unit. The holders of these target-based put rights exercised their options and were paid \$3.6 million for their ownership units in February 2005.

The minority owners of 9.5 million ownership units have notified us that they intend to exercise their option to sell their ownership units to us at fair market value (market-based put rights). We have not provided for this potential obligation as the exercise would represent an equity transaction at fair value. We do not believe based on current estimates of fair value that these market-based put rights are a material contingent obligation.

### **Legal**

#### ***Price Reporting Litigation***

On August 18, 2003, Cornerstone Propane Partners filed suit in the Southern District of New York against 35 companies, including Aquila, alleging that the companies manipulated natural gas prices and futures prices on NYMEX through misreporting of natural gas trade data in the

physical market. The suit does not specify alleged damages and was filed on behalf of all parties who bought and sold natural gas futures and options on NYMEX from 2000 to 2002. On September 24, 2004, the court denied Aquila Merchant's motion to dismiss along with similar motions filed by most of the other defendants. Fact discovery closed on December 23, 2005, and the parties have now begun the expert discovery phase of the action. We will defend this case vigorously as we believe we have strong defenses to the plaintiff's claims. We cannot predict with certainty whether we will incur any liability, nor can we estimate the damages, if any, that might be incurred in connection with this lawsuit. However, given the nature of the claims, an adverse outcome could have a material adverse effect on our financial condition, results of operations and cash flows.

On June 7, 2004, the City of Tacoma, Washington, filed suit against 56 companies, including Aquila Merchant, for allegedly conspiring to manipulate the California power market in 2000 and 2001 in violation of the Sherman Act. This case was dismissed in February 2005. The City of Tacoma has appealed to the Ninth Circuit Court of Appeals.

On July 8, 2004, the County of Santa Clara and the City and County of San Francisco each filed suit against seven energy trading companies and their subsidiaries and affiliates, including Aquila and Aquila Merchant, in the Superior Court of California for San Diego County alleging manipulation of the California natural gas market in 1999 through 2002. Since that date, 14 other complaints making nearly identical allegations have been filed against Aquila and Aquila Merchant in California state courts. These lawsuits allege violations of the Cartwright Act and in some cases California's Unfair Competition Law, and also assert an unjust enrichment claim. The lawsuits have been coordinated before a single Motion Coordination Judge in the Superior Court of California for the County of San Diego, in the proceeding entitled *In re Natural Gas Antitrust Cases I, II, III & IV*. We believe we have strong defenses and will defend these cases vigorously. We cannot predict with certainty whether we will incur any liability, nor can we estimate the damages, if any, that might be incurred in connection with these lawsuits. However, given the nature of the claims, an adverse outcome could have a material adverse effect on our financial condition, results of operations and cash flows.

Aquila Merchant is also a defendant in two federal actions that were filed on November 30, 2004 and October 31, 2005 in the United States District Court for the Eastern District of California. These cases were transferred by the Judicial Panel on Multidistrict Litigation to the United States District Court for the District of Nevada on January 21, 2005 and September 1, 2005, respectively. The action originally filed on November 30, 2004 was subsequently consolidated with two other actions. All of these lawsuits are now part of the proceeding known as *In re Western States Wholesale Natural Gas Antitrust Litigation*, MDL Docket No. 1566, and make allegations similar to those made in the *In re Natural Gas Antitrust Cases I, II, III & IV*. The plaintiffs in the November 2004 action allege violations of the Sherman Act, the Cartwright Act, California's Unfair Competition Law, unjust enrichment, and constructive trust, whereas the plaintiffs in the October 2005 action allege only violations of the Sherman Act. The action originally filed on November 30, 2004 has been dismissed, and the plaintiffs have appealed the dismissal to the Ninth Circuit Court of Appeals. We believe we have strong defenses and will defend these cases vigorously. We cannot predict with certainty whether we will incur any liability, nor can we estimate the damages, if any, that might be incurred in connection with these lawsuits. However, given the nature of the claims, an adverse outcome could have a material adverse effect on our financial condition, results of operations and cash flows.

In connection with our continuing evaluation of the above claims, we determined that the ultimate resolution of such claims would likely result in an obligation of at least \$9.0 million. In December 2005, we provided a liability at that amount. The timing and amount of the ultimate resolution of these claims remains uncertain and could exceed that reserve by a material amount.

On February 22, 2005, Utility Choice and Cirro Group filed suit against three major Texas utilities and retail electricity providers, including Aquila Merchant, for allegedly conspiring to manipulate the Texas power market in 2000 and 2001 in violation of the Sherman Act. The parties reached an out-of-court settlement on November 16, 2005 for \$175,000, and the case was dismissed with prejudice on November 18, 2005.

### ***Lender Litigation***

On October 5, 2004 and October 15, 2004, lawsuits were filed against us by our lenders alleging that we were obligated to pay a “make whole” amount when we prepaid the \$430 million three-year secured term loan in September 2004. We believe that our termination of the term loan required us to pay a prepayment penalty of \$8.7 million. The plaintiff lenders sued us for breach of contract for their proportionate share of the difference between their prepayment calculation and the \$8.7 million. In May 2005, our motions for summary judgment in these lawsuits were granted and \$20.6 million of restricted cash that we had deposited into an escrow account, which equaled the amount in dispute, was returned to us. Certain of the plaintiffs representing a claim of approximately \$6.0 million have appealed the dismissal of these cases. On February 22, 2006, the Second Circuit Court of Appeals affirmed an order by the District Court for the Southern District of New York, dismissing the claims of plaintiffs representing a claim of approximately \$2.3 million. We believe we have strong defenses and will defend these cases vigorously. We cannot predict with certainty whether we will incur any liability in connection with this lawsuit.

### ***ERISA Litigation***

On September 24, 2004, a lawsuit was filed in the U.S. District Court for the Western District of Missouri against us and certain members of our Board of Directors and management, alleging they violated the Employee Retirement Income Security Act of 1974, as amended (ERISA) and are responsible for losses that participants in the our 401(k) plan experienced as a result of the decline in the value of their Aquila common stock held in the 401(k) plan. A number of similar lawsuits alleging that the defendants breached their fiduciary duties to the plan participants in violation of ERISA by concealing information and/or misleading employees who held our common stock through our 401(k) plan were subsequently filed against us. The suits also seek damages for the plan’s losses resulting from the alleged breaches of fiduciary duties. On January 26, 2005, the court ordered that all of these lawsuits be consolidated into a single case captioned *In re Aquila ERISA Litigation*. The plaintiffs filed an amended consolidated complaint in March 2005, which largely repeats each of the allegations in the first complaint. This case has been set for trial in July 2007. We believe we have strong defenses and will defend this case vigorously. We cannot predict with certainty whether we will incur any liability, nor can we estimate the damages, if any, that might be incurred in connection with this lawsuit. However, given the nature of the claims, an adverse outcome could have a material adverse effect on our financial condition, results of operations and cash flows.

### ***South Harper Peaking Facility***

We have constructed a 315 MW natural gas “peaking” power plant and related substation in an unincorporated area of Cass County, Missouri. Cass County and local residents filed suit claiming that county zoning approval was required to construct the project. In January 2005, a trial court judge granted the County’s request for an injunction; however, we were permitted to continue construction while the order was appealed. We appealed the trial court decision to the Missouri Court of Appeals for the Western District of Missouri and, on June 21, 2005, the appellate court affirmed the circuit court ruling. In July 2005, we requested that the Court of

Appeals either rehear the case or transfer the case to the Missouri Supreme Court and, in October 2005, the Court of Appeals granted our request for rehearing.

On December 20, 2005, the appellate court issued a new opinion affirming the trial court's opinion, but also opining that we could obtain the necessary approval for the project either from Cass County (in the form of zoning approval) or the Missouri Commission (in the form of specific authority). We decided not to appeal the order of the Court of Appeals and instead filed an application for approval with the Missouri Commission on January 24, 2006. On January 27, 2006, the trial court granted our request to stay the permanent injunction until May 31, 2006, and ordered us to post a \$20 million bond to secure the cost of removing the project. Given that the remedy sought is the removal of the plant and substation, an adverse outcome could have a material impact on our financial condition, results of operations and cash flows. If we are not successful in obtaining the required approvals, we currently estimate the cost to dismantle the plant and substation to be approximately \$20 million based on an engineering study. Significant additional costs would be incurred to store the equipment, secure replacement power and/or build the plant at a new site. We cannot estimate with certainty the total amount of these incremental costs that could be incurred, or the potential impairment of the carrying value of our investment in the plant we could suffer to the extent the cost exceeds the amount allowed for recovery in rates.

## **Environmental**

We are subject to various environmental laws. These include regulations governing air and water quality and the storage and disposal of hazardous or toxic wastes. We continually assess ways to ensure we comply with laws and regulations on hazardous materials and hazardous waste and remediation activities.

As of December 31, 2005, we estimate probable costs of future investigation and remediation on our identified MGP sites, PCB sites and retained liabilities to be \$8.2 million, of which \$5.4 million relates to sites that will be assumed by the buyers of our Michigan and Missouri gas utilities. This is our best estimate based upon a comprehensive review of the potential costs associated with conducting investigative and remedial actions at our identified sites, as well as the likelihood of whether such actions will be necessary. There are also additional costs that we consider to be less likely but still "reasonably possible" to be incurred at these sites. Based upon the results of studies at these sites and our knowledge and review of potential remedial actions, it is reasonably possible that these additional costs could exceed our best estimate by approximately \$13.0 million, of which \$8.8 million relates to sites that will be assumed by the buyers of our Michigan and Missouri gas utilities. This estimate could change materially after further investigation. It could also be affected by the actions of environmental agencies and the financial viability of other responsible parties.

The EPA finalized CAIR and CAMR regulations in 2005 that would affect our coal-fired power plants by requiring reductions in emissions of sulfur dioxide, nitrogen oxide and mercury. We initiated engineering studies to evaluate the costs and likely controls for compliance with CAIR and CAMR in 2005. For continuing operations, we estimate that probable capital expenditures will be approximately \$159 million and reasonably possible expenditures could be \$293 million to comply with the regulations. We estimate the capital expenditures for 2006 to be approximately \$7 million. If our Kansas electric utility is not sold, our estimated probable capital expenditures would be approximately \$187 million and reasonably possible expenditures could be \$322 million. We believe these costs would likely be allowed for recovery in future rate cases.

## Note 21: Quarterly Financial Data (Unaudited)

Financial results for interim periods do not necessarily indicate trends for any 12-month period. Quarterly results can be affected by the timing of acquisitions, the effect of weather on sales, and other factors typical of utility operations and energy related businesses. All periods presented have been adjusted to reflect the reclassification of discontinued operations.

<i>In millions, except per share amounts</i>	2005 Quarters				2004 Quarters			
	First	Second	Third	Fourth	First	Second	Third	Fourth
Sales	\$352.9	\$262.7	\$300.9	\$ 397.7	\$282.7	\$207.1	\$ 209.2	\$272.0
Gross profit	97.7	105.6	149.7	97.5	44.0	62.1	77.4	66.3
Loss from continuing operations	(13.2)	(23.6)	(80.0)	(41.2)	(94.3)	(60.8)	(110.4)	(82.8)
Earnings (loss) from discontinued operations	13.9	(3.6)	4.3	(86.6)	42.5	17.5	(6.0)	1.8
Net income (loss)	\$ .7	\$ (27.2)	\$ (75.7)	\$ (127.8)	\$ (51.8)	\$ (43.3)	\$ (116.4)	\$ (81.0)
Basic and diluted earnings (loss) per common share: <i>(a)</i>								
From continuing operations	\$ (.02)	\$ (.05)	\$ (.21)	\$ (.11)	\$ (.48)	\$ (.31)	\$ (.42)	\$ (.22)
From discontinued operations	.04	(.01)	.01	(.23)	.22	.09	(.02)	.01
Net income (loss)	\$ .02	\$ (.06)	\$ (.20)	\$ (.34)	\$ (.26)	\$ (.22)	\$ (.44)	\$ (.21)

*(a) The sum of the quarterly earnings per share amounts may differ from that reflected in Note 16 due to the weighting of common shares outstanding during each of the respective periods.*

## **Report of Independent Registered Public Accounting Firm**

### **To the Board of Directors and Shareholders of Aquila, Inc.:**

We have audited the accompanying consolidated balance sheets of Aquila, Inc. and subsidiaries as of December 31, 2005 and 2004, and the related consolidated statements of income, common shareholders' equity, comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2005. In connection with our audits of the consolidated financial statements, we also have audited the financial statement schedule, "Schedule II—Valuation and Qualifying Accounts," for each of the years in the three-year period ended December 31, 2005. These consolidated financial statements and the financial statement schedule are the responsibility of the company's management. Our responsibility is to express an opinion on these consolidated 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, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Aquila, Inc. and subsidiaries as of December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2005 in conformity with United States generally accepted accounting principles. Also, in our opinion, the related 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.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Aquila, Inc.'s internal control over financial reporting as of December 31, 2005 based on criteria established in *Internal Control—Integrated Framework*, issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 3, 2006 expressed an unqualified opinion on management's assessment of, and the effective operation of, internal control over financial reporting.

/s/ KPMG LLP  
Kansas City, Missouri

March 3, 2006

## **Report of Independent Registered Public Accounting Firm**

### **To the Board of Directors and Shareholders of Aquila, Inc.:**

We have audited management's assessment, included in the Management's Report on Internal Control Over Financial Reporting appearing under Item 9A, that Aquila, Inc. (the Company) maintained effective internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control—Integrated Framework*, issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Aquila, Inc.'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. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of 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, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, 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 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 its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that Aquila, Inc. maintained effective internal control over financial reporting as of December 31, 2005 is fairly stated, in all material respects, based on criteria established in *Internal Control—Integrated Framework*, issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Also, in our opinion, Aquila, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005 based on criteria established in *Internal Control—Integrated Framework*, issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Aquila, Inc. and subsidiaries as of December 31, 2005 and 2004, and the related consolidated statements of income, common shareholders' equity, comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2005, and our report dated March 3, 2006 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP  
Kansas City, Missouri

March 3, 2006

**Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure**

Not Applicable.

**Item 9A. Controls and Procedures****Disclosure Controls and Procedures**

Our Chief Executive Officer (CEO) and Chief Financial Officer (CFO) are responsible for establishing and maintaining the company's disclosure controls and procedures. These controls and procedures were designed to ensure that material information relating to the company and its subsidiaries are communicated to the CEO and the CFO. We evaluated these disclosure controls and procedures as of the end of the period covered by this report under the supervision of our CEO and CFO. Based on this evaluation, our CEO and CFO concluded that our disclosure controls and procedures are effective in timely alerting them to material information required to be included in our periodic reports filed with the SEC. There has been no change in our internal controls over financial reporting during the period covered by this report that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

**Management's Report on Internal Control Over Financial Reporting**

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under the framework in *Internal Control—Integrated Framework*, our management concluded that our internal control over financial reporting was effective as of December 31, 2005.

Our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2005, has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their report which is included herein.

**Item 9B. Other Information**

Not Applicable.

**Part III****Items 10, 11, 12 and 13. Directors and Executive Officers of the Company, Executive Compensation, Security Ownership of Certain Beneficial Owners and Management, and Certain Relationships and Related Transactions**

Information regarding these items appears in our proxy statement and is hereby incorporated by reference in this Annual Report on Form 10-K. For information regarding our executive officers, see "Our Executive Team" in Part I, Item 1 of this Form 10-K.

## Equity Compensation Plan Information

The following table provides information as of December 31, 2005 about our compensation plans under which shares of stock have been authorized.

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders *	6,333,518	\$14.62	4,988,400 **
Equity compensation plans not approved by security holders	212,089 ***	\$24.02	—
<b>Total</b>	<b>6,545,607</b>		<b>4,988,400</b>

\* Includes 661,292 options issued upon conversion of Merchant Services options in connection with our acquisition of the minority interest in Merchant Services. These options have a weighted average price of \$34.81 per share.

\*\* These shares are available for issuance under our 2002 Omnibus Incentive Compensation Plan. Awards may be in the form of stock options, restricted stock awards, stock appreciation rights, stock awards or other forms of equity based compensation.

\*\*\* Options issued under a broad-based employee stock option plan that has since been terminated.

### Item 14. Principal Accountant Fees and Services

Information regarding this item appears in our proxy statement and is hereby incorporated by reference in this Annual Report on Form 10-K.

## Part IV

### Item 15. Exhibits and Financial Statement Schedules

The following documents are filed as part of this report:

#### (a)(1) Financial Statements:

The consolidated financial statements required under this item are included under Item 8.

#### (a)(2) Financial Statement Schedules

Schedule II—Valuation and Qualifying Accounts for the years 2005, 2004 and 2003 on page 148.

All other schedules are omitted because they are not applicable or the required information is shown in the financial statements or notes thereto.

#### (a)(3) List of Exhibits\*

The following exhibits relate to a management contract or compensatory plan or arrangement:

- 10(a)(12) Annual and Long-Term Incentive Plan.
- 10(a)(13) First Amendment to Annual and Long-Term Incentive Plan.
- 10(a)(14) Form of Severance Compensation Agreement (change in control agreement) of Certain Executives.
- 10(a)(15) Life Insurance Program for Officers.
- 10(a)(16) Supplemental Executive Retirement Plan, Amended and Restated, effective January 1, 2001.
- 10(a)(17) Employment Agreement for Richard C. Green
- 10(a)(18) Aquila, Inc. Capital Accumulation Plan, as amended and restated, effective January 1, 2005
- 10(a)(19) Form of Performance Bonus Agreement
- 10(a)(20) Severance Compensation Agreement (change in control agreement) dated as of March 16, 2001, by and between Aquila Merchant Services, Inc. (formerly Aquila, Inc.) and Keith Stamm.
- 10(a)(21) Aquila, Inc. 2002 Omnibus Incentive Compensation Plan.
- 10(a)(22) Executive Security Trust Amended and Restated as of April 4, 2002.
- 10(a)(23) Supplemental Executive Retirement Agreement, by and between Aquila, Inc. (formerly UtiliCorp United Inc.) and John R. Baker, dated as of May 7, 1990.

\* *Incorporated by reference to the Index to Exhibits.*

#### (b) Exhibits

The Index to Exhibits follows on page 149.

**AQUILA, INC.**  
**SCHEDULE II—VALUATION AND QUALIFYING ACCOUNTS**

**For the Three Years Ended December 31, 2005**  
**(in millions)**

Column A	Column B	Column C	Column D	Column E
Description	Beginning Balance at January 1	Additions Charged to Expense	Deductions from Reserves for Purposes for Which Created	Ending Balance at December 31
<b>Allowance for Doubtful Accounts</b>				
2005	\$ 27.7	\$ 1.2	\$ (19.6)	\$ 9.3
2004	34.4	6.7	(13.4)	27.7
2003	26.0	14.0	(5.6)	34.4
<b>Maintenance Reserves (a)</b>				
2005	\$ 2.9	\$ 2.9	\$ (2.3)	\$ 3.5
2004	3.8	2.9	(3.8)	2.9
2003	2.5	2.2	(0.9)	3.8
<b>Other Reserves (b)</b>				
2005	\$ 17.6	\$ 36.1	\$ (32.7)	\$ 21.0
2004	21.8	32.2	(36.4)	17.6
2003	13.2	45.8	(37.2)	21.8
<b>Restructuring Reserves (c)</b>				
2005	\$ 7.8	\$ 6.6	\$ (14.3)	\$ .1
2004	16.9	.9	(10.0)	7.8
2003	49.2	28.2	(60.5)	16.9
<b>Deferred Tax Valuation Allowance</b>				
2005	\$304.7	\$ (53.2)	\$ (2.6)	\$248.9
2004	341.7	(19.2)	(17.8)	304.7
2003	381.6	(39.9)	—	341.7
<b>Reserve for Contingent Tax Liabilities (d)</b>				
2005	\$244.0	\$ 43.6	—	\$287.6
2004	208.7	35.3	—	244.0
2003	93.2	115.5	—	208.7

(a) *Costs to be incurred related to scheduled maintenance outages on regulated generating facilities are accrued in advance of the scheduled outage consistent with current regulatory treatment.*

(b) *Includes reserves for self-insurance, environmental claims and other.*

(c) *Includes restructuring reserves for severance, lease and other costs.*

(d) *The additions to this reserve include amounts originally charged to current or deferred tax expense, and reclassified to the reserve for tax contingencies after the tax returns were filed.*

**AQUILA, INC.**  
**INDEX TO EXHIBITS**

<u>Exhibit Number</u>	<u>Description</u>
*3(a)	Restated Certificate of Incorporation of the company (Exhibit 3(a) to the company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2002).
*3(b)	Amended and Restated By-Laws of the company (Exhibit 3.1 to the company's Current Report on Form 8-K filed May 6, 2005).
*4(a)	Long-term debt instruments of the company in amounts not exceeding 10% of the total assets of the company and its subsidiaries on a consolidated basis will be furnished to the Commission upon request.
*4(b)	Form of Rights Agreement between the company and UMB Bank, N.A. (as successor to First Chicago Trust Company of New York), as Rights Agent (Exhibit 4 to the company's Form 10-Q for the period ended September 30, 1996).
*4(c)	Amendment to Rights Agreement (Exhibit 4(d) to the company's Post Effective Amendment No. 1 to Registration Statement on Form S-3 No. 333-29657 filed March 15, 2002).
*10(a)(1)	Indenture, dated as of August 24, 2001, between the company and BankOne Trust Company, N.A., as Trustee (Exhibit 4(d) to the company's Registration Statement on Form S-3 (File No. 333-68400) filed August 27, 2001).
*10(a)(2)	First Supplemental Indenture to the August 24, 2001 Indenture, dated February 28, 2002, between the company and BankOne Trust Company, N.A., as Trustee (Exhibit 4 to the company's Current Report on Form 8-K filed February 27, 2002).
*10(a)(3)	Third Supplemental Indenture to the August 24, 2001 Indenture, between the company and J.P. Morgan Trust Company (Exhibit 4 to the company's Current Report on Form 8-K filed August 20, 2004).
*10(a)(4)	Bond Indenture, Mortgage, Deed of Trust, Security Agreement and Fixture Filing, dated as of August 31, 2005, between the company and Union Bank of California, N.A., as trustee and securities intermediary (Exhibit 10.2 to the company's Current Report on Form 8-K filed September 6, 2005 (the "September 6 Form 8-K")).
*10(a)(5)	First Supplemental Bond Indenture, Mortgage, Deed of Trust, Security Agreement and Fixture Filing, dated as of August 31, 2005, between the company and Union Bank of California, N.A., as trustee and securities intermediary (Exhibit 10.3 to the September 6 Form 8-K).
*10(a)(6)	\$110 million Revolving Credit Agreement among the company, the lenders and Credit Suisse First Boston dated September 20, 2004 (Exhibit 10.1 to the company's Current Report on Form 8-K filed September 21, 2004).
*10(a)(7)	\$220 million Credit Agreement among the company, the lenders and Credit Suisse First Boston dated September 20, 2004 (Exhibit 10.2 to the company's Current Report on Form 8-K filed September 21, 2004).
*10(a)(8)	\$180 Million Credit Agreement dated as of April 13, 2005, among the company, the lenders, Citicorp USA, Inc., as issuing bank and administrative agent, and Union Bank of California, N.A., as paying agent (Exhibit 10.1 to the company's Current Report on Form 8-K filed April 18, 2005).

- \*10(a)(9) Financing Agreement dated as of April 22, 2005, among the company, the lenders from time to time party thereto, and Union Bank of California, N.A., as agent (Exhibit 10.1 to the company's Current Report on Form 8-K filed April 26, 2005).
- \*10(a)(10) \$300 Million Credit Agreement, dated as of August 31, 2005, among the company, the banks and other lenders party thereto, and Union Bank of California, N.A., as issuing bank, administrative agent, and sole lead arranger (Exhibit 10.1 to the September 6 Form 8-K).
- \*10(a)(11) \$100,000,000 Credit Agreement, dated as of January 19, 2006, among the company, the banks named therein, and Union Bank of California, N.A., as administrative agent and collateral agent (Exhibit 10.1 to the company's Current Report on Form 8-K filed January 23, 2006).
- \*10(a)(12) Annual and Long-Term Incentive Plan (Exhibit 10(a)(3) to the company's Annual Report on Form 10-K for the year ended December 31, 1999).
- \*10(a)(13) First Amendment to Annual and Long-Term Incentive Plan. (Exhibit 10(a)(5) to the company's Annual Report on Form 10-K for the year ended December 31, 2001).
- \*10(a)(14) Form of Severance Compensation Agreement (change in control agreement) between the company and certain Executives of the company (Exhibit 10(a)(7) to the company's Annual Report on Form 10-K for the year ended December 31, 2001).
- \*10(a)(15) Life Insurance Program for Officers (Exhibit 10 (a)(13) to the company's Annual Report on Form 10-K for the year ended December 31, 1995).
- \*10(a)(16) Supplemental Executive Retirement Plan, Amended and Restated, effective January 1, 2001 (Exhibit 10(a)(1) to the company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2001).
- \*10(a)(17) Employment Agreement for Richard C. Green (Exhibit 10.1 to the company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2002).
- \*10(a)(18) Aquila, Inc. Capital Accumulation Plan, as amended and restated, effective January 1, 2005 (Exhibit 10.1 to the company's Current Report on Form 8-K filed January 6, 2006).
- \*10(a)(19) Form of Performance Bonus Agreement (Exhibit 10.5 to the company's Current Report on Form 8-K filed September 27, 2005 (the "September 27 Form 8-K")).
- \*10(a)(20) Severance Compensation Agreement (change in control agreement) dated as of March 16, 2001, by and between Aquila Merchant Services, Inc. (formerly Aquila, Inc.) and Keith Stamm (Exhibit 10.7 to Registration Statement No. 333-51718, filed April 18, 2001 by Aquila Merchant Services, Inc. (formerly Aquila, Inc.)).
- \*10(a)(21) Aquila, Inc. 2002 Omnibus Incentive Compensation Plan (Exhibit 10.3 to the company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2002).
- \*10(a)(22) Executive Security Trust Amended and Restated as of April 4, 2002 (Exhibit 10.5 to the company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2002).
- \*10(a)(23) Supplemental Executive Retirement Agreement, by and between Aquila, Inc. (formerly UtiliCorp United Inc.) and John R. Baker, dated as of May 7, 1990.

- \*10(a)(24) Asset Purchase Agreement by and between the company and The Empire District Electric Company, dated September 21, 2005 (Exhibit 10.1 to the September 27 Form 8-K).
- \*10(a)(25) Asset Purchase Agreement by and between the company and WPS Michigan Utilities, dated September 21, 2005 (Exhibit 10.2 to the September 27 Form 8-K).
- \*10(a)(26) Asset Purchase Agreement by and between the company and WPS Minnesota Utilities, dated September 21, 2005 (Exhibit 10.3 to the September 27 Form 8-K).
- \*10(a)(27) Asset Purchase Agreement by and between the company and Mid-Kansas Electric Company, dated September 21, 2005 (Exhibit 10.4 to the September 27 Form 8-K).
- \*10(a)(28) Asset Purchase and Sale Agreement by and between Aquila Piatt County Power, L.L.C. and Union Electric Company d/b/a AmerenUE, dated as of December 16, 2005 (Exhibit 10.1 to the company's Current Report on Form 8-K filed December 16, 2005 (the "December 16 Form 8-K")).
- \*10(a)(29) Asset Purchase and Sale Agreement by and between MEP Flora Power, LLC and Union Electric Company d/b/a AmerenUE, dated as of December 16, 2005 (Exhibit 10.2 to the December 16 Form 8-K).
- 10(a)(30) Amended and Restated Power Sales Agreement, dated as of June 30, 2000 between Aquila Energy Marketing Corporation, the company and Elwood Energy II, LLC.
- 10(a)(31) Power Sales Agreement, dated as of June 30, 2000 between Aquila Energy Marketing Corporation, the company and Elwood Energy III, LLC.
- \*10(a)(32) Unit Purchase Agreement by and between Everest Global Technologies Group, LLC and Everest Connections Holdings, Inc. (Exhibit 10.1 to the company's Current Report on Form 8-K filed March 6, 2006).
- 12 Ratio of Earnings to Fixed Charges.
- \*14 Code of Ethics (Exhibit 14 to the company's Annual Report on Form 10-K for the year ended December 31, 2004).
- \*17 Gerald L. Shaheen resignation letter (Exhibit 99.1 to the company's Current Report on Form 8-K filed January 6, 2006).
- 21 Subsidiaries of the company.
- 23 Consent of KPMG LLP.
- 31.1 Certification of Chief Executive Officer under Section 302.
- 31.2 Certification of Chief Financial Officer under Section 302.
- 32.1 Certification of Chief Executive Officer under Section 906.
- 32.2 Certification of Chief Financial Officer under Section 906.
- \*99.1 Order of the State Corporation Commission of the State of Kansas on Docket No. 02-UTCG-701-GIG, dated May 7, 2003 (Exhibit 99.1 to the company's Annual Report on Form 10-K for the year ended December 31, 2003).
- \*99.2 Order of the State Corporation Commission of the State of Kansas on Docket No. 02-UTCG-701-GIG, dated June 26, 2003 (Exhibit 99.2 to the company's Annual Report on Form 10-K for the year ended December 31, 2003).

\* *Exhibits marked with an asterisk are incorporated by reference herein. Parenthetical references describe the SEC filing that included the document incorporated by reference.*

## SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized as of March 6, 2006.

### **Aquila, Inc.**

By: /s/ RICHARD C. GREEN

Richard C. Green  
*President, Chief Executive Officer and Chairman of the Board of Directors*

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 indicated, as of March 6, 2006.

By: <u>/s/ RICHARD C. GREEN</u> Richard C. Green	President, Chief Executive Officer and Chairman of the Board of Directors (Principal Executive Officer)
By: <u>/s/ RICK J. DOBSON</u> Rick J. Dobson	Senior Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)
By: <u>/s/ HERMAN CAIN</u> Herman Cain	Director
By: <u>/s/ DR. MICHAEL M. CROW</u> Dr. Michael M. Crow	Director
By: <u>/s/ IRVINE O. HOCKADAY, JR.</u> Irvine O. Hockaday, Jr.	Director
By: <u>/s/ HEIDI E. HUTTER</u> Heidi E. Hutter	Director
By: <u>/s/ DR. STANLEY O. IKENBERRY</u> Dr. Stanley O. Ikenberry	Director
By: <u>/s/ PATRICK J. LYNCH</u> Patrick J. Lynch	Director
By: <u>/s/ NICHOLAS J. SINGER</u> Nicholas J. Singer	Director

**Aquila, Inc.**  
**Chief Executive Officer**  
**Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002**

I, Richard C. Green, certify that:

1. I have reviewed the annual report of Aquila, Inc. for the annual period ending December 31, 2005;
2. Based on my knowledge, the report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by the report;
3. Based on my knowledge, the financial statements, and other financial information included in the report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal controls over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
  - a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this periodic report is being prepared;
  - b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
  - c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
  - d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the board of directors (or persons performing the equivalent functions):
- a) All significant deficiencies and material weakness in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
  - b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

March 6, 2006

/s/ RICHARD C. GREEN

---

Richard C. Green  
Chairman, President and  
Chief Executive Officer, Aquila, Inc.

**Aquila, Inc.**  
**Chief Financial Officer**  
**Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002**

I, Rick J. Dobson, certify that:

1. I have reviewed the annual report of Aquila, Inc. for the annual period ending December 31, 2005;
2. Based on my knowledge, the report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by the report;
3. Based on my knowledge, the financial statements, and other financial information included in the report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal controls over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
  - a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this periodic report is being prepared;
  - b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
  - c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
  - d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the board of directors (or persons performing the equivalent functions):
  - a) All significant deficiencies and material weakness in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
  - b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

March 6, 2006

/s/ RICK J. DOBSON

---

Rick J. Dobson  
Senior Vice President and Chief Financial Officer,  
Aquila, Inc.

**Aquila, Inc.**  
**Chief Executive Officer**  
**Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002**

I, Richard C. Green, certify that:

1. Aquila, Inc.'s annual report on Form 10-K for the annual period ending December 31, 2005 accompanying this Certification, in the form filed with the Securities and Exchange Commission (the "Report") fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934; and
2. The information in the Report fairly presents, in all material respects, the financial condition and results of operations of Aquila, Inc.

Dated: March 6, 2006

/s/ RICHARD C. GREEN

---

Richard C. Green  
Chairman, President and Chief Executive Officer  
Aquila, Inc.

**Aquila, Inc.**  
**Chief Financial Officer**  
**Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002**

I, Rick J. Dobson, certify that:

1. Aquila, Inc.'s annual report on Form 10-K for the annual period ending December 31, 2005 accompanying this Certification, in the form filed with the Securities and Exchange Commission (the "Report") fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934; and
2. The information in the Report fairly presents, in all material respects, the financial condition and results of operations of Aquila, Inc.

Dated: March 6, 2006

/s/ RICK J. DOBSON

---

Rick J. Dobson  
Senior Vice President and Chief Financial Officer  
Aquila, Inc.

# Management and Directors

## Management Team

		Age/Year Joined Company
<b>Richard C. Green</b>	Chairman of the Board, President and Chief Executive Officer	51 / 1976
<b>Keith G. Stamm</b>	Senior Vice President and Chief Operating Officer	45 / 1983
<b>Rick J. Dobson</b>	Senior Vice President and Chief Financial Officer	46 / 1989
<b>Christopher M. Reitz</b>	Senior Vice President, General Counsel and Corporate Secretary	39 / 2000
<b>Jon R. Empson</b>	Senior Vice President, Regulated Operations	60 / 1978
<b>Norma F. Dunn</b>	Senior Vice President, Communications and Stakeholder Outreach	52 / 2005
<b>Leo E. Morton</b>	Senior Vice President and Chief Administrative Officer	60 / 1994
<b>Scott H. Heidtbrink</b>	Vice President, Power Generation and Energy Resources	44 / 1987

## Board of Directors

		Age/Year Joined Company
<b>Richard C. Green</b>	Chairman, President and Chief Executive Officer	51 / 1982
<b>Herman Cain</b>	Chief Independent Director; Chief Executive Officer of T.H.E. New Voice, a leadership consulting company, and former Chairman of the Board of Godfather's Pizza, Inc., Omaha, NE	60 / 1992
<b>Dr. Michael M. Crow</b>	President of Arizona State University, Tempe, AZ	50 / 2003
<b>Irvine O. Hockaday, Jr.</b>	Retired President and Chief Executive Officer of Hallmark Cards, Inc., Kansas City, MO	68 / 1995
<b>Heidi E. Hutter</b>	Managing General Partner, Black Diamond Capital Partners, a merchant bank and advisory company, Austin, TX	47 / 2002
<b>Dr. Stanley O. Ikenberry</b>	Former President of the American Council on Education, Washington, DC	70 / 1993
<b>Patrick J. Lynch</b>	Retired Senior Vice President and Chief Financial Officer, Texaco, Inc., Houston, TX	68 / 2004
<b>Nicholas J. Singer</b>	Senior Partner, Cyrus Capital Partners, L.P.	26 / 2005

## Committees of the Board

*Committee chairmen are underlined.*

### **Executive Committee: Green, Cain and Hockaday.**

Exercises the authority of the Board on matters of an urgent nature that arise when the Board is not in session.

### **Audit Committee: Lynch, Hutter and Singer.**

Retains independent accountants and preapproves their services. Reviews and approves audit plans, accounting policies, financial statements and reporting, and internal audit reports and controls.

### **Business Process Improvement Committee: Crow, Cain and Singer.**

Oversees, monitors, evaluates, and makes recommendations regarding the formation, development, and operation of the company's business process improvement program.

### **Compensation and Benefits Committee: Hockaday, Crow and Ikenberry.**

Evaluates the performance of the chief executive officer and establishes the compensation of the chief executive officer and other senior officers. Establishes and monitors management's administration of the company's retirement and employee benefit plans.

### **Nominating and Corporate Governance Committee: Ikenberry, Cain and Hockaday.**

Identifies, considers and recommends to the Board nominees for director. Develops and recommends to the Board corporate governance principles applicable to Aquila. Oversees the annual evaluation of the Board and its committees.