Exhibit No.:
Issues: Financial Statement
Witness: Beth A. Armstrong
Sponsoring Party: Aquila Networks-MPS
Case No.: EA-

Before the Public Service Commission
of the State of Missouri

Direct Testimony

of

Beth A. Armstrong

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI
DIRECT TESTIMONY OF BETH A. ARMSTRONG
ON BEHALF OF AQUILA, INC.
D/B/A AQUILA NETWORKS-MPS
CASE NO. EA-____________

Q. Please state your name and business address.

A. My name is Beth A. Armstrong and my business address is 20 West 9th Street, Kansas City, Mo. 64105.

Q. By whom are you employed and in what capacity?

A. I am employed by Aquila Inc. ("Aquila" or "the Company") as Vice President and Controller, Aquila, Inc.

Q. Please briefly describe your educational and professional background.

A. I have been employed in a variety of roles of increasing responsibility at Aquila since I joined the Company in 1991, including my current position which I have held since July 2005. Prior to my experience at Aquila, I was employed at the public accounting firm of Price Waterhouse from 1984 to 1991 as a staff and senior auditor and eventually as an audit manager. I graduated *summa cum laude* from Southeast Missouri State University in 1984 with a B.S. degree in Business Administration and I am Certified Public Accountant.

Q. What is the purpose of your testimony?

A. While the construction of the South Harper Peaking Facility has caused the Company to commit a considerable amount of funds towards its completion, the purpose of my testimony is to demonstrate that Aquila has more than had the financial wherewithal to fund its construction and operation. After all, the plant is finished, it has been funded and Aquila has suffered no impairment to its credit as a result of completing construction.

Q. Why do you say that Aquila has had the financial ability to build the plant?

A. Construction on the South Harper Peaking Facility commenced in late 2004 at which time the Company's consolidated equity ratio was approximately 32% (as of December 2004 year end). As of September 2005, Aquila's consolidated equity ratio had grown to approximately 42%. I have attached the Company's 2005 Third Quarter 10Q as Schedule BAA – 1 as support for these figures. Thus, despite the significant capital commitment made to fund the construction of the South Harper Facility, which is now completed and operating, the Company's financial condition has actually strengthened since the time construction on the plant started.

Q. To what do you attribute the Company's ability to strengthen its financial profile over the past year?

A. Since 2002, the Company has undergone a financial restructuring that continues to this day. It has sold most of its non-regulated businesses and is in the process of selling those that remain. It is also in the process of selling some select domestic utility properties with the proceeds earmarked to reduce debt and further strengthen the Company's balance sheet. It is through this ongoing process that we have been able to strengthen our financial profile and simultaneously construct the South Harper facility.

Q. Does this conclude your testimony?

A. Yes it does.

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

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 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** (IRS Employer Identification No.)
20 West Ninth Street, Kansas City, Missouri (Address of principal executive offices)	**64105** (Zip Code)

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

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

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

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

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

Class	Outstanding at October 28, 2005
Common Stock, $1 par value	373,402,842

PART I—FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

Information regarding the consolidated financial statements is on pages 3 through 26.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Management's discussion and analysis of financial condition and results of operations is on pages 27 through 51.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are subject to market risk as described on pages 69 through 72 of our 2004 Annual Report on Form 10-K. See discussion on page 52 of this document for changes in market risk since December 31, 2004.

ITEM 4. CONTROLS AND PROCEDURES

Information regarding disclosure controls and procedures is on page 53.

PART II—OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Information regarding legal proceedings is on page 53.

ITEM 2. CHANGES IN SECURITIES AND USE OF PROCEEDS

Not applicable.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

Not applicable.

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

Not applicable.

ITEM 5. OTHER INFORMATION

Not applicable.

ITEM 6. EXHIBITS

Exhibits are on page 54.

Part I. Financial Information
Item 1. Financial Statements

Aquila, Inc.
Consolidated Statements of Income—Unaudited

In millions, except per share amounts	Three Months Ended September 30, 2005	2004
Sales:		
Electricity—regulated	$ 215.4	$ 185.9
Natural gas—regulated	74.2	56.2
Other—non-regulated	30.2	(23.3)
Total sales	319.8	218.8
Cost of sales:		
Electricity—regulated	89.9	83.2
Natural gas—regulated	46.7	32.3
Other—non-regulated	23.8	19.6
Total cost of sales	160.4	135.1
Gross profit	159.4	83.7
Operating expenses:		
Operating expense	92.4	88.3
Net (gain) loss on sale of assets and other charges	82.3	114.5
Depreciation and amortization expense	30.5	29.8
Total operating expenses	205.2	232.6
Other income (expense):		
Other income, net	2.6	8.9
Total other income (expense)	2.6	8.9
Interest expense	41.4	58.5
Loss from continuing operations before income taxes	(84.6)	(198.5)
Income tax benefit	(.4)	(80.8)
Loss from continuing operations	(84.2)	(117.7)
Earnings from discontinued operations, net of tax	8.5	1.3
Net loss	$ (75.7)	$ (116.4)
Basic and diluted earnings (loss) per common share:		
Continuing operations	$ (.22)	$ (.45)
Discontinued operations	.02	.01
Net loss	$ (.20)	$ (.44)
Dividends per common share	$ –	$ –

See accompanying notes to consolidated financial statements.

Aquila, Inc.
Consolidated Statements of Income—Unaudited

In millions, except per share amounts	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
Sales:		
Electricity—regulated	$ 517.4	$ 455.7
Natural gas—regulated	386.3	347.4
Other—non-regulated	61.7	(76.1)
Total sales	965.4	727.0
Cost of sales:		
Electricity—regulated	246.6	224.2
Natural gas—regulated	276.0	239.0
Other—non-regulated	61.7	62.3
Total cost of sales	584.3	525.5
Gross profit	381.1	201.5
Operating expenses:		
Operating expense	265.7	288.0
Restructuring charges	6.6	.9
Net (gain) loss on sale of assets and other charges	56.7	136.2
Depreciation and amortization expense	91.5	88.9
Total operating expenses	420.5	514.0
Other income (expense):		
Equity in earnings of investments	–	2.1
Other income, net	15.0	14.7
Total other income (expense)	15.0	16.8
Interest expense	134.2	163.6
Loss from continuing operations before income taxes	(158.6)	(459.3)
Income tax benefit	(28.2)	(173.8)
Loss from continuing operations	(130.4)	(285.5)
Earnings from discontinued operations, net of tax	28.2	74.0
Net loss	$ (102.2)	$ (211.5)
Basic and diluted earnings (loss) per common share:		
Continuing operations	$ (.33)	$ (1.30)
Discontinued operations	.08	.34
Net loss	$ (.25)	$ (.96)
Dividends per common share	$ –	$ –

See accompanying notes to consolidated financial statements.

Aquila, Inc.

Consolidated Balance Sheets

In millions	September 30, 2005	December 31, 2004
	(Unaudited)	
Assets		
Current assets:		
Cash and cash equivalents	$ 184.3	$ 225.1
Short-term investments	45.3	–
Restricted cash	17.3	22.8
Funds on deposit	244.3	353.1
Accounts receivable, net	297.1	344.9
Inventories and supplies	121.3	88.0
Price risk management assets	333.9	124.9
Prepaid pension	75.4	67.5
Other current assets	78.7	80.9
Current assets of discontinued operations	223.4	241.6
Total current assets	1,621.0	1,548.8
Property, plant and equipment, net	2,269.8	2,199.3
Price risk management assets	203.0	136.1
Goodwill, net	111.3	111.0
Deferred charges and other assets	153.9	174.4
Non-current assets of discontinued operations	623.7	607.7
Total Assets	$ 4,982.7	$ 4,777.3
Liabilities and Shareholders' Equity		
Current liabilities:		
Current maturities of long-term debt	$ 22.4	$ 42.0
Accounts payable	291.2	368.5
Accrued interest	49.3	66.3
Other accrued liabilities	210.2	188.1
Price risk management liabilities	251.8	136.1
Current portion of long-term gas contracts	15.7	15.0
Customer funds on deposit	150.3	20.4
Current liabilities of discontinued operations	58.2	18.0
Total current liabilities	1,049.1	854.4
Long-term liabilities:		
Long-term debt, net	1,987.1	2,329.9
Deferred income taxes and credits	138.8	148.0
Price risk management liabilities	159.8	102.3
Long-term gas contracts, net	21.3	32.9
Deferred credits	133.8	130.9
Non-current liabilities of discontinued operations	52.0	48.4
Total long-term liabilities	2,492.8	2,792.4
Common shareholders' equity	1,440.8	1,130.5
Total Liabilities and Shareholders' Equity	$ 4,982.7	$ 4,777.3

See accompanying notes to consolidated financial statements.

Aquila, Inc.
Consolidated Statements of Comprehensive Income—Unaudited

In millions	Three Months Ended September 30, 2005	Three Months Ended September 30, 2004	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
Net loss	$ (75.7)	$ (116.4)	$ (102.2)	$ (211.5)
Other comprehensive loss, net of related tax:				
Foreign currency adjustments:				
Foreign currency translation adjustments, net of deferred tax expense (benefit) of $.5 million and $.2 million for the three months ended September 30, 2005 and 2004, respectively, and $(14.0) million for the nine months ended September 30, 2004	.8	.4	–	(21.3)
Reclassification of foreign currency (gains) losses to income due to sale of businesses and other, net of deferred tax (expense) benefit of $(4.7) million and $(26.2) million for the three and nine months ended September 30, 2004, respectively	–	(7.2)	–	(41.0)
Total foreign currency adjustments	.8	(6.8)	–	(62.3)
Cash flow hedges:				
Unrealized gains (losses) on hedging instruments net of deferred tax expense (benefit) of $3.8 million and $2.8 million for the three and nine months ended September 30, 2004, respectively	–	6.1	–	4.5
Reclassification of net (gains) losses on hedging instruments to net income, net of deferred tax (expense) benefit of $.6 million and $.8 million for the three and nine months ended September 30, 2004, respectively	–	1.0	–	1.3
Reclassification of net (gains) losses to income on cash flow hedges in equity method investments due to sale, net of deferred tax (expense) benefit of $5.5 million for the nine months ended September 30, 2004	–	–	–	9.1
Total cash flow hedges	–	7.1	–	14.9
Decrease in minimum pension liability, net of deferred tax expense of $2.7 million for the nine months ended September 30, 2004, respectively	–	–	–	4.4
Other comprehensive loss	.8	.3	–	(43.0)
Total Comprehensive Loss	$ (74.9)	$ (116.1)	$ (102.2)	$ (254.5)

See accompanying notes to consolidated financial statements.

Aquila, Inc.
Consolidated Statements of Common Shareholders' Equity

In millions	September 30, 2005	December 31, 2004
	(Unaudited)	
Common stock: authorized 400 million shares at September 30, 2005 and December 31, 2004, par value $1 per share; 373,393,525 shares issued at September 30, 2005 and 241,739,573 shares issued at December 31, 2004; authorized 20 million shares of Class A common stock, par value $1 per share, none issued	$ 373.4	$ 241.7
Premium on capital stock	3,509.5	3,228.6
Retained deficit	(2,442.9)	(2,340.6)
Accumulated other comprehensive income	.8	.8
Total Common Shareholders' Equity	$ 1,440.8	$ 1,130.5

See accompanying notes to consolidated financial statements.

Aquila, Inc.
Consolidated Statements of Cash Flows—Unaudited

In millions	Nine Months Ended September 30, 2005	2004
Cash Flows From Operating Activities:		
Net loss	$ (102.2)	$ (211.5)
Adjustments to reconcile net loss to net cash used for operating activities:		
Depreciation and amortization expense	116.9	112.3
Restructuring charges	6.6	.9
Cash received (paid) for restructuring and other charges	(1.8)	(130.5)
Net (gain) loss on sale of assets and other charges	56.7	62.2
Foreign currency gains	–	(13.0)
Net changes in price risk management assets and liabilities	(143.5)	73.9
Deferred income taxes and investment tax credits	(9.2)	(167.1)
Equity in earnings of investments	–	(2.1)
Dividends and fees from investments	.5	1.1
Changes in certain assets and liabilities, net of effects of divestitures:		
Restricted cash	5.4	230.9
Funds on deposit	108.7	127.5
Accounts receivable/payable, net	35.7	39.6
Inventories and supplies	(71.1)	(39.4)
Prepaid pension and other current assets	26.1	(2.4)
Deferred charges and other assets	(5.2)	13.7
Accrued interest and other accrued liabilities	52.5	(77.3)
Customer funds on deposit	130.4	(234.5)
Deferred credits	5.3	(.6)
Other	(.5)	5.7
Cash provided from (used for) operating activities	211.3	(210.6)
Cash Flows From Investing Activities:		
Funds on deposit for long-term contract surety	–	(136.5)
Utilities capital expenditures	(175.9)	(160.0)
Cash proceeds received on sale of assets	13.8	1,267.9
Purchases of short-term investments	(45.3)	–
Other	(13.1)	(14.0)
Cash provided from (used for) investing activities	(220.5)	957.4
Cash Flows From Financing Activities:		
Issuance of common stock	–	112.4
Issuance of long-term debt	2.0	339.8
Retirement of long-term debt	(23.4)	(793.7)
Short-term borrowings (repayments), net	–	(3.7)
Cash paid on long-term gas contracts	(11.0)	(522.3)
Other	.8	1.2
Cash used for financing activities	(31.6)	(866.3)
Decrease in cash and cash equivalents	(40.8)	(119.5)
Cash and cash equivalents at beginning of period	225.1	657.5
Cash and cash equivalents at end of period	$ 184.3	$ 538.0

See accompanying notes to consolidated financial statements.

AQUILA, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Summary of Significant Accounting Policies

Basis of Presentation

The accompanying unaudited consolidated financial statements have been prepared in accordance with the accounting policies described in the consolidated financial statements and related notes included in our 2004 Annual Report on Form 10-K filed with the Securities and Exchange Commission on March 14, 2005. You should read our 2004 Form 10-K in conjunction with this report. The accompanying Consolidated Balance Sheets and Consolidated Statements of Common Shareholders' Equity as of December 31, 2004, were derived from our audited financial statements, but do not include all disclosures required by accounting principles generally accepted in the United States. In our opinion, the accompanying consolidated financial statements reflect all adjustments (which include only normal recurring adjustments) necessary for a fair representation of our financial position and the results of our operations. Certain estimates and assumptions have been made in preparing the consolidated financial statements that affect reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of sales and expenses during the reporting periods shown. Actual results could differ from these estimates.

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 4, the results of operations from certain utilities that we have agreed to sell have been reclassified as discontinued operations in the accompanying balance sheets and statements of income for all periods presented.

Stock Based Compensation

We issue stock options to employees from time to time and account for these options under Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" (APB 25). All stock options issued are granted at the common stock's market price on the date of the grant. Therefore we record no compensation expense related to stock options.

Because we account for options under APB 25, we disclose a pro forma net loss and a basic and diluted earnings (loss) per share as if we reflected the estimated fair value of options as compensation expense in accordance with Statement of Financial Accounting Standards (SFAS) No. 123, "Accounting for Stock-Based Compensation." Our pro forma net loss and basic and diluted loss per share are as follows:

In millions, except per share amounts	Three Months Ended September 30, 2005	2004	Nine Months Ended September 30, 2005	2004
Net loss:				
As reported	$ (75.7)	$ (116.4)	$ (102.2)	$ (211.5)
Premium Income Equity Securities adjustment (Note 5)	.1	2.7	12.5	2.7
Loss available for common shares	(75.6)	(113.7)	(89.7)	(208.8)
Total stock-based employee compensation expense determined under fair value method, net of related tax benefits	–	(.7)	(1.9)	(3.6)
Pro forma loss available for common shares	$ (75.6)	$ (114.4)	$ (91.6)	$ (212.4)
Basic and diluted loss per share:				
As reported	$ (.20)	$ (.44)	$ (.25)	$ (.96)
Pro forma	(.20)	(.44)	(.25)	(.98)

In December 2004, the Financial Accounting Standards Board issued SFAS No. 123R, "Share-Based Payment" (SFAS 123R). SFAS 123R, which will replace SFAS No. 123 and supersede APB No. 25, will require us to recognize the compensation costs associated with employee stock options and other share-based payments in our consolidated income statement. In April 2005, the Securities and Exchange Commission approved a rule that delayed the effective date of SFAS 123R for public companies. As a result, SFAS 123R will be effective for us in the first quarter of 2006, and will apply to all of our outstanding unvested share-based payment awards as of January 1, 2006 and all prospective awards. Based on the small number of options that are expected to be unvested on January 1, 2006, we do not expect this standard to have a material effect on our financial statements.

New Accounting Standard

In March 2005, the FASB issued Financial Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations" (FIN 47). FIN 47 clarifies the term "conditional asset retirement obligation," as used in SFAS No. 143 "Accounting for Asset Retirement Obligations," which refers to a legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event. Uncertainty about the timing and (or) method of settlement of a conditional asset retirement obligation should be factored into the measurement of the liability when sufficient information exists. FIN 47 is effective no later than the end of fiscal years ending after December 15, 2005. We are currently evaluating the effect FIN 47 will have on our consolidated financial statements.

2. Restructuring Charges

We recorded the following restructuring charges:

In millions	Three Months Ended September 30, 2005	2004	Nine Months Ended September 30, 2005	2004
Merchant Services:				
Severance and retention costs	$ –	$ .1	$ –	$ .7
Lease agreements	–	–	6.6	–
Total Merchant Services	–	.1	6.6	.7
Corporate and Other severance costs	–	(.1)	–	.2
Total restructuring charges	$ –	$ –	$ 6.6	$ .9

Severance Costs and Retention Payments

For the nine months ended September 30, 2004, we incurred severance and other related costs of $.9 million related to the continued exit of our Merchant Services business and the sale of our investments in international networks.

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.

Restructuring Reserve Activity

The following table summarizes activity in accrued restructuring charges for the nine months ended September 30, 2005:

In millions		
Severance and Retention Costs:		
Accrued severance costs as of December 31, 2004	$	.8
Additional expense during the period		–
Cash payments during the period		(.6)
Accrued severance and retention costs as of September 30, 2005	$	.2
Other Restructuring Costs:		
Accrued other restructuring costs as of December 31, 2004	$	7.0
Additional expense during the period		6.6
Cash payments during the period		(13.5)
Accrued other restructuring costs as of September 30, 2005	$	.1

3. Net (Gain) Loss on Sale of Assets and Other Charges

We have sold the assets and terminated the contracts in the table below and recorded the following pretax net losses (gains) on sale of assets and other charges:

In millions	Three Months Ended September 30, 2005	Three Months Ended September 30, 2004	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
Merchant Services:				
Batesville tolling contract	$ –	$ –	$ (16.3)	$ –
ICE sale	–	–	(9.3)	–
Long-term gas contract terminations	–	117.2	–	117.2
Aries power project and tolling agreement	–	(.4)	–	46.6
Independent power plants	–	–	–	(6.1)
Marchwood development project	–	–	–	(5.0)
Investment in BAF Energy	–	–	–	(9.1)
Total Merchant Services	–	116.8	(25.6)	143.6
Corporate and Other:				
Early conversion of the PIES	82.3	–	82.3	–
Midlands Electricity	–	–	–	(3.3)
Everest target-based put rights	–	(2.3)	–	(4.1)
Total Corporate and Other	82.3	(2.3)	82.3	(7.4)
Total net (gain) loss on sale of assets and other charges	$ 82.3	$ 114.5	$ 56.7	$ 136.2

After-tax losses (gains) 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. 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 prices for tax purposes and the filing of tax returns including these sales.

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 IntercontinentalExchange, Inc. (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.

Long-Term Gas Contract Terminations

In the third quarter of 2004, we terminated three of our former long-term gas supply contracts resulting in payments of $580.8 million and pretax losses of $117.2 million, or $73.2 million after tax.

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 the project, cash of $5.0 million 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.

Independent Power Plants

In November 2003, we agreed to sell our interests in 12 power plants to Teton Power Funding LLC. Two of the power plants, Lake Cogen Ltd. (Lake Cogen) and Onondaga Cogen Ltd Partnership (Onondaga), were consolidated on our balance sheet. Therefore, in accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS 144), we have reported the results of operations and assets of these two plants in discontinued operations. See Note 4 for further explanation.

Our interests in 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 in the third quarter of 2003. This sale closed in March 2004. We received proceeds of approximately $256.9 million and paid approximately $4.1 million in transaction fees. As the actual proceeds realized were greater than estimated when we recorded the 2003 impairment charge, we recorded a pretax gain of $6.1 million, or $6.3 million after tax, in the first quarter of 2004. The after-tax gain was adjusted further in the fourth quarter of 2004 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.

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. The after-tax gain was $3.1 million.

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.

Early Conversion of the Premium Income Equity Securities (PIES)

As discussed in more detail in Note 7, we completed an exchange offer that resulted in the early conversion of approximately 98.9% of the PIES in July 2005. We recorded a pretax and after-tax early conversion loss of approximately $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.

Midlands Electricity

In October 2003, we and FirstEnergy Corp. agreed to sell 100% of the shares of Aquila Sterling Limited, the owner of Midlands Electricity plc, to a subsidiary of Powergen UK plc for approximately £36 million. Upon completion of the sale in January 2004, we 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 $3.3 million in the first quarter of 2004. The gain resulted from strengthening in the British pound exchange rate after we recorded a pretax and after-tax impairment charge of approximately $4.0 million in the third quarter of 2003. In 2002, we recorded a pretax and after-tax impairment charge of $247.5 million to record an other-than-temporary decline in this investment.

Everest 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, the probability of achieving the operating targets increased 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 $2.3 million and $4.1 million pretax and after tax of this reserve for the three and nine months ended September 30, 2004, respectively. 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.

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 $21.25 million. The transaction was approved by the Kansas Corporation Commission in October 2005 and is expected to close in November 2005. We expect to record a pretax gain on this transaction of approximately $6 million in the fourth quarter of 2005.

4. Discontinued Operations

We are in the process of selling our Kansas electric utility and our Michigan, Minnesota and Missouri gas utilities, and have sold our investments in independent power plants and Canadian utility businesses. These assets have been reclassified as 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 more than 68,000 customers in central and western Kansas, our natural gas distribution business serving more than 161,000 customers in southern and eastern

Michigan, our natural gas distribution business serving approximately 200,000 Minnesota customers (including a non-regulated appliance repair business in that state) and our natural gas distribution business serving approximately 49,000 customers in central and northwest Missouri. Additional information on these sales includes:

	Buyer	Base Price (in millions)
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 is subject to working capital and capital expenditure adjustments. 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 Federal Energy Regulatory Commission (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. <u>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.</u> 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:

	Three Months Ended September 30,		Nine Months Ended September 30,	
In millions	2005	2004	2005	2004
Allocated expenses of Kansas electric and Michigan, Minnesota and Missouri gas retained in continuing operations	$ 9.9	$ 9.5	$ 30.4	$ 28.3

The buyers of our utility divisions 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 lenders in our $220 million term loan (see Note 7) 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.

The discontinued utility operations participate in our single qualified pension plan, single non-qualified 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.

As a result of the expected sale of our electric distribution business in Kansas, we have begun an assessment of the realizability of the $111.0 million of goodwill, net of accumulated amortization, related to our Electric Utilities reporting segment. We expect to complete this assessment in the fourth quarter of 2005.

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 preliminary adjustments for working capital and capital expenditures as provided under the sales agreements. These proceeds were subject to final adjustments, which were completed in the third quarter of 2004. We recorded a pretax gain from this sale of $65.7 million, or $9.1 million after tax, in the second quarter of 2004, subject to adjustment for final working capital and capital expenditure adjustments. In September 2004, we agreed with Fortis on a final purchase price adjustment which resulted in a $3.2 million payment to Fortis and decreased our pretax and after-tax gain by $.1 million in the third quarter of 2004.

The effective tax rate on the pretax gain on sale of our Canadian utility businesses 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.

Independent Power Plants

In November 2003, we agreed to sell our interests in 12 plants to Teton Power Funding LLC. Two of the plants, Lake Cogen and Onondaga, 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. In the third quarter of 2003 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 this sale 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 resulted in a portion of these losses being realized as ordinary losses. The related valuation allowance was therefore reversed in the first quarter of 2004. The remaining valuation allowance for the capital losses on the sale of the independent power plants may be adjusted again after the final tax returns are filed related to the sale.

We have reported the results of operations from the above businesses in discontinued operations 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 Consolidated Balance Sheets.

In millions	September 30, 2005	December 31, 2004
Current assets of discontinued operations:		
Accounts receivable, net	$ 54.4	$ 118.5
Inventories and supplies	104.8	67.0
Prepaid pension	22.7	31.2
Price risk management assets	39.8	–
Other current assets	1.7	24.9
Total current assets of discontinued operations	$ 223.4	$ 241.6
Non-current assets of discontinued operations:		
Property, plant and equipment, net	$ 587.4	$ 578.1
Other non-current assets	36.3	29.6
Total non-current assets of discontinued operations	$ 623.7	$ 607.7
Current liabilities of discontinued operations:		
Other current liabilities	$ 58.2	$ 18.0
Total current liabilities of discontinued operations	$ 58.2	$ 18.0
Non-current liabilities of discontinued operations:		
Deferred credits	$ 52.0	$ 48.4
Total non-current liabilities of discontinued operations	$ 52.0	$ 48.4

Operating results from our discontinued operations are as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
In millions	2005	2004	2005	2004
Sales	$ 123.9	$ 103.5	$ 536.9	$ 614.8
Cost of sales	70.0	55.8	364.5	344.7
Gross profit	53.9	47.7	172.4	270.1
Operating expenses:				
Operating expense	21.3	24.8	65.7	133.1
Net (gain) loss on sale of assets and other charges	–	.1	–	(74.0)
Depreciation and amortization expense	8.1	7.7	25.3	23.4
Total operating expenses	29.4	32.6	91.0	82.5
Other income	.2	.6	.2	2.8
Interest expense	10.6	13.2	34.9	50.5
Earnings before income taxes	14.1	2.5	46.7	139.9
Income tax expense	5.6	1.2	18.5	65.9
Earnings from discontinued operations, net of tax	$ 8.5	$ 1.3	$ 28.2	$ 74.0

5. Earnings (Loss) per Common Share

The table below shows how we calculated basic and diluted earnings (loss) per share. 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 our loss available for common shares for the period by our weighted average shares outstanding, without adjusting for dilutive items. Weighted average shares used in basic earnings (loss) per share included 110.9 million shares issuable on the conversion of the mandatorily convertible 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 7 for further discussion. Diluted earnings (loss) per share is calculated by dividing our net loss, after assumed conversion of dilutive securities, by our weighted average shares outstanding, adjusted for the effect of dilutive securities. However, as a result of the net loss in the three and nine months ended September 30, 2005 and 2004, the potential issuances of common stock for dilutive securities were considered anti-dilutive in those periods and were therefore not included in the calculation of diluted earnings (loss) per share.

	Three Months Ended September 30,		Nine Months Ended September 30,	
In millions, except per share amounts	2005	2004	2005	2004
Loss from continuing operations	$ (84.2)	$ (117.7)	$ (130.4)	$ (285.5)
Earnings from discontinued operations	8.5	1.3	28.2	74.0
Net loss as reported	(75.7)	(116.4)	(102.2)	(211.5)
Interest and debt amortization costs associated with the PIES	.1	2.7	12.5	2.7
Loss available for common shares	$ (75.6)	$ (113.7)	$ (89.7)	$ (208.8)
Basic and diluted earnings (loss) per share:				
Loss from continuing operations	$ (.22)	$ (.45)	$ (.33)	$ (1.30)
Earnings from discontinued operations	.02	.01	.08	.34
Net loss	$ (.20)	$ (.44)	$ (.25)	$ (.96)
Weighted average number of common shares used in basic and diluted earnings (loss) per share	372.9	260.5	359.5	217.3

6. Reportable Segment Reconciliation

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 two business groups: Utilities and Merchant Services. The Utilities group consists 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. 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, New Zealand, Australia and the United Kingdom.

Our reportable segment reconciliation is shown below:

	Three Months Ended September 30,		Nine Months Ended September 30,	
In millions	**2005**	**2004**	**2005**	**2004**
Sales: *(a)*				
Utilities:				
Electric Utilities	$ 215.4	$ 186.0	$ 517.7	$ 456.2
Gas Utilities	81.5	63.0	401.7	365.4
Total Utilities	296.9	249.0	919.4	821.6
Merchant Services	11.1	(39.9)	11.9	(122.7)
Corporate and Other	11.8	9.7	34.1	28.1
Total sales	$ 319.8	$ 218.8	$ 965.4	$ 727.0

(a) *For the three months ended September 30, 2005 and 2004, and nine months ended September 30, 2005 and 2004, respectively, the following (in millions) have been reclassified to discontinued operations and are not included in the above amounts: Electric Utilities of $67.2, $53.8, $143.9 and $125.9; Gas Utilities of $56.7, $49.8, $393.0 and $358.0; Corporate and Other sales related to our former Canadian utility businesses of $122.9 for the nine months ended September 30, 2004; Merchant Services sales of $8.0 for the nine months ended September 30, 2004.*

Earnings (Loss) Before Interest and Taxes, Depreciation and Amortization (EBITDA): *(a)*				
Utilities:				
Electric Utilities	$ 82.4	$ 60.9	$ 139.8	$ 105.9
Gas Utilities	(2.0)	(2.4)	19.9	24.5
Total Utilities	80.4	58.5	159.7	130.4
Merchant Services	(9.0)	(174.6)	(7.7)	(331.7)
Corporate and Other	(84.1)	5.9	(84.9)	(5.5)
Total EBITDA	(12.7)	(110.2)	67.1	(206.8)
Total depreciation and amortization	30.5	29.8	91.5	88.9
Interest expense	41.4	58.5	134.2	163.6
Loss from continuing operations before income taxes	$ (84.6)	$ (198.5)	$ (158.6)	$ (459.3)

(a) *For the three months ended September 30, 2005 and 2004, and nine months ended September 30, 2005 and 2004, respectively, the following (in millions) have been reclassified to discontinued operations and are not included in the above amounts: Electric Utilities of $22.2, $16.0, $38.5 and $26.9; Gas Utilities of $10.6, $7.2, $68.4 and $61.2; Corporate and Other related to our former Canadian utility businesses of $118.8 for the nine months ended September 30, 2004; Merchant Services of $7.0 for the nine months ended September 30, 2004.*

Depreciation and Amortization: *(a)*				
Utilities:				
Electric Utilities	$ 15.7	$ 14.9	$ 46.3	$ 45.5
Gas Utilities	8.6	8.4	26.7	25.8
Total Utilities	24.3	23.3	73.0	71.3
Merchant Services	4.3	4.2	12.9	13.0
Corporate and Other	1.9	2.3	5.6	4.6
Total depreciation and amortization	$ 30.5	$ 29.8	$ 91.5	$ 88.9

(a) *For the three months ended September 30, 2005 and 2004, and nine months ended September 30, 2005 and 2004, respectively, the following (in millions) have been reclassified to discontinued operations and are not included in the above amounts: Electric Utilities of $3.3, $2.8, $9.7 and $8.5; and Gas Utilities of $4.8, $4.9, $15.6 and $14.9.*

In millions	September 30, 2005		December 31, 2004	
Assets: *(a)*				
Utilities:				
Electric Utilities	$	2,060.6	$	1,862.3
Gas Utilities		1,253.8		1,353.4
Total Utilities		3,314.4		3,215.7
Merchant Services		1,211.3		1,080.6
Corporate and Other		457.0		481.0
Total assets	$	4,982.7	$	4,777.3

(a) Included in total assets as of September 30, 2005 and December 31, 2004 are total current and non-current assets of discontinued operations as follows: Electric Utilities $267.1 million and $250.5 million, respectively, and Gas Utilities $580.0 million and $598.8 million, respectively.

7. Financings

Note Payable

In connection with the acquisition of our interest in Midlands Electricity from FirstEnergy Corp., we issued a note payable to the seller, FirstEnergy, for a portion of the purchase price. This note required us to make annual payments of $19.0 million through May 2008. The note obligation was recorded at its net present value at the date of acquisition, discounted at 8.15%, our incremental borrowing rate at that time. In February 2004, we paid $78.6 million to extinguish the entire note payable and accrued interest, resulting in other income related to this transaction of approximately $1.9 million.

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 September 30, 2005, $45.0 million of letters of credit remained outstanding under this facility. Additionally, we have other cash-collateralized letters of credit outstanding of approximately $6.5 million as of September 30, 2005.

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 September 30, 2005, we had $150.0 million of availability at an average cost of 3.65% under this agreement and had issued $121.9 million of unsecured letters of credit against that availability.

Mandatorily Convertible Senior Notes

In August 2004, we issued 13.8 million Premium Income Equity Securities (PIES) 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.

Five-Year 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. We received extension approval from the FERC and various public utility commissions in December 2004, automatically extending the term of both of these facilities to September 2009 (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. We had not drawn on the revolving credit facility as of September 30, 2005. The Five-Year Facilities bear interest at the London Inter-Bank Offering Rate (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 September 30, 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, 2004 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 earnings before interest, taxes, depreciation and amortization (EBITDA), as defined in the agreement, to interest expense of no less than 1.0 to 1.0 from December 31, 2004 to September 30, 2005; 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 9.5 to 1.0 from December 31, 2004 to September 30, 2005; 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 Standard & Poor's, or if such a payment would cause a default under the facilities.

Secured Revolving Credit Facilities

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.

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 above. There have been no borrowings under this facility as of September 30, 2005.

As we close the sale 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.

Iatan 2 Construction Financing

On August 31, 2005, we entered into a $300 million credit agreement with Union Bank of California, N.A. 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 Kansas City Power & Light Company (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. Among other restrictions, the Iatan Facility contains the following financial covenants with which we were in compliance as of September 30, 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 facilities.

8. Employee Benefits

The following table shows the components of net periodic benefit costs:

	Pension Benefits		Other Post-retirement Benefits	
	Three Months Ended September 30,			
In millions	**2005**	**2004**	**2005**	**2004**
Components of Net Periodic Benefit Cost:				
Service cost	$ 2.3	$ 2.0	$ –	$ .1
Interest cost	5.7	4.9	1.0	1.1
Expected return on plan assets	(7.0)	(6.0)	(.2)	(.3)
Amortization of transition amount	(.2)	(.3)	.3	.1
Amortization of prior service cost	1.2	.2	.2	.4
Recognized net actuarial loss	.9	2.1	.2	.4
Net periodic benefit cost before regulatory expense adjustments	2.9	2.9	1.5	1.8
Regulatory gain/loss adjustment	.8	–	.2	.3
SFAS 71 regulatory adjustment	1.0	1.5	–	–
Net periodic benefit cost after regulatory expense adjustments	$ 4.7	$ 4.4	$ 1.7	$ 2.1

	Pension Benefits		Other Post-retirement Benefits	
	Nine Months Ended September 30,			
In millions	**2005**	**2004**	**2005**	**2004**
Components of Net Periodic Benefit Cost:				
Service cost	$ 6.6	$ 5.9	$ .4	$ .2
Interest cost	16.3	14.6	3.7	3.5
Expected return on plan assets	(20.5)	(18.0)	(.7)	(.8)
Amortization of transition amount	(.6)	(.9)	1.1	.5
Amortization of prior service cost	2.8	.8	1.5	1.2
Recognized net actuarial loss	3.2	6.1	.4	1.4
Net periodic benefit cost before regulatory expense adjustments	7.8	8.5	6.4	6.0
Regulatory gain/loss adjustment	2.5	.2	.7	.7
SFAS 71 regulatory adjustment	3.0	2.7	–	–
Net periodic benefit cost after regulatory expense adjustments	$ 13.3	$ 11.4	$ 7.1	$ 6.7

We previously disclosed in our financial statements for the year ended December 31, 2004, that we expected to contribute $.8 million and $6.1 million to our U.S. defined benefit pension plans and other post-retirement benefit plan, respectively, in 2005. Our qualified pension plan is funded in compliance with income tax regulations and federal funding requirements. We expect to fund no less than the IRS minimum funding amount and no more than the IRS maximum tax deductible amount. On September 30, 2005, we contributed $8.0 million to our qualified pension plan. We expect to contribute $.8 million to our non-qualified supplemental executive retirement plan (SERP) and $6.1 million to our other post-retirement benefit plan in 2005. We further expect to contribute an additional $7.0 million to a Voluntary Employee Benefits Association (VEBA) trust in order to fund our other post-retirement benefit obligations.

As disclosed in Note 4, the four utility operations being held for sale have been reclassified as discontinued operations. The components of net periodic benefit cost presented in the tables above disclose information for these plans in total. For the three months and nine months ended September 30, 2005, the net periodic pension benefit cost charged to discontinued operations was $1.0 million and $2.6 million, respectively. In addition, for the three months and nine months ended September 30, 2005, the net periodic other post-retirement benefits cost charged to discontinued operations was $.7 million and $2.5 million, respectively.

9. Legal

AMS Shareholder Lawsuit

A consolidated lawsuit was filed against us in federal court in Missouri in connection with our recombination with our Aquila Merchant subsidiary that occurred pursuant to an exchange offer completed in January 2002. The suit raised allegations concerning the lack of independent members on the board of directors of Aquila Merchant to negotiate the terms of the exchange offer on behalf of the public shareholders of Aquila Merchant. On March 23, 2005, we were granted our motion for summary judgment in this case. In the third quarter of 2005 we reached an agreement with counsel for the plaintiffs to settle the case for $1 million. The court has set a February 3, 2006 hearing date to consider approval of the settlement.

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. 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 alleged 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, 12 other complaints making nearly identical allegations have been filed against 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. Aquila Merchant is also a defendant in two federal actions that have been transferred by the Judicial Panel on Multidistrict Litigation to the United States District Court for the District of Nevada, and consolidated with the proceeding known as *In re Western States Wholesale Natural Gas Antitrust Litigation*, MDL Docket No. 1566. These lawsuits make allegations similar to those made in the *In re Natural Gas Antitrust Cases I, II, III & IV*. One of the actions alleges violations of the Sherman Act, the Cartwright Act, California's Unfair Competition Law, unjust enrichment, and constructive trust, and the other action alleges violations of the Sherman Act. 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.

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. 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.

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. 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 this lawsuit. However, given the nature of the claims, an adverse outcome could have a material adverse effect on our results of operations.

ERISA Litigation

On September 24, 2004, a lawsuit was filed in the U.S. District Court for the Western District of Missouri against us, certain members of the Board of Directors and certain members of management alleging they violated the Employee Retirement Income Security Act of 1974, as amended (ERISA) and are responsible for losses that participants in the Aquila 401(k) plan experienced as a result of the decline in the value of their Aquila stock held in the Aquila 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 Aquila stock through the Aquila 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. We believe the County is prohibited by state law from applying its zoning ordinances in this instance to Aquila and utilities generally. On January 11, 2005, a trial court judge granted the County's request for an injunction; however, we were permitted to continue construction while the order is appealed. We appealed the trial court decision to the Missouri Court of Appeals for the Western District of Missouri. On June 21, 2005, the Missouri Court of Appeals 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. On October 4, 2005, the Missouri Court of Appeals granted our request for rehearing. We will continue to vigorously defend our position in this case, however, given that the remedy sought is the removal of the plant, an adverse outcome could have a material impact on our financial condition, results of operations and cash flows. Because there are a range of possible outcomes that includes being required to dismantle, remove and store the equipment, secure replacement power and/or relocate the plant to a new site, we cannot estimate with certainty the total cost that may be incurred as a result of this lawsuit. The total investment in this plant and related transmission is expected to be approximately $155 million.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

See Forward-Looking Information and Risk Factors beginning on page 50.

Strategy

On September 21, 2005, we entered into asset purchase agreements to sell our electric distribution business in Kansas and our gas distribution businesses in Michigan, Minnesota and Missouri for an aggregate base price of $896.7 million, subject to working capital and capital expenditure adjustments. We expect to close these sales in 2006. Additionally, we have outlined the other key elements of our repositioning plan as follows:

- Maintain synergies of an integrated, multi-state utility.
- Significantly reduce our debt levels.
- 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 our rate base to meet customer needs.
- Actively work with regulators and legislators to address rate and fuel cost issues.
- Efficiently monetize our interest in our three remaining Merchant peaking facilities and Everest Connections and exit our Elwood tolling obligation.

Also under consideration are various strategies proposed by financial advisors that could, under the right circumstances, enhance (or potentially accelerate) our repositioning efforts. Alternatives proposed for our consideration include debt redemption, exchange or tender offers; formation of a holding company; and/or a reverse stock split. Any decision to pursue part or all of the proposed strategies will be subject to review and approval by our board of directors and, if appropriate, our shareholders.

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 commodity prices following the recent hurricane season, we believe this working capital peak could be between $350 and $400 million. We anticipate using the combination of our $110 million five-year unsecured revolving credit facility, $150 million secured accounts receivable facility, up to $180 million unsecured revolving credit and letter of credit facility, and cash on hand to meet our peak winter working capital requirements.

Cash Flows

Cash Flows Provided From (Used For) Operating Activities

Our positive nine-month 2005 operating cash flows were driven primarily by seasonal declines in working capital requirements for our utility operations and an increase in natural gas prices. The seasonal decline in working capital requirements was the primary cause of the return of $108.7 million of funds on deposit and a $26.1 million decrease in prepayments. The increase in natural gas prices required our merchant and utilities counterparties to post an additional $130.4 million of collateral with us. Offsetting these increases were the use of $71.1 million of cash to increase our natural gas 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 negative nine-month 2004 operating cash flows were driven by the following events and factors:

- We had a net loss from continuing operations of $459.3 million before income tax benefits, including $117.2 million in losses relating to the termination of three long-term gas supply contracts.

- During 2004, we paid a $26.5 million civil penalty settlement to the Commodity Futures Trading Commission related to the reporting of natural gas trading information to publications and we paid $38.0 million to settle an appraisal rights lawsuit.

- Offsetting cash outflows in 2004 were collateral returns resulting from the end of the winter season for our utility business and continued wind-down of our trading positions, use of inventory and other positive working capital in our utility business.

Our Elwood tolling contracts will have a material negative impact on our operating cash flows for the foreseeable future. We are attempting to restructure 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 Provided From (Used For) Investing Activities

The decrease in cash provided from (used for) investing activities 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, offset by the 2004 restriction of cash related to the surety bond settlement related to our former long-term gas contracts, and the 2005 purchase of short-term investments with funds in excess of current working capital needs.

Cash Flows Used For Financing Activities

Cash flows used for financing activities in the nine months ended September 30, 2005 and 2004 consist primarily of cash we paid to retire our long-term debt obligations and our payments under our remaining long-term gas contracts. The decrease in cash flows used for financing activities in 2005 was primarily related to funds used in 2004 to terminate three of our long-term gas contracts, and retire debt associated with our acquisition of Midlands Electricity, our 7.00% senior notes due July 15, 2004, and our three year secured term loan. Partially offsetting this decrease was the issuance of common stock and the PIES which generated approximately $446.7 million in August 2004.

Collateral Positions

As of September 30, 2005, we had posted collateral for the following in the form of cash or cash collateralized letters of credit:

In millions		
Trading positions	$	119.7
Utility cash collateral requirements		53.8
Elwood tolling contract		38.5
Insurance and other		32.3
Total Funds on Deposit	$	244.3

Collateral requirements for our remaining trading positions will fluctuate based on movement in commodity prices. This will vary depending on the magnitude of the price movement and the current position of our portfolio. We expect to receive our posted collateral related to trading positions as we settle those positions in the future. Additionally, with our unsecured five-year credit facility we have the ability to post unsecured letters of credit versus cash or cash-collateralized letters of credit. This will accelerate the return of cash related to collateral postings.

We are required to post collateral to certain of our commodity and pipeline transportation vendors. The amount fluctuates with gas prices and projected volumetric deliveries. The return of this collateral depends on our achieving a stronger 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 ratings from certain major rating agencies. We will not be required to post any additional collateral related to this contract.

FINANCIAL REVIEW

Except where noted, the following discussion refers to the consolidated entity, Aquila, Inc. Our businesses are structured as follows: (a) Electric Utilities, our electric utilities in three mid-continent states, (b) Gas Utilities, our gas utilities in seven mid-continent states, and (c) Merchant Services, our non-regulated power generation operations, our former investments in independent power plants, and the remaining portfolio from our North American and European energy trading businesses. We sold or received distributions from our investments in our independent power plants in March and June 2004. Two consolidated plants, Lake Cogen and Onondaga, were classified in discontinued operations in 2004. All other operations are included in Corporate and Other, including costs that are not allocated to our operating businesses; our investment in Everest Connections; and our former investments in Australia, New Zealand and the United Kingdom. Our former Canadian utility businesses were classified in discontinued operations in 2004. Our electric utility division in Kansas and our gas utility divisions in Michigan, Minnesota and Missouri have also been classified in discontinued operations.

As described in Note 4 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.

This review of performance is organized by business segment, reflecting the way we manage our business. Each business group leader is responsible for operating results down to EBITDA and for depreciation and amortization. We use EBITDA as a performance measure as it captures the income and expenses within the management control of our segment business leaders. Corporate management is responsible for making all financing decisions. Therefore, each segment discussion focuses on the factors affecting EBITDA, while interest expense and income taxes are separately discussed at the corporate level.

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 generally accepted accounting principles (GAAP). In addition, the term may not be comparable to similarly titled measures used by other companies.

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
In millions	**2005**	**2004**	**2005**	**2004**
Earnings (Loss) Before Interest and Taxes, Depreciation and Amortization:				
Utilities:				
Electric Utilities	$ 82.4	$ 60.9	$ 139.8	$ 105.9
Gas Utilities	(2.0)	(2.4)	19.9	24.5
Total Utilities	80.4	58.5	159.7	130.4
Merchant Services	(9.0)	(174.6)	(7.7)	(331.7)
Corporate and Other	(84.1)	5.9	(84.9)	(5.5)
Total EBITDA	(12.7)	(110.2)	67.1	(206.8)
Depreciation and amortization	30.5	29.8	91.5	88.9
Interest expense	41.4	58.5	134.2	163.6
Income tax benefit	(.4)	(80.8)	(28.2)	(173.8)
Loss from continuing operations	(84.2)	(117.7)	(130.4)	(285.5)
Earnings from discontinued operations, net of tax	8.5	1.3	28.2	74.0
Net loss	$ (75.7)	$ (116.4)	$ (102.2)	$ (211.5)

Key Factors Impacting Results of Continuing Operations

For the nine months ended September 30, 2005, total EBITDA increased $273.9 million compared to 2004. Key factors affecting 2005 results were as follows:

- Total Utilities EBITDA increased $29.3 million primarily due to mark-to-market income related to our NYMEX natural gas contracts for gas-fired generation, favorable weather for our electric utilities, and rate increases in Missouri, Colorado and Kansas, 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 $25.6 million of gains on the sale of our investment in ICE and termination of our Batesville tolling agreement and associated forward sale contract, resulted in a $324.0 million decrease in losses before interest and taxes, depreciation and amortization from Merchant Services in 2004. Merchant Services' loss before interest, taxes, depreciation and amortization in 2004 included $143.6 million of net losses on sale of assets and other charges, and $166.2 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 interest, taxes, depreciation and amortization increased $79.4 million in 2005 compared to 2004, primarily due to the early conversion of the PIES offset in part by costs incurred in 2004 related to the settlement of a shareholder appraisal rights claim and exiting our international investments that did not recur in 2005.

Discontinued Operations

As further discussed in Note 4 to the Consolidated Financial Statements, we have reported the results of operations of our Kansas electric utility, our Michigan, Minnesota, and Missouri gas utilities, our former Canadian utility businesses and our former consolidated independent power plants, Lake Cogen and Onondaga, in discontinued operations in the Consolidated Statements of Income for all periods presented. The unaudited operating results of these operations are summarized in the table below. Our Canadian utility businesses and consolidated independent power plants were sold in May 2004 and March 2004, respectively. Therefore, no earnings from these operations were reported in 2005.

	Three Months Ended September 30,		Nine Months Ended September 30,	
Dollars in millions	**2005**	**2004**	**2005**	**2004**
Sales	$ 123.9	$ 103.5	$ 536.9	$ 614.8
Cost of sales	70.0	55.8	364.5	344.7
Gross profit	53.9	47.7	172.4	270.1
Operating expenses:				
Operating expense	21.3	24.8	65.7	133.1
Net (gain) loss on sale of assets and other charges	–	.1	–	(74.0)
Total operating expenses	21.3	24.9	65.7	59.1
Other income	.2	.6	.2	2.8
EBITDA	32.8	23.4	106.9	213.8
Depreciation and amortization expense	8.1	7.7	25.3	23.4
Interest expense	10.6	13.2	34.9	50.5
Earnings before income taxes	14.1	2.5	46.7	139.9
Income tax expense	5.6	1.2	18.5	65.9
Earnings from discontinued operations, net of tax	$ 8.5	$ 1.3	$ 28.2	$ 74.0
Electric sales and transportation volumes (GWh)	675.6	708.5	1,765.5	1,812.7
Electric customers at end of period			68,764	68,604
Gas sales and transportation volumes (Bcf)	18.6	17.9	89.0	86.8
Gas customers at end of period			404,251	399,844

Quarter-to-Quarter

Sales, Cost of Sales and Gross Profit

<u>Electric Utilities</u>

Sales, cost of sales and gross profit for our Kansas electric utility increased $13.4 million, $8.8 million and $4.6 million, respectively, in 2005 compared to 2004. Sales and gross profit increased by $2.9 million due to a rate increase in Kansas effective in April 2005. Lower demand charges and transmission costs offset increased fuel and purchased power costs resulting in a net $2.0 million decrease in cost of sales. In addition, favorable weather-related volume was offset by decreased wholesale sales of power resulting in a $.5 million decrease in gross profit in 2005.

Gas Utilities

Sales, cost of sales, and gross profit for our Michigan, Minnesota, and Missouri gas utilities increased $6.9 million, $5.4 million and $1.5 million, respectively, primarily due to $1.6 million of pipeline supplier metering adjustments in 2005 associated with prior periods.

Operating Expense

Operating expense decreased $3.5 million in 2005 compared to 2004, primarily due to a Michigan property tax settlement and reductions in other operating costs, offset in part by increased labor and benefit costs.

Income Tax Expense

The income tax expense for 2005 increased $4.4 million from 2004 due to higher pretax income resulting from the issues discussed above.

Year-to-Date

Sales, Cost of Sales and Gross Profit

Electric Utilities

Sales, cost of sales and gross profit for our Kansas electric utility increased $18.0 million, $11.2 million and $6.8 million, respectively, in 2005 compared to 2004. Sales and gross profit increased by $4.4 million due to a rate increase in Kansas effective in April 2005. Lower demand charges and transmission costs offset increased fuel and purchased power costs resulting in a net $2.6 million decrease in cost of sales. In addition, favorable weather-related volume was offset by decreased wholesale sales of power resulting in a $.6 million decrease in gross profit in 2005.

Gas Utilities

Sales, cost of sales, and gross profit for Michigan, Minnesota, and Missouri gas utilities increased $35.0 million, $33.8 million and $1.2 million, respectively. Sales and gross profit increased by $1.4 million due to rate increases in Missouri effective in May and July 2004. In addition, gross profit also increased $1.6 million due to pipeline supplier metering adjustments in 2005 associated with prior periods. These increases were offset in part by unfavorable weather and other volume variances of $1.8 million due to milder winter weather in 2005 compared to 2004.

Other

Sales, cost of sales and gross profit decreased $122.9 million, $20.5 million and $102.4 million, respectively, in 2005 compared to 2004, as our Canadian utilities were sold in May 2004. In addition, the sale of our consolidated independent power plants, Lake Cogen and Onondaga, in March 2004 resulted in decreases in sales, cost of sales and gross profit of $7.9 million, $4.6 million and $3.3 million, respectively.

Operating Expense

Operating expense decreased $67.4 million in 2005 compared to 2004, primarily due to the sale of our Canadian utility businesses in May 2004, which had $52.5 million of operating expense in 2004, and our consolidated independent power plants, Lake Cogen and Onondaga, in March 2004, which had $4.0 million of operating expense in 2004. Approximately $7.7 million of the decrease related to the property tax settlements in our Minnesota and Michigan gas utilities and other reductions in other property and sales and use taxes in the utilities held for sale. The remaining decrease related to lower insurance, claims and other expenses of the utilities held for sale, offset in part by increased labor and benefit costs.

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

Gain on sale of assets in 2004 consisted primarily of a $8.4 million gain related to the sale of our consolidated independent power plants, Lake Cogen and Onondaga in March 2004 and a $65.6 million gain related to the sale of our Canadian utility businesses in May 2004.

Interest Expense

Interest expense decreased $15.6 million in 2005 compared to 2004, primarily due to the sale of our Canadian utility businesses in May 2004. The interest expense related to the debt of these operations was $14.6 million in January through May 2004.

Income Tax Expense

The income tax expense for 2005 decreased $47.4 million from 2004 primarily due to lower pretax income resulting from the issues discussed above, as well as from 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 the third quarter of 2003. This valuation allowance was required, as it was expected that approximately $28.0 million of the losses on the sale of the independent power plants 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 resulted in a portion of these losses being realized as ordinary losses. The related valuation allowance was therefore reversed in the first quarter of 2004. The remaining valuation allowance for the capital losses on the sale of the independent power plants may be adjusted again in the fourth quarter of 2005 as we analyze the final income tax returns filed in comparison to the 2004 income tax provision. 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 regulatory decision in 2003 increased pretax income but had no impact on income tax expense.

Electric Utilities

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

Dollars in millions	Three Months Ended September 30, 2005	Three Months Ended September 30, 2004	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
Sales:				
Electricity—regulated	$ 215.4	$ 185.9	$ 517.4	$ 455.7
Other—non-regulated	–	.1	.3	.5
Total sales	215.4	186.0	517.7	456.2
Cost of sales:				
Electricity—regulated	89.9	83.2	246.6	224.2
Other—non-regulated	.1	.1	.2	.2
Total cost of sales	90.0	83.3	246.8	224.4
Gross profit	125.4	102.7	270.9	231.8
Operating expense	45.4	42.0	138.4	126.0
Other income	2.4	.2	7.3	.1
EBITDA	$ 82.4	$ 60.9	$ 139.8	$ 105.9
Depreciation and amortization expense	$ 15.7	$ 14.9	$ 46.3	$ 45.5
Electric sales and transportation volumes (GWh)	3,105.2	2,742.9	8,325.4	7,473.6
Electric customers at end of period			391,126	383,559

Quarter-to-Quarter

Sales, Cost of Sales and Gross Profit

Sales, cost of sales and gross profit for the Electric Utilities business increased $29.4 million, $6.7 million, and $22.7 million, respectively, in 2005 compared to 2004. These changes were primarily due to the following factors:

- Sales and gross profit increased by $1.7 million due to a rate increase in Colorado effective in September 2004, plus $1.9 million of additional margin from an increase in customers.
- Favorable weather-related volume and other variances increased gross profit by $3.5 million in third quarter of 2005.
- We recognized $20.7 million of mark-to-market gains on certain NYMEX natural gas contracts as a result of increases in forward gas prices. These contracts were primarily purchased to offset the risk of increased gas costs in our Missouri electric operations.
- The increases above were offset in part by higher costs of fuel, purchased power, transmission and emission allowances, net of offsetting derivative settlements, which reduced margins by approximately $5.1 million.

Operating Expense

Operating expenses consisted of the following:

In millions	Three Months Ended September 30, 2005	2004
Operating expenses of Colorado and Missouri electric	$ 42.8	$ 39.7
Allocated expenses of Kansas electric	2.6	2.3
Total operating expenses	$ 45.4	$ 42.0

Operating expense increased $3.4 million from the 2004 quarter primarily due to higher labor and benefit costs.

Other Income

Other income increased $2.2 million primarily due to increased Allowances for Funds Used During Construction (AFUDC) associated with the construction of our South Harper Peaking Facility. 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.

Year-to-Date

Sales, Cost of Sales and Gross Profit

Sales, cost of sales and gross profit for the Electric Utilities business increased $61.5 million, $22.4 million, and $39.1 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 $3.9 million of additional margin from an increase in customers.

- We recognized $26.6 million of mark-to-market income on certain NYMEX natural gas contracts as a result of increases in forward gas prices. These contracts were primarily purchased to offset the risk of increased gas costs in our Missouri electric operations.

- Favorable weather-related volume and other variances increased gross profit by $4.3 million in 2005.

- The increases above were offset in part by higher costs of fuel, purchased power, transmission and emission allowances, net of offsetting derivative settlements, which reduced margins by approximately $11.3 million.

Operating Expense

Operating expenses consisted of the following:

In millions	Nine Months Ended September 30, 2005	2004
Operating expenses of Colorado and Missouri electric	$ 130.5	$ 118.9
Allocated expenses of Kansas electric	7.9	7.1
Total operating expenses	$ 138.4	$ 126.0

Operating expense increased $12.4 million from 2004 primarily due to higher labor and benefit costs and increased service costs associated with storm-related outages in 2005.

Other Income

Other income increased $7.2 million primarily due to increased AFUDC associated with the construction of our South Harper Peaking Facility. 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.

Current Developments

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 Public Service Commission (MPSC) 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. Aquila and The Empire District Electric Company, minority co-owners in Iatan 1, are considered "preferred potential partners" in 30% of the proposed plant. We are currently negotiating the terms of our participation in the Iatan 2 unit and expect (but cannot guarantee) to have an 18% ownership share.

Clean Air Rules

In March 2005, the Environmental Protection Agency finalized the Clean Air Interstate Rule and the Clean Air Mercury Rule. These rules establish a stringent cap and trade program for sulfur dioxide, nitrogen oxides and mercury emissions beginning in 2009. These rules will impact our generation fleet, including facilities that we own in part but do not operate. Our current cost estimate to comply with the draft rules ranged between $100 million to $400 million. Although we do not believe the final versions of these rules will result in a material change in our original estimates, we are performing a more detailed engineering study to narrow the range of our estimated compliance costs. These rules are under a legal challenge to make them more stringent. A successful legal challenge could materially increase our cost estimates. We anticipate that we would seek to recover any costs incurred to comply with the final rules in future rate cases. However, given the nature of the costs, an adverse outcome during the rate recovery process could have a material adverse effect on our financial condition, results of operations and cash flows.

Earnings Trend

The April 2004 settlement of our electric rate case in Missouri is expected to increase annual sales approximately $37.5 million. However, our costs of natural gas used for fuel and purchased power have exceeded the level of costs recovered under the Interim Energy Charge (IEC) discussed under Regulatory Matters below. If these costs remain above the IEC base cost for the two-year period, we will not recover the excess. A portion of the rate increase is to cover increased costs in the 12-month test period such as additional staffing to improve customer service. To the extent that operating costs increase or decrease subsequent to the test period, the impact of the change will affect our operating results.

Our power supply agreement with Aries, which provided up to 500 MW of peaking capacity, expired in May 2005. We replaced this capacity with the construction of the South Harper Peaking Facility, a 315-megawatt combustion turbine generation plant near Peculiar, Missouri at a total cost of approximately $155 million, and by entering into power purchase agreements. Any differences in the total energy and purchased power demand cost from what was previously included in base rates and the IEC will impact our operating results until the conclusion of our pending rate cases in Missouri.

In April 2005, one of our coal suppliers notified us that it was terminating our coal supply contract because of labor problems at the mine. We have notified the supplier that we do not believe the termination was valid and have filed suit against the supplier to pursue our rights and remedies under the contract. This contract provided for the delivery of 450,000 tons in 2004 and 550,000 tons of coal annually to our Missouri electric utilities in 2005 through 2008, with extension options, at an average cost of $20 per ton. The supplier curtailed production beginning in January 2004 which resulted in the delivery of approximately 30% of the contracted volumes of low-sulfur, high-Btu coal. In response, we have secured substantial quantities of alternate supply through spot purchases, despite a general decrease in availability of comparable coal on the spot market. Some of the available substitute supplies of coal are of higher sulfur content and therefore require the purchase of additional SO_2 emission allowances at a time when the cost of such allowances is substantially higher than historical levels. Until such time that this increased fuel cost is reflected in customer rates, our operating results will be adversely affected.

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 is expected to result in a 15-20% reduction in contracted deliveries through November 2005. We have analyzed the potential effects of this reduction 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 November 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 modest coal conservation measures at both plants. If the deliveries are returned to normal levels after November this event is not expected to have a direct material effect on our operations.

As discussed in Note 4 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 sales close. Management intends 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 $26.6 million recognized during the nine months ended September 30, 2005 is primarily related to contracts that will settle against actual purchases of natural gas and purchased power in 2006 and 2007. If the market prices at September 30, 2005 were to remain in effect and no additional contracts were purchased throughout the remaining term of the program, approximately $22.5 million of mark-to-market earnings recognized in 2005 would be realized in cash when the contracts settle in 2006 and 2007 but there would be no earnings offset against the cost of fuel and power purchased in the market.

As a result of the fuel adjustment clause legislation signed into law in July 2005, the MPSC will set forth regulations 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.

Gas Utilities

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
Dollars in millions	**2005**	**2004**	**2005**	**2004**
Sales:				
Natural gas—regulated	$ 74.2	$ 56.2	$ 386.3	$ 347.4
Other—non-regulated	7.3	6.8	15.4	18.0
Total sales	81.5	63.0	401.7	365.4
Cost of sales:				
Natural gas—regulated	46.7	32.3	276.0	239.0
Other—non-regulated	4.6	3.5	8.5	9.6
Total cost of sales	51.3	35.8	284.5	248.6
Gross profit	30.2	27.2	117.2	116.8
Operating expense	32.2	29.8	97.9	92.7
Other income (expense)	–	.2	.6	.4
EBITDA	$ (2.0)	$ (2.4)	$ 19.9	$ 24.5
Depreciation and amortization expense	$ 8.6	$ 8.4	$ 26.7	$ 25.8
Gas sales and transportation volumes (Bcf)	16.0	13.2	67.3	67.6
Gas customers at end of period			496,629	488,884

Quarter-to-Quarter

Sales, Cost of Sales and Gross Profit

Sales, cost of sales and gross profit for the Gas Utilities business increased $18.5 million, $15.5 million and $3.0 million, respectively, in 2005 compared to 2004. These changes were primarily due to the following factors:

- Sales and cost of sales increased approximately $9.9 million due to a 28% 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.

- Sales and gross profit increased $1.6 million due to a rate increase in Kansas effective in June 2005.

- Weather-related volume and other variances increased gross profit by approximately $1.9 million in third quarter 2005.

Operating Expense

Operating expenses consisted of the following:

	Three Months Ended September 30,	
In millions	**2005**	**2004**
Operating expenses of Colorado, Iowa, Kansas and Nebraska gas	$ 24.9	$ 22.6
Allocated expenses of Michigan, Minnesota and Missouri gas	7.3	7.2
Total operating expenses	$ 32.2	$ 29.8

Operating expense for the third quarter 2005 increased $2.4 million from the 2004 quarter primarily as a result of increased labor and benefit costs.

Year-to-Date

Sales, Cost of Sales and Gross Profit

Sales, cost of sales and gross profit for the Gas Utilities business increased $36.3 million, $35.9 million and $.4 million, respectively, in 2005 compared to 2004. These changes were primarily due to the following factors:

- Sales and cost of sales increased approximately $36.4 million due to a 15% 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.

- Regulated gas gross profit increased by approximately $1.9 million due to of rate increases in Missouri effective in May and August 2004 and Kansas in June 2005, as well as $1.0 million of additional margins from customer growth in 2005.

- The increases in regulated gas gross profit were offset in part by decreased transmission sales of $1.0 million in 2005.

- Non-regulated gross profit decreased $1.5 million due to lower sales of excess pipeline capacity compared to 2004.

Operating Expense

Operating expenses consisted of the following:

	Nine Months Ended September 30,	
In millions	**2005**	**2004**
Operating expenses of Colorado, Iowa, Kansas and Nebraska gas	$ 75.4	$ 71.5
Allocated expenses of Michigan, Minnesota and Missouri gas	22.5	21.2
Total operating expenses	$ 97.9	$ 92.7

Operating expense for 2005 increased $5.2 million from 2004 primarily as a result of increased labor and benefit costs.

Regulatory Matters

The following is a summary of our recent rate case activity:

In millions	Type of Service	Date Requested	Date Effective	Amount Requested	Amount Approved
Missouri	Electric	7/2003	4/2004	$ 79.6	$ 36.2
Missouri	Steam	7/2003	4/2004	1.3	1.3
Missouri	Gas	8/2003	5 & 8/2004	6.4	3.4
Colorado	Electric	12/2003	9/2004	11.4	8.2
Kansas	Electric	6/2004	4/2005	16.4	8.0
Kansas	Gas	11/2004	6/2005	6.2	2.7
Iowa	Gas	5/2005	Pending	4.1	Pending
Missouri	Electric	5/2005	Pending	78.6	Pending
Missouri	Steam	5/2005	Pending	5.0	Pending
Nebraska	Gas	8/2005	Denied	1.1	Denied

In July 2003, we filed for rate increases totaling $79.6 million for our electric territories in Missouri and $1.3 million for Missouri steam customers. These applications were to recover increased costs of natural gas used to fuel our power plants, necessary capital expenditures since our prior rate case, increased pension costs and decreased off-system sales. In March 2004, we reached a settlement with the MPSC staff and intervenors for an increase of $36.2 million in electric rates and a $1.3 million increase in steam rates. This settlement was approved by the MPSC in April 2004. This settlement included a two-year IEC that allows the company to recover variable generation and purchased power costs up to a specified amount per Mwh specific to each Missouri regulatory jurisdiction. The IEC rate per unit sold is $13.98/Mwh for St. Joseph Light & Power and $19.71/Mwh for Missouri Public Service. If the amounts collected under the IEC exceed our average cost incurred for the two-year period, we will 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 rate increase. Also, as part of the settlement we agreed not to seek a general increase in our Missouri electric rates that would be effective in less than two years from the current rate increase, unless certain significant events occur that impact our operations.

In August 2003, we filed for a rate increase totaling $6.4 million for our gas territories in Missouri. These increases are needed primarily to recover the cost of system improvements and higher operating costs. In March 2004, we reached a settlement with the MPSC staff and intervenors for an increase of $3.4 million. This settlement was approved by the MPSC in April 2004 and rates became effective for Missouri Public Service in May 2004 and for St. Joseph Light & Power gas in August 2004.

In December 2003, we filed a "limited" rate filing in Colorado in order to recover approximately $11.4 million in ongoing costs (e.g., capital improvements) that occurred in 2003 or were to occur in 2004. In July 2004, we reached a settlement with the Colorado Commission staff and intervenors for an increase of $8.2 million. In addition, our Incentive Clause Adjustment was modified to provide for the recovery from customers of 100% of the variability of energy costs, an increase from 75%. The settlement was approved by the Colorado Commission in August 2004 and rates became effective in September 2004.

In June 2004, we filed for a rate increase totaling $19.2 million, later revised to $16.4 million, for our electric territories in Kansas. This application was primarily to recover infrastructure improvements and increased maintenance and operating costs. In January 2005, the Kansas Commission issued an order approving a rate increase of $7.4 million. On reconsideration, the formal order was issued in March 2005 adjusting the approved rate increase to $8.0 million. We appealed to the Circuit Court of the State of Kansas on a number of issues included in the final rate order but were denied reconsideration.

In November 2004, we filed for a rate increase totaling $6.2 million for our gas territories in Kansas. This application is primarily to recover infrastructure improvements and increased operating and maintenance costs. On May 2, 2005, the Kansas Commission approved a settlement we reached with the Staff at the Kansas Commission and other intervening parties for an increase in rates of $2.7 million, plus $244,000 per year for three years for a pipe replacement program. This rate increase was effective in June 2005.

In May 2005, we filed for a rate increase totaling $4.1 million for our gas territories in Iowa. This application is primarily to recover system improvement costs we have incurred. Under Iowa regulations, we instituted interim rates, subject to refund, totaling approximately $1.7 million in May 2005. We reached a settlement with the Office of Consumer Advocate for a $2.6 million rate increase subject to approval by the state public utility commission. The settlement has been filed with the Iowa Utilities Board with a hearing scheduled for November 7, 2005 to litigate a recovery mechanism for investments in distribution system integrity and rate design issues. Final rates will be effective in April 2006.

In May 2005, we filed for a rate increase totaling $78.6 million for our electric territories in Missouri. The application represents a net $60.1 million increase in rates charged to our customers because approximately $18.5 million of the increase reflects the replacement of the current IEC which expires in April 2006. In the absence of a rate case, our rates in Missouri would automatically decrease by $18.5 million at the expiration of the IEC. The primary purpose of the application is to recover higher fuel costs and system improvements. In addition to the electric rate case filing, we filed for a rate increase totaling $5.0 million in relation to servicing our industrial steam customers in Missouri. The primary purpose of the application is to recover the increased cost of fuel, as well as the removal of previously allowed subsidies currently borne by our St. Joseph Light & Power division electric customers. The MPSC Staff filed testimony recommending a $39.9 million electric rate increase, including fuel costs, and a $4.1 million steam rate increase. Hearings are scheduled to conclude in the first quarter of 2006, with final rates effective in April 2006.

On July 14, 2005, the governor of the State of Missouri signed into law new legislation establishing a means for the recovery of prudently incurred fuel and purchased power costs without going through a general rate case. This legislation also permits the recovery of government-mandated environmental investments. The initial filing of fuel and environmental tariffs must be made in connection with a general rate proceeding. This legislation must be implemented through the issuance of regulations by the MPSC. We expect these provisions to be considered in our current electric rate cases pending before the MPSC, with such rates to be effective in April 2006. We cannot estimate with certainty the impact implementing these provisions may have on the company's financial results and financial condition.

In August 2005, we filed a limited cost recovery application for $1.1 million for our gas territories in Nebraska. This application is to recover increased costs of operations through an increase in residential and commercial customer charges. The Nebraska Public Service Commission ruled on November 1, 2005 that they did not have authority to grant our application and denied our requested rate increase.

Merchant Services

The table below summarizes the operations of our Merchant Services businesses:

In millions	Three Months Ended September 30, 2005	Three Months Ended September 30, 2004	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
Sales	$ 11.1	$ (39.9)	$ 11.9	$ (122.7)
Cost of sales	15.5	12.8	42.5	43.5
Gross loss	(4.4)	(52.7)	(30.6)	(166.2)
Operating expenses:				
Operating expense (income), net	4.6	7.0	(.7)	26.0
Restructuring charges	–	.1	6.6	.7
Net (gain) loss on sale of assets and other charges	–	116.8	(25.6)	143.6
Total operating expenses (income), net	4.6	123.9	(19.7)	170.3
Other income (expense):				
Equity in earnings of investments	–	–	–	1.9
Other income	–	2.0	3.2	2.9
Earnings (loss) before interest and taxes, depreciation and amortization	$ (9.0)	$ (174.6)	$ (7.7)	$ (331.7)
Depreciation and amortization expense	$ 4.3	$ 4.2	$ 12.9	$ 13.0

We show 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.

Quarter-to-Quarter

Sales, Cost of Sales and Gross Loss

Gross loss for our Merchant Services operations for the three months ended September 30, 2005 was $4.4 million, primarily due to the following factors:

- 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 and recorded additional margin of $2.4 million in the third quarter of 2005, the final quarter of our obligation.

- In the third quarter of 2005, we recorded a net margin loss of $7.8 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 exceeds the value of the power that could be generated. Accordingly, we did not generate material revenues.

- Approximately $3.0 million of gross profit was a non-cash gain 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 the future cash flows of our price risk management liabilities that are discounted at our credit standing.

- We also incurred margin losses of $1.8 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. These contracts expire by early 2008.

Gross loss for our Merchant Services operations for the three months ended September 30, 2004 was $52.7 million, primarily due to the following factors:

- The settlement of our price risk management assets and liabilities associated with three of our long-term gas contracts resulted in non-cash, mark-to-market losses of approximately $29.2 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 three long-term contracts and their corresponding commodity hedges of approximately $29.2 million prior to our settlement. Additionally, we recorded a margin loss of approximately $11.7 million for margin recorded on these long-term contracts and approximately $6.0 million related to replacement gas payments we made under the termination provisions of these contracts.

- In the third quarter of 2004, we incurred margin losses of $3.9 million resulting from the difference between revenue recognized on our remaining long-term gas contracts and the net cost of gas delivered under these contracts.

- We make fixed capacity payments evenly throughout the year that entitle us to generate power at merchant power plants owned by others. For the third quarter of 2004, we recorded net margin losses associated with these agreements of $9.0 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.

- Offsetting the above losses, we recorded gross profit related to movements in our non-cash credit reserves of approximately $2.6 million and on natural gas call options used for hedging our winter 2004-2005 working capital requirements of approximately $3.2 million. These call options provided cash flow protection against a potential escalation or spike in natural gas prices for the portion of our total company gas supply portfolio that was purchased at index.

Operating Expense

Operating expense decreased $2.4 million primarily due to lower litigation, insurance and other costs associated with the continued wind-down of our Merchant operations, and reduced surety payments due to the settlement of four long-term gas contracts in 2004.

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

In the third quarter of 2004, we recorded pretax losses of $117.2 million on the termination of three long-term gas supply contracts.

Year-to-Date

Sales, Cost of Sales and Gross Loss

Gross loss for our Merchant Services operations for the nine months ended September 30, 2005 was $30.6 million, primarily due to the following factors:

- In the first nine months of 2005, we recorded a net margin loss of $24.0 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.

- Included in our gross loss for the nine months ended September 30, 2005 were mark-to-market losses 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 $5.2 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 related reserves of $7.1 million associated with these contracts.

- We also recorded $3.3 million of gross profit associated with the non-cash gains 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 the future cash flows of our price risk management liabilities that are discounted at our credit standing.

Gross loss for our Merchant Services operations for the nine months ended September 30, 2004 was $166.2 million, primarily due to the following factors:

- Approximately $24.6 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 discounted our price risk management assets and liabilities as described above. 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 indexes we use to determine the discount rate appropriate for our credit standing decreased resulting in the partial reversal of the previous earnings and asset recorded.

- In the nine months of 2004, we incurred margin losses of $28.3 million resulting from the difference between revenue recognized on our long-term gas contracts and the net cost of gas delivered under these contracts.

- We make fixed capacity payments evenly throughout the year that entitle us to generate power at merchant power plants owned by others. For the nine months of 2004, we recorded net margin loss associated with these agreements of $28.0 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. We terminated our Aries capacity contract in the first quarter of 2004.

- The settlement of our price risk management assets and liabilities associated with three of our long-term gas contracts, resulted in margin losses of approximately $46.9 million. See quarter-to-quarter discussion above.

- We incurred approximately $5.9 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 and the exit of other hedges related to previous contracts.

- Our remaining gross loss for the nine months mainly stems from mark-to-market losses and unfavorable settlements of approximately $28.2 million, related to a long-term power supply transaction with NYSEG and our stream flow transaction which we exited in the third quarter of 2005. 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 who assumed this contract.

Operating Expense

Operating expense decreased $26.7 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, reduced surety payments due to the settlement of four long-term gas contracts in 2004, and reduced staffing needed to manage our remaining trading positions and non-regulated power generation assets.

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 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.

Net loss on sale of assets in 2004 consists of a $117.2 million loss on the termination of three long-term gas contracts and a $46.6 million loss on the transfer of our equity interest in the Aries power project and termination of our tolling obligation, 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 and a $9.1 million gain on a distribution from BAF Energy.

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. Because it is generally expected that the fuel and start-up costs of operating our merchant power plants will exceed the revenues that would be generated from the power sold, we believe that during the foreseeable future we will have limited ability to generate power at a gross profit. We will continue to have operating and maintenance cost associated with our owned merchant generation plants, whether the facilities are being utilized to generate power or are idle. 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 2005 related to this arrangement. We have sold capacity in three of these plants, which will partially offset these costs in 2005 and 2006, and we are attempting to restructure our Elwood obligation. We will incur a significant charge if 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 three merchant power peaking plants. As of September 30, 2005, the carrying value of these plants was $457.3 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 these plants 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 each plant based on estimated margin contributions and forecasted operating expenses over their remaining plant lives. These peaking plants were placed into service in 2002 and 2003 and we depreciate these facilities 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 these assets, the undiscounted probability weighted cash flows for each of these plants exceeded their current book value. Therefore, under SFAS 144 no impairment was required as of September 30, 2005. We have evaluated these assets as held and used. If at some future date we determine these assets are held for sale, based on current market values, we would likely record a material impairment charge.

We attempt to optimize and hedge our power plants with forward contracts which qualify as derivative instruments. When we enter into these positions, we account for them at fair market value under mark-to-market accounting. The hedges are an offset to our power plants, which use accrual accounting. Because different accounting rules are used on each side of the transaction, this can cause significant fluctuations in earnings with limited impacts on cash flow.

We began winding down and terminating our trading positions with our various counterparties during the third quarter of 2002. However, it will take a number of years to complete the wind-down. Because most of our trading positions are offsetting, we should experience limited fluctuation in earnings or losses other than the impacts from counterparty credit, the discounting or accretion of interest, or the termination or liquidation of additional trading contracts.

Corporate and Other

The table below summarizes the operating results of Corporate and Other:

	Three Months Ended September 30,		Nine Months Ended September 30,	
In millions	**2005**	**2004**	**2005**	**2004**
Sales	$ 11.8	$ 9.7	$ 34.1	$ 28.1
Cost of sales	3.6	3.2	10.5	9.0
Gross profit	8.2	6.5	23.6	19.1
Operating expenses:				
Operating expense	10.2	9.5	30.1	43.3
Restructuring charges	–	(.1)	–	.2
Net loss (gain) on sale of assets and other charges	82.3	(2.3)	82.3	(7.4)
Total operating expenses	92.5	7.1	112.4	36.1
Other income (expense):				
Equity in earnings of investments	–	–	–	.2
Other income	.2	6.5	3.9	11.3
Earnings (loss) before interest and taxes, depreciation and amortization	$ (84.1)	$ 5.9	$ (84.9)	$ (5.5)
Depreciation and amortization expense	$ 1.9	$ 2.3	$ 5.6	$ 4.6

Quarter-to-Quarter

Sales, Cost of Sales and Gross Profit

Sales, cost of sales and gross profit increased $2.1 million, $.4 million and $1.7 million, respectively, in 2005 compared to 2004, due to an increase in customers at Everest Connections.

Net Gain on Sale of Assets and Other Charges

In the third quarter of 2005, we recorded a loss of $82.3 million related to the early conversion of the PIES. The $2.3 million gain in 2004 was related to the fair value adjustment of Everest Connections' target-based put rights liability.

Other Income

Other income decreased $6.3 million in 2005 compared to 2004 primarily due to the $11.9 million of realized foreign currency gains related to the wind-down of our Canadian merchant subsidiaries in 2004, partially offset by $8.7 million of prepayment penalties and fees we paid in association with the retirement of the $430 million three-year secured loan in 2004. In addition, we paid fees of $1.9 million on our $180 million credit facility in 2005.

Year-to-Date

Sales, Cost of Sales and Gross Profit

Sales, cost of sales and gross profit increased $6.0 million, $1.5 million and $4.5 million, respectively, in 2005 compared to 2004 due to an increase in customers at Everest Connections.

Operating Expense

Operating expense decreased $13.2 million in 2005 compared to 2004 resulting from the $8.4 million settlement of the appraisal rights shareholder lawsuit in 2004, $4.4 million of costs associated with the exit our international networks investments in 2004 and lower insurance costs compared to 2004. These decreases were offset, in part, by increased legal fees related to the ERISA litigation and increased consulting and other costs associated with sale of our electric and gas utilities in 2005.

Net Gain on Sale of Assets and Other Charges

The $82.3 million loss on sale of assets and other charges in 2005 primarily related to the early conversion of the PIES. The 2004 gain on sale of assets and other charges of $7.4 million is mainly due to the fair value adjustment of our Everest Connections' target-based put rights liability of $4.1 million, and the 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 $3.3 million gain on the closing of the sale.

Other Income

Other income decreased $7.4 million primarily due to the $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. The 2004 gains were partially offset by $8.7 million of prepayment penalties and fees we paid in association with the retirement of the secured term loan. In addition, fees on the $180 million facility supporting our unsecured letters of credit totaled $1.9 million in 2005 and interest and other income decreased on lower cash and investment balances.

Interest Expense and Income Tax Benefit

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

In millions	Three Months Ended September 30, 2005	Three Months Ended September 30, 2004	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
Interest expense	$ 41.4	$ 58.5	$ 134.2	$ 163.6
Income tax benefit	$ (.4)	$ (80.8)	$ (28.2)	$ (173.8)

Quarter-to-Quarter

Interest Expense

Interest expense decreased $17.1 million in 2005 compared to 2004 due to the early retirement of the $430 million secured term loan which decreased interest expense by $18.9 million including the write-off of amortized debt issue costs and other debt retirements in 2004 and early 2005 and the early conversion of the PIES in July 2005 which decreased interest expense by $7.1 million. These reductions were offset in part by $5.1 million of increased interest expense associated with the borrowing of $220 million under our unsecured term loan in September 2004.

Income Tax Benefit

The income tax benefit decreased $80.4 million in 2005 compared to 2004, primarily as a result of a lower pretax loss in 2005, and the treatment of the early conversion associated with the PIES as non-deductible for income tax purposes.

Year-to-Date

Interest Expense

Interest expense decreased $29.4 million in 2005 compared to 2004 primarily due to the early retirement of the $430 million secured term loan which decreased interest expense by $35.3 million including the write-off of unamortized debt issue costs. In addition, the repayment of debt associated with the senior notes in 2004 and 2005 reduced interest expense by $18.1 million. These reductions were offset in part by $10.6 million of additional interest expense related to the issuance of the PIES in August 2004 and $14.5 million of increased interest expense associated with the borrowing of $220 million under our unsecured term loan in September 2004.

Income Tax Benefit

The income tax benefit decreased $145.6 million in 2005 compared to 2004, primarily as a result of a lower pretax loss in 2005. Included in the income tax benefit for 2005 was the reversal of income tax valuation allowances previously provided on capital losses due to the recognition of a capital gain on the sale of our ICE shares. Also impacting the lower income tax benefit in 2005 was the treatment of loss associated with the conversion of the PIES as non-deductible for income tax purposes.

Significant Balance Sheet Movements

Total assets increased by $205.4 million since December 31, 2004. This increase is primarily due to the following:

- Cash decreased $40.8 million. See our Consolidated Statement of Cash Flows for analysis of this decrease.

- Short-term investments increased $45.3 million as we moved funds in excess of immediate liquidity needs into investments with terms longer than three months.

- Funds on deposit decreased $108.8 million, primarily due to the return of margin deposits associated with the seasonal decrease in gas purchases by our regulated utilities and the replacement of cash-collateralized letters of credit with unsecured letters of credit.

- Accounts receivable decreased $47.8 million, primarily reflecting lower volumes of gas and electricity delivered due to our exit from wholesale energy trading, and seasonal declines in regulated gas customer deliveries, offset in part by the effects of higher natural gas prices.

- Inventories and supplies increased $33.3 million, primarily due to the seasonal injections of natural gas into underground storage by our Gas Utilities businesses for winter deliveries to customers.

- Price risk management assets increased $275.9 million, primarily due to an increase in natural gas prices since December 31, 2004.

- Property, plant and equipment increased $70.5 million, primarily due to capital expenditures on our South Harper Peaking Facility.

Total liabilities decreased by $104.9 million and common shareholders' equity increased by $310.3 million since December 31, 2004. These changes are primarily attributable to the following:

- Accounts payable decreased by $77.3 million, primarily reflecting lower volumes of gas and electricity delivered due to our exit from wholesale energy trading and the seasonal decrease in gas purchases by our regulated utilities, offset in part by the effects of higher natural gas prices.

- Other accrued liabilities increased $22.1 million, primarily due to the deferral of mark-to-market gains on derivative contracts for natural gas to be passed through to our gas utility customers.

- Current liabilities of discontinued operations increased $40.2 million primarily due to the deferral of mark-to-market gains on derivative contracts for natural gas to be passed through to our gas utility customers.

- Price risk management liabilities increased $173.2 million, primarily due to an increase in natural gas prices since December 31, 2004.

- Customer funds on deposit increased $129.9 million, primarily due to additional postings required from our merchant and utilities counterparties due to the impact of higher natural gas prices on our positions with these counterparties.

- Long-term debt, including current maturities of long-term debt, decreased by $362.4 million primarily due to the PIES exchange transaction and scheduled retirement of senior notes.

- Common shareholder's equity increased $310.3 million primarily due to the PIES exchange transaction, offset in part by the net loss for the nine months ended September 30, 2005.

Forward-Looking Information and Risk Factors

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

- We expect to sell our Kansas electric utility business and our Michigan, Minnesota and Missouri utility businesses in 2006. Some important factors that could cause actual results to differ materially from those anticipated include:
    - Regulatory commissions may not approve some or all of the contemplated divestitures.
    - The expected closing timeframe of our utility divestitures may be affected by the regulatory approval process and other factors beyond our control.
- We are developing a comprehensive plan to eliminate the majority of costs allocated to four utilities that we have agreed to sell when the support services underlying those costs are no longer required, through a combination of business efficiency improvements, cost reductions, and, where appropriate, cost reallocations among our remaining utility businesses. Some important factors that could cause actual results to differ materially from those anticipated include:
    - Regulatory commissions may not approve some or all of the contemplated cost reallocations in future rate cases or allow us to retain any savings garnered through our business improvement initiatives.
    - We may not be able to reduce costs and improve business efficiencies in a manner that would help sufficiently eliminate these cost inefficiencies and, in turn, improve our credit profile.
- We expect to recover in rates the costs of replacing the power supplied to our Missouri Public Service operations under the Aries power supply agreement with the power supplied by our South Harper Peaking Facility and power purchased under additional power supply agreements. Some important factors that could cause actual results to differ materially from those anticipated include:
    - The operation of our South Harper Peaking Facility could be barred by an adverse outcome of litigation pending against us.
    - Regulatory commissions may refuse to allow us to recover in rates part or all of the costs related to the construction and financing of our South Harper Peaking Facility or the additional power purchases.
- We intend to secure additional base-load capacity for our Missouri electric operations by acquiring a significant ownership interest in the Iatan 2 station being developed by KCPL. Some important factors that could cause actual results to differ materially from those anticipated include:
    - KCPL may not receive the regulatory approvals necessary to construct and operate the project.
    - We may not be able to successfully negotiate the terms and conditions of our investment and participation in the project.
- We believe 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 believe that the coal inventory levels at our coal-fired generation power plants will be sufficient in the near future to withstand a curtailment of coal shipments without material disruption. Some important factors that could cause actual results to differ materially from those anticipated include:

  - An unanticipated significant increase in electric demand may require our coal-fired generation power plants to burn more fuel than expected.
  - An extended delay of the expected curtailment period may result in a reduction in the utilization of these power plants below current levels.

- We anticipate that the costs of compliance with the Clean Air Interstate Rule and the Clean Air Mercury Rule 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 costs related to compliance with these rules.
  - Changes in applicable law or regulation may prohibit us from recovering in rates part or all of the costs related to compliance with these rules.

- 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 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.
  - 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.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Price Risk Management

We engage in price risk management activities for both the continued mitigation of our trading portfolio and commodity risk mitigation in our utilities business. Transactions carried out in connection with trading activities that are derivatives under SFAS 133 are accounted for under the fair value 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:

In millions	Utilities	Merchant Services
Fair value at December 31, 2004	$ (3.3)	$ 25.9
Change in fair value during the period	93.2	(1.2)
Contracts realized or cash settled	13.4	(2.7)
Fair value at September 30, 2005	$ 103.3	$ 22.0

The fair value of contracts maturing in the remainder of 2005, each of the next three years and thereafter are shown below:

In millions	Utilities	Merchant Services
2005	$ 32.0	$ (11.8)
2006	64.5	1.6
2007	6.7	20.3
2008	.1	6.5
Thereafter	–	5.4
Total fair value	$ 103.3	$ 22.0

In addition to the natural gas derivative instruments purchased to mitigate our exposure to changes in natural gas and purchased power prices in our Missouri electric operations, the totals above include natural gas derivative instruments purchased to reduce our natural gas customers' underlying exposure to fluctuations in gas prices where programs have been approved by state regulatory commissions. These instruments are collectible under the provisions of the purchased gas adjustment provisions of those states. The changes in fair value of these contracts are recorded in current assets or liabilities for under- or over-recovered purchase gas adjustments until passed through to customers in rates.

Item 4. 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 Securities and Exchange Commission. There has been no change in our internal controls over financial reporting during the quarter covered by this report that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Part II – Other Information

Item 1. Legal Proceedings

Information on our legal proceedings is set forth in Note 9 to the Consolidated Financial Statements, which is incorporated herein by reference.

Item 6. Exhibits

(a) List of Exhibits

Exhibits filed herewith are designated by an asterisk (*). All exhibits not so designated are incorporated by reference to a prior filing, as indicated below.

Exhibit No.	Description
10.1	Asset Purchase Agreement by and between Aquila, Inc. and The Empire District Electric Company, dated September 21, 2005 (incorporated herein by reference to Exhibit 10.1 to the registrant's Current Report on Form 8-K dated September 21, 2005 and filed with the Securities and Exchange Commission on September 27, 2005 (the "September 27 Form 8-K")).
10.2	Asset Purchase Agreement by and between Aquila, Inc. and WPS Michigan Utilities, dated September 21, 2005 (incorporated herein by reference to Exhibit 10.2 to the September 27 Form 8-K).
10.3	Asset Purchase Agreement by and between Aquila, Inc. and WPS Minnesota Utilities, dated September 21, 2005 (incorporated herein by reference to Exhibit 10.3 to the September 27 Form 8-K).
10.4	Asset Purchase Agreement by and between Aquila, Inc. and Mid-Kansas Electric Company, dated September 21, 2005 (incorporated herein by reference to Exhibit 10.4 to the September 27 Form 8-K).
10.5	Form of Performance Bonus Agreement (incorporated herein by reference to Exhibit 10.5 to the September 27 Form 8-K).
10.6	$300 Million Credit Agreement, dated as of August 31, 2005, among Aquila, Inc., the banks and other lenders party thereto, and Union Bank of California, N.A., as issuing bank, administrative agent, and sole lead arranger (incorporated herein by reference to Exhibit 10.1 to the registrant's Current Report on Form 8-K dated August 31, 2005 and filed with the Securities and Exchange Commission on September 6, 2005 (the "September 6 Form 8-K")).
10.7	Bond Indenture, Mortgage, Deed of Trust, Security Agreement and Fixture Filing, dated as of August 31, 2005, between Aquila, Inc. and Union Bank of California, N.A., as trustee and securities intermediary (incorporated herein by reference to Exhibit 10.2 to the September 6 Form 8-K).
10.8	First Supplemental Bond Indenture, Mortgage, Deed of Trust, Security Agreement and Fixture Filing, dated as of August 31, 2005, between Aquila, Inc. and Union Bank of California, N.A., as trustee and securities intermediary (incorporated herein by reference to Exhibit 10.3 to the September 6 Form 8-K).
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

Signatures

Pursuant to the requirements 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.

Aquila, Inc.

By: /s/ RICK J. DOBSON

Rick J. Dobson
Senior Vice President and Chief Financial Officer
Signing on behalf of the registrant and as principal financial and accounting officer

Date: November 2, 2005

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the matter of the Application of Aquila, Inc. for Permission and Approval and a Certificate of Public Convenience and Necessity authorizing it to acquire, construct, Install, own, operate, maintain, and otherwise Control and manage electrical production and Related facilities in unincorporated areas of Cass County, Missouri near the town of Peculiar.	)	Case No. EA-________

County of Jackson)
) ss
State of Missouri)

AFFIDAVIT OF BETH A. ARMSTRONG

Beth A. Armstrong, being first duly sworn, deposes and says that she is the witness who sponsors the accompanying testimony entitled "Direct Testimony of Beth A. Armstrong;" that said testimony was prepared by her and under her direction and supervision; that if inquiries were made as to the facts in said testimony and schedules, she would respond as therein set forth; and that the aforesaid testimony and schedules are true and correct to the best of her knowledge, information, and belief.

Beth A Armstrong
Beth A. Armstrong

Subscribed and sworn to before me this 25th day of January, 2006.

Terry D. Lutes
Notary Public

My Commission expires:

8-20-2008

Notary Public Notary Seal State of Missouri

TERRY D. LUTES
Jackson County
My Commission Expires
August 20, 2008