SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K/A

Current Report

Pursuant to Section 13 or 15(d) of the
Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): August 13, 2008 (July 14, 2008)

Commission File Number	Registrant, State of Incorporation, Address and Telephone Number	I.R.S. Employer Identification Number
001-32206	**GREAT PLAINS ENERGY INCORPORATED** (A Missouri Corporation) 1201 Walnut Street Kansas City, Missouri 64106 (816) 556-2200 NOT APPLICABLE (Former name or former address, if changed since last report)	43-1916803
000-51873	**KANSAS CITY POWER & LIGHT COMPANY** (A Missouri Corporation) 1201 Walnut Street Kansas City, Missouri 64106 (816) 556-2200 NOT APPLICABLE (Former name or former address, if changed since last report)	44-0308720

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

[ ] Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

[ ] Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

[ ] Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

[ ] Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

This combined Current Report on Form 8-K/A is being filed by Great Plains Energy Incorporated (Great Plains Energy) and Kansas City Power & Light Company (KCP&L). KCP&L is a wholly owned subsidiary of Great Plains Energy and represents a significant portion of its assets, liabilities, revenues, expenses and operations. Thus, all information contained in this report relates to, and is filed by, Great Plains Energy. Information that is specifically identified in this report as relating solely to Great Plains Energy, such as its financial statements and all information relating to Great Plains Energy's other operations, businesses and subsidiaries, including Aquila, Inc., does not relate to, and is not filed by, KCP&L. KCP&L makes no representation as to that information. Neither Great Plains Energy nor Aquila has any obligation in respect of KCP&L's debt securities and holders of such securities should not consider Great Plains Energy's or Aquila's financial resources or results of operations in making a decision with respect to KCP&L's debt securities. Similarly, KCP&L has no obligation in respect of securities of Great Plains Energy or Aquila.

Item 2.01 Completion of Acquisition or Disposition of Assets

This Amendment No. 1 amends the combined Current Report on Form 8-K dated July 14, 2008, as filed with the Securities and Exchange Commission on July 18, 2008 (the "July 8-K") related to Great Plains Energy's acquisition of Aquila. As disclosed in Item 2.01 of the July 8-K, which is incorporated by reference herein, the acquisition of Aquila by Great Plains Energy was completed on July 14, 2008. Immediately prior, Aquila sold its Colorado electric utility assets and its Colorado, Iowa, Kansas and Nebraska gas utility assets (the "Asset Sale Transactions") to Black Hills Corporation ("Black Hills").

Amendment No. 1 amends the July 8-K to include the audited financial statements of Aquila for the three years ended December 31, 2007, the unaudited Aquila consolidated balance sheet as of March 31, 2008, and the related unaudited Aquila consolidated statements of income, comprehensive income, and cash flows for the three-month periods ended March 31, 2008 and 2007 (collectively, the "Aquila Financial Statements"), and the pro forma financial information (the "Pro Forma Financial Information") as required by Items 9.01(a) and (b) of Form 8-K. As the Asset Sale Transactions were completed immediately before Great Plains Energy completed its acquisition of Aquila, the Aquila Financial Statements reflect the Asset Sale Transactions as discontinued operations. The Pro Forma Financial Information includes unaudited pro forma condensed combined statements of income for the year ended December 31, 2007, and the quarter ended March 31, 2008, and the unaudited pro forma condensed combined balance sheet as of March 31, 2008, for Great Plains Energy, reflecting the Aquila acquisition subsequent to the Asset Sale Transactions. The underlying unaudited pro forma condensed consolidated statements of income and unaudited pro forma condensed consolidated balance sheet for Aquila, reflecting the Asset Sale Transactions, are also provided in the Pro Forma Financial Information.

Item 9.01 Financial Statements and Exhibits

(a) Financial statements of businesses acquired

The Aquila, Inc., audited consolidated balance sheets as of December 31, 2007 and 2006, and the related consolidated statements of income, comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2007, reflecting the Asset Sale Transactions as discontinued operations, are filed as Exhibit 99.1 to this Amendment No. 1 and incorporated herein by reference.

The Aquila, Inc. unaudited consolidated balance sheet as of March 31, 2008, and the related unaudited consolidated statements of income, comprehensive income, and cash flows for the three-month periods ended March 31, 2008 and 2007, reflecting the Asset Sale Transactions as discontinued operations, are filed as Exhibit 99.2 to this Amendment No. 1 and incorporated herein by reference.

(b) Pro forma financial information

The Great Plains Energy Incorporated unaudited pro forma condensed combined statements of income for the year ended December 31, 2007, and the three months ended March 31, 2008, and unaudited pro forma condensed combined balance sheet as of March 31, 2008, reflecting the Aquila acquisition subsequent to the Asset Sale Transactions, and the underlying Aquila, Inc., unaudited pro forma condensed consolidated statements of income for the year ended December 31, 2007, and the quarter ended March 31, 2008, and unaudited pro forma condensed consolidated balance sheet for Aquila, reflecting the Asset Sale Transactions, and notes thereto are filed as Exhibit 99.3 to this Amendment No. 1 and incorporated herein by reference.

(d) Exhibit No.

23.1	Consent of KPMG LLP
99.1	Aquila, Inc., audited consolidated financial statements described in Item 9.01(a).
99.2	Aquila, Inc., unaudited consolidated financial statements described in Item 9.01(a).
99.3	Aquila, Inc., and Great Plains Energy Incorporated pro forma information described in Item 9.01(b).

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 hereunto duly authorized.

GREAT PLAINS ENERGY INCORPORATED

/s/ Lori A. Wright
Lori A. Wright
Controller

KANSAS CITY POWER & LIGHT COMPANY

/s/ Lori A. Wright
Lori A. Wright
Controller

Date: August 13, 2008

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

The Board of Directors
Great Plains Energy Incorporated:

We consent to the incorporation by reference in the registration statements (Nos. 333-97263, 333-132829, 333-114486, and 333-133891) on Form S-3 and registration statements (Nos. 333-132828, 333-45618, 333-142774, 333-147939, 333-152313, and 333-152314) on Form S-8 of Great Plains Energy Incorporated of our report dated July 25, 2008, with respect to the consolidated balance sheets of Aquila, Inc. as of December 31, 2007 and 2006, and the related consolidated statements of income, comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2007, which report appears in the Current Report on Form 8-K of Great Plains Energy Incorporated dated August 13, 2008. Our audit report refers to the adoption of Financial Accounting Standards Board (FASB) Interpretation No. 48, *Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109, Accounting for Income Taxes*, and FASB Staff Position (FSP) AUG AIR-1, *Accounting for Planned Major Maintenance Activities*.

/s/ KPMG LLP
Kansas City, Missouri
August 13, 2008

Aquila, Inc.

Consolidated Statements of Income

In millions	Year Ended December 31, 2007	2006	2005
Sales:			
Electricity—regulated	$ 659.8	$ 596.3	$ 510.6
Other	(8.2)	(8.0)	(1.3)
Total sales	651.6	588.3	509.3
Cost of sales:			
Electricity—regulated	334.7	310.5	243.6
Other	2.9	18.4	41.1
Total cost of sales	337.6	328.9	284.7
Gross profit	314.0	259.4	224.6
Operating expenses:			
Operation and maintenance expense	214.8	220.1	237.5
Taxes other than income taxes	15.4	20.1	12.9
Restructuring charges	1.5	5.7	6.6
Net loss on sale of assets and other charges	1.3	246.9	55.4
Depreciation and amortization expense	66.3	65.1	64.8
Total operating expenses	299.3	557.9	377.2
Operating income (loss)	14.7	(298.5)	(152.6)
Other income, net	26.3	33.5	14.2
Interest expense	110.0	121.4	103.1
Loss from continuing operations before income taxes	(69.0)	(386.4)	(241.5)
Income tax expense (benefit)	(16.4)	(81.8)	(58.9)
Loss from continuing operations	(52.6)	(304.6)	(182.6)
Earnings (loss) from discontinued operations, net of tax	47.2	328.5	(47.4)
Net income (loss)	$ (5.4)	$ 23.9	$(230.0)

See accompanying notes to consolidated financial statements.

Aquila, Inc.

Consolidated Balance Sheets

	December 31,	
In millions	**2007**	**2006**
Assets		
Current assets:		
Cash and cash equivalents	$ 34.4	$ 232.8
Restricted cash	1.2	9.1
Funds on deposit	41.3	107.9
Accounts receivable, net	136.8	142.4
Inventories and supplies	62.3	68.2
Price risk management assets	32.0	71.3
Regulatory assets, current	25.5	4.1
Other current assets	8.5	7.3
Current assets of discontinued operations	213.6	230.9
Total current assets	555.6	874.0
Utility plant, net	1,484.3	1,309.8
Non-utility plant, net	119.5	126.7
Price risk management assets	13.1	43.4
Goodwill, net	111.0	111.0
Pension asset	26.0	3.4
Regulatory assets	84.6	92.3
Deferred charges and other assets	39.3	52.3
Non-current assets of discontinued operations	583.1	862.8
Total Assets	$3,016.5	$3,475.7
Liabilities and Shareholders' Equity		
Current liabilities:		
Current maturities of long-term debt	$ 2.4	$ 19.7
Short-term debt	25.0	-
Accounts payable	85.5	106.9
Accrued interest	45.8	49.7
Accrued compensation and benefits	21.7	25.2
Pension and post-retirement benefits, current	1.6	1.7
Other accrued liabilities	46.8	92.9
Price risk management liabilities	28.7	61.7
Customer funds on deposit	14.0	5.6
Current liabilities of discontinued operations	150.0	138.3

Total current liabilities	421.5	501.7
Long-term liabilities:		
Long-term debt, net	1,035.4	1,385.9
Deferred income taxes and credits	-	19.3
Price risk management liabilities	.5	27.1
Pension and post-retirement benefits	25.4	25.4
Regulatory liabilities	75.4	68.9
Deferred credits	41.7	39.1
Non-current liabilities of discontinued operations	60.9	102.2
Total long-term liabilities	1,239.3	1,667.9
	1,355.7	1,306.1
Common shareholders' equity		
Total Liabilities and Shareholders' Equity	$3,016.5	$3,475.7

See accompanying notes to consolidated financial statements.

Aquila, Inc.

Consolidated Statements of Comprehensive Income

	Year Ended December 31,		
In millions	**2007**	**2006**	**2005**
Net income (loss)	$(5.4)	$ 23.9	$(230.0)
Other comprehensive income (loss), net of related tax:			
Foreign currency adjustments:			
Foreign currency translation adjustments, net of deferred tax expense (benefit) of $.6 million, $(.1) million and $(.2) million for 2007, 2006 and 2005, respectively	.9	(.1)	(.3)
Reclassification of foreign currency (gains) losses to income due to sale of businesses and other, net of deferred tax (expense) benefit of $(.5) million, $.1 million and $(.4) million for 2007, 2006 and 2005, respectively	(.8)	.2	(.6)
Total foreign currency adjustments	.1	.1	(.9)
Pension and post-retirement benefits costs arising during the period:			
Net actuarial gain, net of deferred tax expense (benefit) of $–million after valuation allowance for 2007	21.6	-	-
Pension and post-retirement benefits costs amortized to income:			
Prior service cost, net of deferred tax expense (benefit) of $–million after valuation allowance for 2007	2.4	-	-
Net actuarial loss, net of deferred tax expense (benefit) of $–million after valuation allowance for 2007	1.4	-	-
Accumulated regulatory loss adjustment, net of deferred tax expense (benefit) of $– million after valuation allowance for 2007	5.6	-	-
Total pension and post-retirement benefit costs	31.0	-	-
Other comprehensive income (loss)	31.1	.1	(.9)
Total Comprehensive Income (Loss)	$25.7	$24.0	$(230.9)

See accompanying notes to consolidated financial statements.

Aquila, Inc.

Consolidated Statements of Cash Flows

In millions	Year Ended December 31, 2007	2006	2005
Cash Flows From Operating Activities:			
Net income (loss)	$ (5.4)	$ 23.9	$(230.0)
Adjustments to reconcile net income (loss) to net cash provided from operating activities:			
Depreciation and amortization expense	108.3	104.8	148.9
Restructuring charges	1.5	7.7	6.6
Cash paid for restructuring and other charges	(2.7)	(223.5)	(2.3)
Net (gain) loss on sale of assets and other charges	(2.3)	(21.0)	214.9
Net changes in price risk management assets and liabilities	(.4)	69.7	(61.2)
Deferred income taxes and investment tax credits	.2	(33.8)	(81.5)
Changes in certain assets and liabilities, net of effects of divestitures:			
Funds on deposit	66.7	157.0	88.2
Accounts receivable/payable, net	(39.3)	51.3	(98.7)
Inventories and supplies	12.7	27.8	(33.3)
Other current assets	(14.4)	33.7	25.3
Deferred charges and other assets	26.6	3.8	(13.8)
Accrued interest and other accrued liabilities	(24.4)	(86.2)	16.8
Customer funds on deposit	10.5	(58.4)	54.6
Deferred credits	10.1	(4.1)	18.8
Other	4.9	.9	(1.2)
Cash provided from operating activities	152.6	53.6	52.1
Cash Flows From Investing Activities:			
Utilities capital expenditures	(284.2)	(184.8)	(233.7)
Investments in communication services	-	(8.2)	(11.4)
Cash proceeds received on sale of assets	294.1	1,003.7	36.0
Other	(5.6)	(22.6)	(3.2)
Cash provided from (used for) investing activities	4.3	788.1	(212.3)
Cash Flows From Financing Activities:			
Premium on the retirement of long-term debt	(1.3)	(28.2)	-
Issuance of long-term debt	-	-	2.0

Retirement of long-term debt	(365.1)	(574.7)	(45.9)
Short-term borrowings (repayments), net	25.0	(12.0)	12.0
Cash paid on long-term gas contracts	(15.8)	(15.7)	(15.0)
Other	1.9	2.7	1.0
Cash used for financing activities	(355.3)	(627.9)	(45.9)
Increase (decrease) in cash and cash equivalents	(198.4)	213.8	(206.1)
Cash and cash equivalents at beginning of year (includes $4.8 million and $6.6 million of cash included in current assets of discontinued operations in 2006 and 2005, respectively)	232.8	19.0	225.1
Cash and Cash Equivalents at End of Year (includes $4.8 million of cash included in current assets of discontinued operations in 2005)	$ 34.4	$232.8	$19.0
Supplemental cash flow information:			
Interest paid, net of amount capitalized	$150.2	$209.0	$223.1
Income taxes paid (refunded), net	4.3	(15.9)	28.8

See accompanying notes to consolidated financial statements.

Note 1: Merger and Asset Sale

On February 6, 2007, Aquila, Inc. (Aquila) entered into an agreement and plan of merger with Great Plains Energy, Gregory Acquisition Corp., a wholly-owned subsidiary of Great Plains Energy, and Black Hills, which provided for the merger of Gregory Acquisition Corp. into us, with Aquila continuing as the surviving corporation. As of July 14, 2008, all required approvals had been received. Upon completion of the Merger, we became a wholly-owned subsidiary of Great Plains Energy, and our shareholders received cash and shares of Great Plains Energy common stock in exchange for their shares of Aquila common stock. As of July 14, 2008, each share of Aquila common stock converted into the right to receive 0.0856 of a share of Great Plains Energy common stock and a cash payment of $1.80. The exchange ratio was fixed and was not adjusted to reflect stock price changes prior to the completion of the Merger. Upon consummation of the Merger, our shareholders owned approximately 27% of the outstanding common stock of Great Plains Energy, and the Great Plains Energy shareholders owned approximately 73% of the outstanding common stock of Great Plains Energy.

On July 14, 2008, subsequent to the merger a dividend of approximately $675 million was declared and paid to Great Plains Energy.

In connection with the Merger, we also entered into agreements with Black Hills under which we sold our Colorado electric utility and our Colorado, Iowa, Kansas and Nebraska gas utilities to Black Hills for $940 million in cash, subject to certain working capital and other purchase price adjustments, in a transaction that also closed on July 14, 2008. The agreements contained various provisions customary for transactions of this size and type, including representations, warranties and covenants with respect to the Colorado, Iowa, Kansas and Nebraska utility businesses that are subject to usual limitations. The employees of these utility operations were transferred to Black Hills upon completion of the sale.

The Merger and the asset sales were contingent upon the closing of the other transaction, meaning that one transaction would not close unless the other transaction closes.

We evaluated the accounting classification of the assets to be acquired by Black Hills relative to SFAS 144. Based on our assessment, the criteria for classification of the assets as “held for sale” and discontinued operations was met upon the closing of the transactions. As a result, we have reclassified the assets to be acquired by Black Hills as “held for sale” and reported those results as discontinued operations herein.

We incurred significant costs in connection with the merger and related asset sale, primarily consisting of investment banking, legal, employee retention, and other severance costs which we expensed as they were incurred. We incurred approximately $2.3 million and $16.6 million of costs (primarily investment banking and legal costs) relating to these transactions in 2006 and 2007, respectively. In connection with the closing of the transactions we paid an additional $14.2 million of fees in 2008, including $11.9 million to investment advisors. These costs are included in operation and maintenance expense in Corporate and Other.

Beginning in February 2007, we executed retention agreements totaling $8.8 million with numerous non-executive employees to mitigate employee attrition prior to the closing of the Merger. The retention awards were paid on January 31, 2008. We accrued $7.9 million of expense related to these retention agreements in 2007. These costs are included in operation and maintenance expense in Corporate and Other.

Note 2: Summary of Significant Accounting Policies

Description of Business

Aquila, Inc. (Aquila) is a regulated utility headquartered in Kansas City, Missouri. We operate in three business segments, Electric Utilities, Gas Utilities and Merchant Services.

Electric Utilities operates in the distribution and transmission of electricity to retail and wholesale customers in Colorado and Missouri. Our electric generation facilities and purchase power contracts supply electricity to our own distribution systems in these two states. We also sell a small amount of excess power to wholesale customers outside our service areas. During peak periods, we buy energy in the wholesale market for our utility load. Our former Kansas electric utility was sold on April 1, 2007, and has been reclassified as discontinued operations. In addition, in connection with the closing of the sale of our Colorado electric utility to Black Hills in July 2008, these operations have been reclassified as discontinued operations.

Gas Utilities operates in the distribution of natural gas to retail and wholesale customers in Colorado, Iowa, Kansas and Nebraska. Our former Michigan, Missouri and Minnesota gas operations were sold in 2006 and have been reclassified as discontinued operations. In addition, in connection with the sale of our Colorado, Iowa, Kansas and Nebraska gas utilities to Black Hills in July 2008, these operations have been reclassified as discontinued operations.

Our Merchant Services business includes our contractual interest in the Crossroads Energy Center, a “peaking” power generation facility, and our Aquila Merchant subsidiary, whose assets and liabilities are limited to its energy trading portfolio of natural gas delivery and transportation contracts. Two former merchant peaking plants, which were sold in March 2006, have been reclassified as discontinued operations.

Corporate and Other includes the costs of the Company that are not allocated to our operating businesses. Our former communications business, Everest Connections, was sold on June 30, 2006 and is reported in discontinued operations.

Use of Estimates

The preparation of these financial statements in conformity with accounting principles generally accepted in the United States required that we make certain estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of December 31, 2007 and 2006, and the reported amounts of sales and expenses during the three years ended December 31, 2007. Significant items subject to such estimates and assumptions include the carrying value of property, plant and equipment and goodwill; the valuation of derivative instruments; unbilled utility revenues; valuation allowances for receivables and deferred income taxes; reserves for potential litigation obligations; and assets and liabilities related to employee benefits. Actual results could differ materially from those estimates and assumptions.

Collective Bargaining Agreements

Approximately 43% of our employees are represented by local unions under collective bargaining agreements. The collective bargaining agreements covering approximately 54% of those employees expire and are subject to renegotiation in 2008.

Principles of Consolidation

Our consolidated financial statements include all of our operating divisions and majority-owned subsidiaries for which we maintain controlling interests. We eliminate inter-company accounts and transactions.

Utility and Non-Utility Plant

We initially record utility and non-utility plant at cost. Repairs of property and replacements of items not considered to be units of property are expensed as incurred, except for certain major repairs at our generating facilities that are accrued in advance as allowed by regulatory authorities. Depreciation is provided on a straight-line basis over the estimated lives of the assets. When utility plant is replaced, removed or abandoned, its cost, less salvage, is charged to accumulated depreciation. See Note 9 for further information.

Impairment of Long-Lived Assets

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

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

Goodwill

We have recorded goodwill, representing the excess of the cost of acquisitions over the fair value of the related net assets at the dates of acquisition. Currently the only significant goodwill we have recorded has been allocated to our Electric Utilities segment. We performed our annual assessment of the realizability of this goodwill at the Missouri electric reporting unit level as of November 30, 2007. We concluded that the goodwill was not impaired. At December 31, 2007, we had goodwill in continuing operations of $113.6 million, less accumulated amortization of $2.6 million.

Our goodwill was allocated to each segment as follows:

In millions	Electric Utilities	Discontinued Operations – Corporate and Other
Balance, December 31, 2004	$111.0	$ -
Other	-	.3
Balance, December 31, 2005	111.0	.3
Reserve for minority market-based puts	-	2.7
Sale of Everest Connections	-	(3.0)
Balance, December 31, 2006	111.0	-
None	-	-
Balance, December 31, 2007	$111.0	$ -

Sales Recognition

Utility Activities

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

Franchise fees and other taxes imposed on sales or gross receipts which are collected from customers and remitted to government authorities are presented net in sales.

Trading Activities

Transactions carried out in connection with trading activities that are derivatives under SFAS 133, are accounted for under the mark-to-market method of accounting. Under SFAS 133, our energy commodity trading contracts, including physical transactions (mainly gas) and 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 or other external sources or use comparable transactions to obtain current values of our contracts. When market prices are not readily available or determinable, certain contracts are recorded at fair value using an alternate approach such as model pricing. In addition, the market prices or fair values used in determining the value of our portfolio are our best estimates utilizing information such as historical volatility and the potential impact on market prices of liquidating our positions in an orderly manner over a reasonable period of time under current market conditions. When the market value of the portfolio changes (primarily due to the effect of price changes, newly originated transactions and the settlement of existing transactions), the change is immediately recognized as a gain or loss. We record the resulting unrealized gains or losses as price risk management assets or price risk management liabilities, respectively.

Weather Derivatives

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

Funds on Deposit

Funds on deposit consist primarily of cash we have provided with counterparties in support of margin requirements related to commodity purchases, commodity swaps and futures contracts. Pursuant to individual contract terms with counterparties, deposit amounts required vary with changes in market prices, credit provisions and various other factors. Interest is earned on most funds on deposit. We also hold funds on deposit from counterparties in the same manner. These are included in customer funds on deposit in our Consolidated Balance Sheets.

Inventories

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

Pension and Other Post-retirement Plans

We have a defined benefit pension plan covering substantially all of our employees. We also provide post-retirement health care and life insurance benefits for certain retired employees. See Note 16 for further discussion.

Regulatory Matters

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

Income Taxes

We use the liability method to reflect income taxes on our financial statements. We recognize deferred tax assets and liabilities by applying enacted tax rates and regulations to the differences between the carrying value of existing assets and liabilities and their respective tax basis and net operating and capital loss carryforwards. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that the change is enacted. We amortize deferred investment tax credits over the lives of the related properties. We assess the realizability of deferred tax assets and provide valuation allowances when we determine it is more likely than not that such assets will not be realized. See Note 15 for further discussion.

Environmental Matters

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

Legal Costs

Litigation accruals are recorded when we determine it is probable we will incur costs and the amount can be reasonably estimated. Receivables for insurance recoveries are recorded when probable. Costs of defending against litigation are expensed as incurred.

Cash and Cash Equivalents

Cash and cash equivalents includes cash in banks and temporary investments with an original maturity of three months or less. As of December 31, 2007 and 2006, our cash held in foreign countries was $.1 million and $3.9 million, respectively. In addition, as of December 31, 2007 and 2006, we had restricted cash in foreign countries of $1.2 million and $1.1 million, respectively.

Currency Adjustments

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

Reclassifications

Certain prior year amounts in the consolidated financial statements have been reclassified where necessary to conform to the 2007 presentation, including the reclassification of $13.8 million of Electric Utilities' unbilled fuel adjustment clause balances from accounts receivable to current regulatory assets to be more consistent with industry presentation.

Note 3: New Accounting Standards

Fair Value Measurements

In September 2006, the FASB issued SFAS 157, "Fair Value Measurements", which defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. This statement is effective for our financial statements as of January 1, 2008. We have determined the adoption of SFAS 157 will not have a material impact on our financial condition or results of operations.

Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans

In September 2006, the FASB issued SFAS 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans – an amendment of FASB Statements No. 87, 88, 106, and 132(R)". SFAS 158 requires an employer to recognize the over-funded or under-funded status of a defined benefit postretirement plan (other than a multiemployer plan) as an asset or liability in its balance sheet and to recognize changes in that funded status in the year in which the changes occur through comprehensive income. Under SFAS 158, we were required to recognize the funded status of our defined benefit and other postretirement plans and to provide the required disclosures commencing as of December 31, 2006. SFAS 158 also requires companies to use a measurement date that is the same as its fiscal year-end. For our financial statements as of December 31, 2008, we will have to change our September 30 measurement date for our plans' assets and obligations to comply with this requirement. In addition, we have recorded a deferred tax benefit associated with the temporary differences between liabilities recognized for tax and book purposes under SFAS 158. See Note 16 for discussion of the impact of adopting SFAS 158 as of December 31, 2006.

Accounting for Uncertainty in Income Taxes

We adopted FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes," (FIN 48) effective January 1, 2007. This interpretation sets a "more likely than not" threshold before tax benefits can be recognized in our financial statements. Our practice prior to FIN 48 was to recognize income tax benefits when they were reflected on filed income tax returns and establish a reserve against these tax benefits when their ultimate realization was not deemed to be "probable." See Note 15 for discussion of the impact of the adoption of FIN 48.

Accounting for Planned Major Maintenance

In September 2006, the FASB issued FSP AUG AIR-1, “Accounting for Planned Major Maintenance Activities”. FSP AUG AIR-1 amends the guidance on the accounting for planned major maintenance activities; specifically, it precludes the use of the previously acceptable “accrue in advance” method, which we currently follow as allowed by regulatory authorities. FSP AUG AIR-1 was effective for our financial statements as of January 1, 2007, and was applied retrospectively. Before considering the effect of our regulatory “accrue-in-advance” method, we adopted the direct expense method under FSP AUG AIR-1. We, however, believe that it is probable that the cost of planned major maintenance will be recovered through customer rates charged by our rate-regulated utility operations in advance of such maintenance being performed. Therefore, a regulatory liability was recorded. As of December 31, 2006, our accrued liability for planned major maintenance was $3.4 million for continuing operations and $1.9 million for discontinued operations.

Considering the Effects of Prior Year Misstatements

In September 2006, the SEC issued SAB 108, “Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements”, which addresses how the effects of prior year misstatements should be considered when quantifying misstatements in current year financial statements. SAB 108 was effective as of the end of our 2006 fiscal year, allowing a one-time transitional cumulative effect adjustment to beginning retained earnings as of January 1, 2006 for errors that were not previously deemed material, but would be material under the guidance in SAB 108. The implementation of SAB 108 has not had a material impact on our financial condition and results of operations.

Noncontrolling Interests

In December 2007, the FASB issued SFAS No. 160, “Noncontrolling Interests in Consolidated Financial Statements-an amendment of ARB No. 51” (SFAS 160). SFAS 160 establishes accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. It clarifies that a noncontrolling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. SFAS 160 is effective for fiscal years beginning after December 15, 2008. We do not expect SFAS 160 to have a material impact on our financial position or results of operations.

Business Combinations

In December 2007, the FASB issued SFAS No. 141R “Business Combinations” (SFAS 141R). SFAS 141R establishes principles and requirements for how the acquirer of a business recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree. SFAS 141R also provides guidance for recognizing and measuring the goodwill acquired in the business combination and determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. SFAS 141R is effective for business combinations with acquisition dates in fiscal years beginning after December 15, 2008. As we have no business acquisitions pending, we do not expect that SFAS 141R will have a material impact on our financial position or results of operations.

Note 4: Risk Management

Overview

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

Merchant Trading Activities

Prior to exiting the merchant energy business, Aquila Merchant traded energy commodity contracts daily. The trading activities attempted to match the portfolio of physical and financial contracts to current or anticipated market conditions. Within the trading portfolio, Aquila Merchant took certain positions to hedge physical sale or purchase contracts and to take advantage of market trends and conditions. Aquila Merchant continues to use all forms of financial instruments, including futures, forwards, and swaps, to help hedge its remaining portfolio. Each type of financial instrument involves different risks. We believe financial instruments help Aquila Merchant manage its remaining contractual commitments and reduce its exposure to changes in market prices.

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

Regulated Commodity Management

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

In 2007, our continuing regulated electric business generated approximately 62% of the power that we sold and purchased the remaining 38% through long-term contracts or in the open market. The regulatory provisions for recovering power costs vary by state. In Missouri, we have the ability to pass through 95% of the changes in purchased power and fuel costs outside of a rate case filing through a fuel clause adjustment. To the extent that our fuel and purchased power energy costs are higher or lower than the energy cost built into our tariffs, 95% of the difference is passed through to the customer. In Colorado electric, included in discontinued operations, we have an ECA that serves a purpose similar to that of the PGAs for the gas utilities.

We have also entered into a program for our electric utility customers in Missouri to mitigate price exposure to natural gas price volatility in the market. This program extends multiple years and the mark-to-market value of the portfolio, a loss of $3.9 million, relates to contracts that will settle against actual purchases of natural gas and purchased power in 2008 through 2010. In connection with the 2005 Missouri electric rate case, we agreed that these contracts would be recognized into cost of sales when they settle. The settlement cost is a component of the energy cost included in the Missouri fuel adjustment clause. A regulatory asset has been recorded under SFAS 71 in the amount of $3.9 million to reflect the change in the timing of recognition authorized by the Missouri Commission.

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

Market Risk

Our price risk management activities involve commitments to purchase or sell financial instruments or commodities at fixed prices at future dates. The contractual amounts and terms of these financial instruments at December 31, 2007 are below:

	December 31, 2007		
Dollars in millions	**Fixed Price Payor**	**Fixed Price Receiver**	**Maximum Term in Years**
Energy Commodities:			
Natural gas *(trillion Btu's)*	28	17	3
Financial Products:			
Interest rate instruments	$–	$.1	6

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

Market Valuation

The prices we use to value price risk management activities reflect our best estimate of fair values considering various factors, including closing exchange and over-the-counter quotations, time value of money and price volatility factors underlying the commitments. The prices also reflect the potential impact of liquidating our position in an orderly manner over a reasonable period of time under present market conditions.

We consider a number of risks and costs associated with the future contractual commitments included in our energy portfolio, including credit risks associated with the financial condition of counterparties and the time value of money. The values of all forward and future contracts are discounted to December 31, 2007, using market interest rates for the contract term adjusted for our credit rating for liabilities or the credit rating of the counterparty for assets. We continuously monitor the portfolio and value it daily based on present market conditions. The following table displays the fair values of price risk management assets and liabilities at December 31, 2007, and the average value for the year ended December 31, 2007:

	Price Risk Management Assets		Price Risk Management Liabilities	
In millions	**Average Value**	**December 31, 2007**	**Average Value**	**December 31, 2007**
Natural gas	$88.7	$45.1	$61.5	$28.4
Electricity	.1	-	-	-
Other	.2	-	1.4	.8
Total	$89.0	$45.1	$62.9	$29.2

Our price risk management assets are concentrated with less than 15 counterparties representing the total asset value of the portfolio. This concentration of customers may impact our overall exposure to credit risk, either positively or negatively, as the counterparties may be similarly affected by changes in economic, regulatory or other conditions.

Hedging Activities

We have not designated any derivatives as cash flow or fair value hedges.

Normal Purchases and Sales Exception

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

Note 5: Restructuring Charges

We recorded the following restructuring charges:

	Year Ended December 31,		
	2007	**2006**	**2005**
Merchant Services lease agreements	$ -	-	$6.6
Corporate and Other severance costs	1.5	5.7	-
Total restructuring charges	$1.5	$5.7	$6.6

Lease Agreements

In the first quarter of 2005, we terminated the majority of the remaining leases 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 in the first quarter of 2005.

Severance Costs and Retention Payments

We recorded $1.5 million of one-time termination benefits in 2007 primarily related to the departure of our Chief Operating Officer. These benefits are being paid over a two-year period beginning April 28, 2007.

In connection with the sale of our Kansas electric and Michigan, Minnesota and Missouri gas utility operations, our management adopted and communicated to employees a plan to reduce corporate and central services costs, which included the elimination of approximately 220 positions through attrition and employee terminations. The 83 employees who were involuntarily terminated received severance and other one-time termination benefits. The total cost of one-time termination benefits was approximately $5.7 million, which was recognized in 2006 over the remaining service period of terminated employees and was paid out over time.

In addition, upon closing of the sale of Everest Connections in June 2006, its employees received retention payments of approximately $2.0 million, which were recognized over the period through the closing of the sale. These charges were included in discontinued operations.

Restructuring Reserve Activity

The following table summarizes activity in accrued restructuring charges for our continuing and discontinued operations:

	Year Ended December 31,		
In millions	**2007**	**2006**	**2005**
Severance and Retention Costs:			
Accrued severance and retention costs at beginning of period	$2.3	$ .1	$ .8
Additional expense during the period	1.5	7.7	-
Cash payments during the period	(2.7)	(5.5)	(.7)
Accrued severance and retention costs at end of period	$1.1	$2.3	$ .1
Other Restructuring Costs:			
Accrued other restructuring costs at beginning of period	$-	$-	$ 7.0
Additional expense during the period	-	-	6.6
Cash payments during the period	-	-	(13.6)
Accrued other restructuring costs at end of period	$-	$-	$ -

Note 6: Net (Gain) Loss on Sale of Assets and Other Charges

Pretax net (gains) losses on sale of assets and other charges we recorded for the years ended December 31, 2007, 2006 and 2005 are shown below:

	Year Ended December 31,		
In millions	**2007**	**2006**	**2005**
Merchant Services:			
Elwood tolling contract	$-	$218.0	$ -
Batesville tolling agreement	-	-	(16.3)
ICE sale	-	-	(9.3)
Red Lake gas storage development project	-	-	(6.2)
Other	-	.7	.5
Total Merchant Services	-	218.7	(31.3)
Corporate and Other:			
Early retirement of debt	1.3	28.2	-
Early conversion of the PIES	-	-	82.3
Turbines impairment	-	-	4.4
Total Corporate and Other	1.3	28.2	86.7
Total net loss on sale of assets and other charges	$1.3	$246.9	$ 55.4

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

During 2007, 2006 and 2005, we also incurred net loss (gain) on sale of assets and other charges of $(3.6) million, $(267.9) million and $159.5 million, respectively, relating to our discontinued operations. These charges are reflected in discontinued operations and are not included in the table above. See Note 7 for further discussion.

Elwood Tolling Contract

In 2006, we paid $218 million to a third party to assume our rights and obligations under the Elwood tolling contract. This transaction resulted in a pretax and after-tax loss of $218 million, and terminated approximately $405 million of our fixed capacity payments through August 2017. For income tax purposes, we treated the $218 million payment as an ordinary loss on our 2006 income tax return. However, because we did not conclude that it was probable that the IRS would agree with this treatment, we increased our reserve for uncertain tax positions by $84.6 million, thereby fully offsetting the tax benefit of the loss. When we implemented FIN 48 on January 1, 2007 we recognized this tax benefit through a reduction of our reserve for uncertain tax positions because we concluded that the benefit satisfied the FIN 48 “more likely than not” threshold.

Batesville Tolling Contract

In 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. 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.

Red Lake Storage Development Project

In 2002, we acquired land in Arizona to develop natural gas storage facilities. In 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. In 2005, we sold the land for $21.2 million. We recorded a pretax gain of $6.2 million, or $3.9 million after tax, in the fourth quarter of 2005.

Early Retirement of Debt

As discussed in more detail in Note 12, we completed a cash tender offer that resulted in the early retirement of approximately $350 million of outstanding senior notes in June 2006. We recorded a pretax early retirement loss of $22.7 million, or $14.0 million after tax, in connection with this transaction. We also incurred fees of $5.5 million, or $3.4 million after tax, primarily on the prepayment of the $220 million outstanding on our five-year term loan.

As discussed in more detail in Note 12, we retired $344 million of callable debt in June 2007. We recorded a pretax early retirement loss of $1.3 million, or $.8 million after tax, in connection with this transaction.

Early Conversion of the Premium Income Equity Securities (PIES)

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

Turbines Impairment

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

Note 7: Discontinued Operations

We have sold or wound-down a number of operations since 2002 to generate cash to be used to reduce debt and eliminate other long-term obligations. We have sold the assets discussed below, which are considered discontinued operations in accordance with SFAS 144.

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

Electric and Gas Utilities

In September 2005, we entered into agreements to sell our Kansas electric distribution business and our Michigan, Minnesota and Missouri natural gas distribution businesses. We completed these asset sales in 2006, except for the Kansas electric sale, which was completed on April 1, 2007. These sales resulted in pretax and after tax gains. In February 2007, we entered into agreements to sell our Colorado electric distribution business and our Colorado, Iowa, Kansas and Nebraska gas distribution businesses to Black Hills. The classification of the tax gains between ordinary income and capital gain depends upon the final allocation of the purchase price based upon the terms of the respective asset purchase agreements. Ordinary income has been offset by current year net operating losses and/or net operating loss carryforwards. Capital gains have been offset by capital loss carryforwards. To the extent capital loss carryforwards were utilized, the valuation allowance against the tax benefit of the capital loss carryforwards has been reversed for 2006 sales. The tax gains have been adjusted for the 2006 sales based upon the final allocations included in our 2006 income tax return. The tax gain on the sale of the Kansas electric properties will be adjusted when the final determination is made and as the 2007 income tax return is filed in 2008.

On April 1, 2006, we closed the sale of our Michigan gas operations and received gross cash proceeds of $338.1 million, including the base purchase price of $269.5 million plus preliminary working capital and other adjustments of $68.6 million. In connection with this sale we recorded a pretax gain of approximately $92.2 million after transaction fees and expenses in 2006. The estimated after-tax gain in 2006 was approximately $99.5 million, including an estimate of $44.0 million for the valuation allowance reversal related to the estimated capital gain amount discussed above. The final after-tax gain is $103.7 million, including the final valuation allowance reversal related to capital gains realized on our 2006 income tax return.

On June 1, 2006, we closed the sale of our Missouri gas operations and received gross cash proceeds of $101.3 million, including the base purchase price of $85.0 million plus preliminary working capital and other adjustments of $16.3 million. In connection with this sale we recorded a pretax gain of approximately $30.7 million after transaction fees and expenses in 2006. The estimated after-tax gain in 2006 was approximately $31.1 million, including an estimate of $11.7 million for the valuation allowance reversal related to the estimated capital gain amount discussed above. In 2007, final adjustments related to pensions and other items reduced the pretax gain by $.6 million, or $.4 million after tax. The final after-tax gain is $34.1 million, including the final valuation reversal related to capital gains realized in our 2006 income tax return.

On July 1, 2006, we closed the sale of our Minnesota gas operations and received gross cash proceeds of $317.1 million, including the base purchase price of $288.0 million plus preliminary working capital and other adjustments of $29.1 million. In connection with this sale we recorded a pretax gain of approximately $120.5 million after transaction fees and expenses in 2006. The estimated after-tax gain in 2006 was approximately $127.5 million, including an estimate of $56.9 million for the valuation allowance reversal related to the estimated capital gain amount discussed above. In 2007, final adjustments primarily related to pensions increased the pretax gain $.7 million, or $.4 million after tax. The final after-tax gain is $126.3 million, including the final valuation allowance reversal related to capital gains realized in our 2006 income tax return.

On April 1, 2007, we closed the sale of our Kansas electric operations and received gross cash proceeds of $292.2 million, including the base purchase price of $249.7 million plus preliminary working capital and other adjustments of $42.5 million. In connection with this sale we recorded a pretax gain of approximately $1.8 million in 2007 after transaction fees and expenses, including an adjustment for the final determination of pension assets transferred to the buyer as discussed below. The estimated after-tax gain was approximately $1.1 million, subject to the determination of the capital gain amount discussed above.

On July 14, 2008, we closed the sale of our Colorado electric operations and Colorado, Iowa, Kansas and Nebraska gas operations to Black Hills and received gross cash proceeds of $908.8 million, subject to true-up within 120 days after close. We expect the sale to result in a pretax and after-tax gain of approximately $315.0 million. This amount will be adjusted for final working capital and capital expenditure adjustments determined through July 14, 2008.

The operating results of the utility divisions sold or held for sale 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 EITF Consensus 87-24, “Allocation of Interest to Discontinued Operations” (EITF 87-24). We provide corporate 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 based on various cost drivers. Effective January 1, 2006, we ceased allocating costs to our Kansas electric and Michigan, Minnesota and Missouri gas utilities. With the exception of certain central services operations acquired by Black Hills, these allocated costs were not included in the reclassification to earnings from discontinued operations because these support services were necessary to maintain ongoing operations until the sales were completed. The allocated operating expenses related to the utility divisions held for sale that were not assumed by Black Hills were as follows:

	Year Ended December 31,		
In millions	**2007**	**2006**	**2005**
Allocated expenses retained in continuing operations	$38.2	$48.3	$83.5

The discontinued utility operations participate in our qualified pension plan, non-qualified Supplemental Executive Retirement Plan (SERP) and other post-retirement benefit plan. Under the asset purchase agreements, the buyers assumed the accrued pension obligations owed to the current and former employees of the operations they acquired. After determination of final individual account balances as of the closing date, benefit plan assets were or will be transferred to comparable plans established by the buyers in accordance with the terms of the asset purchase agreements and the applicable ERISA requirements. These benefit plan asset transfers result in plan curtailments. In connection with the sale of our Michigan, Minnesota and Missouri gas operations we included $13.0 million of net prepaid pension assets and pension and post-retirement benefit obligations, including the effect of plan curtailment and settlement losses, in the determination of the pretax gains on these sales. The plan curtailment and settlement losses related to the sale of our Kansas electric operations was $5.3 million. We expect to recognize plan curtailment and settlement gains related to our sale of electric and gas utility operations to Black Hills of approximately $12.6 million. The effect of the plan curtailments will depend on the final determination of the asset transfers, which will not be completed until late 2008 or early 2009.

Other Asset Sales

In March 2006, we sold two merchant “peaking” power plants located in Illinois for gross proceeds of $175 million. We recorded a pretax, non-cash impairment charge of $159.5 million, or $99.7 after tax relating to these plants in 2005. Final adjustments to contingent liabilities decreased the pretax loss by $1.7 million, or $1.0 million after tax in 2007. In June 2006, we sold our telecommunication business (Everest Connections) for net proceeds of approximately $78 million. We recorded a pretax gain of $25.5 million, or $15.7 million after tax in 2006.

Interest Allocation to Discontinued Operations

The buyers of the assets in discontinued operations did not assume any of our long-term debt. The direct debt and related interest of Everest Connections was included in discontinued operations as this debt was required to be repaid from the proceeds from the sale. 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. As we completed each asset sale the allocation of interest to discontinued operations ceased, thereby increasing interest expense in continuing operations, without impacting total interest expense, until the sales proceeds were used to reduce debt.

Summary

We have reported the results of operations from these assets in discontinued operations for the three years ended December 31, 2007 in the Consolidated Statements of Income.

Operating results of discontinued operations are as follows:

	Year Ended December 31,		
In millions	**2007**	**2006**	**2005**
Sales	$860.7	$1,297.6	$1,684.8
Cost of sales	586.7	896.0	1,187.0
Gross profit	274.0	401.6	497.8
Operating expenses:			
Operation and maintenance expense	116.3	174.1	193.2
Taxes other than income taxes	14.8	22.0	17.5
Restructuring charges	-	2.0	-
Net loss (gain) on sale of assets and other charges	(3.6)	(268.0)	159.5
Depreciation and amortization expense	42.1	39.7	84.1
Total operating expenses (income)	169.6	(30.2)	454.3
Other income	(1.7)	(.9)	2.2
Interest expense	36.9	72.4	118.2
Earnings (loss) before income taxes	65.8	358.5	(72.5)
Income tax expense (benefit)	18.6	30.0	(25.1)
Earnings (loss) from discontinued operations	$ 47.2	$ 328.5	$ (47.4)

The related assets and liabilities included in the sale of these businesses, as detailed below, have been reclassified as current and non-current assets and liabilities of discontinued operations on the December 31, 2007 and 2006 Consolidated Balance Sheets as follows:

	December 31,	
In millions	**2007**	**2006**
Current assets of discontinued operations:		
Accounts receivable, net	$119.3	$113.8
Inventories and supplies	40.3	53.4
Regulatory assets, current	33.0	38.8
Other current assets	21.0	24.9
Total current assets of discontinued operations	$213.6	$230.9
Non-current assets of discontinued operations:		
Utility plant, net	$537.6	$751.8
Regulatory assets	40.5	85.6
Other non-current assets	5.0	25.4
Total non-current assets of discontinued operations	$583.1	$862.8
Current liabilities of discontinued operations:		
Accounts payable	$105.2	$ 98.6
Regulatory liabilities, current	19.4	10.8
Other current liabilities	25.4	28.9
Total current liabilities of discontinued operations	$150.0	$138.3
Non-current liabilities of discontinued operations:		
Pension and post-retirement benefits	$ 43.9	$ 68.2
Regulatory liabilities	5.0	5.8
Deferred credits	12.0	28.2
Total non-current liabilities of discontinued operations	$ 60.9	$102.2

Note 8: Accounts Receivable

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

	December 31,	
In millions	**2007**	**2006**
Merchant Services accounts receivable	$ 42.3	$ 40.8
Utilities billed accounts receivable	55.7	77.3
Utilities unbilled revenue	26.0	20.4

Other accounts receivable	15.2	6.3
Allowance for doubtful accounts	(2.4)	(2.4)
Total	$136.8	$142.4

In 2005, we entered into a $150 million four-year secured revolving credit facility. Borrowings under this facility are secured by the accounts receivable generated by our regulated utility operations in Colorado, Iowa, Kansas, Missouri and Nebraska. We had $25.0 million of borrowings outstanding under this facility as of December 31, 2007. See Note 11 for further discussion.

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

Note 9: Utility and Non-Utility Plant

The components of utility and non-utility plant from continuing operations are listed below:

Utility Plant	**December 31,**	
In millions	**2007**	**2006**
Electric utility	$1,948.9	$1,900.3
Gas utility	–	–
Corporate and other	153.9	166.4
Electric and gas utility plant—construction in process	208.5	51.5
	2,311.3	2,118.2
Less—accumulated depreciation and amortization	(827.0)	(808.4)
Total utility plant, net	$1,484.3	$1,309.8

Non-Utility Plant	**December 31,**	
In millions	**2007**	**2006**
Non-regulated electric and gas plant	$ .4	$ .4
Non-regulated electric power generation	132.3	135.2
Corporate and other	23.9	24.3
	156.6	159.9
Less—accumulated depreciation and amortization	(37.1)	(33.2)
Total non-utility plant, net	$119.5	$126.7

Our utility plant from continuing operations includes acquisition-related adjustments that are being amortized over useful lives not exceeding 40 years. Net utility plant assets from continuing operations not included in our rate base were $2.8 million and $2.9 million at December 31, 2007 and 2006, respectively.

	Composite Depreciation Rates		
	2007	**2006**	**2005**
Continuing Operations –			
Electric utility	2.8%	2.7%	2.5%
Corporate and other	9.5%	10.9%	10.6%
Non-regulated electric power generation	2.8%	2.8%	2.8%
Discontinued Operations –			
Electric utility	3.7%	3.7%	3.6%
Gas utility	2.7%	2.7%	2.9%
Corporate and other	12.9%	12.1%	12.5%
Non-regulated electric power generation	n/a	n/a	2.8%
Communications	n/a	n/a	9.2%

Depreciation and amortization of our Kansas electric and Michigan, Minnesota and Missouri gas discontinued operations ceased in accordance with SFAS 144 upon the classification of these assets as held-for-sale in September 2005.

Jointly Owned Electric Utility Plant

We own an 8% interest in a coal-fired plant (Jeffrey Energy Center) with generating capacity of approximately 2,190 MWs, operated by Westar. We also own an 18% interest in a 654-megawatt coal-fired plant (Iatan 1) operated by KCPL and an 18% interest in an 850-megawatt coal-fired plant (Iatan 2) being constructed by KCPL. Our pro rata share of Jeffrey Energy Center's and Iatan 1's operating costs are included in our Consolidated Statements of Income.

Our investment in jointly-owned plant at December 31, 2007 was as follows:

In millions	Jeffrey Energy Center	Iatan 1	Iatan 2
Utility plant	$110.8	$ 68.1	$ –
Construction in progress	16.5	27.0	85.7
	127.3	95.1	85.7
Less: Accumulated depreciation and amortization	(72.4)	(49.4)	–
Jointly-owned utility plant, net	$ 54.9	$ 45.7	$85.7

AFUDC

AFUDC represents the capitalized cost of debt and equity funds used to finance construction projects for our regulated utilities. For the years ended December 31, 2007, 2006 and 2005, our continuing Electric and Gas Utilities recorded approximately $6.7 million, $1.5 million and $5.0 million, respectively, of additional income and construction work in progress related to AFUDC. The non-cash earnings are classified as other income (expense) in our Consolidated Statements of Income. The increase in AFUDC in 2007 primarily related to the construction of Iatan 2.

Under accepted rate making practices, we are allowed cash recovery of AFUDC, as well as other capitalized construction costs, once completed construction projects are placed into service and reflected in customer rates. The rates used for capitalizing AFUDC are generally computed using agreed upon methods prescribed by the FERC. The rate used for capitalizing AFUDC on Iatan 2 construction is computed based on the financing cost of our Iatan Facility (see further discussion in Note 12) per the stipulation agreement settling our 2005 Missouri rate case.

Asset Retirement Obligations

In August 2001, the FASB issued SFAS 143. SFAS 143 requires us to record the fair value of an asset retirement obligation as a liability in the period in which a legal obligation associated with the retirement of tangible long-lived assets is incurred. When the liability is initially recorded, we capitalize the estimated cost by increasing the carrying amount of the related long-lived asset. The liability will be accreted to its present value each subsequent period. The capitalized cost will be depreciated over the life of the related asset. Upon satisfaction of the liability, we will record a gain or loss for the difference between the actual cost incurred and the recorded liability.

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

In March 2005, the FASB issued FIN 47, which clarifies the term “conditional asset retirement obligation” used in SFAS 143, and specified when an entity has sufficient information to reasonably estimate the fair value of an asset retirement obligation. The adoption of FIN 47 on December 31, 2005, required us to update an existing inventory of identified legal obligations, originally created under SFAS 143, for conditional asset retirement obligations.

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

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

Our continuing Electric and Gas Utilities recorded an asset retirement obligation of $7.0 million and increased property, plant and equipment, net of accumulated depreciation, by $.2 million in 2005. Because this business is a regulated utility subject to the provisions of SFAS 71, the $6.8 million cumulative effect of adoption of FIN 47 was recorded as a regulatory asset and therefore had no impact on net income. In addition, our discontinued utility operations recognized an asset retirement obligation of $5.9 million, increased net property, plant and equipment by $.1 million, and recorded an offsetting regulatory asset of $5.8 million in 2005. These liabilities will be adjusted on an ongoing basis due to the passage of time, new laws and regulations and revisions to either the timing or amount of our original cost estimates.

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

Our liability for asset retirement obligations was approximately $9.1 million and $8.2 million as of December 31, 2007 and 2006, respectively for continuing operations. For discontinued operations, our liability for asset retirement obligations was approximately $2.3 million and $7.0 million as of December 31, 2007 and 2006, respectively.

Depreciation rates approved by regulatory commissions in certain states include a provision for the cost of future removal of assets for which there is no legal removal obligation. Under SFAS 143, the net provision for these "non-legal" removal costs has been classified as a regulatory liability. See Note 10 for further discussion.

Note 10: Regulatory Assets and Liabilities

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

The following table details our regulatory assets and liabilities.

In millions	December 31, 2007	2006
Regulatory Assets:		
Energy clause adjustment	$ 20.1	$ .4
Income taxes	52.9	55.8
Environmental	1.9	1.9
Regulatory accounting orders	11.8	2.0
Gas price derivatives	5.4	17.9
Asset retirement obligations	9.0	8.1
Pensions and post-retirement benefits	4.0	5.0
Other	5.0	5.3
Total regulatory assets	$110.1	$ 96.4
Regulatory Liabilities:		
Cost of removal	$ 53.5	$ 50.2
Income taxes	3.5	4.0
Pensions	9.7	10.1
Other	8.7	4.6
Total regulatory liabilities	$ 75.4	$ 68.9

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

- Energy clause adjustment represents the cost of electricity delivered to our electric utility customers in excess of that allowed in current rates. We do not earn a return on these costs which are collected from customers in future periods of less than one year as rates are periodically adjusted.

- Income taxes represent amounts of accelerated tax benefits previously flowed through to customers and expected to be collected from customers over the remaining life of the utility plant as accelerated tax benefits reverse. We do not earn a return on these items.

- Environmental costs include certain site clean-up costs that are deferred and expected to be collected from customers in future periods when authorized by regulatory authorities. Prudently incurred environmental remediation costs have traditionally been allowed for recovery by our regulatory jurisdictions over periods of five to 10 years. We do not earn a return on these items.

- Regulatory accounting orders include costs such as ice storm recovery and others that have been specifically approved for recovery over future periods, generally five years or less. We do not earn a return on these items.

- In connection with adoption of SFAS 158 we reflected the unrecognized prior service cost and net actuarial loss associated with our defined benefit pension plan and post-retirement benefit plans as regulatory assets rather than accumulated other comprehensive income in jurisdictions where we believe it is probable we will recover these costs in future rates. Whether we earn a return on these costs, in addition to the return of their costs, varies by regulatory jurisdiction.

- Asset retirement obligations represent the estimated recoverable costs for legally required removal obligations. See Note 9 for further discussion. We do not earn a return on these items.

- Gas price derivatives represents the mark-to-market value of the portfolio of natural gas financial contracts that will settle against actual purchases of natural gas and purchased power in future periods. In connection with the recently settled Missouri electric rate case, we agreed that these contracts would be recognized into cost of sales

when they settle. A regulatory asset has been recorded under SFAS 71 to reflect the change in the timing of recognition authorized by the Missouri Commission.

- Other primarily includes costs related to energy efficiency, demand side management and regulatory proceedings that are deferred and expected to be recovered from customers in future periods. Prudent costs such as these have traditionally been allowed for recovery by our regulatory jurisdictions over various periods. We do not earn a return on these items.

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

- Cost of removal represents the estimated cumulative net provision for future removal costs included in depreciation expense for which there is no legal removal obligation. See Note 9 for further discussion.

- Income taxes generally represent taxes previously collected at tax rates that were greater than the rates we expect to pay. We expect to refund this amount to customers in future periods.

- Pensions represent the cumulative excess of pension costs recovered in rates over pension expense recorded under SFAS No. 87, "Employers' Accounting for Pensions" (SFAS 87). We expect to return this amount to customers in future periods through reduced cost of service in rates.

In addition, our discontinued Electric and Gas Utilities had recognized $73.7 million and $124.4 million of regulatory assets and $24.4 million and $16.8 million of regulatory liabilities as of December 31, 2007 and 2006, respectively.

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

Note 11: Short-Term Debt

We had $25.0 million in short-term borrowings outstanding under our four-year secured revolving credit facility on December 31, 2007. No short-term borrowings were outstanding on December 31, 2006.

Five-Year Unsecured Revolving Credit Facility

In September 2004, we completed a $110 million unsecured revolving credit facility that matures in September 2009 (the Five-Year Unsecured Revolving Credit Facility). There were no borrowings outstanding on this facility as of December 31, 2007. The Five-Year Unsecured Revolving Credit Facility bears interest at the Eurodollar Rate plus 5.50%, subject to reduction if our credit rating improves. Among other restrictions, the Five-Year Unsecured Revolving Credit Facility contains financial covenants similar to, but less restrictive than, those contained in the Iatan Facility described in Note 12. We were in compliance with these covenants as of December 31, 2007.

The Five-Year Unsecured Revolving Credit Facility contains a $40 million "cross default" provision, as well as covenants that restrict certain activities including, among others, limitations on additional indebtedness, restrictions on acquisitions, sale transactions and investments. In addition, we are prohibited from paying dividends and from making certain other payments if our senior unsecured debt is not rated at least Ba2 by Moody's and BB by S&P, or if such a payment would cause a default under the facility.

Effective July 14, 2008, this facility was terminated.

$180 Million Unsecured Revolving Credit and Letter of Credit Facility

In April 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. Cash advances must be repaid within 364 days unless we obtain the necessary regulatory approvals to incur long-term indebtedness under the facility. As of December 31, 2007, we had $150.0 million of uncollateralized capacity at an average cost of 3.65% under this agreement, which contains a $40 million "cross default" provision. As of December 31, 2007, $146.4 million of the available capacity had been utilized for letters of credit under this facility.

Four-Year Secured Revolving Credit Facility

In April 2005, we executed a 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, Iowa, Kansas, 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 Unsecured Revolving Credit Facility discussed above. The credit agreement also contains a $40 million "cross default" provision. We had borrowed $25.0 million under this facility as of December 31, 2007 at a rate of 7.75%.

We have entered into an amendment of the facility to permit the obligation to be transferred to Great Plains Energy upon the closing of the merger and to release the accounts receivable generated by our Colorado electric and Colorado, Iowa, Kansas and Nebraska gas operations. In addition, the maximum borrowing limit will be reduced from $150 million to $65 million.

$50 Million Revolving Credit and Letter of Credit Facility

In January 2006, we closed on a $50 million short-term letter of credit facility with a commercial lender that allows us to issue letters of credit under the facility. The credit agreement contains a $40 million "cross default" provision. On December 19, 2007, we extended the maturity date to December 17, 2008, and increased the advance rate to 1.10%. There were $41.1 million of letters of credit outstanding under this facility as of December 31, 2007.

Other

We had an additional $.8 million of letters of credit outstanding as of December 31, 2007.

Note 12: Long-Term Debt

This table summarizes our long-term debt:

	December 31,	
In millions	**2007**	**2006**
First Mortgage Bonds:		
9.44% Series, due annually through 2021 *(a)*	$15.7	$16.9
Senior Notes:		
8.2% Series, due January 15, 2007	-	14.6
7.625% Series, due November 15, 2009	68.5	68.5
9.95% Series, due February 1, 2011	137.3	137.3
7.75% Series, due June 15, 2011	197.0	197.0
14.875% Series, due July 1, 2012	500.0	500.0
8.27% Series, due November 15, 2021	80.9	80.9
9.0% Series, due November 15, 2021	-	5.0
8.0% Series, due March 1, 2023	-	51.5
7.875% Series, due March 1, 2032	-	287.5
Medium Term Notes:		
Various, 7.2%*, due 2013-2023	16.0	17.0
Mandatorily Convertible Notes:		
6.75% Series, converted on September 15, 2007 into common shares at a conversion rate of 8.0386 shares per $25 par value convertible note	-	2.6
Convertible Subordinated Debentures:		
6.625%, due July 1, 2011	-	2.0
Other:		
Other notes and obligations 4.88%*, due 2008-2028 *(a)*	22.4	24.8
Total long-term debt	1,037.8	1,405.6
Less current maturities	2.4	19.7
Long-term debt, net	$1,035.4	$1,385.9
Fair value of long-term debt, including current maturities *(b)*	$1,187.4	$1,600.5

* *Weighted average interest rate.*

(a) *Approximately $32.6 million of our long-term debt, including $16.8 million of other notes, is secured by certain assets of the Company as specified in various mortgages, indentures and security agreements.*

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

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

In millions	**Maturing Amounts**
2008	$ 2.4
2009	70.8
2010	1.1
2011	335.5
2012	501.2
Thereafter	126.8
Total	$1,037.8

Each series of our unsecured senior notes is subject to a "cross default" provision ranging from $5 million to $40 million, as applicable.

Early Retirement of Senior Notes

In May 2006, we announced a cash tender offer for the early retirement of certain of our outstanding senior notes. Noteholders that accepted the tender received the accrued interest from the last interest payment date, and those that properly tendered their notes before the early tender time date were also entitled to receive an additional early tender premium of 2% of the debt tendered. We completed the cash tender offer in June 2006, which resulted in the early retirement of $350 million of aggregate debt principal. We recorded a pretax early retirement loss of $22.7 million, or $14.0 million after tax, in connection with the transaction. The table below provides the detail on the notes retired:

Title of Security	Principal Amount Retired (in millions)
6.7% Notes due 10/15/2006	$ 84.5
8.2% Notes due 1/15/2007	22.3
7.625% Notes due 11/15/2009	130.5
9.95% Notes due 2/01/2011	112.7
Total	$350.0

In May 2007, we announced that call notices had been issued for the redemption of certain of our senior notes. In June 2007, we completed the redemption, which resulted in the early retirement of $344 million of aggregate debt principal. We recorded a pretax early retirement loss of $1.3 million, or $.8 million after tax, in connection with the transaction in the second quarter of 2007. The table below provides the detail on the notes retired:

Title of Security	Principal Amount Retired (in millions)
7.875% Notes due 3/1/2032	$287.5
8.0% Notes due 3/1/2023	51.5
9.0% Notes due 11/15/2021	5.0
Total	$344.0

Mandatorily Convertible Senior Notes

In 2004, we issued 13.8 million PIES units at $25 per PIES unit, including an over-allotment of 1.8 million PIES, representing $345.0 million of mandatorily convertible senior notes. These unsecured notes paid interest at 6.75% and converted automatically into shares of our common stock on September 15, 2007, at a conversion rate ranging from 8.0386 to 9.8039 shares of common stock per PIES unit. Our net proceeds on the issuance of the PIES were $334.3 million.

In 2005, we announced an exchange offer related to the optional conversion of our PIES into shares of our common stock. Holders who tendered their securities received 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. 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.

On September 15, 2007, the remaining $2.6 million of PIES units automatically converted into 835,640 shares of our common stock.

Five-Year Unsecured Term Loan

In September 2004, we completed a $220 million unsecured term loan. We borrowed the full amount of the term loan and received $211.3 million of net proceeds after upfront fees and expenses. In June 2006, the holder of $10 million of term loan notes elected to receive an optional prepayment from the proceeds of the sale of our Missouri gas operations. In September 2006, we prepaid the remaining $210 million outstanding and paid a 2.5% prepayment fee of approximately $5.5 million.

Iatan Construction Financing

In August 2005, we entered into a $300 million credit agreement that 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 Iatan 2 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 the Eurodollar Rate plus 1.375%, subject to reduction if our credit rating improves. A fee based on our credit ratings will be paid on the amount of letters of credit outstanding. Obligations under the credit agreement are secured by the assets of our Missouri Public Service electric operations. There were no borrowings or letters of credit outstanding under this facility at December 31, 2007. Among other restrictions, the Iatan Facility contains the following financial covenants with which we were in compliance as of December 31, 2007:

(1) We are required to maintain a ratio of total debt to total capital (expressed as a percentage) of not more than 75% from October 1, 2007 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 1.4 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 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 contains a $40 million “cross default” provision, as well as covenants that restrict certain activities including, among others, limitations on additional indebtedness, restrictions on acquisitions, sale transactions and investments. In addition, we are prohibited from paying dividends and from making certain other payments if our senior unsecured debt is not rated at least Ba2 by Moody's and BB by S&P, or if such a payment would cause a default under the facility.

Senior Notes Rating Triggers

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

In February 2001, we issued $250.0 million of 7.95% senior notes due in February 2011. Because Moody’s and S&P downgraded our credit ratings after the issuance of these notes, the interest rate on these notes has been adjusted to a maximum rate of 9.95%. The current balance outstanding on these notes after our tender offer in June 2006 is $137.3 million.

If our credit ratings improve to certain levels, the interest rates on these notes will be lowered.

Note 13: Capital Stock and Stock Compensation

Capital Stock

We have two types of authorized common stock—unclassified common stock and Class A common stock. No Class A common stock is issued or outstanding. We also have authorized 10,000,000 shares of preference stock, with no par value, none of which is issued or outstanding.

Suspension of Dividend

In November 2002, the Board of Directors suspended the annual dividend on common stock for an indefinite period. Currently three of our loan agreements and a regulatory order prohibit us from paying any dividends. We can make no determination as to whether or when we will pay dividends in the future.

Retirement Investment Plan

A defined contribution plan, the Retirement Investment Plan (Savings Plan), covers all of our full-time and eligible part-time employees. Participants may generally elect to contribute up to 50% of their annual pay on a before- or after-tax basis subject to certain limitations. The Company generally matches contributions up to 6% of pay. Participants may direct their contributions into various investment options. Matching contributions are made in cash and invested as directed by the employee. Company contributions for continuing operations were $4.0 million, $4.1 million and $3.3 million and for discontinued operations were $2.6 million, $3.4 million and $4.5 million during the years ended December 31, 2007, 2006, and 2005, respectively. The Savings Plan also includes a discretionary contribution fund to which the Company historically contributed an additional 3% of base wages for eligible full-time employees. These contributions are made in cash and invested as directed by the employee. For 2007, 2006 and 2005, compensation expense discretionary contributions for continuing operations of $2.3 million, $2.5 million and $1.9 million, respectively, and for discontinued operations of $1.4 million, $1.9 million and $2.9 million, respectively, was recognized. Any Aquila common shares that have been elected by the employee related to this program are classified as outstanding when calculating earnings per share. Under the terms of the ERISA class action lawsuit settlement, all existing and future matching and discretionary contributions will become immediately 100% vested.

Omnibus Incentive Compensation Plan

In 2002, the Board and our shareholders approved the Omnibus Incentive Compensation Plan. This plan authorizes the issuance of 9,000,000 shares of Aquila common stock as stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance units, stock awards, cash-based awards and annual incentive awards to all eligible employees and directors of the Company. All equity-based awards are issued under this plan. Stock options under this plan and preceding plans have generally been granted at fair market value with one to three year vesting terms and have been exercisable for seven to 10 years from the date of grant. Fair market value is defined as the average of the high and low prices for the day the grant was awarded. Cash received on stock options exercised was $1.0 million, the intrinsic value of options exercised was $.5 million and the tax benefit realized was $.2 million for the year ended December 31, 2007. As of December 31, 2007, we have approximately 4.4 million shares of common stock available for grant under this plan. Shares awarded are generally issued first from treasury shares then from newly issued shares.

The terms of all grants outstanding under our Omnibus Incentive Compensation Plan provide for accelerated vesting of restricted stock awards and for accelerated vesting at target levels for performance-based restricted stock awards in the event of a change in control. A change in control also causes the time restrictions in our restricted stock awards to lapse.

Effective on July 14, 2008, the Omnibus Incentive Compensation Plan was terminated and all outstanding, vested awards were converted to Great Plains Energy awards.

Share-Based Payments

In December 2004, the FASB issued SFAS No. 123R, “Share-Based Payments” (SFAS 123R), that requires all companies to expense the value of employee stock options. SFAS 123R became effective for us as of January 1, 2006, and was applied to all outstanding unvested share-based awards on that date, consisting of 74,700 unvested stock options. We elected to use the modified prospective method to adopt SFAS 123R. The 2006 impact of the adoption of SFAS 123R was immaterial.

We issued stock options to employees from time to time and had accounted for these options under APB Opinion No. 25, “Accounting for Stock Issued to Employees” (APB 25), through December 31, 2005. All stock options issued are granted at the common stock's market price on the date of grant. Therefore, prior to 2006 we recorded no compensation expense related to stock options in continuing or discontinued operations.

Because we accounted for options under APB 25 in 2005, we disclosed a pro forma net loss as if we reflected the estimated fair value of options as compensation expense in accordance with SFAS 123R. Our pro forma net loss was as follows:

In millions	**Year Ended December 31, 2005**
Net loss:	
As reported	$(230.0)
Total stock-based employee compensation expense determined under fair value method, net of related tax benefits	(1.9)
Pro forma net loss	$(231.9)

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

	Year Ended December 31, 2005
Weighted average fair value per share	$2.08
Expected volatility	83%
Risk-free interest rate	3.82%
Expected lives	3.7 years
Dividend yield	-

Summary of Stock Options

This table summarizes all stock option activity:

	Year Ended December 31,		
	2007	2006	2005
Shares:			
Beginning balance	4,865,866	6,545,607	9,638,099
Granted	-	-	30,000
Exercised	(362,115)	(779,852)	(308,763)
Forfeited	(763,031)	(899,889)	(2,813,729)
Ending balance	3,740,720	4,865,866	6,545,607
Weighted average prices:			
Beginning balance	$15.57	$14.92	$17.73
Granted price	-	-	3.44
Exercised price	2.83	2.61	2.28
Forfeited price	19.55	21.95	25.76
Ending balance	$16.00	$15.57	$14.92

This table summarizes all outstanding and exercisable stock options as of December 31, 2007:

	Outstanding Options			Exercisable Options	
Exercise Price Range	Number	Weighted Average Remaining Contractual Life in Years	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
$1.44 - 1.83	518,281	1.97	$ 1.80	518,281	$ 1.80
$3.75	1,137,125	3.99	3.75	1,137,125	3.75
$18.50 - 24.90	1,321,853	1.01	22.47	1,321,853	22.47
$28.42 - 39.52	763,461	3.24	32.67	763,461	32.67
Total	3,740,720			3,740,720	

The aggregate intrinsic value of “in-the-money” outstanding and exercisable options was $1.0 million as of December 31, 2007.

Time-Based Restricted Stock Awards

In 2005, 183,823 shares of restricted stock were awarded to certain managers and executives, excluding senior management, as an incentive to retain their services through this transition time. These awards vested in 2007 and have no further restrictions on the sale of the shares. On July 31, 2007, 106,000 shares of restricted stock were awarded to senior management; each recipient is a named executive officer of the Company. These awards will vest in three years, and no restrictions on the sale of shares will apply thereafter. The fair value of these stock awards is determined based on the number of shares granted and the average of the high and low quoted price of our stock on the date of the award. The total continuing and discontinued operations compensation expense related to these awards was $.3 million for the year ended December 31, 2007. As of December 31, 2007, the estimated total compensation cost not yet recognized was $.3 million. This compensation cost will be recognized over the respective restriction periods. The total fair value of restricted stock released for the year ended December 31, 2007 was $2.4 million. Non-vested, time-based restricted stock awards and changes for the three years ended December 31, 2007 were as follows:

	Year Ended December 31,		
	2007	2006	2005
Shares:			
Beginning balance	351,515	632,210	453,326
Awarded	106,000	-	183,823
Released	(196,533)	(273,695)	(4,939)
Forfeited	(2,000)	(7,000)	-
Ending balance	258,982	351,515	632,210
Weighted average prices:			
Beginning balance	$16.79	$17.81	$23.64
Awarded price	3.80	-	3.59
Released price	12.05	19.47	24.19
Forfeited price	3.60	3.60	-
Ending balance	$15.17	$16.79	$17.81
Remaining Contractual Terms in Years	1.18	.97	1.33

The aggregate intrinsic value of outstanding time-based restricted stock was $1.0 million as of December 31, 2007.

Performance-Based Restricted Stock Awards

Performance-based restricted stock awards were granted in the third quarter of 2006 to qualified individuals, excluding senior management, consisting of the right to receive a number of shares of common stock at the end of the restriction period, March 1, 2008, assuming performance criteria were met. Additional performance based restricted stock awards were granted to senior management in the third quarter of 2007 and will vest on December 31, 2008. The performance measure for the awards was the ratio of 2007 adjusted EBITDA to 2007 average net utility plant investment. The threshold level of performance was a ratio of 10.0%, target at a ratio of 11.5%, and maximum at a ratio of 13.0%. Shares would be earned at the end of the performance period as follows: 100% of the target number of shares if the target level of performance was reached, 50% if the threshold was reached, and 150% if the ratio was at or above the maximum, with the number of shares interpolated between these levels. No shares would be payable if the threshold is not reached.

For the senior management who received these awards, the amount of performance-based restricted stock earned based upon the EBITDA-to-net utility plant investment ratio described above would be reduced if the Company failed to achieve one or more of the operating metrics. If the Company failed to achieve one of the four operating metrics, the amount of performance-based restricted stock would be reduced by 25%. If the Company failed to achieve two or three of the four operating metrics, the amount of performance-based restricted stock would be reduced by 50% or 75%, respectively. If the Company failed to achieve all four operating metrics for fiscal year 2007, the shares of performance-based restricted stock earned under the EBITDA-to-net utility plant investment calculation would be reduced to zero.

The fair value of these stock awards was determined based on the number of shares granted and the average of the high and low quoted price of our stock on the date of the award. An estimated annual turnover rate of 8% was assumed to determine the compensation expense related to the 2006 award. No estimated turnover was assumed to determine the compensation expense in the 2007 award to members of senior management. The total continuing and discontinued operations compensation expense related to these awards was $.8 million for the year ended December 31, 2007. As of December 31, 2007, the estimated total compensation cost not yet recognized was $.5 million. This deferred compensation cost is reflected as a deduction from our premium on capital stock and will be recognized over the period through March 1, 2008 for the 2006 award and December 31, 2008 for the 2007 award. Non-vested, performance-based restricted stock awards (based on target number) as of December 31, 2007 and changes during the years ended December 31, 2007 and 2006 were as follows:

	Year Ended December 31,	
	2007	2006
Shares:		
Beginning balance	176,000	-
Awarded	124,000	176,000
Released	(8,000)	-
Forfeited	(4,000)	-
Ending balance	288,000	176,000
Weighted average prices:		
Beginning balance	$4.44	$-
Awarded price	3.80	4.44
Released price	4.44	-
Forfeited price	4.44	-
Ending balance	$4.16	$4.44
Remaining Contractual Terms in Years	.53	.17

The aggregate intrinsic value of outstanding performance-based restricted stock was $1.1 million as of December 31, 2007.

On February 26, 2008, committees of the Company's Board of Directors verified the 2007 actual results of the performance metrics applicable to the performance-based restricted stock awards, as set forth below.

Financial Metric	Threshold	Target	Maximum	2007 Actual	Payout as of % of Target
2007 Adjusted EBITDA to Average Net Utility Plant Investment	10%	11.5%	13%	13.8%	150%

In determining the 2007 actual results above, the committees verified that the Company's non-GAAP 2007 Adjusted EBITDA was $265.0 million and the Company's 2007 average net utility plant investment was $1.9 billion. To compute the Company's 2007 Adjusted EBITDA, the Company's actual 2007 EBITDA from continuing operations of $239.0 million was increased by excluding $26.0 million of merger-related costs and severance costs incurred last year.

	Electric States		Gas States				
Operating Metrics	**CO**	**MO**	**CO**	**KS**	**IA**	**NE**	**Total**
Network Reliability (Target)	n/a	n/a	2	2	2	2	n/a
Network Reliability (2007 Actual)	n/a	n/a	1	–	1	–	n/a
Network Reliability – SAIFI (Target)	1.32	1.73	n/a	n/a	n/a	n/a	n/a
Network Reliability – SAIFI (2007 Actual)	.93	1.58	n/a	n/a	n/a	n/a	n/a
Customer Service – Meter Reading	99.4%	99.4%	99.4%	99.4%	99.4%	99.4%	n/a

Accuracy (Target)							
Customer Service – Meter Reading Accuracy (2007 Actual)	99.8%	99.9%	99.5%	99.7%	99.7%	99.7%	n/a
Customer Service – Customer Service Calls within 20 Seconds (Target)	n/a	n/a	n/a	n/a	n/a	n/a	72.0%
Customer Service – Customer Service Calls within 20 Seconds (2007 Actual)	n/a	n/a	n/a	n/a	n/a	n/a	82.0%

Because the 2007 actual performance for each operating metric exceeded target, none of the shares of performance-based restricted stock awarded to our senior officers (including Jon Empson, Leo Morton, Beth Armstrong, and Christopher Reitz) will be forfeited. As a result, 100% of the shares of performance-based restricted stock granted to these named executive officers was earned.

Director Stock Awards

Non-employee directors receive as part of his or her annual retainer, an annual award of 7,500 shares of fully vested common stock of the Company. Each director may elect to defer receipt of their shares until retirement or until they are no longer a member of our Board of Directors. Shares are awarded on the last trading day of each calendar quarter. Compensation expense is based upon the fair market value defined as the average of the high and low quoted price of the Company's common stock at the date of issuance.

	Year Ended December 31,		
	2007	**2006**	**2005**
Shares:			
Beginning balance	208,372	211,187	164,312
Awarded	52,500	50,625	56,250
Released	(15,000)	(53,440)	(9,375)
Ending balance	245,872	208,372	211,187
Weighted average prices:			
Beginning balance	$4.45	$4.33	$4.51
Awarded price	4.03	4.30	3.71
Released price	4.03	3.83	3.71
Ending balance	$4.38	$4.45	$4.33

The aggregate intrinsic value of outstanding director stock awards was $.9 million as of December 31, 2007.

Note 14 Accumulated Other Comprehensive Income (Loss)

The table below reflects the activity for continuing and discontinued operations accumulated other comprehensive income (loss) for 2005, 2006 and 2007:

In millions	**Foreign Currency Adjustments**	**Unrecognized Pension and Post-retirement Benefit Costs**	**Accumulated Other Comprehensive Income (Loss)**
Balance December 31, 2004	$ .8	$ –	$ .8
2005 Change	(.9)	–	(.9)
Balance December 31, 2005	(.1)	–	(.1)
2006 Change	.1	-	.1
Effect of SFAS 158 adoption	-	(30.6)	(30.6)
Balance December 31, 2006	-	(30.6)	(30.6)
2007 Change	.1	31.0	31.1

Balance December 31, 2007	$ .1	$ .4	$ .5

See Note 16 for further discussion of the effects of the adoption of SFAS 158 as of December 31, 2006.

Note 15. Income Taxes

Loss from continuing operations before income taxes consisted of:

	Year Ended December 31,		
In millions	**2007**	**2006**	**2005**
Domestic	$(75.3)	$(384.8)	$(223.6)
Foreign	6.3	(1.6)	(17.9)
Total	$(69.0)	$(386.4)	$(241.5)

Our income tax expense (benefit) consisted of the following:

	Year Ended December 31,		
In millions	**2007**	**2006**	**2005**
Current:			
Federal	$(5.9)	$(11.4)	$ -
Foreign	8.8	(4.8)	(2.6)
State	(1.0)	(2.0)	-
Deferred:			-
Federal	(18.0)	(57.4)	(44.2)
Foreign	1.9	3.2	(5.1)
State	(2.2)	(9.4)	(7.0)
Income tax expense (benefit) from continuing operations	(16.4)	(81.8)	(58.9)
Income tax expense (benefit) from discontinued operations:			
Current	-	-	-
Deferred	18.6	30.0	(25.1)
Income tax expense (benefit) from discontinued operations	18.6	30.0	(25.1)
Total	$ 2.2	$(51.8)	$(84.0)

The principal components of deferred income taxes consist of the following:

	December 31,	
In millions	**2007**	**2006** *(1)*
Deferred Tax Assets:		
Alternative minimum tax credit carryforward	$ 76.1	$ 63.4
General business credit carryforward	.4	1.1
Capital loss carryforward	187.0	187.6
Unrealized capital losses	-	11.3
U.S. net operating loss carryforward	311.6	327.5
State net operating loss carryforward	73.7	67.1
Pension and post-retirement benefits obligations	17.9	36.8
Other	15.1	15.0
Less: valuation allowance	(385.4)	(374.3)
Total deferred tax assets	296.4	335.5
Deferred Tax Liabilities and Credits:		
Accelerated depreciation and other plant differences:		
Regulated	217.1	237.0
Non-regulated	8.2	16.2
Regulatory asset – income taxes	49.4	50.8
Regulatory asset – pension and post-retirement benefits	11.2	28.5
Other, net	10.5	3.0
Total deferred tax liabilities and credits	296.4	335.5
Deferred income taxes and credits, net	$ -	$ -

(1) Balances adjusted to reflect adoption of FIN 48. See discussion below.

Our effective income tax rate from continuing operations differed from the statutory federal income tax rate primarily due to the following:

	Year Ended December 31,		
	2007	**2006**	**2005**
Statutory Federal Income Tax Rate	(35.0)%	(35.0)%	(35.0)%
Tax effect of:			
State income taxes, net of federal benefit	(4.0)	(3.8)	(2.1)
Increased state NOL benefit	(12.1)	(4.3)	-
Change in unrecognized tax benefits	(39.0)	23.2	18.0

PIES conversion costs/amortization	-	.1	13.7
Canadian tax audit	12.5	-	-
Settlement of 1996-1997 IRS audit	(4.2)	-	-
Estimate of non-deductible transaction costs	7.0	-	-
Valuation allowance adjustments	51.4	.8	(22.0)
Other	(.5)	(2.2)	3.0
Effective Income Tax Rate	(23.9)%	(21.2)%	(24.4)%

FIN 48 Unrecognized Tax Benefits

Impact of Adoption of FIN 48

We adopted FIN 48 on January 1, 2007. This interpretation sets a “more likely than not” threshold before tax benefits can be recognized in our financial statements. Our practice prior to FIN 48 was to recognize income tax benefits when they were reflected on filed income tax returns and establish a reserve against these tax benefits when their ultimate realization was deemed to be not “probable.” Our reserve for uncertain tax positions was $377.3 million at December 31, 2006.

In connection with the adoption of FIN 48 we analyzed our uncertain tax positions using the new “more likely than not” threshold. Based on this analysis, the reserve for uncertain tax positions was reduced by $175.4 million. This reduction was substantially offset by the establishment of a valuation allowance against net deferred tax assets (discussed below) in the amount of $156.1 million. These two adjustments were effected through a $19.3 million net increase to beginning accumulated deficit in the first quarter of 2007.

As discussed above, our practice prior to implementing FIN 48 was to record tax benefits based on returns as filed and establish a reserve against tax benefits when they were deemed to be uncertain. Under FIN 48, however, tax benefits are not recorded when their ultimate realization is deemed to be uncertain. Rather, they are separately disclosed as unrecognized tax benefits. As such, in conjunction with the implementation of FIN 48, we reclassified our deferred tax accounts at January 1, 2007 to reduce deferred tax assets that relate to unrecognized tax benefits. The reserve for uncertain tax benefits was reduced by the same amount.

Significant deferred tax accounts impacted by these adjustments related to net operating loss (NOL) carryforwards, AMT credit carryforwards, general business credit carryforwards and deferred tax liabilities. In addition, some tax uncertainties relate to the characterization of certain taxable gains as capital gains instead of ordinary income. Thus, the reduction in deferred tax assets for NOL carryforwards was partially offset by an increase in deferred tax assets for capital loss carryforwards. However, we maintain a full valuation allowance against the tax benefits from our capital loss carryforwards (discussed below), so this valuation allowance was likewise increased. These adjustments did not change the amount of net deferred tax assets. The following table illustrates the FIN 48 adjustments and the reclassification of our deferred tax accounts.

In millions	**Pre FIN 48 12/31/2006**	**Adjustment**	**Reclass**	**Post FIN 48 1/1/2007**
Summary Deferred Tax Assets:				
Alternative minimum tax credit carryforward	$ 92.3		$ (28.9)	$ 63.4
General business credits	6.8		(5.7)	1.1
Federal and State net operating loss carryforwards	596.9		(202.3)	394.6
Realized and unrealized capital loss carryforwards	120.3		78.6	198.9
Other deferred tax assets	53.7		(1.9)	51.8
Reserve for uncertain tax positions	(377.3)	175.4	201.9	-
Valuation allowances	(139.7)	(156.1)	(78.5)	(374.3)
Total deferred tax assets	353.0	19.3	(36.8)	335.5
Summary Deferred Tax Liabilities:				
Accelerated depreciation	(286.0)		32.8	(253.2)
Other deferred tax liabilities	(86.3)		4.0	(82.3)
Total deferred tax liabilities	(372.3)		36.8	(335.5)
Net deferred tax liability	$ (19.3)	$ 19.3	$ –	$ –

Unrecognized Tax Benefits

The amount of unrecognized income tax benefits at January 1, 2007 was $222.6 million. Of this amount, $196.9 million would have impacted the effective rate, if recognized. We recognize accrued interest and penalties associated with uncertain tax positions as part of the tax provision. As of January 1, 2007, we had $8.2 million of accrued interest and penalties, net of $3.2 million of tax benefit, included in the reserve for uncertain tax positions. At December 31, 2007, the amount of unrecognized income tax benefits decreased to $205.2 million. Of this amount, $169.2 million would impact the effective rate if recognized. Accrued interest and penalties associated with uncertain tax positions at December 31, 2007 were $9.5 million, net of $3.7 million tax benefit. The following table illustrates the changes to our unrecognized tax benefits during 2007.

Rollforward of Unrecognized Tax Benefits from Uncertain Tax Positions

In millions	Unrecognized Tax Benefits	Accrued Interest
Balance at Adoption (January 1, 2007)	$222.6	$8.2
Additions related to 2007 tax positions	–	–
Additions related to tax positions prior years	8.4	1.3
Reductions related to tax positions prior years	(15.9)	–
Reduction related to lapse of statue of limitations	–	–
Settlements	(9.9)	–
Balance at December 31, 2007	$205.2	$9.5

In addition to our consolidated Federal and various state tax returns, we file separate subsidiary tax returns in Canada and certain other states. All of our federal income tax returns are examined by the Internal Revenue Service (IRS). The IRS is currently auditing the years 2003-2004 and the audit report for years 1998-2002 is currently under review by The Joint Committee on Taxation.

On May 7, 2007 the Canada Revenue Agency (CRA) proposed to disallow certain deductions relating to Goods and Service Taxes and intercompany accounts taken on the 2002 Canadian income tax return of our wholly-owned subsidiary, Aquila Canada Corp (ACC). ACC was part of our Merchant Services business in Canada. We contested the proposed adjustments. Pursuant to FIN 48, during the second quarter we wrote off our Canadian current income tax receivable of $4.8 million and recorded a current income tax payable of $3.6 million. This increased our unrecognized tax benefits by $8.4 million in the second quarter. In November 2007, we agreed with the CRA to a reduced adjustment to ACC’s 2002 taxable income consistent with the amount of our second quarter adjustment. No additional write off or expense was recorded due to the settlement. This settlement reduced unrecognized tax benefits by $8.4 million in the fourth quarter.

On October 9, 2007 we agreed to adjustments contained in IRS audit reports related to our 1998 to 2002 taxable years. In addition, the agreement stipulates consistent treatment during our 2003 and 2004 taxable years for certain issues related to our former Networks businesses in Australia and Canada. The audit report and agreements must be approved by the Joint Committee on Taxation. There is no timetable for such approval, but the statute of limitations for the years 1998 to 2002 is scheduled to expire on November 30, 2008. We expect the following consequences upon conclusion of these audits: (i) tax refunds of $19.7 million, $4.8 million of which will be received after the full 2003-2004 audit is complete; (ii) our federal net operating loss carryforwards will be decreased by $250.1 million ($87.6 million of tax benefit); (iii) our capital loss carryforwards will be decreased by $53 million ($18.6 million of tax benefit offset by a reduction in valuation allowance by the same amount); (iv) our AMT credit will be decreased by $7.5 million; (v) our general business credit carryforward will be decreased by $5.6 million; and (vi) we will pay interest to the IRS of $7.7 million, $3.4 million of which is currently on deposit with the IRS. In addition, we expect our deferred tax liability to decrease by $34.4 million for those IRS adjustments that do not impact our effective tax rate. We do not anticipate additional income statement or balance sheet impact upon conclusion of these audits. Rather, the impact of these adjustments, both positive and negative, is currently included in our unrecognized tax benefits.

Unrecognized income tax benefits decreased $115.3 million in the first quarter of 2008 due to our determination that tax positions related to the years 1998-2002 were effectively settled upon receipt of Joint Committee approval in March 2008. It is possible that the amount of unrecognized tax benefits will change significantly within the next twelve months. This change could occur due to the IRS examination of our 2003-2004 tax years which is currently underway. We do not have an estimate of any changes at this time.

<u>Significant Deferred Tax Assets</u>

Tax Credits

At December 31, 2007 and 2006, after implementation of FIN 48 we had tax benefits related to alternative minimum tax credit carryforwards of $76.1 million and $63.4 million, respectively. These credits do not expire and can be used to decrease future cash tax payments.

At December 31, 2007 and 2006, after implementation of FIN 48 we had tax benefits related to general business tax credit carryforwards of $.4 million and $1.1 million, respectively.

Capital Loss Carryforwards

As of December 31, 2007 and 2006, respectively, after implementation of FIN 48, we had approximately $187 million and $198.9 million of tax benefits related to capital loss carryforwards. The benefits from the capital loss carryforwards at December 31, 2007 expire as follows: $88.6 million in 2008, $85.1 million in 2009, and $13.3 million in 2012. Included in the tax benefits that expire in 2008 and 2009 respectively are $20.1 million and $52.4 million of tax benefits for capital losses that we treated as ordinary losses on filed income tax returns. The tax benefits from the ordinary losses on the returns as filed are included in unrecognized tax benefits for net operating loss carryforwards discussed below. If the unrecognized tax benefits from the net operating loss carryforwards are recognized, then the recognized tax benefits from capital loss carryforwards will be decreased by the same amount. The tax benefits from capital loss carryforwards are subject to a full valuation allowance, as discussed below. Thus, any changes to unrecognized tax benefits impacting capital loss carryforwards will have an offsetting impact on the related valuation allowance.

Net Operating Loss Carryforwards

At December 31, 2007 and 2006, after implementation of FIN 48 we had tax benefits of $311.6 million and $327.5 million, respectively, related to federal NOL carryforwards. As of December 31, 2007, $ 83.1 million related to NOLs originating in 2003, $103.2 million originating in 2004, $74.1 million originating in 2005 and $82.3 million originating in 2006. We estimate 2007 taxable income to be $88.8 million. The $31.1 million federal tax liability related to this income will be offset by tax benefits from the 2003 NOL. The balance of the 2003 federal net operating loss carryforward expires in 2023 and can be carried back to 2001 to offset potential IRS audit adjustments. The 2004, 2005 and 2006 federal net operating loss carryforwards expire in 2024, 2025 and 2026, respectively, and cannot be carried back due to losses in the carryback years.

In addition to the deferred tax benefits related to federal NOLs, after implementation of FIN 48, we also have deferred tax benefits of $73.7 million and $ 67.1 million related to state net operating losses as of December 31, 2007 and 2006, respectively. In addition to our normal tax provision, during 2007 we recorded $11.5 million of incremental tax benefit substantially due to the increase in our apportionment factor for Missouri and we recorded $3.2 million of tax expense to write off the benefit of NOLs because we no longer operate in certain states. The state net operating loss carryforwards expire in various years.

<u>Valuation Allowances</u>

We are required to assess the ultimate realization of deferred tax assets using a “more likely than not” assessment threshold. This assessment takes into consideration tax planning strategies within our control. This assessment, however, does not take into consideration the expected taxable gains, both ordinary and capital, from pending sales of our Colorado electric properties and our Colorado, Kansas, Iowa and Nebraska gas properties. In addition, the assessment does not take into consideration our pending merger with a subsidiary of Great Plains Energy.

As a result of this assessment, we have established a full valuation allowance against tax benefits from net capital loss carryforwards, a partial valuation allowance against tax benefits from state net operating loss carryforwards, and a full valuation allowance against the remaining balance of net deferred tax assets. The valuation allowance against our net deferred tax assets was initially established in an amount of $156.1 million on January 1, 2007 in conjunction with the implementation of FIN 48. It was recorded through a decrease to beginning accumulated deficit, partially offsetting the FIN 48 increase to retained earnings of $175.4 million. The following table illustrates the changes to our tax valuation allowances during 2007.

In millions	**Pre FIN 48 12/31/2006**	**Adjustment**	**Reclass**	**Post FIN 48 1/1/2007**	**2007 Adjustments**	**12/31/2007**
Valuation Allowance Against:						
Capital Loss Carryforwards	$(120.3)		$(78.6)	$(198.9)	$11.9	$(187.0)
State NOL Carryforwards	(19.4)		4.4	(15.0)	.5	(14.5)
Net Deferred Tax Assets	–	(156.1)	(4.3)	(160.4)	(23.5)	(183.9)
Total	$(139.7)	$ (156.1)	$(78.5)	$(374.3)	$(11.1)	$(385.4)

The 2007 adjustments include $35.4 million of tax expense recorded in continuing operations primarily related to the valuation allowance against net deferred tax assets and $11.9 million tax benefit in other comprehensive income. The tax benefit recorded in other comprehensive income relates to the decrease in valuation allowance due to the decrease in deferred tax assets associated with SFAS 158 pension, SERP and post-retirement benefit adjustments which were also recorded in other comprehensive income. In addition, 2007 adjustments include a $7.2 million tax benefit recorded in discontinued operations related to the release of valuation allowance against capital loss carryforwards. Lastly, 2007 adjustments also include a $5.2 million FIN 48 adjustment primarily related to the valuation allowance against capital losses. This adjustment did not impact our provision since it was fully offset by an adjustment to our deferred tax assets.

Loss on PIES Exchange

As discussed in Note 12, we recorded a pretax loss of $82.3 million in 2005 on the early conversion of the PIES. In addition, in 2007, 2006 and 2005 we recorded interest and amortization of debt issue costs on our PIES of $.1 million, $.2 million and $12.6 million, respectively. No tax benefits were recorded as these costs were not deductible for income tax purposes.

Note 16: Employee Benefits

We provide defined benefit pension plans for our employees. Benefits under the plans reflect the employees' compensation, years of service and age at retirement. We satisfy the minimum funding requirements under ERISA. In addition to pension benefits, we provide post-retirement health care and life insurance benefits for certain retired employees. We fund the net periodic post-retirement benefit costs to the extent that they are tax-deductible and/or recoverable in our utility rates.

On August 17, 2006, President Bush signed The Pension Protection Act of 2006 (the “Pension Protection Act”) into law. The Pension Protection Act makes changes to important aspects of qualified retirement plans. Among other things, it introduces a new funding requirement for single- and multi-employer defined benefit pension plans, provides legal certainty on a prospective basis for cash balance and other hybrid plans and addresses contributions to defined contribution plans, deduction limits for contributions to retirement plans and investment advice provided to plan participants. We have conformed to the Pension Protection Act.

The following tables show the total funded status of our pension and post-retirement benefit plans and the amounts included continuing and discontinued operations in the Consolidated Balance Sheets, and Consolidated Statements of Comprehensive Income. For measurement purposes, projected benefit obligations and the fair value of plan assets were determined as of September 30, 2007 and 2006.

	Pension Benefits		Other Post-retirement Benefits	
Dollars in millions	**2007**	**2006**	**2007**	**2006**
Change in Projected Benefit Obligation:				
Benefit obligation at start of year	$381.7	$408.9	$ 56.9	$ 85.4
Service cost	8.9	9.3	1.2	.8
Interest cost	19.9	20.9	2.7	4.0
Plan participants' contribution	-	-	1.8	7.5
Transfers	.3	-	-	-
Effects of curtailments	(.9)	(17.8)	(10.5)	(5.7)
Effects of settlements	(22.9)	(32.9)	-	(15.6)
Actuarial (gain) loss	(35.9)	10.7	5.5	(13.5)
Benefits paid	(14.9)	(17.4)	(5.5)	(6.0)
Projected benefit obligation at end of year	$336.2	$381.7	$ 52.1	$ 56.9
Change in Plan Assets:				
Fair value of plan assets at start of year	$325.7	$353.4	$ 17.2	$ 13.1
Actual return on plan assets	32.4	21.8	(.6)	(4.2)
Employer contribution	1.0	.8	7.1	13.0
Transfers	(22.9)	(32.9)	-	(6.2)
Plan participants' contribution	-	-	1.8	7.5
Benefits paid	(14.9)	(17.4)	(5.5)	(6.0)
Fair value of plan assets at end of year	$321.3	$325.7	$ 20.0	$ 17.2
Funded status:				
Funded status	$(14.9)	$(56.0)	$(32.1)	$(39.7)
4th quarter employer contribution	.2	.2	1.1	2.6
Liability for pension and post-retirement benefits	$(14.7)	$(55.8)	$(31.0)	$(37.1)
Assets and Liabilities Recognized in the Consolidated Balance Sheets:				
Pension asset	$26.0	$ 3.4	$ -	$ -
Pension and post-retirement benefits, current	(.7)	(.6)	(.9)	(1.0)
Pension and post-retirement benefits	(15.3)	(15.6)	(9.3)	(9.0)
Non-current assets of discontinued operations	21.9	57.1	9.7	11.3
Current liabilities of discontinued operations	(.1)	(.1)	(1.6)	(1.8)
Non-current liabilities of discontinued operations	(24.7)	(42.9)	(19.1)	(25.3)

SFAS 71 regulatory asset – unrecognized costs	2.2	3.7	1.8	1.2
SFAS 71 net regulatory liability – Missouri	(9.0)	(10.1)	-	-
Amounts Recognized in the Consolidated Statements of Comprehensive Income :				
Unrecognized transition amount	$ -	$ -	$ 4.3	$ 6.7
Unrecognized net actuarial (gain) loss	15.3	69.8	(4.7)	(10.0)
Unrecognized prior service cost	29.0	36.9	16.0	19.9
Accumulated regulatory (gain) loss adjustment	(3.4)	2.3	(2.9)	(2.5)
Less: SFAS 71 regulatory assets (continuing and discontinued)	(23.4)	(60.9)	(11.4)	(12.5)
Accumulated other comprehensive loss	17.5	48.1	1.3	1.6
Provision for deferred taxes	(18.6)	(18.5)	(.6)	(.6)
Accumulated other comprehensive (gain) loss	$ (1.1)	$ 29.6	$ .7	$ 1.0

	Pension Benefits		Other Post-retirement Benefits	
Dollars in millions	**2007**	**2006**	**2007**	**2006**
Weighted Average Assumptions as of September 30:				
Discount rate for expense	6.01%	5.80%	5.76%	5.53%
Discount rate for disclosure	6.51%	6.01%	6.12%	5.76%
Expected return on plan assets for expense	8.50%	8.50%	7.00%	7.00%
Expected return on plan assets for disclosure	8.25%	8.50%	6.00%	7.00%
Rate of compensation increase	4.40%	4.40%	n/a	n/a

Included in the $336.2 million projected benefit obligation for pension benefits and $321.3 million of fair value of pension plan assets is an $11.9 million estimated transfer made to the buyer of our Kansas electric operations on December 31, 2007.

For measurement purposes, to calculate the annual rate of increase in the per capita cost of covered health benefits for each future fiscal year, we used a graded rate for non-prescription drug medical costs starting at 7% in 2007 and decreasing 1% annually until the rate levels out at 5% for years 2009 and thereafter. For prescription drug costs, we used a graded rate starting at 11% in 2007 and decreasing 1% annually until the rate levels out at 5% for years 2013 and thereafter.

In millions	Pension Benefits 2007	Pension Benefits 2006	Pension Benefits 2005	Other Post-retirement Benefits 2007	Other Post-retirement Benefits 2006	Other Post-retirement Benefits 2005
Components of Net Periodic Benefit Cost:						
Service cost	$9.0	$9.4	$8.9	$1.2	$.8	$.6
Interest cost	19.8	20.9	22.0	2.8	4.0	5.0
Expected return on plan assets	(23.8)	(26.8)	(27.6)	(1.2)	(.6)	(1.0)
Amortization of transition amount	-	(.8)	(.8)	1.0	1.3	1.5
Amortization of prior service cost	4.5	5.1	4.2	2.0	2.3	2.2
Recognized net actuarial (gain) loss	2.6	3.6	4.1	(.4)	-	.5
Net periodic benefit cost before regulatory expense adjustments	12.1	11.4	10.8	5.4	7.8	8.8
Regulatory gain/loss adjustment	5.6	4.9	3.4	.4	.8	1.0
SFAS 71 regulatory adjustment	(1.1)	.7	3.9	-	-	-
Net periodic benefit cost after regulatory expense adjustments	16.6	17.0	18.1	5.8	8.6	9.8
Effect of curtailments and settlements included in gain on sale of assets	10.4	13.5	-	(4.8)	(.5)	-
Total periodic benefit costs	$27.0	$30.5	$18.1	$1.0	$8.1	$9.8
Other Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income						
Amounts arising during the period:						
Recognized net actuarial (gain)/loss	$(21.4)	n/a	n/a	$(.2)	n/a	n/a
Total arising during the period	$(21.4)	n/a	n/a	$(.2)	n/a	n/a
Components of Net Periodic Benefit Cost Amortized to Income:						
Prior service cost	$ (2.3)	n/a	n/a	$(.1)	n/a	n/a
Recognized net actuarial (gain)/loss	(1.4)	n/a	n/a	-	n/a	n/a
Regulatory (gain)/loss adjustment	(5.6)	n/a	n/a	-	n/a	n/a
Total pension and post-retirement benefit costs amortized to income	$ (9.3)	n/a	n/a	$(.1)	n/a	n/a
Total recognized in other comprehensive income	$(30.7)	n/a	n/a	$(.3)	n/a	n/a
Total recognized in net periodic benefit cost and other comprehensive income	$ (3.7)	n/a	n/a	$.7	n/a	n/a

The other changes in plans assets and benefit obligations recorded in the regulatory asset and other comprehensive income accounts during 2007 are as follows:

	Pension Benefits	**Other Post-retirement Benefits**

In millions	Regulatory Asset	Other Comprehensive Income	Regulatory Asset	Other Comprehensive Income
Amounts arising during the period:				
Recognized net actuarial (gain)/loss	$(14.9)	$(21.4)	$5.7	$(.2)
Total arising during the period	$(14.9)	$(21.4)	$5.7	$(.2)

The unrecognized net periodic benefit costs amortized to income from the regulatory asset and accumulated other comprehensive income accounts during 2007 are as follows:

	Pension Benefits		Other Post-retirement Benefits	
In millions	Regulatory Asset	Other Comprehensive Income	Regulatory Asset	Other Comprehensive Income
Components of Net Periodic Benefit Cost Amortized to Income:				
Transition amount	$–	$–	$1.0	$–
Prior service cost	2.2	2.3	1.9	.1
Recognized net actuarial (gain)/loss	1.2	1.4	(.4)	–
Regulatory (gain)/loss adjustment	–	5.6	.4	–
Total pension and post-retirement benefit costs amortized	$3.4	$9.3	$2.9	$ .1

In connection with the sale of our Kansas electric operations in 2007 and our Michigan, Minnesota and Missouri gas operations in 2006, we included the effects of curtailments and settlements in the determination of the gains on sales of these operations by considering the prepaid pension asset and pension and post-retirement benefit obligations in the net asset basis sold.

In a 2004 settlement with the Missouri Commission, we agreed to recover our Missouri-related pension funding at an agreed-upon annual amount for ratemaking purposes. As ordered by the Missouri Commission, the difference between the agreed-upon expense for ratemaking purposes and the amount determined under SFAS 87 has been recognized as a regulatory liability of $9.0 million as of December 31, 2007, in accordance with SFAS 71. Previously, the Missouri Commission ordered the recognition of actuarial gains/losses for our Missouri-related pension and post-retirement benefit plans to follow an alternative method to the prescribed “corridor” method outlined in SFAS 87 and SFAS 106, “Employers’ Accounting for Postretirement Benefits Other Than Pension.” The difference between the “Missouri” method and the “corridor” method is noted as regulatory gain/loss adjustment or accumulated regulatory gain/loss adjustment in the preceding tables.

The regulatory gain/loss adjustment and prior service cost for the defined benefit pension plans that will be amortized from accumulated other comprehensive income into net periodic benefit cost over the next fiscal year are $4.1 million and $2.2 million, respectively. The prior service cost for the defined benefit pension plans that will be amortized from the regulatory asset accounts into net periodic benefit cost over the next fiscal year is $2.1 million. The prior service cost and transition obligation for the other post-retirement benefit plan that will be amortized from accumulated other comprehensive income into net periodic benefit cost over the next fiscal year are immaterial. The regulatory gain/loss adjustment, prior service cost and transition obligation for the other post-retirement benefit plan that will be amortized from the regulatory asset accounts into net periodic benefit cost over the next fiscal year are $(.3) million, $2.0 million and $.9 million, respectively.

The funded status for the SERP plan with an accumulated benefit obligation in excess of plan assets is summarized below:

In millions	**2007**	**2006**
Accumulated Benefit Obligations in Excess of Plan Assets:		
Fair value of plan assets at end of year	$ -	$ -
Accumulated benefit obligation at end of year	17.5	17.9
Funded status *(a)*	$(17.5)	$(17.9)

(a) *The SERP is reflected as an unfunded accumulated benefit obligation as plan assets are not netted against the obligations for non-qualified plans. We have segregated approximately $6.5 million of assets for the SERP as of December 31, 2007. We expect to fund estimated future benefit payments from these assets and Company contributions as needed.*

The accumulated benefit obligation for all our defined benefit pension plans was $302.5 million and $339.0 million at September 30, 2007 and 2006, respectively.

On February 29, 2008, we amended the SERP to clarify (i) that a participant's combined benefit under our pension plan and SERP will not be less than his or her combined benefit under such plans as of December 31, 2004, and (ii) the formula used to compute benefits and the time at which small benefit amounts will be paid. These revisions are consistent with our past administrative practice and do not change the substantive provisions of the SERP. The foregoing description is qualified by reference to the plan amendment filed as an exhibit to this Form 10-K.

We engaged benefit plan consultants to assist in the development of a statement of pension plan investment objectives and to perform a study modeling expectations of future returns of numerous portfolios using historic rates of return.

Pension Plan Investment Objectives

1. We desire to maintain an appropriately funded status of the defined benefit pension plan. This implies an investment posture that is intended to increase the probability of investment performance exceeding the actuarial assumed rate of return over the long-term.

2. The investment objective is intended to be strategic in nature. Over the long-term, it is expected to protect the funded status of the Plan, enhance the real purchasing power of Plan assets, and not threaten the Plan's ability to meet currently committed obligations.

3. Distinct asset classes and investment approaches have unique return and risk characteristics. The combination of asset classes and approaches produces diversification benefits in the form of enhancement of expected return at a given risk level and/or reduction of the risk level associated with a specific expected return.

Our qualified pension plan weighted-average asset allocations by asset category at September 30, 2007 and 2006 along with the long-term targets and target ranges, are as follows:

	Plan Assets at September 30,		Plan Asset Allocation Targets	
	2007	2006	Long-Term	Range
Asset Category:				
Core fixed income	20.4%	20.5%	21.0%	5.0-25.0%
High yield bonds	9.5	9.8	10.0	6.0-10.0
Large cap equities	27.4	27.3	29.0	27.0-37.0
Mid cap equities	11.0	10.5	10.0	8.0-12.0
Small cap equities	3.9	3.3	3.5	2.5-12.0
International equities	14.5	14.2	14.0	10.0-15.0
Emerging markets equities	2.9	2.4	2.5	0.0-5.0
Real estate	9.9	9.0	7.5	5.0-10.0
Private equity	.3	.7	2.5	0.0-5.0
Cash	.2	2.3	-	-
Total	100.0%	100.0%	100.0%	100.0%

Our other post-retirement benefit plan assets at December 31, 2007 and 2006 were invested in government securities and short-term investments.

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

The following chart reflects the sensitivities associated with a change in certain actuarial assumptions by the indicated percentage. While the chart below reflects an increase in the percentage for each assumption, we and our actuaries expect that the inverse of this change would impact the projected benefit obligation (PBO) at December 31, 2007 and our estimated annual pension cost (APC) on the income statement for 2008 by a similar amount in the opposite direction. Each sensitivity below reflects an evaluation of the change based solely on a change in that assumption.

Dollars in millions	**Change in Assumption** Incr.(decr.)	**Impact on PBO** Incr.(decr.)	**Impact on APC** Incr.(decr.)
Discount rate	.25%	$(10.4)	$(1.3)
Rate of return on plan assets	.25%	-	(.8)

The discount rate is defined as the rate at which plan obligations could effectively be settled. We utilize the Hewitt Yield Curve (HYC) in selecting the discount rate assumption for our pension and other post-retirement benefit plans. The HYC method is to project all benefit payments (PBO benefit payments) payable over the life of the plan. Then, stripped investment grade coupons (the top quartile of non-callable, Corporate Aa bonds or higher) are matched to the benefit payments and discounted back to the current date. The result is a PBO. Then, a single discount rate is produced that generates the same PBO. This single discount rate is the weighted-average of the stripped investment grade coupon rates.

In selecting the expected rate of return on plan assets, we reviewed the three, five and ten year average historical returns of the plan. In addition, we considered current economic conditions, inflation and market dynamics. Finally, we reviewed benchmark information to ensure that our assumption was in line with rates used by other companies.

Our health care plans are contributory, with participants' contributions adjusted annually. The life insurance plans are generally non-contributory. In estimating future health care costs, we have assumed future cost-sharing changes. The assumed health care cost trends significantly affect the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects for 2008:

	1 Percentage-Point	
In millions	**Increase**	**Decrease**
Effect on total of service and interest cost components	$ .1	$ (.1)
Effect on post-retirement benefit obligation	2.0	(1.8)

Based on actuarial projections, we expect to contribute $.8 million and $5.1 million to our defined benefit pension plans and other post-retirement benefit plans, respectively, in 2008. Discretionary contributions in 2008 will be based upon fluctuations in the plan investments and discount rates.

To comply with a regulatory condition related to the closing of the sale of our Kansas electric operations, we contributed $3.4 million to our qualified defined benefit pension plan and $1.1 million to our other post-retirement benefit plan in April 2007. As a result of the transfer of pension plan assets and pension benefits obligations in accordance with ERISA requirements to the buyers of our utility assets as discussed in Note 7, we expect to make an additional voluntary contribution of approximately $7.7 million to our defined benefit plan to maintain the funded status of our pension plan.

Following are estimated future benefit payments, which reflect expected future service, as appropriate. Other post-retirement benefits are reflected gross without considering the estimated subsidy to be received under the Medicare Prescription Drug, Improvement and Modernization Act of 2003, while the estimated subsidy is shown separately.

In millions	**Pension Benefits**	**Other Post-retirement Benefits**	**Medicare Drug Subsidy**
Estimated Future Benefit Payments:			
2008	$ 14.0	$ 5.1	$ (.8)
2009	15.1	5.4	(.9)
2010	16.5	5.6	(1.0)
2011	17.6	5.8	(1.1)
2012	18.9	5.6	(1.1)
2013-2017	116.6	23.5	(4.5)

As disclosed in Note 7, the utility operations which were sold July 14, 2008, have been reclassified as discontinued operations. The preceding employee benefits footnote information, including the various tables, has been presented for these plans in total. As of and for the year ended December 31, 2007, select pension and other post-retirement benefit plan information related to discontinued operations is summarized below.

In millions	Pension Benefit	Other Post-retirement Benefits
Discontinued Operations:		
Accumulated benefit obligation at end of year	$120.7	$ 26.5
Projected benefit obligation at end of year	135.9	26.5
Pension and post-retirement benefit obligations	(24.8)	(20.7)
SFAS Regulatory asset – unrecognized costs	21.9	9.7
Accumulated – other comprehensive (gain) loss	1.3	-
Net periodic benefit cost	6.5	3.2
Estimated future benefit payments for 2008	5.7	2.5

Note 17: Segment Information

We manage our business in three business segments: Electric Utilities, Gas Utilities and Merchant Services. Our Electric and Gas Utilities currently consist of our regulated electric utility operations in two states and our natural gas utility operations in four 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 electric utility divisions into the Electric Utilities reporting segment and our gas utility divisions into the Gas Utilities reporting segment. The operating results of our former Kansas (sold April 1, 2007), Michigan (sold April 1, 2006), Missouri (sold June 1, 2006), and Minnesota (sold July 1, 2006) utility divisions have been reclassified to discontinued operations. In addition, the operating results of our Colorado electric and Colorado, Iowa, Kansas and Nebraska gas operations (sold to Black Hills on July 14, 2008) have been reclassified to discontinued operations. Merchant Services includes the residual operations of Aquila Merchant Services, Inc. These operations include its commitments under long-term gas contracts and remaining wholesale energy contracts. Merchant Services also includes Aquila's contractual interest in the Crossroads plant, which is an investment of Aquila, Inc. and is not an asset of Aquila Merchant Services, Inc. The operating results of our two former Illinois merchant power plants, which were sold on March 31, 2006, have been reclassified to discontinued operations. The operating results of Everest Connections, which was sold on June 30, 2006, have also been reclassified to discontinued operations. All other operations are included in Corporate and Other, including the costs not allocated to our operating businesses.

Each segment is managed based on operating results, expressed as EBITDA. Generally, decisions on finance, dividends and taxes are made at the Corporate level. The current and non-current assets of our discontinued operations are included in the segments referenced above.

In millions	Year Ended December 31, 2007	2006	2005
Sales: *(a)*			
Utilities:			
Electric Utilities	$ 660.0	$ 596.5	$ 510.8
Gas Utilities	–	1.4	–
Total Utilities	660.0	597.9	510.8
Merchant Services	(8.4)	(9.7)	(1.6)
Corporate and Other	–	.1	.1
Total	$651.6	$588.3	$509.3

(a) For the years ended December 31, 2007, 2006 and 2005, respectively, the following (in millions) have been reclassified to discontinued operations and are not included in the above amounts: Electric Utilities sales of $221.1, $361.1 and $364.8; Gas Utilities sales of $639.6, $909.3 and $1,256.9; Merchant Services sales of $–, $2.2 and $17.0; and Corporate and Other sales related to Everest Connections of $–, $25.1 and $46.1.

In millions	Year Ended December 31, 2007	2006	2005
Earnings (Loss) Before Interest, Taxes, Depreciation and Amortization (EBITDA): *(a)*			
Utilities:			
Electric Utilities	$156.2	$ 104.2	$ 108.1
Gas Utilities	(27.5)	(31.8)	(55.8)
Total Utilities	128.7	72.4	52.3
Merchant Services	(5.6)	(244.7)	(22.5)
Corporate and Other	(15.8)	(27.6)	(103.4)
Total EBITDA	107.3	(199.9)	(73.6)
Depreciation and amortization	66.3	65.1	64.8
Interest expense	110.0	121.4	103.1
Loss from continuing operations before income taxes	$(69.0)	$(386.4)	$(241.5)

(a) For the years ended December 31, 2007, 2006 and 2005, respectively, the following (in millions) have been reclassified to discontinued operations and are not included in the above amounts: Electric Utilities EBITDA of $47.1, $86.0 and $87.6; Gas Utilities EBITDA of $96.0, $355.2 and $186.3; Merchant Services EBITDA of $1.7, $(.8) and $(156.1); and Corporate and Other EBITDA relating to Everest Connections of $–, $30.2 and $12.0.

In millions	Year Ended December 31, 2007	2006	2005
Depreciation and Amortization Expense: *(a)*			
Utilities:			
Electric Utilities	$61.6	$59.8	$53.7
Gas Utilities	.5	2.3	4.6
Total Utilities	62.1	62.1	58.3
Merchant Services	4.0	4.1	6.3
Corporate and Other	.2	(1.1)	.2
Total	$66.3	$65.1	$64.8

(a) For the years ended December 31, 2007, 2006 and 2005, respectively, the following depreciation and amortization expense (in millions) have been reclassified to discontinued operations and are not included in the above amounts: Electric Utilities $10.7, $10.8 and *$20.1; Gas Utilities $31.4, $28.9 and $47.3; Merchant Services $–, $–* and *$9.3; and Corporate and Other relating Everest Connections $–, $–* and *$7.4.*

In millions	December 31, 2007	2006
Identifiable Assets:		
Utilities:		
Electric Utilities	$1,858.6	$1,655.8
Gas Utilities	51.0	109.6
Total Utilities	1,909.6	1,765.4
Merchant Services	205.0	316.2
Corporate and other	105.2	300.4
Total Continuing Operations	2,219.8	2,382.0
Discontinued Operations:		
Electric Utilities	201.0	513.7
Gas Utilities	595.7	580.0
Total Discontinued Operations	796.7	1,093.7
Total	$3,016.5	$3,475.7

In millions	Year Ended December 31, 2007	2006	2005
Capital Expenditures:			
Electric Utilities	$213.8	$107.7	$143.5
Corporate and other	7.9	12.5	6.3
Total Continuing Operations	221.7	120.2	149.8
Discontinued Operations:			
Electric Utilities	29.6	34.3	35.4
Gas Utilities	40.8	42.8	54.8
Corporate and other	–	8.2	11.4
Total Discontinued Operations	70.4	85.3	101.6
Total	$292.1	$205.5	$251.4

Note 18: Commitments and Contingencies

Capital Expenditures

We have made certain construction commitments in connection with our 2008 capital expenditure plan. During 2008, we estimate that our total capital expenditures will be approximately $429.9 million for continuing operations, including $116.1 million related to Iatan 2 and $120.1 million of environmental upgrades and $73.7 million for discontinued operations.

Commitments

We have various commitments relating to power, gas and coal supply commitments and lease commitments as summarized below.

In millions	2008	2009	2010	2011	2012	Thereafter	Total
Continuing Operations:							
Future minimum payments—							
Facilities, equipment and other	$ 8.7	$ 6.4	$ 5.3	$ 4.7	$ 4.3	$ 11.8	$ 41.2
Merchant gas transportation obligations	5.5	5.5	5.5	5.0	2.5	10.8	34.8
Regulated business purchase obligations:							
Purchased power obligations	50.7	41.1	41.3	34.3	29.20	68.2	264.8
Purchased gas obligations	4.8	4.6	4.2	4.1	4.2	8.9	30.8
Coal and rail contracts	87.6	65.7	61.5	22.5	22.7	102.2	362.2
Discontinued Operations:							
Future minimum payments—							
Facilities, equipment and other	$ 3.6	$ 3.2	$ 2.4	$ 1.8	$ 1.0	$ 1.2	$ 13.2
Regulated business purchase obligations:							
Purchased power obligations	69.6	71.8	74.2	74.0	-	-	289.6
Purchased gas obligations	53.7	52.0	52.1	49.4	42.8	68.1	318.1
Coal and rail contracts	8.3	-	-	-	-	-	8.3

Operating Lease Obligations

Future minimum payments include operating leases of coal rail cars, vehicles and office space over terms of up to 20 years. Included in lease commitments above are approximately $15.7 million for continuing operations and $12.4 million for discontinued operations for vehicles and equipment under a one-year term renewable master personal property lease. We routinely exercise various lease renewal options and from time to time purchase leased assets for fair value at the end of lease terms. Contingent residual value obligations under this master lease were approximately $18.0 million for continuing operations and $14.5 million for discontinued operations at December 31, 2007. Rent expense for continuing operations for the years 2007, 2006 and 2005 was (in millions), $5.8, $6.1 and $7.2, respectively, and for discontinued operations was $4.9, $5.3 and $7.1, respectively.

We previously leased an 8% interest in the Jeffrey Energy Center through 2019. The lease payments varied by year but were recognized as lease expense on a straight-line basis of approximately $10.4 million annually. This lease interest was transferred to Westar in connection with the sale of our Kansas electric operations and is included in discontinued operations.

Merchant gas transportation obligations

We have long-term commitments through 2017 for gas transportation capacity remaining from our wholesale energy trading business. We may terminate these commitments and may incur losses in future periods.

Regulated business purchase obligations

In 2007, our continuing electric utility operations generated 62% of the power delivered to their customers. Our electric utility operations purchase coal and natural gas, including transportation capacity, as fuel for its generating power plants under long-term contracts through 2020. These operations also purchase power and gas to meet customer needs under short-term and long-term purchase contracts. Our gas utility operations purchase natural gas, including transportation capacity to meet customer needs under short- and long-term contracts through 2028.

Contingent Obligations

Credit Support

We have entered into various agreements for commodity purchases, fleet leasing and insurance that require letters of credit for financial assurance purposes. These letters of credit are available to fund the payment of such obligations. At December 31, 2007, we had $188.3 million of letters of credit outstanding with expiration dates generally ranging from one month to 16 months.

Equity Put Rights

Certain minority owners of Everest Connections had the option to sell their ownership units to us if Everest Connections did not meet certain financial and operational performance measures as of December 31, 2004 (target-based put rights). If the target-based put rights were exercised, we would have been obligated to purchase up to 4.0 million and 1.5 million ownership units at a price of $1.00 and $1.10 per unit, respectively, for a total potential cost of $5.65 million. In 2004, we believe we achieved the operating targets related to these ownership units. The holders of these ownership units are disputing our conclusion that Everest achieved these operating targets and are attempting to exercise these target-based put rights. We do not believe we have any obligation with regard to these target-based put rights.

The minority owners notified us that they also intend to exercise their option to sell their 9.5 million ownership units to us at fair market value (market-based put rights). We have recorded a reserve of $2.8 million in connection with the sale of Everest Connections for this potential obligation. These minority owners have been unwilling to accept our fair market value analysis which was based on the auction results and ultimate sale price of Everest. They have filed suit against us with respect to our disputes involving both the target-based put rights and the market-based put rights. We believe we have strong defenses and will defend these cases vigorously.

Legal

In the normal course of business, we are subject to various lawsuits, actions, proceedings, claims and other matters asserted under laws and regulations. We believe the amounts provided in our consolidated financial statements are adequate in light of the probable and estimable contingencies. However, there can be no assurances that the actual amounts required to satisfy alleged liabilities from various legal proceedings, claims and other matters discussed below, and to comply with applicable laws and regulations, will not exceed the amounts reflected in our consolidated financial statements. As such, costs, if any, that may be incurred in excess of those amounts provided as of December 31, 2007, cannot be reasonably determined.

Price Reporting Litigation

In response to complaints of manipulation of the California energy market, in 2002 the FERC issued an order requiring net sellers of power in the California markets from October 2, 2000 through June 20, 2001 at prices above a FERC determined competitive market clearing price to make refunds to net purchasers of power in the California market during that time period. Because Aquila Merchant was a net purchaser of power during the refund period it has received approximately $7.6 million in refunds. However, various parties appealed the FERC order to the United States Court of Appeals for the Ninth Circuit seeking review of a number of issues, including changing the refund period to include periods prior to October 2, 2000. On August 2, 2006, the U.S. Court of Appeals for the Ninth Circuit issued an order finding, among other things, that FERC did not provide a sufficient justification for refusing to exercise its remedial authority under the Federal Power Act to determine whether market participants violated FERC-approved tariffs during the period prior to October 2, 2000, and imposing a remedy for any such violations. The court remanded the matter to FERC to determine whether tariff violations occurred and, if so, the appropriate remedy. In March 2008, the FERC issued an order declining to order refunds for the period prior to October 2, 2000. We expect that order to be appealed by other companies impacted by this decision. The ultimate outcome of this matter cannot be predicted.

On October 6, 2006, the Missouri Commission filed suit in the Circuit Court of Jackson County, Missouri against 18 companies, including Aquila and Aquila Merchant, alleging that the companies manipulated natural gas prices through the misreporting of natural gas trade data and, therefore, violated Missouri antitrust laws. The suit does not specify alleged damages and was filed on behalf of all local distribution gas companies in Missouri who bought and sold natural gas from June 2000 to October 2002. Our motion to have the case dismissed is pending. We believe we have strong defenses and will defend this case vigorously. We cannot predict 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.

ERISA Litigation

On September 24, 2004, a lawsuit was filed in the U.S. District Court for the Western District of Missouri against us and certain members of our Board of Directors and management, alleging they violated the ERISA and were responsible for losses that participants in our 401(k) plan experienced as a result of the decline in the value of their Aquila common stock held in the 401(k) plan. A number of similar lawsuits alleging that the defendants breached their fiduciary duties to the plan participants in violation of ERISA by concealing information and/or misleading employees who held our common stock through our 401(k) plan were subsequently filed against us. The suits also sought damages for the plan's losses resulting from the alleged breaches of fiduciary duties. The court ordered that all of these lawsuits be consolidated into a single case captioned In re Aquila ERISA Litigation and certified the case as a class action. In April 2007, we settled the case for $10.5 million, which was paid by our insurance carrier. The settlement agreement was approved by the court in November 2007.

South Harper Peaking Facility

We have constructed a 315 MW natural gas power plant and related substation in an unincorporated area of Cass County, Missouri. Cass County and local residents filed suit claiming that county zoning approval was required to construct the project. In January 2005, a Circuit Court of Cass County judge granted the County's request for an injunction; however, we were permitted to continue construction while the order was appealed. We appealed the Circuit Court decision to the Missouri Court of Appeals for the Western District of Missouri and, in June 2005, the appellate court affirmed the circuit court ruling. In October 2005, the Court of Appeals granted our request for rehearing.

In December 2005, the appellate court issued a new opinion affirming the Circuit Court's opinion, but also opining that it was not too late to obtain the necessary approval. In light of this, we filed an application for approval with the Missouri Commission in January 2006. In January 2006, the trial court granted our request to stay the permanent injunction until May 31, 2006, and ordered us to post a $20 million bond to secure the cost of removing the project. Effective May 31, 2006, the Missouri Commission issued an order specifically authorizing our construction and operation of the power plant and substation. On June 2, 2006, the trial court dissolved the $20 million bond, further stayed its injunction, and authorized us to operate the plant and substation while Cass County appealed the Missouri Commission's order.

In June 2006, Cass County filed an appeal with the Circuit Court, challenging the lawfulness and reasonableness of the Missouri Commission's order. On October 20, 2006, the Circuit Court ruled that the Missouri Commission's order was unlawful and unreasonable. The Missouri Commission and Aquila appealed, and on March 4, 2008, the Missouri Court of Appeals for the Western District of Missouri affirmed the district court's decision. In March, the Missouri Commission and Aquila each requested that the Court of Appeals either rehear the case or transfer the case to the Missouri Supreme Court. On April 25, 2008, we entered into an agreement with Cass County pursuant to which we filed and Cass County is processing a land use application for the facilities. This application is set for a hearing before the County's Planning Board on July 22, 2008. The parties have also requested that the Court of Appeals stay a ruling on the rehearing and transfer request pending Cass County's review of the land use application. In addition, on June 12, 2008, we entered into a final settlement agreement with the members of StopAquila.org, an unincorporated association of approximately 100 individuals who opposed the facilities. This settlement agreement finally resolves our dispute with StopAquila. In addition, we have entered into agreements in principal to settle six of seven pending private lawsuits filed by Cass County residents alleging that the facilities constitute a public and private nuisance. We recorded reserves of $10.7 million for fines, legal fees, infrastructure investments and the potential resolution of various related claims in 2008. The actual amount required to resolve the related claims may be different than the amounts recorded. On June 16, 2008, Missouri Lt. Governor Peter Kinder (serving as acting Governor in Governor Blunt’s absence from the state) signed into law SB720, a bill that grants to the Missouri Commission the authority to retroactively approve the development and construction of our South Harper facilities. The law will become effective August 28, 2008.

Coal Supply Litigation

In the spring of 2005, one of our coal suppliers, C. W. Mining, terminated a long term, fixed price coal supply agreement allegedly because of a force majeure event. We incurred significant costs procuring replacement coal and disputed that the supplier was entitled to terminate the contract. We filed a lawsuit against the supplier in federal court in Salt Lake City and the trial was held in February 2007. On October 29, 2007, the United States District Court for the District of Utah, Central Division held that C.W. Mining's performance under the coal contract was not excused by a force majeure event and awarded us $24.8 million in damages. In order to preserve and recover on our claim, on January 8, 2008, we participated in the filing of an involuntary Chapter 11 bankruptcy petition against C.W. Mining in the United States Bankruptcy Court in Salt Lake City, Utah. With the implementation of a fuel adjustment clause in our recent Missouri rate case, we expect that 95% of any damages collected as a result of this litigation will be for the benefit of our Missouri customers through lower rates.

Environmental

We are subject to various environmental laws. These include regulations governing air and water quality and the storage and disposal of hazardous or toxic wastes. We continually assess ways to ensure we comply with laws and regulations on hazardous materials and hazardous waste and remediation activities.

As of December 31, 2007, we estimate probable costs of future investigation and remediation on our identified MGP sites, PCB sites and retained liabilities to be $3.6 million, of which $1.3 million relates to sites that will be assumed by Black Hills. This is our best estimate based upon our review of the potential costs associated with conducting investigative and remedial actions at our identified sites, as well as the likelihood of whether such actions will be necessary. There are also additional costs that we consider to be less likely but still “reasonably possible” to be incurred at these sites. Based upon the results of studies at these sites and our knowledge and review of potential remedial actions, it is reasonably possible that these additional costs could exceed our best estimate by approximately $5.1 million, of which $3.7 million relates to sites that will e assumed by Black Hills. This estimate could change materially after further investigation. It could also be affected by the actions of environmental agencies and the financial viability of other responsible parties.

The EPA finalized several Clean Air Act regulations such as CAIR, BART and CAMR regulations in 2005 that would affect our coal-fired power plants by requiring reductions in emissions of SO_2, NOx and mercury. We have completed engineering studies and obtained vendor bids which evaluated the costs and likely controls for compliance with these Clean Air Act regulations. For Missouri electric operations, we estimate that probable capital expenditures through 2010 will be approximately $144.7 million based on current engineering bids. Costs have been increasing because of the shortage of labor needed in the power sector and at this point we are not able to reasonably estimate if additional costs may be incurred.

Note 19: Quarterly Financial Data (Unaudited)

Financial results for interim periods do not necessarily indicate trends for any 12-month period. Quarterly results can be affected by the timing of acquisitions and dispositions, the effect of weather on sales, and other factors typical of utility operations and energy related businesses. All periods presented have been adjusted to reflect the reclassification of discontinued operations.

	2007 Quarters				**2006 Quarters**			
In millions	**First**	**Second**	**Third**	**Fourth**	**First**	**Second**	**Third**	**Fourth**
Sales	$124.5	$150.9	$234.4	$141.8	$122.2	$149.7	$194.0	$122.4
Gross profit	38.4	76.2	127.1	72.3	46.5	69.1	87.2	56.6
Income (loss) from continuing operations	(42.5)	(16.9)	27.9	(21.1)	(29.5)	(253.0)	(20.7)	(1.4)
Earnings (loss) from discontinued operations	18.2	2.2	12.6	14.2	28.4	98.0	136.4	65.7
Net income (loss)	$(24.3)	$(14.7)	$40.5	$ (6.9)	$ (1.1)	$(155.0)	$115.7	$64.3

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders

Great Plains Energy Incorporated:

We have audited the accompanying consolidated balance sheets of Aquila, Inc. and subsidiaries (the Company) as of December 31, 2007 and 2006, and the related consolidated statements of income, comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2007. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of the Company as of December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2007 in conformity with accounting principles generally accepted in the United States of America.

As discussed in note 3 to the consolidated financial statements, effective January 1, 2007, the Company adopted Financial Accounting Standards Board (FASB) Interpretation No. 48, *Accounting for Uncertainty in Income Taxes — an interpretation of FASB Statement No. 109, Accounting for Income Taxes*, and FASB Staff Position (FSP) AUG AIR-1, *Accounting for Planned Major Maintenance Activities*.

/s/KPMG LLP

Kansas City, Missouri

July 25, 2008

Aquila, Inc.
Consolidated Statements of Income—Unaudited

In millions	Three Months Ended March 31, 2008	Three Months Ended March 31, 2007
Sales:		
Electricity—regulated	$ 148.4	$ 127.9
Other	(1.1)	(3.4)
Total sales	147.3	124.5
Cost of sales:		
Electricity—regulated	77.0	86.1
Other	–	–
Total cost of sales	77.0	86.1
Gross profit	70.3	38.4
Operating expenses:		
Operation and maintenance expense	56.9	59.9
Taxes other than income taxes	4.3	5.8
Restructuring charges	–	1.6
Depreciation and amortization expense	18.4	17.1
Total operating expenses	79.6	84.4
Operating loss	(9.3)	(46.0)
Other income (expense), net	3.5	6.2
Interest expense	24.2	26.5
Loss from continuing operations before income taxes	(30.0)	(66.3)
Income tax expense (benefit)	(17.5)	(23.8)
Loss from continuing operations	(12.5)	(42.5)
Earnings from discontinued operations, net of tax	21.0	18.2
Net income (loss)	$ 8.5	$ (24.3)

See accompanying notes to consolidated financial statements.

Aquila, Inc.
Consolidated Balance Sheets—Unaudited

In millions		March 31, 2008		December 31, 2007
Assets				
Current assets:				
Cash and cash equivalents	$	28.2	$	34.4
Funds on deposit		33.9		41.3
Accounts receivable, net		121.7		136.8
Inventories and supplies		67.3		62.3
Price risk management assets		44.4		32.0
Regulatory assets, current		24.9		25.5
Other current assets		8.2		9.7
Current Assets of discontinued operations		166.8		213.6
Total current assets		495.4		555.6
Utility plant, net		1,551.1		1,484.3
Non-utility plant, net		127.0		119.5
Price risk management assets		16.4		13.1
Goodwill, net		111.0		111.0
Pension asset		26.3		26.0
Regulatory assets		81.7		84.6
Deferred charges and other assets		39.1		39.3
Non-current assets of discontinued operations		575.1		583.1
Total Assets	$	3,023.1	$	3,016.5
Liabilities and Shareholders' Equity				
Current liabilities:				
Current maturities of long-term debt	$	2.4	$	2.4
Short-term debt		100.0		25.0
Accounts payable		63.6		85.5
Accrued interest		30.9		45.8
Accrued compensation and benefits		9.9		21.7
Pension and post-retirement benefits, current		1.6		1.6
Other accrued liabilities		65.7		46.8
Price risk management liabilities		30.6		28.7
Customer funds on deposit		10.7		14.0
Current liabilities of discontinued operations		90.7		150.0
Total current liabilities		406.1		421.5
Long-term liabilities:				
Long-term debt, net		1,034.1		1,035.4
Deferred income taxes and credits		–		–
Price risk management liabilities		.6		.5
Pension and post-retirement benefits		25.7		25.4
Regulatory liabilities		87.4		75.4
Deferred credits		41.5		41.7
Non-current liabilities of discontinued operations		61.8		60.9
Total long-term liabilities		1,251.1		1,239.3
Common shareholders' equity		1,365.9		1,355.7
Total Liabilities and Shareholders' Equity	$	3,023.1	$	3,016.5

See accompanying notes to consolidated financial statements.

Aquila, Inc.
Consolidated Statements of Comprehensive Income—Unaudited

In millions	Three Months Ended March 31, 2008	2007
Net income (loss)	$ 8.5	$ (24.3)
Other comprehensive income (loss), net of related tax:		
Foreign currency adjustments:		
Reclassification of foreign currency (gains) losses to income, net of deferred tax (expense) benefit of $– million for the three months ended March 31, 2008	(.1)	–
Total foreign currency adjustments	(.1)	–
Pension and post-retirement benefits costs amortized to income:		
Prior service cost, net of deferred tax expense (benefit) of $– million after valuation allowance and $.2 million for the three months ended March 31, 2008 and 2007, respectively	.6	.3
Net actuarial loss, net of deferred tax expense (benefit) of $.2 million for the three months ended March 31, 2007	–	.2
Accumulated regulatory loss adjustment, net of deferred tax expense (benefit) of $– million after valuation allowance and $.5 million for the three months ended March 31, 2008 and 2007, respectively	1.0	.9
Total pension and post-retirement benefit costs	1.6	1.4
Other comprehensive income	1.5	1.4
Total Comprehensive Income (Loss)	$ 10.0	$ (22.9)

See accompanying notes to consolidated financial statements.

Aquila, Inc.
Consolidated Statements of Cash Flows—Unaudited

In millions	Three Months Ended March 31, 2008	Three Months Ended March 31, 2007
Cash Flows From Operating Activities:		
Net income (loss)	$ 8.5	$ (24.3)
Adjustments to reconcile net income (loss) to net cash provided from operating activities:		
Depreciation and amortization expense	29.1	27.2
Net changes in price risk management assets and liabilities	(17.9)	(25.2)
Changes in certain assets and liabilities, net of effects of divestitures:		
Funds on deposit	7.4	39.3
Accounts receivable/payable, net	(44.8)	(48.7)
Inventories and supplies	23.9	18.9
Other current assets	24.3	32.6
Deferred charges and other assets	9.2	16.1
Accrued interest and other accrued liabilities	(31.3)	(26.0)
Customer funds on deposit	(3.1)	1.0
Deferred credits	11.7	5.8
Other	1.3	2.1
Cash provided from operating activities	18.3	18.8
Cash Flows From Investing Activities:		
Utilities capital expenditures	(94.6)	(56.0)
Cash proceeds received on sale of assets	–	22.3
Other	(2.4)	4.6
Cash used for investing activities	(97.0)	(29.1)
Cash Flows From Financing Activities:		
Retirement of long-term debt	(1.3)	(15.9)
Short-term debt borrowings, net	75.0	–
Cash paid on long-term gas contracts	(1.4)	(4.3)
Other	.2	.6
Cash provided from (used for) financing activities	72.5	(19.6)
Decrease in cash and cash equivalents	(6.2)	(29.9)
Cash and cash equivalents at beginning of period	34.4	232.8
Cash and cash equivalents at end of period	$ 28.2	$ 202.9

See accompanying notes to consolidated financial statements.

Note 1: Merger and Asset Sale

On February 6, 2007, Aquila, Inc. (Aquila) entered into an agreement and plan of merger with Great Plains Energy, Gregory Acquisition Corp., a wholly-owned subsidiary of Great Plains Energy, and Black Hills, which provided for the merger of Gregory Acquisition Corp. into us, with Aquila continuing as the surviving corporation. As of July 14, 2008, all required approvals had been received. Upon completion of the Merger, we became a wholly-owned subsidiary of Great Plains Energy, and our shareholders received cash and shares of Great Plains Energy common stock in exchange for their shares of Aquila common stock. As of July 14, 2008, each share of Aquila common stock converted into the right to receive 0.0856 of a share of Great Plains Energy common stock and a cash payment of $1.80. The exchange ratio was fixed and was not adjusted to reflect stock price changes prior to the completion of the Merger. Upon consummation of the Merger, our shareholders owned approximately 27% of the outstanding common stock of Great Plains Energy, and the Great Plains Energy shareholders owned approximately 73% of the outstanding common stock of Great Plains Energy.

On July 14, 2008, subsequent to the merger a dividend of approximately $675 million was declared and paid to Great Plains Energy.

In connection with the Merger, we also entered into agreements with Black Hills under which we sold our Colorado electric utility and our Colorado, Iowa, Kansas and Nebraska gas utilities to Black Hills for $940 million in cash, subject to certain working capital and other purchase price adjustments, in a transaction that also closed on July 14, 2008. The agreements contained various provisions customary for transactions of this size and type, including representations, warranties and covenants with respect to the Colorado, Iowa, Kansas and Nebraska utility businesses that are subject to usual limitations. The employees of these utility operations were transferred to Black Hills upon completion of the sale.

The Merger and the asset sales were contingent upon the closing of the other transaction, meaning that one transaction would not close unless the other transaction closes.

We evaluated the accounting classification of the assets to be acquired by Black Hills relative to SFAS 144. Based on our assessment, the criteria for classification of the assets as “held for sale” and discontinued operations was met upon closing of the transactions. As a result, we have reclassified the assets to be acquired by Black Hills as “held for sale” and reported those results as discontinued operations herein.

We incurred significant costs in connection with the merger and related asset sale, primarily consisting of investment banking, legal, employee retention, and other severance costs which we expensed as they were incurred. We incurred approximately $.3 million and $7.3 million of costs (primarily investment banking and legal costs) relating to these transactions in the three months ended March 31, 2008 and 2007, respectively. In connection with the closing of the transactions we paid an additional $14.2 million of fees in 2008 including $11.9 million to investment advisors. These costs are included in operation and maintenance expense in Corporate and Other.

Beginning in February 2007, we executed retention agreements totaling $8.8 million with numerous non-executive employees to mitigate employee attrition prior to the closing of the Merger. The retention awards were paid on January 31, 2008. We accrued $.9 million and $1.2 million of expense related to these retention agreements in the three months ended March 31, 2008 and 2007, respectively. These costs are included in operation and maintenance expense in Corporate and Other.

Note 2. 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 2007 Annual Report on Form 10-K filed with the SEC on February 29, 2008. You should read our 2007 Form 10-K in conjunction with this report. The accompanying Consolidated Balance Sheets and Consolidated Statements of Common Shareholders' Equity as of December 31, 2007, 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.

Our consolidated financial statements include all of our operating divisions and majority-owned subsidiaries for which we maintain controlling interests, including Aquila Merchant.

Seasonal Variations of Business

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

Operations	**Peak**
Gas Utilities	November through March
Electric Utilities	July and August

New Accounting Standards

Fair Value Measurements

In September 2006, the FASB issued SFAS 157, "Fair Value Measurements", which defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. This statement is effective for our financial statements as of January 1, 2008. The adoption of SFAS 157 did not have a material impact on our financial condition or results of operations. See Note 11 for additional disclosures required by SFAS 157.

Offsetting of Amounts Related to Certain Contracts

In April 2007, the FASB issued FSP FIN 39-1, "Amendment of FASB Interpretation No. 39." FSP FIN 39-1 replaces certain terms in FIN No. 39 with "derivative instruments" (as defined in SFAS No. 133) and permits the offsetting of fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral against fair value amounts recognized for derivative instruments executed with the same counterparty under the same master netting arrangement. FSP FIN 39-1 is effective for fiscal years beginning after November 15, 2007. The adoption of this FSP did not have a material impact on our financial condition or results of operations.

Noncontrolling Interests

In December 2007, the FASB issued SFAS No. 160, “Noncontrolling Interests in Consolidated Financial Statements-an amendment of ARB No. 51” (SFAS 160). SFAS 160 establishes accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. It clarifies that a noncontrolling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. SFAS 160 is effective for fiscal years beginning after December 15, 2008. We do not expect SFAS 160 to have a material impact on our financial position or results of operations.

Business Combinations

In December 2007, the FASB issued SFAS No. 141R “Business Combinations” (SFAS 141R). SFAS 141R establishes principles and requirements for how the acquirer of a business recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree. SFAS 141R also provides guidance for recognizing and measuring the goodwill acquired in the business combination and determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. SFAS 141R is effective for business combinations with acquisition dates in fiscal years beginning after December 15, 2008. As we have no business acquisitions pending, we do not expect SFAS 141R to have a material impact on our financial position or results of operations.

Disclosures about Derivative Instruments and Hedging Activities

In March 2008, the FASB issued SFAS No. 161, “Disclosures about Derivative Instruments and Hedging Activities-an amendment to FASB Statement No. 133” (SFAS 161), effective for fiscal years beginning after November 15, 2008. SFAS 161 requires an entity to provide enhanced disclosures about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under SFAS 133 and its related interpretations, and (c) how derivative instruments and related hedged items affect an entity’s financial position, financial performance, and cash flows. We are currently evaluating the disclosures required by SFAS 161.

Note 3. Restructuring Charges

We recorded the following restructuring charges:

	Three Months Ended March 31,	
In millions	**2008**	**2007**
Corporate and Other severance costs	$ –	$ 1.6
Total restructuring charges	$ –	$ 1.6

Severance Costs

We recorded $1.6 million of one-time termination benefits in first quarter of 2007 related to the departure of our Chief Operating Officer. These benefits are being paid over a two-year period which began April 28, 2007.

Restructuring Reserve Activity

The following table summarizes activity in accrued restructuring charges for the three months ended March 31, 2008:

In millions		
Severance Costs:		
Accrued severance costs as of December 31, 2007	$	1.1
Additional expense during the period		–
Cash payments during the period		(.1)
Accrued severance costs as of March 31, 2008	$	1.0

In connection with the closing of the merger with Great Plains Energy and sale of certain operations to Black Hills, approximately 200 employees were severed or agreed to transitional employment agreements. As a result, approximately $23.8 million of severance-related costs were paid or accrued. In accordance with the sale agreements, Black Hills will reimburse approximately $8.6 million of these costs.

Note 4. Discontinued Operations

As part of our ongoing effort to reduce debt and other long-term obligations, we have sold the assets discussed below, which are considered discontinued operations in accordance with SFAS 144. After-tax losses discussed below are reported after giving consideration to the effect of capital loss carryback and carryforward limitations. As a result, the net tax effect may differ substantially from our expected statutory tax rates.

Electric and Gas Utilities

In September 2005, we entered into agreements to sell our Kansas electric distribution business and our Michigan, Minnesota and Missouri natural gas distribution businesses. We completed these asset sales in 2006, except for the Kansas electric sale, which was completed on April 1, 2007. The tax gain on the sale of the Kansas electric properties will be adjusted when the final determination as to the amount of capital gain on the sale is made and as the 2007 income tax return is filed in 2008.

In March 2007, we paid $1.8 million to the buyer of the Michigan properties to settle a gas-in-storage issue and other matters.

On April 1, 2007, we closed the sale of our Kansas electric operations and received gross cash proceeds of $292.2 million, including the base purchase price of $249.7 million plus preliminary working capital and other adjustments of $42.5 million. In connection with this sale we recorded a pretax gain of approximately $1.8 million in 2007 after transaction fees and expenses, including an adjustment for the final determination of pension assets transferred to the buyer. The estimated after-tax gain was approximately $1.1 million, subject to the determination of the capital gain amount discussed above.

On July 14, 2008, we closed the sale of our Colorado electric operations and Colorado, Iowa, Kansas and Nebraska gas operations to Black Hills and received gross cash proceeds of $908.8 million, subject to true-up within 120 days after close. We expect the sale to result in a pretax and after-tax gain of approximately $315.0 million. This amount will be adjusted for final working capital and capital expenditure adjustments determined through July 14, 2008.

The operating results of the utility divisions sold or held for sale 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 EITF Consensus 87-24, “Allocation of Interest to Discontinued Operations” (EITF 87-24). We provide corporate 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 based on various cost drivers. With the exception of certain central services operations acquired by Black Hills, these allocated costs were not included in the reclassification to earnings from discontinued operations because these support services were necessary to maintain ongoing operations until the sales were completed. The allocated operating expenses related to the utility divisions held for sale that were not assumed by Black Hills were as follows:

	Three Months Ended March 31,	
In millions	**2008**	**2007**
Allocated expenses retained in continuing operations	$ 9.8	$ 9.8

Interest Allocation to Discontinued Operations

The buyers of the assets in discontinued operations did not assume any of our long-term debt. 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. As we completed each asset sale the allocation of interest to discontinued operations ceased, thereby increasing interest expense in continuing operations, without impacting total interest expense, until the sales proceeds were used to reduce debt.

Summary

We have reported the results of operations from these assets in discontinued operations for the three months ended March 31, 2008 and 2007 in the Consolidated Statements of Income as follows.

	Three Months Ended March 31,	
In millions	**2008**	**2007**
Sales	$ 335.8	$ 363.1
Cost of sales	248.5	264.6
Gross profit	87.3	98.5
Operating expenses:		
Operation and maintenance expense	30.5	41.1
Taxes other than income taxes	3.0	4.9
Net (gain) on sale of assets and other charges	–	(.1)
Depreciation and amortization expense	10.7	10.1
Total operating expenses	44.2	56.0
Operating income	43.1	42.5
Other income	(.4)	(.2)
Interest expense	7.8	12.3
Income before income taxes	34.9	30.0
Income tax expense	13.9	11.8
Earnings from discontinued operations, net of tax	$ 21.0	$ 18.2

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 March 31, 2008 and December 31, 2007 Consolidated Balance Sheets as follows:

In millions	**March 31, 2008**	**December 31, 2007**
Current assets of discontinued operations:		
Accounts receivable, net	$ 122.1	$ 119.3
Inventories and supplies	11.4	40.3
Regulatory assets, current	18.8	33.0
Other current assets	14.5	21.0
Total current assets of discontinued operations	$ 166.8	$ 213.6
Non-current assets of discontinued operations:		
Utility plant, net	$ 537.2	$ 537.6
Regulatory assets	36.4	40.5
Other non-current assets	1.5	5.0
Total non-current assets of discontinued operations	$ 575.1	$ 583.1
Current liabilities of discontinued operations:		
Accounts Payable	$ 65.0	$ 105.2
Regulatory liabilities, current	8.0	19.4
Other current liabilities	17.7	25.4
Total current liabilities of discontinued operations	$ 90.7	$ 150.0
Non-current liabilities of discontinued operations:		
Pension and post-retirement benefits	$ 44.9	$ 43.9
Regulatory liabilities	5.1	5.0
Deferred credits	11.8	12.0
Total non-current liabilities of discontinued operations	$ 61.8	$ 60.9

Note 5. Reportable Segment Reconciliation

We manage our business in three business segments: Electric Utilities, Gas Utilities and Merchant Services. Our Electric and Gas Utilities consist of our regulated electric utility operations in two states and our natural gas utility operations in four 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 electric utility divisions into the Electric Utilities reporting segment and our gas utility divisions into the Gas Utilities reporting segment. The operating results of our Kansas electric division, which was sold April 1, 2007, and our Michigan, Missouri and Minnesota gas divisions, which were sold on April 1, 2006, June 1, 2006 and July 1, 2006, respectively, have been reclassified to discontinued operations. In addition, the operating results of our Colorado electric and Colorado, Iowa, Kansas and Nebraska gas operations (sold to Black Hills on July 14, 2008) have been reclassified to discontinued operations. Merchant Services includes the residual operations of Aquila Merchant Services, Inc. These operations primarily include remaining contracts from its former wholesale energy trading operations and our investment in the Crossroads plant, which is an investment of Aquila, Inc. and is not an asset of Aquila Merchant Services, Inc. All other operations are included in Corporate and Other, including the costs not allocated to our operating businesses.

Each segment is managed based on operating results, expressed as EBITDA. Generally, decisions on finance and taxes are made at the Corporate level.

Our reportable segment reconciliation is shown below:

In millions	Three Months Ended March 31, 2008		Three Months Ended March 31, 2007	
Sales: *(a)*				
Electric Utilities	$	148.4	$	127.9
Merchant Services		(1.1)		(3.4)
Corporate and Other		–		–
Total sales	$	147.3	$	124.5

(a) For the three months ended March 31, 2008 and 2007, respectively, the following sales (in millions) were reclassified to discontinued operations and are not included in the above amounts: Electric Utilities of $51.0 and $85.5; and Gas Utilities of $284.8 and $277.6.

	2008		2007	
EBITDA: *(a)*				
Utilities:				
Electric Utilities	$	22.1	$	(1.2)
Gas Utilities		(7.4)		(7.0)
Total Utilities		14.7		(8.2)
Merchant Services		(1.8)		(4.1)
Corporate and Other		(.3)		(10.4)
Total EBITDA		12.6		(22.7)
Depreciation and amortization expense		18.4		17.1
Interest expense		24.2		26.5
Loss from continuing operations before income taxes	$	(30.0)	$	(66.3)

(a) For the three months ended March 31, 2008 and 2007, respectively, the following EBITDA (in millions) were reclassified to discontinued operations and are not included in the above amounts: Electric Utilities of $10.8 and $14.5; and Gas Utilities of $42.6 and $37.9.

	2008		2007	
Depreciation and Amortization: *(a)*				
Utilities:				
Electric Utilities	$	16.1	$	15.7
Gas Utilities		.1		.4
Total Utilities		16.2		16.1
Merchant Services		2.3		1.0
Corporate and Other		(.1)		–
Total depreciation and amortization	$	18.4	$	17.1

(a) For the three months ended March 31, 2008 and 2007, respectively, the following EBITDA (in millions) were reclassified to discontinued operations and are not included in the above amounts: Electric Utilities of $2.7 and $2.7; and Gas Utilities of $8.0 and $7.4.

In millions	March 31, 2008		December 31, 2007	
Assets:				
Utilities:				
Electric Utilities	$	1,993.2	$	1,858.6
Gas Utilities		35.8		51.0
Total Utilities		2,029.0		1,909.6
Merchant Services		202.4		205.0
Corporate and Other		49.8		105.2
Total Continuing Operations		2,281.2		2,219.8
Discontinued Operations:				
Electric Utilities		202.4		201.0
Gas Utilities		539.5		595.7
Total Discontinued Operations		741.9		796.7
Total assets	$	3,023.1	$	3,016.5

Note 6. Financings

Five-Year Unsecured Revolving Credit Facility

In September 2004, we completed a $110 million unsecured revolving credit facility that matures in September 2009 (the Five-Year Unsecured Revolving Credit Facility). There were no borrowings outstanding on this facility as of March 31, 2008. The Five-Year Unsecured Revolving Credit Facility bears interest at the Eurodollar Rate plus 5.50%, subject to reduction if our credit rating improves. Among other restrictions, the Five-Year Unsecured Revolving Credit Facility contains financial covenants similar to, but less restrictive than, those contained in the Iatan Facility described below. We were in compliance with these covenants as of March 31, 2008.

The Five-Year Unsecured Revolving Credit Facility contains a $40 million "cross default" provision, as well as covenants that restrict certain activities including, among others, limitations on additional indebtedness, restrictions on acquisitions, sale transactions and investments. In addition, we are prohibited from paying dividends and from making certain other payments if our senior unsecured debt is not rated at least Ba2 by Moody's and BB by S&P, or if such a payment would cause a default under the facility.

Effective July 14, 2008, this facility was terminated.

$180 Million Unsecured Revolving Credit and Letter of Credit Facility

On April 13, 2005, we entered into a five-year credit agreement with a commercial lender. Subject to the satisfaction of certain conditions, the facility provides for up to $180 million of cash advances and letters of credit for working capital purposes. Cash advances must be repaid within 364 days unless we obtain the necessary regulatory approvals to incur long-term indebtedness under the facility. As of March 31, 2008, we had $150.0 million of uncollateralized capacity at an average cost of 3.65% under this agreement, which contains a $40 million "cross default" provision. As of March 31, 2008, $149.7 million of this capacity had been utilized for letters of credit issued to commodity suppliers, lessors and insurance companies for financial assurance purposes.

Four-Year Secured Revolving Credit Facility

On April 22, 2005, we executed a 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, Iowa, Kansas, Missouri and Nebraska. Borrowings under the AR Facility bear interest at LIBOR plus 1.25% or prime plus .375% depending on the term of the advance, 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 Unsecured Revolving Credit Facility discussed above. The credit agreement also contains a $40 million "cross default" provision. We had borrowed $100.0 million under this facility as of March 31, 2008 at a rate of 5.12%.

We have entered into an amendment of the facility to permit the obligation to be transferred to Great Plains Energy upon the closing of the merger and to release the accounts receivable generated by our Colorado electric and Colorado, Iowa, Kansas and Nebraska gas operations. In addition, the maximum borrowing limit was reduced from $150 million to $65 million.

$50 Million Revolving Credit and Letter of Credit Facility

In January 2006, we closed on a $50 million short-term letter of credit facility with a commercial lender that allows us to issue letters of credit under the facility. The credit agreement contains a $40 million "cross default" provision. The advance rate under this facility is 1.10%. There were $49.8 million of letters of credit outstanding under this facility as of March 31, 2008. These letters of credit have been issued to commodity suppliers, lessors and insurance companies for financial assurance purposes.

Iatan Construction Financing

On August 31, 2005, we entered into a $300 million credit agreement with a commercial lender and a syndicate of other lenders (the Iatan Facility). The credit agreement allows us to obtain loans in support of our participation in the construction of the Iatan 2 facility being developed by KCPL near Weston, Missouri (Iatan 2), 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 the Eurodollar Rate plus 1.375%, subject to reduction if our credit rating improves. Obligations under the credit agreement are secured by the assets of our Missouri Public Service electric operations. There were no borrowings outstanding under this facility at March 31, 2008. Among other restrictions, the Iatan Facility contains the following financial covenants with which we were in compliance as of March 31, 2008:

(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 1.4 to 1.0 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 6.0 to 1.0 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 contains a $40 million "cross default" provision, as well as covenants that restrict certain activities including, among others, limitations on additional indebtedness, restrictions on acquisitions, sale transactions and investments. In addition, we are prohibited from paying dividends and from making certain other payments if our senior unsecured debt is not rated at least Ba2 by Moody's and BB by S&P, or if such a payment would cause a default under the facility.

Other

We had an additional $.8 million of letters of credit outstanding under another arrangement as of March 31, 2008.

Note 7. Employee Benefits

The following table shows the components of net periodic benefit costs for total continuing and discontinued operations:

	Pension Benefits		Other Post-retirement Benefits	
	Three Months Ended March 31,			
In millions	2008	2007	2008	2007
Components of Net Periodic Benefit Cost:				
Service cost	$ 2.0	$ 2.4	$ .3	$ .3
Interest cost	5.2	5.4	.8	.8
Expected return on plan assets	(6.3)	(6.4)	(.3)	(.3)
Amortization of transition amount	–	–	.2	.3
Amortization of prior service cost	1.1	1.2	.5	.5
Recognized net actuarial (gain)/loss	–	.8	–	(.1)
Net periodic benefit cost before regulatory expense adjustments	2.0	3.4	1.5	1.5
Regulatory (gain)/loss adjustment	1.0	1.4	(.1)	.1
SFAS 71 regulatory adjustment	.7	–	–	–
Net periodic benefit cost after regulatory expense adjustments	3.7	4.8	1.4	1.6
Effect of curtailments and settlements included in gain on sale of assets	–	–	–	–
Total periodic benefit costs	$ 3.7	$ 4.8	$ 1.4	$ 1.6

The unrecognized net periodic benefit costs amortized to income for total continuing and discontinued operations from the regulatory asset and accumulated other comprehensive income accounts are as follows:

	Pension Benefits		Other Post-retirement Benefits	
	Three Months Ended March 31, 2008			
In millions	Regulatory Asset	Other Comprehensive Income	Regulatory Asset	Other Comprehensive Income
Components of Net Periodic Benefit Cost Amortized to Income:				
Transition amount	$ –	$ –	$ .2	$ –
Prior service cost	.5	.6	.5	–
Regulatory (gain)/loss adjustment	–	1.0	(.1)	–
Total pension and post-retirement benefit costs amortized	$ .5	$ 1.6	$ .6	$ –

We previously disclosed in our financial statements for the year ended December 31, 2007, that we expected to contribute in 2008 $.8 million and $5.1 million to our defined benefit pension plans and other post-retirement benefit plan, respectively. 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.

To comply with a regulatory condition related to the closing of the sale of our Kansas electric operations, we contributed $3.4 million to our qualified defined benefit pension plan and $1.1 million to our other post-retirement benefit plan in April 2007. As a result of the transfer of pension plan assets and pension benefits obligations in accordance with ERISA requirements to the buyers of our utility assets as discussed in Note 3, we made an additional voluntary contribution of approximately $7.7 million to our defined benefit plan in July 2008 to maintain the funded status of our pension plan.

As disclosed in Note 3, certain former utility operations have been reclassified as discontinued operations. The components of net periodic benefit cost presented in the tables above disclose information for the plans in total. For the three months ended March 31, 2008 and 2007, respectively, the net periodic pension benefit cost charged to discontinued operations was $1.2 million and $2.0 million. In addition, for the three months ended March 31, 2008 and 2007, respectively, the net periodic other post-retirement benefits cost charged to discontinued operations was $.8 million and $1.0 million.

Note 8. Legal

In the normal course of business, we are subject to various lawsuits, actions, proceedings, claims and other matters asserted under laws and regulations. We believe the amounts provided in our consolidated financial statements are adequate in light of the probable and estimable contingencies. However, there can be no assurances that the actual amounts required to satisfy alleged liabilities from various legal proceedings, claims and other matters discussed below, and to comply with applicable laws and regulations, will not exceed the amounts reflected in our consolidated financial statements. As such, costs, if any, that may be incurred in excess of those amounts provided as of March 31, 2008, cannot be reasonably determined.

Price Reporting Litigation

In response to complaints of manipulation of the California energy market, in 2002 the FERC issued an order requiring net sellers of power in the California markets from October 2, 2000 through June 20, 2001 at prices above a FERC determined competitive market clearing price to make refunds to net purchasers of power in the California market during that time period. Because Aquila Merchant was a net purchaser of power during the refund period it has received approximately $7.6 million in refunds. However, various parties appealed the FERC order to the United States Court of Appeals for the Ninth Circuit seeking review of a number of issues, including changing the refund period to include periods prior to October 2, 2000. On August 2, 2006, the U.S. Court of Appeals for the Ninth Circuit issued an order finding, among other things, that FERC did not provide a sufficient justification for refusing to exercise its remedial authority under the Federal Power Act to determine whether market participants violated FERC-approved tariffs during the period prior to October 2, 2000, and imposing a remedy for any such violations. The court remanded the matter to FERC to determine whether tariff violations occurred and, if so, the appropriate remedy. In March 2008, the FERC issued an order declining to order refunds for the period prior to October 2, 2000. We expect that order to be appealed by other companies impacted by this decision. The ultimate outcome of this matter cannot be predicted.

On October 6, 2006, the Missouri Commission filed suit in the Circuit Court of Jackson County, Missouri against 18 companies, including Aquila and Aquila Merchant, alleging that the companies manipulated natural gas prices through the misreporting of natural gas trade data and, therefore, violated Missouri antitrust laws. The suit does not specify alleged damages and was filed on behalf of all local distribution gas companies in Missouri who bought and sold natural gas from June 2000 to October 2002. Our motion to have the case dismissed is pending. We believe we have strong defenses and will defend this case vigorously. We cannot predict 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 power plant and related substation in an unincorporated area of Cass County, Missouri. Cass County and local residents filed suit claiming that county approval was required to construct the project. In January 2005, a Circuit Court of

Cass County judge granted the County's request for an injunction; however, we were permitted to continue construction while the order was appealed. We appealed the Circuit Court decision to the Missouri Court of Appeals for the Western District of Missouri and, in June 2005, the appellate court affirmed the circuit court ruling. In October 2005, the Court of Appeals granted our request for rehearing.

In December 2005, the appellate court issued a new opinion affirming the Circuit Court's opinion, but also opining that it was not too late to obtain the necessary approval. In light of this, we filed an application for approval with the Missouri Commission in January 2006. In January 2006, the trial court granted our request to stay the permanent injunction until May 31, 2006, and ordered us to post a $20 million bond to secure the cost of removing the project. Effective May 31, 2006, the Missouri Commission issued an order specifically authorizing our construction and operation of the power plant and substation. On June 2, 2006, the trial court dissolved the $20 million bond, further stayed its injunction, and authorized us to operate the plant and substation while Cass County appealed the Missouri Commission's order.

In June 2006, Cass County filed an appeal with the Circuit Court, challenging the lawfulness and reasonableness of the Missouri Commission's order. On October 20, 2006, the Circuit Court ruled that the Missouri Commission's order was unlawful and unreasonable. The Missouri Commission and Aquila appealed, and on March 4, 2008, the Missouri Court of Appeals for the Western District of Missouri affirmed the district court's decision. In March, the Missouri Commission and Aquila each requested that the Court of Appeals either rehear the case or transfer the case to the Missouri Supreme Court. On April 25, 2008, we entered into an agreement with Cass County pursuant to which we filed and Cass County is processing a land use application for the facilities. This application is set for a hearing before the County's Planning Board on July 22, 2008. The parties have also requested that the Court of Appeals stay a ruling on the rehearing and transfer request pending Cass County's review of the land use application. In addition, on June 12, 2008, we entered into a final settlement agreement with the members of StopAquila.org, an unincorporated association of approximately 100 individuals who opposed the facilities. This settlement agreement finally resolves our dispute with StopAquila. In addition, we have entered into agreements in principal to settle six of seven pending private lawsuits filed by Cass County residents alleging that the facilities constitute a public and private nuisance. We recorded reserves of $10.7 million for fines, legal fees, infrastructure investments and the potential resolution of various related claims in 2008, including $7.1 million in the first quarter of 2008. The actual amount required to resolve the related claims may be different than the amounts recorded. On June 16, 2008, Missouri Lt. Governor Peter Kinder (serving as acting Governor in Governor Blunt's absence from the state) signed into law SB720, a bill that grants to the Missouri Commission the authority to retroactively approve the development and construction of our South Harper facilities. The law will become effective August 28, 2008.

Note 9. Share-Based Compensation

In 2002, the Board and our shareholders approved the Omnibus Incentive Compensation Plan. This plan authorizes the issuance of 9,000,000 shares of Aquila common stock as stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance units, stock awards, cash-based awards and annual incentive awards to all eligible employees and directors of the company. All equity-based awards are issued under this plan. Generally, shares issued for stock option exercises and other share awards are made first from treasury shares, if available, and then from newly issued shares.

Effective on July 14, 2008, the Omnibus Incentive Compensation Plan was terminated and all outstanding, vested awards were converted to Great Plains Energy awards.

Stock Options

Stock options under this plan and preceding plans have been granted at market prices generally with one to three year vesting terms and have been exercisable for seven to 10 years from the date of grant. Cash received on stock options exercised, the intrinsic value of options exercised and the tax benefit realized were immaterial for the three months ended March 31, 2008. Stock options as of March 31, 2008 and changes during the three months ended March 31, 2008 were as follows:

	Shares	Weighted Average Exercise Prices	Remaining Contractual Term in Years
Beginning balance	3,740,720	$ 16.00	2.51
Granted	-	-	
Exercised	(8,750)	1.60	
Forfeited	(358,037)	22.89	
Ending balance	3,373,933	$ 15.30	2.50
Exercisable at March 31, 2008	3,373,933	$ 15.30	2.50

The aggregate intrinsic value of "in-the-money" outstanding and exercisable options was $.7 million as of March 31, 2008.

Time-Based Restricted Stock Awards

On July 31, 2007, 106,000 shares of restricted stock were awarded to members of our senior management. This award will vest in three years, and no restrictions on the sale of shares will apply thereafter. The time restriction on this award will lapse upon a change in control of the Company. The fair value of these stock awards is determined based on the number of shares granted and the quoted price of our stock on the date of the award. The total continuing and discontinued operations compensation expense related to this award was $.1 million for the three months ended March 31, 2008. As of March 31, 2008, the total compensation cost not yet recognized was $.3 million. This compensation cost will be recognized over the remaining restriction period through July 31, 2010. The total fair value of restricted stock released for the three months ended March 31, 2008 was $.2 million. Non-vested, time-based restricted stock awards as of March 31, 2008 and changes during the three months ended March 31, 2008 were as follows:

	Shares	Weighted Average Grant Date Fair Value	Remaining Contractual Term in Years
Beginning balance	258,982	$ 15.17	1.18
Awarded	–	–	
Released	(152,982)	23.06	
Forfeited	–	–	
Ending balance	106,000	$ 3.80	2.33

The aggregate intrinsic value of outstanding time-based restricted stock was $.3 million as of March 31, 2008.

Performance-Based Restricted Stock Awards

Performance-based restricted stock awards were granted in the third quarter of 2006 to qualified individuals, excluding senior management, consisting of the right to receive a number of shares of common stock at the end of the restriction period, March 1, 2008, assuming performance criteria were met. Additional performance-based restricted stock awards were granted to senior management in the third quarter of 2007 and will vest on December 31, 2008. The performance measure for both awards was the ratio of 2007 adjusted EBITDA to

2007 average net utility plant investment. The threshold level of performance was a ratio of 10.0%, target at a ratio of 11.5%, and maximum at a ratio of 13.0%. Shares would be earned at the end of the performance period as follows: 50% of the target number of shares if the threshold was reached, 100% if the target level of performance was reached and 150% if the ratio was at or above the maximum, with the number of shares interpolated between these levels. No shares would be payable if the threshold was not reached. The awards to senior management were also subject to reduction or forfeiture if the Company failed to achieve one or more of four operating metrics.

On February 26, 2008, our directors verified that the Company's non-GAAP 2007 Adjusted EBITDA was $265.0 million and the Company's 2007 average net utility plant investment was $1.9 billion, yielding a 13.8% ratio and a 150% payout. To compute the Company's 2007 Adjusted EBITDA, the Company's actual 2007 EBITDA from continuing operations of $239.0 million was increased by excluding $26.0 million of merger-related costs and severance costs incurred last year. Our directors also verified that each of the four operating metrics applicable to the restricted shares granted to senior management had been achieved, resulting in 100% of these restricted shares being earned by senior management. As a result, an additional 144,000 restricted shares were issued under both awards of performance-based restricted shares.

The fair value of these stock awards was determined based on the number of shares granted and the average of the high and low quoted price of our stock on the date of the award. An estimated annual turnover rate of 8% was assumed to determine the compensation expense related to the 2006 award. No estimated turnover was assumed to determine the compensation expense in the 2007 award to members of senior management. The total continuing and discontinued operations compensation expense related to these awards was $.4 million for the three months ended March 31, 2008. As of March 31, 2008, the estimated total compensation cost not yet recognized was $.4 million. This compensation cost will be recognized over the period through December 31, 2008. The total fair value of restricted stock released for the three months ended March 31, 2008 was $.3 million. Non-vested, performance-based restricted stock awards as of March 31, 2008 and changes during the three months ended March 31, 2008 were as follows:

	Shares	**Weighted Average Grant Date Fair Value**	**Remaining Contractual Term in Years**
Beginning balance	288,000	$ 4.16	.53
Awarded	144,000	4.16	
Released	(246,000)	4.44	
Forfeited	–	–	
Ending balance	186,000	$ 3.80	.75

The aggregate intrinsic value of outstanding performance-based restricted stock was $.6 million as of March 31, 2008.

Director Stock Awards

Non-employee directors receive as part of his or her annual retainer, an annual award of 7,500 shares of common stock of the Company. Each director may elect to defer receipt of their shares until retirement or until they are no longer a member of our Board of Directors. Shares are awarded on the last trading day of each calendar quarter. Compensation expense is based upon the fair market value of the Company's common stock at the date of issuance determined as the average of the high and low quoted price on that date. Director stock awards as of March 31, 2008 and changes during the three months ended March 31, 2008 were as follows:

	Shares	Weighted Average Grant Date Fair Value
Beginning balance	245,872	$ 4.38
Awarded	13,125	3.21
Released	(40,499)	4.76
Ending balance	218,498	$ 4.24

The aggregate intrinsic value of outstanding director stock awards was $.7 million as of March 31, 2008.

Note 10: Income Taxes

Income tax benefit in the first quarter of 2008 was $3.6 million. The effective tax rate was (74.0)%. The effective tax rate differed from the combined statutory rate primarily as a result of the recognition of $24.4 million of previously unrecognized tax benefits due to the settlement of an IRS examination discussed below. These tax benefits were partially offset by $15.6 million of valuation allowance provided against net deferred tax assets.

On October 9, 2007, we agreed to adjustments contained in IRS audit reports related to our 1998 to 2002 taxable years. In addition, the agreement stipulates consistent treatment during our 2003 and 2004 taxable years for certain issues related to our former businesses in Australia and Canada. On February 29, 2008, we received notice from the IRS indicating that the Joint Committee on Taxation had completed their review of the audits without objection. The audits resulted in the following adjustments: (i) we will receive tax refunds of $19.7 million, $4.9 million of which will be received after the 2003-2004 audit is complete; (ii) our federal net operating loss carryforwards decreased by $251.9 million; (iii) our capital loss carryforwards decreased by $53 million; (iv) our AMT credit decreased by $7.5 million; (v) our general business credit carryforward decreased by $5.7 million; and (vi) we will pay interest to the IRS of $6.2 million, $3.3 million of which is currently on deposit with the IRS. The impact of these adjustments, both positive and negative, was included in unrecognized tax benefits as of January 1, 2008.

The total amount of unrecognized income tax benefits at January 1, 2008 was $205.2 million, $169.2 million of which would have impacted the effective rate if recognized. We recognize accrued interest and penalties associated with uncertain tax positions as part of the tax provision. As of January 1, 2008, we had reserved $9.5 million of accrued interest, net of a $3.7 million tax benefit, associated with tax positions included in unrecognized tax benefits. At March 31, 2008, the amount of unrecognized income tax benefits decreased to $89.9 million. Of this amount, $88.3 million would impact the effective rate if recognized. We have no accrued interest and penalties associated with uncertain tax positions at March 31, 2008.

The $115.3 million decrease in unrecognized income tax benefits in the first quarter is due to our determination that tax positions related to the years 1998-2002 were effectively settled upon receipt of Joint Committee approval. It is possible that the amount of unrecognized tax benefits will change significantly within the next twelve months. This change could occur due to the IRS examination of our 2003-2004 tax years which is currently underway. We do not have an estimate of any changes at this time.

Rollforward of Unrecognized Tax Benefits from Uncertain Tax Positions

In millions	Unrecognized Tax Benefits	Accrued Interest
Balance at December 31, 2007	$ 205.2	$ 9.5
Additions related to 2008 tax positions	–	–
Additions related to tax positions prior years	–	–
Reductions related to tax positions prior years	–	–
Settlements	(115.3)	(9.5)
Balance at March 31, 2008	$ 89.9	$ –

Note 11. Fair Value Measurements

Effective January 1, 2008, we adopted SFAS 157, which provides a framework for measuring fair value under GAAP. SFAS 157 requires that the impact of this change in accounting for fair valued assets and liabilities be recorded as an adjustment to beginning retained earnings in the period of adoption. We did not have any adjustments to beginning retained earnings in the period of adoption.

SFAS 157 defines fair value as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. SFAS 157 also establishes a fair value hierarchy that requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. The standard describes three levels of inputs that may be used to measure fair value:

Level 1

Level 1 inputs are defined as quoted prices in active markets for identical assets or liabilities. Our Level 1 assets and liabilities include forward natural gas contracts and options that are traded on NYMEX.

Level 2

Level 2 inputs are observable inputs other than Level 1 prices such as quoted prices for similar assets or liabilities, quoted prices in markets that are not active, or other inputs that are observable or can be corroborated by observable market data for substantially the full term of the assets or liabilities. Our Level 2 assets and liabilities include physical natural gas delivery contracts, forward contracts and swaps with quoted prices primarily from direct broker quotes that are traded less frequently than exchange-traded instruments.

Level 3

Level 3 inputs are unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets or liabilities. Our Level 3 assets and liabilities include long-term physical natural gas delivery contracts for which observable prices are not available throughout the term. We determine the fair value of these contracts by modeling or extrapolating observable prices over the full term of the contracts.

Following is a summary of our net price risk management assets and liabilities by category as of March 31, 2008:

In millions	Utilities	Merchant Services	Total
Level 1	$ 22.0	$ –	$ 22.0
Level 2	–	2.1	2.1
Level 3	–	5.5	5.5
Total Fair Value	$ 22.0	$ 7.6	$ 29.6

Following is a reconciliation of fair value measurements using significant unobservable inputs (Level 3) from initial adoption on January 1, 2008 through March 31, 2008:

In millions	Utilities	Merchant Services	Total
Balance at January 1, 2008	$ –	$ 4.8	$ 4.8
Gains or (losses) in earnings	–	.4	.4
Purchases, sales, issuances and settlements, net	–	.3	.3
Transfers in and/or out of Level 3	–	–	–
Balance at March 31, 2008	$ –	$ 5.5	$ 5.5

The total of unrealized gains or (losses) for the three months ended March 31, 2008, included in net sales for Merchant Services was $.4 million.

FSP SFAS 157-2 allows for a deferral from the SFAS 157 disclosures for non-financial assets or liabilities until fiscal years beginning after November 15, 2008. We did not have any non-financial assets or liabilities accounted for on a fair value basis in the period ending March 31, 2008.

AQUILA, INC.

UNAUDITED PRO FORMA CONDENSED CONSOLIDATED FINANCIAL INFORMATION

The Unaudited Pro Forma Condensed Consolidated Financial Statements of Aquila have been prepared to reflect the sale of Aquila's electric utility assets in Colorado and its gas utilities assets in Colorado, Kansas, Nebraska and Iowa along with the associated liabilities to Black Hills (Asset Sale).

The following Aquila Unaudited Pro Forma Condensed Consolidated Statement of Income for the three months ended March 31, 2008 and the year ended December 31, 2007, gives effect to the Asset Sale as if it had occurred on January 1, 2007. The Unaudited Pro Forma Condensed Consolidated Balance Sheet as of March 31, 2008, gives effect to the Asset Sale as if it had occurred on March 31, 2008. The pro forma adjustments are described in the accompanying notes.

The Unaudited Pro Forma Condensed Consolidated Financial Statements should be read in connection with Aquila's consolidated financial statements as of December 31, 2007, including the notes thereto, included in this Current Report on Form 8-K as Exhibit 99.1. The statements should also be read in conjunction with the unaudited consolidated financial statements as of March 31, 2008, including the notes thereto, included in this Current Report on Form 8-K as Exhibit 99.2. The accompanying Unaudited Pro Forma Condensed Consolidated Financial Statements are provided for informational purposes only and are not necessarily indicative of the consolidated financial position or results of operations of Aquila that would have been reported had the Asset Sale been completed at the dates indicated, nor is it indicative of Aquila's future consolidated financial position or results of operations.

The accompanying Unaudited Pro Forma Condensed Consolidated Financial Statements do not reflect the impact of all financing, liquidity, acquisition or other use of proceeds from the Asset Sale that may have occurred (or may occur) subsequent to March 31, 2008.

AQUILA, INC.
Unaudited Pro Forma Condensed Consolidated Statement of Income
For the Three Months Ended March 31, 2008

	Aquila Historical	Pro Forma Adjustments A	Aquila Historical As Adjusted
	(millions, except per share amounts)		
Operating Revenues			
Electric revenues	$ 199.1	$ (50.7)	$ 148.4
Gas revenues	277.6	(277.6)	-
Other revenues	6.4	(7.5)	(1.1)
Total	483.1	(335.8)	147.3
Operating Expenses			
Fuel	247.4	(211.8)	35.6
Purchased power	72.8	(31.7)	41.1
Operating expenses	76.8	(32.3)	44.5
Selling, general and administrative - non-regulated	1.9	(0.8)	1.1
Maintenance	13.9	(2.4)	11.5
Depreciation and amortization	29.1	(10.7)	18.4
General taxes	7.3	(3.0)	4.3
Total	449.2	(292.7)	156.5
Operating income (loss)	33.9	(43.1)	(9.2)
Non-operating income (expense)	3.0	0.4	3.4
Interest charges	(38.2)	-	(38.2)
Loss from continuing operations before income taxes	(1.3)	(42.7)	(44.0)
Income tax benefit	9.8	-	9.8
Income (loss) from continuing operations	$ 8.5	$ (42.7)	$ (34.2)
Average number of basic common shares outstanding	375.9		375.9
Average number of diluted common shares outstanding	376.1		376.1
Basic and diluted income (loss) from continuing operations per common share	$ 0.02		$ (0.09)

The accompanying Notes to Unaudited Pro Forma Condensed Consolidated Financial Statements are an integral part of these statements.

AQUILA, INC.
Unaudited Pro Forma Condensed Consolidated Statement of Income
For the Year Ended December 31, 2007

	Aquila Historical	Pro Forma Adjustments A	Aquila Historical As Adjusted
Operating Revenues	(millions, except per share amounts)		
Electric revenues	$ 837.8	$ (178.0)	$ 659.8
Gas revenues	606.1	(606.1)	-
Other revenues	22.7	(30.9)	(8.2)
Total	1,466.6	(815.0)	651.6
Operating Expenses			
Fuel	594.0	(443.5)	150.5
Purchased power	287.6	(103.4)	184.2
Operating expenses	276.8	(107.8)	169.0
Selling, general and administrative - non-regulated	8.1	(3.1)	5.0
Maintenance	56.0	(10.6)	45.4
Depreciation and amortization	108.3	(42.1)	66.2
General taxes	28.2	(12.8)	15.4
Loss on property and other charges	1.3	-	1.3
Total	1,360.3	(723.3)	637.0
Operating income (loss)	106.3	(91.7)	14.6
Non-operating income (expense)	24.4	1.9	26.3
Interest charges	(141.2)	-	(141.2)
Loss from continuing operations before income taxes	(10.5)	(89.8)	(100.3)
Income tax expense	(7.6)	-	(7.6)
Loss from continuing operations	$ (18.1)	$ (89.8)	$ (107.9)
Average number of basic common shares outstanding	375.7		375.7
Average number of diluted common shares outstanding	375.7		375.7
Basic and diluted loss from continuing operations per common share	$ (0.05)		$ (0.29)

The accompanying Notes to Unaudited Pro Forma Condensed Consolidated Financial Statements are an integral part of these statements.

AQUILA, INC.
Unaudited Pro Forma Condensed Consolidated Balance Sheet
March 31, 2008

	Aquila Historical	Pro Forma Adjustments		Aquila Historical As Adjusted
ASSETS		(millions)		
Current Assets				
Cash and cash equivalents	$ 28.2	$ 908.8	C	$ 937.0
Restricted cash	1.3	-		1.3
Funds on deposit	33.9	-		33.9
Receivables, net	241.0	(115.1)	B	125.9
Fuel inventories, at average cost	41.4	(6.0)	B	35.4
Materials and supplies, at average cost	37.3	(5.4)	B	31.9
Derivative instruments	46.0	(1.6)	B	44.4
Other	19.8	(12.9)	B	6.9
Total	448.9	767.8		1,216.7
Nonutility Property and Investments				
Nonutility plant, net	129.0	(2.0)	B	127.0
Other	-	-		-
Total	129.0	(2.0)		127.0
Utility Plant, at Original Cost				
Utility Plant	3,207.9	(1,087.4)	B	2,120.5
Less-accumulated depreciation	1,399.4	(563.0)	B	836.4
Net utility plant in service	1,808.5	(524.4)		1,284.1
Construction work in progress	279.8	(12.8)	B	267.0
Total	2,088.3	(537.2)		1,551.1
Deferred Charges and Other Assets				
Regulatory assets	161.9	(55.3)	B	106.6
Goodwill	111.0	-		111.0
Deferred income taxes	6.3	-		6.3
Derivative instruments	16.4	-		16.4
Pension asset	2.6	23.7	B	26.3
Other	38.5	0.6	B	39.1
Total	336.7	(31.0)		305.7
Total	$ 3,002.9	$ 197.6		$ 3,200.5

The accompanying Notes to Unaudited Pro Forma Condensed Consolidated Financial Statements are an integral part of these statements.

AQUILA, INC.
Unaudited Pro Forma Condensed Consolidated Balance Sheet
March 31, 2008

	Aquila Historical	Pro Forma Adjustments		Aquila Historical As Adjusted
LIABILITIES AND CAPITALIZATION		(millions)		
Current Liabilities				
Current maturities of long-term debt	$ 2.4	$ -		$ 2.4
Notes payable	100.0	-		100.0
Accounts payable	135.7	(62.0)	B	73.7
Accrued taxes	13.1	-		13.1
Accrued interest	31.4	(0.5)	B	30.9
Accrued compensation and benefits	11.5	(1.6)	B	9.9
Pension and post-retirement liability	3.3	(1.7)	B	1.6
Derivative instruments	30.6	-		30.6
Other	62.9	3.9	B, D	66.8
Total	390.9	(61.9)		329.0
Deferred Credits and Other Liabilities				
Deferred investment tax credits	6.3	-		6.3
Asset retirement obligations	11.6	(2.4)	B	9.2
Pension and post-retirement liability	46.8	(21.2)	B	25.6
Regulatory liabilities	104.9	(13.0)	B	91.9
Derivative instruments	0.6	-		0.6
Other	41.8	(9.5)	B	32.3
Total	212.0	(46.1)		165.9
Capitalization				
Common shareholders' equity				
Common stock	3,888.8	-		3,888.8
Retained earnings (deficit)	(2,524.6)	305.6	E	(2,219.0)
Treasury stock, at cost	(0.3)	-		(0.3)
Accumulated other comprehensive loss	2.0	-		2.0
Total	1,365.9	305.6		1,671.5
Long-term debt	1,034.1	-		1,034.1
Total	2,400.0	305.6		2,705.6
Commitments and Contingencies				
Total	$ 3,002.9	$ 197.6		$ 3,200.5

The accompanying Notes to Unaudited Pro Forma Condensed Consolidated Financial Statements are an integral part of these statements.

AQUILA, INC.
NOTES TO UNAUDITED PRO FORMA CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

1. Basis of Presentation

The Unaudited Pro Forma Condensed Consolidated Financial Statements have been prepared to reflect the Asset Sale.

2. Synergies

The pro forma adjustments do not include any amounts related to expected synergies or restructuring activities.

3. Reclassifications

Certain reclassifications have been made to Aquila's historical presentation in order to conform to Great Plains Energy's historical presentation. These reclassifications had no impact on the historical loss from continuing operations reported by Aquila.

4. Pro Forma Adjustments

The pro forma adjustments represent preliminary estimates to reflect the Asset Sale.

The pro forma adjustments included in the Unaudited Pro Forma Condensed Consolidated Financial Statements are as follows:

A—These Unaudited Pro Forma Condensed Consolidated Statement of Income adjustments represent the elimination of income from continuing operations directly associated with the Asset Sale. In addition, $9.0 million and $36.6 million of costs related to certain centralized functions to be acquired by Black Hills have been included in the pro forma adjustments for the three months ended March 31, 2008 and year ended December 31, 2007, respectively. Aquila's corporate headquarters and centralized functions to be retained by Great Plains Energy were not included within the pro forma adjustments, including $9.8 million and $38.2 million of net operating expenses that Aquila allocated previously to the utility operations being acquired by Black Hills for the three months ended March 31, 2008 and year ended December 31, 2007, respectively.

B—These pro forma adjustments represent the elimination of assets and liabilities directly associated with the Asset Sale. Assets and liabilities related to certain centralized functions to be acquired by Black Hills have also been included in the pro forma adjustments. Aquila's corporate headquarters and centralized functions to be retained by Great Plains Energy were not included in the pro forma adjustments.

C—This pro forma adjustment represents the net cash proceeds related to the Asset Sale. The net cash proceeds of $908.8 million from the Asset Sale are based on estimated working capital and capital expenditures as of March 31, 2008. The net cash proceeds are subject to a working capital true up later in the year.

D—This pro forma adjustment represents the accrual of $6.2 million in estimated closing transaction costs related to the Asset Sale and a provision for pension funding of $11.8 million.

E—This pro forma adjustment represents the $305.6 million gain on the Asset Sale after transaction costs.

GREAT PLAINS ENERGY INCORPORATED
UNAUDITED PRO FORMA CONDENSED COMBINED FINANCIAL INFORMATION

The Unaudited Pro Forma Condensed Combined Financial Statements have been prepared to reflect the acquisition of Aquila by Great Plains Energy. The acquisition was accomplished by merging a wholly-owned subsidiary of Great Plains Energy into Aquila, with Aquila being the surviving company. Immediately prior to Great Plains Energy's acquisition of Aquila, Black Hills acquired from Aquila its electric utility assets in Colorado and its gas utilities assets in Colorado, Kansas, Nebraska and Iowa along with the associated liabilities (Asset Sale). Following the closing of the Asset Sale and acquisition, Great

Plains Energy became the parent company of Aquila, including its Missouri-based utilities consisting of Missouri Public Service and St. Joseph Light & Power divisions.

The Unaudited Pro Forma Condensed Combined Statement of Income combines the historical consolidated statements of income for Great Plains Energy and Aquila, as adjusted for the Asset Sale, giving effect to the acquisition as if it had occurred on January 1, 2007. The Unaudited Pro Forma Condensed Combined Balance Sheet combines the historical unaudited consolidated balance sheets of Great Plains Energy and Aquila, as adjusted for the Asset Sale, giving effect to the acquisition as if it had been consummated on March 31, 2008. These Unaudited Combined Pro Forma Financial Statements should be read in conjunction with the:

- accompanying notes to the Unaudited Pro Forma Condensed Combined Financial Information;

- separate Unaudited Pro Forma Condensed Consolidated Financial Information (and the notes thereto) of Aquila included in this Exhibit 99.3;

- separate unaudited financial statements of Great Plains Energy as of and for the three months ended March 31, 2008, included in the Great Plains Energy Quarterly Report on Form 10-Q for the three months ended March 31, 2008, which is incorporated by reference into this document;

- separate historical financial statements of Great Plains Energy as of and for the year ended December 31, 2007, included in the Great Plains Energy Current Report on Form 8-K filed August 8, 2008, which is incorporated by reference into this document;

- separate unaudited financial statements of Aquila as of and for the three months ended March 31, 2008, included in this Current Report on Form 8-K as Exhibit 99.2, which is incorporated by reference into this document; and

- separate historical financial statements of Aquila as of and for the year ended December 31, 2007, included in this Current Report on Form 8-K as Exhibit 99.1, which is incorporated by reference.

The historical financial information of Great Plains Energy and Aquila, as adjusted as of and for the three months ended March 31, 2008 reflected in the Unaudited Pro Forma Condensed Combined Financial Information is unaudited. The historical financial information of Great Plains Energy and Aquila, as adjusted as of and for the year ended December 31, 2007, reflected in the Unaudited Pro Forma Condensed Combined Financial Information is derived from the audited financial statements of Great Plains Energy and Aquila, respectively, but does not include all disclosures required by accounting principles generally accepted in the United States of America. The Unaudited Pro Forma Condensed Combined Financial Information is provided for informational purposes only and is not necessarily indicative of what the combined companies' financial position or results of operations actually would have been had the acquisition been completed at the dates indicated. In addition, the unaudited pro forma condensed combined financial information is not intended to project the future financial position or results of operations of the combined company.

The Unaudited Pro Forma Condensed Combined Financial Statements were prepared using the purchase method of accounting with Great Plains Energy as the acquirer. Accordingly, the historical consolidated financial information has been adjusted to give effect to the impact of the consideration issued in connection with the merger. In the Unaudited Pro Forma Condensed Combined Balance Sheet, Great Plains Energy's cost to acquire Aquila has been allocated to the assets to be acquired and liabilities to be assumed based upon Great Plains Energy's management's preliminary estimate of their respective fair values. Any differences between the purchase price and the fair value of the assets and liabilities to be acquired will be recorded as goodwill. In Great Plains Energy's opinion, the fair value of the assets acquired and liabilities (excluding long-term debt) assumed will approximate book value in a rate-regulated merger. Non-regulated assets and liabilities will be recorded at fair value. The amounts allocated to the assets acquired and liabilities assumed in the Unaudited Pro Forma Condensed Combined Financial Statements are based on Great Plains Energy's management's preliminary internal valuation estimates. The final allocation of the purchase price will be based upon the fair value of the assets acquired and liabilities assumed of Aquila on the date the acquisition was completed. Accordingly, the pro forma purchase allocation adjustments are preliminary and have been made solely for the purpose of providing unaudited pro forma condensed combined financial information and are subject to revision based on a final determination of fair value following the closing of the acquisition. Final determinations of fair value may differ materially from those presented herein. Aquila's integrated regulated operations comprised of the Missouri Public Service and St. Joseph Light & Power divisions are accounted for pursuant to SFAS No. 71 "Accounting for the Effects of Certain Types of Regulation." Under the rate setting and recovery provisions currently in place and expected to continue in place for these regulated operations, revenues are derived from earning a return on, and a recovery of, the original cost of assets and liabilities. Accordingly, the fair values of the individual tangible assets and liabilities are estimated to approximate the carrying values. The estimated fair values of the assets and liabilities of these operations could also be materially affected by the rate structure of Aquila's utilities upon completion of the acquisition.

The Unaudited Pro Forma Condensed Combined Statement of Income also includes certain purchase accounting adjustments, including adjustments for events that are directly attributable to the acquisition; factually supportable; and with respect to the statements of income, expected to have a continuing impact on the combined company's results. The pro forma adjustments are described in the accompanying notes.

The purchase method of accounting applied to the acquisition is based on current accounting literature. In December 2007, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 141 (revised 2007), "Business Combinations" changing the rules governing the application of purchase accounting. The provisions of this statement are effective for Great Plains Energy prospectively for business combinations occurring on or after the beginning of January 1, 2009, except it requires the prospective application of the provisions related to income taxes to business combinations occurring in 2008. As SFAS No. 141(R) is effective for the Aquila acquisition as related to provisions for income taxes, any adjustments to Aquila's deferred tax assets and uncertain tax position balances that occur after the measurement period, which is limited to a maximum of one year from the acquisition date, will be recorded as a component of income tax expense as required by the standard. Previously, under SFAS No. 141, adjustments to deferred tax assets and uncertain tax position balances that occurred after the measurement period were recorded as a component of goodwill.

GREAT PLAINS ENERGY INCORPORATED
Unaudited Pro Forma Condensed Combined Statement of Income
For the Three Months Ended March 31, 2008

	Great Plains Energy Historical As Adjusted A	Aquila Historical As Adjusted A	Pro Forma Adjustments	Great Plains Energy Combined Pro Forma
	(millions, except per share amounts)			
Operating Revenues				
Electric revenues - Utility	$ 297.6	$ 148.4	$ -	$ 446.0
Other revenues	-	(1.1)		(1.1)
Total	297.6	147.3	-	444.9
Operating Expenses				
Fuel	54.7	35.6		90.3
Purchased power - Utility	30.8	41.1		71.9
Operating expenses	74.0	44.5	4.8 P	118.1
			(5.2) R	
Selling, general and administrative - non-regulated	8.9	1.1		10.0
Maintenance	30.2	11.5		41.7
Depreciation and amortization	50.2	18.4		68.6
General taxes	29.7	4.3		34.0
Total	278.5	156.5	(0.4)	434.6
Operating income (loss)	19.1	(9.2)	0.4	10.3
Non-operating income (expense)	8.0	3.4		11.4
Interest charges	(41.6)	(38.2)		(79.8)
Income (loss) from continuing operations before income taxes and loss from equity investments	(14.5)	(44.0)	0.4	(58.1)
Income tax (expense) benefit	9.5	9.8	32.2 L	51.4
			1.9 P	
			(2.0) R	
Loss from equity investments, net of income taxes	(0.4)	-		(0.4)
Income (loss) from continuing operations	(5.4)	(34.2)	32.5	(7.1)
Preferred stock dividend requirements	0.4	-		0.4
Income (loss) from continuing operations available for common shareholders	$ (5.8)	$ (34.2)	$ 32.5	$ (7.5)
Average number of basic common shares outstanding	85.9	375.9		118.1
Average number of diluted common shares outstanding	85.9	376.1		118.1
Basic and diluted loss from continuing operations per common share	$ (0.07)	$ (0.09)		$ (0.06)

The accompanying Notes to Unaudited Pro Forma Condensed Combined Financial Statements are an integral part of these statements.

GREAT PLAINS ENERGY INCORPORATED
Unaudited Pro Forma Condensed Combined Statement of Income
For the Year Ended December 31, 2007

	Great Plains Energy Historical	Aquila Historical As Adjusted A	Pro Forma Adjustments	Great Plains Energy Combined Pro Forma
	(millions, except per share amounts)			
Operating Revenues				
Electric revenues - Utility	$ 1,292.7	$ 659.8	$ -	$ 1,952.5
Other revenues	-	(8.2)		(8.2)
Total	1,292.7	651.6	-	1,944.3
Operating Expenses				
Fuel	245.5	150.5		396.0
Purchased power - Utility	101.0	184.2		285.2
Skill set realignment (deferral) cost	(8.9)	-		(8.9)
Operating expenses	295.8	169.0	7.0 P (6.7) R	465.1
Selling, general and administrative - non-regulated	20.9	5.0		25.9
Maintenance	91.7	45.4		137.1
Depreciation and amortization	175.6	66.2		241.8
General taxes	114.4	15.4		129.8
Loss on property and other charges	-	1.3		1.3
Other	0.2	-		0.2
Total	1,036.2	637.0	0.3	1,673.5
Operating income (loss)	256.5	14.6	(0.3)	270.8
Non-operating income (expense)	3.2	26.3		29.5
Interest charges	(91.9)	(141.2)		(233.1)
Income (loss) from continuing operations before income taxes and loss from equity investments	167.8	(100.3)	(0.3)	67.2
Income tax (expense) benefit	(44.9)	(7.6)	70.2 L (2.5) R 2.7 P	17.9
Loss from equity investments, net of income taxes	(2.0)	-		(2.0)
Income (loss) from continuing operations	120.9	(107.9)	70.1	83.1
Preferred stock dividend requirements	1.6	-		1.6
Income (loss) from continuing operations available for common shareholders	$ 119.3	$ (107.9)	$ 70.1	$ 81.5
Average number of basic common shares outstanding	84.9	375.7		117.1
Average number of diluted common shares outstanding	85.2	375.7		117.4
Earnings (loss) from continuing operations per common share				
Basic	$ 1.41	$ (0.29)		$ 0.70
Diluted	1.40	(0.29)		0.69

The accompanying Notes to Unaudited Pro Forma Condensed Combined Financial Statements are an integral part of these statements.

GREAT PLAINS ENERGY INCORPORATED
Unaudited Pro Forma Condensed Combined Balance Sheet
March 31, 2008

	Great Plains Energy Historical As Adjusted A	Aquila Historical As Adjusted A	Pro Forma Adjustments		Great Plains Energy Combined Pro Forma
ASSETS		(millions)			
Current Assets					
Cash and cash equivalents	$ 16.1	$ 937.0	$ (677.2)	K	$ 275.9
Restricted cash	-	1.3			1.3
Funds on deposit	-	33.9			33.9
Receivables, net	139.8	125.9	(0.7)	B	274.1
			5.8	R	
			3.3	J	
Fuel inventories, at average cost	42.9	35.4			78.3
Materials and supplies, at average cost	65.4	31.9			97.3
Deferred refueling outage costs	10.7	-			10.7
Refundable income taxes	21.2	-			21.2
Deferred income taxes	2.0	-			2.0
Assets of discontinued operations	637.5	-			637.5
Derivative instruments	3.1	44.4			47.5
Other	12.7	6.9			19.6
Total	951.4	1,216.7	(668.8)		1,499.3
Nonutility Property and Investments					
Affordable housing limited partnerships	16.6	-			16.6
Nuclear decommissioning trust fund	106.9	-			106.9
Nonutility plant, net	-	127.0			127.0
Other	7.3	-			7.3
Total	130.8	127.0	-		257.8
Utility Plant, at Original Cost					
Utility Plant	5,514.2	2,120.5	(20.0)	S	7,614.7
Less-accumulated depreciation	2,638.9	836.4			3,475.3
Net utility plant in service	2,875.3	1,284.1	(20.0)		4,139.4
Construction work in progress	662.9	267.0			929.9
Nuclear fuel, net of amortization	57.8	-			57.8
Total	3,596.0	1,551.1	(20.0)		5,127.1
Deferred Charges and Other Assets					
Regulatory assets	401.2	106.6	21.6	M	592.0
			62.6	R	
Goodwill	-	111.0	(111.0)	I	138.7
			138.7	D	
Deferred income taxes	-	6.3	(6.3)	N	-
Derivative instruments	0.1	16.4			16.5
Pension asset	-	26.3			26.3
Other	42.7	39.1	(23.6)	H	58.2
Total	444.0	305.7	82.0		831.7
Total	$ 5,122.2	$ 3,200.5	$ (606.8)		$ 7,715.9

The accompanying Notes to Unaudited Pro Forma Condensed Combined Financial Statements are an integral part of these statements.

GREAT PLAINS ENERGY INCORPORATED
Unaudited Pro Forma Condensed Combined Balance Sheet
March 31, 2008

	Great Plains Energy Historical As Adjusted	A	Aquila Historical As Adjusted	A	Pro Forma Adjustments		Great Plains Energy Combined Pro Forma
LIABILITIES AND CAPITALIZATION					(millions)		
Current Liabilities							
Notes payable	$ 68.0		$ 100.0		$ -		$ 168.0
Commercial paper	163.9		-				163.9
Current maturities of long-term debt	0.3		2.4				2.7
Accounts payable	254.5		73.7		(0.7)	B	327.5
Accrued taxes	36.6		13.1				49.7
Accrued interest	26.0		30.9				56.9
Accrued compensation and benefits	24.1		9.9		4.8	P	38.8
Pension and post-retirement liability	1.3		1.6				2.9
Liabilities of discontinued operations	286.4		-				286.4
Derivative instruments	38.4		30.6				69.0
Other	10.1		66.8		56.5	R	166.3
					8.9	H	
					8.3	J	
					15.7	Q	
Total	909.6		329.0		93.5		1,332.1
Deferred Credits and Other Liabilities							
Deferred income taxes	598.7		-		(86.8)	C	423.6
					(88.4)	L	
					8.3	M	
					(6.3)	N	
					(1.9)	P	
Deferred investment tax credits	26.7		6.3				33.0
Asset retirement obligations	107.4		9.2				116.6
Pension and post-retirement liability	156.4		25.6				182.0
Regulatory liabilities	138.9		91.9				230.8
Derivative instruments	-		0.6				0.6
Other	59.7		32.3				92.0
Total	1,087.8		165.9		(175.1)		1,078.6
Capitalization							
Common shareholders' equity							
Common stock	1,070.1		3,888.8		(3,888.8)	E	2,099.8
					1,026.5	F	
					3.2	G	
Retained earnings (deficit)	518.1		(2,219.0)		(111.0)	I	530.0
					2,330.0	E	
					11.9	R	
Treasury stock, at cost	(3.3)		(0.3)		0.3	E	(3.3)
Accumulated other comprehensive income (loss)	48.0		2.0		(2.0)	E, M	48.0
Total	1,632.9		1,671.5		(629.9)		2,674.5
Cumulative preferred stock	39.0		-				39.0
Long-term debt	1,452.9		1,034.1		104.7	O	2,591.7
Total	3,124.8		2,705.6		(525.2)		5,305.2
Commitments and Contingencies							
Total	$ 5,122.2		$ 3,200.5		$ (606.8)		$ 7,715.9

The accompanying Notes to Unaudited Pro Forma Condensed Combined Financial Statements are an integral part of these statements.

1. Basis of Presentation

The Unaudited Pro Forma Condensed Combined Financial Statements have been prepared to reflect the acquisition of Aquila by Great Plains Energy.

The estimated purchase price and the allocation of the estimated purchase price discussed below are preliminary. The actual purchase price will be based upon the value of Great Plains Energy shares issued to Aquila shareholders, the fair value of the Aquila share-based compensation that will be exchanged for Great Plains Energy's share-based compensation and the actual transaction-related costs of Great Plains Energy. The final allocation of the purchase price will be based upon the fair value of the assets acquired and liabilities assumed of Aquila on July 14, 2008, the date the acquisition was completed.

The preliminary estimated total purchase price of the merger, as if it occurred on March 31, 2008, is as follows:

(Amounts in millions, except share data)			
Aquila common shares outstanding	(1)		376.0
Director stock awards			0.2
Total Aquila common shares to be converted to Great Plains Energy shares			376.2
Great Plains Energy share price	(2)	$	31.88
Exchange ratio into Great Plains Energy shares	(3)		0.0856
Equivalent number of Great Plains Energy shares	(4)		32.2
Option exchange ratio	(5)		0.159
Estimated fair value of Great Plains Energy shares issued	(6)	$	1,026.5
Cash consideration paid	(7)	$	677.2
Estimated fair value of stock options exchanged	(8)	$	3.2
Estimated transaction-related costs	(9)	$	32.5
Total preliminary estimated purchase price		$	1739.4

(1) For pro forma purposes, the shares outstanding represent the total number of common shares of Aquila outstanding as of March 31, 2008. The actual purchase price will be based on the total shares of Aquila outstanding as of July 14, 2008, the effective date of the acquisition.

(2) The share price used herein is based on the average closing price of Great Plains Energy common stock for the period beginning two trading days before and ending two trading days after the announcement of the transaction. The range of dates for Great Plains Energy was between February 5, 2007 and February 9, 2007, and is herein referred to as the Great Plains Energy Share Price.

(3) The Exchange Ratio for Great Plains Energy shares to be issued to Aquila shareholders is defined in the Agreement and Plan of Merger among Aquila, Great Plains Energy Incorporated, Gregory Acquisition Corp. and Black Hills Corporation, dated as of February 6, 2007 (Merger Agreement), which was filed as Exhibit 10.1 to Great Plains Energy Incorporated's Current Report on Form 8-K dated February 7, 2007 and filed with the SEC on February 8, 2007.

(4) The equivalent number of Great Plains Energy shares is based on the Aquila common shares outstanding as of March 31, 2008, multiplied by the Exchange Ratio into Great Plains Energy shares.

(5) The Option Exchange Ratio, as defined in the Merger Agreement, is the Exchange Ratio plus the ratio derived by dividing the per share cash amount by the Parent Company Stock Value, which is defined in the agreement as the average of the closing sales prices for a share of Parent Common Stock over the five consecutive trading days ending with the second complete trading day prior to the closing date (not counting the closing date). The Parent Company Stock Value used herein is based on the average

closing price for Great Plains Energy stock for the period between March 20, 2008 and March 27, 2008.

(6) The estimated fair value of Great Plains Energy shares issued is the equivalent number of Great Plains Energy shares multiplied by the Great Plains Energy Share Price.

(7) Cash consideration paid is calculated as the total number of Aquila common shares to be converted to Great Plains Energy Shares, multiplied by $1.80, as defined in the merger agreement.

(8) The estimated fair value of the stock options exchanged in the merger is calculated by multiplying the excess of the Great Plains Energy Share Price of $31.88 over the converted exercise price of Aquila stock options by the new Great Plains Energy options issued. The fair value of the new Great Plains Energy options issued for the purposes of these Unaudited Pro Forma Condensed Combined Financial Statements may differ from the fair value determined at closing.

(9) The estimated costs directly related to the merger transaction are comprised of Great Plains Energy financial advisory, legal, and other professional services fees, excluding all of the merger-related expenses of Aquila.

The Unaudited Pro Forma Condensed Combined Financial Statements do not reflect the impact of all financing, liquidity or other balance sheet repositioning that may be undertaken subsequent to the acquisition, nor does it reflect any other changes that might occur regarding the Great Plains Energy and Aquila combined portfolios of businesses.

2. Synergies

Great Plains Energy expects to incur transaction and transition costs related to the acquisition and to realize cost savings and synergies commencing upon the consummation of the acquisition. These cost savings and synergies are not included in the pro forma financial information.

The Unaudited Pro Forma Condensed Combined Financial Statements are not necessarily indicative of what the combined company's financial position or results of operations actually would have been had the Asset Sale and acquisition been completed at the dates indicated. Aquila historical information has been adjusted for the Asset Sale. In relation to the Asset Sale, the pro forma adjustments include eliminations of the assets sold and the liabilities, revenues and expenses directly associated with the assets sold. Therefore, costs related to centralized functions that have not been eliminated would more than likely be significant in relation to the significant amount of assets sold.

Except as discussed at Note 4, adjustment J & Q to the Unaudited Pro Forma Condensed Combined Balance Sheet, the Unaudited Pro Forma Condensed Combined Financial Statements do not reflect any nonrecurring charges expected to result from the acquisition. The majority of nonrecurring charges resulting from the acquisition are anticipated to be comprised of executive separation, employee termination costs and other exit costs related to the Aquila business that will be recognized in the opening balance sheet in accordance with Emerging Issues Task Force (EITF) Issue No 95-3, "Recognition of Liabilities in Connection with a Purchase Business Combination." Other acquisition-related charges may be incurred that do not meet the criteria in EITF Issue No 95-3, including employee termination and exit costs related to the acquired business and other integration-related costs.

3. Reclassifications

Certain reclassifications have been made to Aquila's historical financial statement presentation in order to conform to Great Plains Energy's historical financial statement presentation. These reclassifications had no impact on the historical income from continuing operations reported by Aquila.

Based on Great Plains Energy's review of Aquila's summary of significant accounting policies disclosed in Aquila's financial statements, the most significant difference in accounting policies noted relates to the accounting for planned major maintenance activities and classification of interest and penalties related to uncertain tax positions.

Great Plains Energy early adopted the provisions of FASB Staff Position (FSP) No. AUG AIR-1, "Accounting for Planned Major Maintenance Activities", which prohibits the use of the accrue-in-advance method of accounting for planned major maintenance activities. Aquila adopted the direct expense method, but, as permitted by regulatory authorities will continue to use the accrue-in-advance method of accounting for planned major maintenance activities.

With the adoption of FASB Interpretation (FIN) No. 48, “Accounting for Uncertainty in Income Taxes,” an interpretation of SFAS No. 109, “Accounting for Income Taxes” January 1, 2007, an accounting policy difference was noted with respect to the classification of interest and penalties related to uncertain tax positions. Upon adoption, Great Plains Energy elected to make an accounting policy change to recognize interest accrued related to unrecognized tax benefits in interest expense and penalties in non-operating expenses. Aquila recognizes interest and penalties as part of the tax provision. Amounts have been reclassified to conform to Great Plains Energy’s presentation in the Unaudited Pro Forma Condensed Combined Financial Statements.

Upon consummation of the acquisition, further review of Aquila’s accounting policies and financial statements may result in required revisions to Aquila’s policies and classifications to conform to those of Great Plains Energy.

4. Pro Forma Adjustments

The pro forma adjustments reflect the allocation of the estimated purchase price at an amount equal to the preliminary estimate of their fair values to the Aquila pro forma current and non-current tangible assets, intangible assets, and current and non-current liabilities; the amortization expense related to the estimated definite-lived intangible assets; changes in depreciation and amortization expense resulting from the estimated fair value adjustments to net tangible assets; elimination of intercompany transactions; and the income tax effect related to the pro forma adjustments.

The pro forma combined provisions for income taxes do not reflect the amounts that would have resulted had Great Plains Energy and Aquila as adjusted filed consolidated income tax returns during the periods presented.

The pro forma adjustments included in the Unaudited Pro Forma Condensed Combined Financial Statements are as follows:

A—Great Plains Energy and Aquila As Adjusted Historical Presentation—The March 31, 2008 amounts presented for Great Plains Energy represent the historical amounts recast to reflect Strategic Energy as discontinued operations consistent with the December 31, 2007 income statement included in this document. The amounts presented for Aquila represent the Aquila historical amounts as adjusted as presented in the Aquila Unaudited Pro Forma Condensed Consolidated Balance Sheet and Statements of Income.

B—The pro forma adjustment represents the elimination of transactions between Great Plains Energy and Adjusted Aquila included in each company’s historical balance sheet. The underlying amounts in these adjustments relate to joint owner activities.

C—The pro forma adjustment represents the deferred tax impact related to the net amount assigned to the current and non-current assets and liabilities of Adjusted Aquila. This adjustment does not consider the goodwill in excess of the Adjusted Aquila historical carrying amount and the deferred tax impacts of the other pro forma adjustments. Income tax effects have been calculated using the Aquila statutory federal and blended state rate of 38.8% and could change based on changes in the applicable tax rates and finalization of the consolidated company’s tax position after the July 14, 2008 close.

D—The pro forma adjustment represents goodwill, i.e. the excess of the purchase price over the fair value of the tangible assets of Adjusted Aquila acquired and liabilities assumed.

Under the purchase method of accounting, the total estimated purchase price is allocated to the tangible and intangible assets acquired and liabilities assumed based on their estimated fair values with the excess of the purchase price over the fair value recorded to goodwill. The fair value of these assets and liabilities is preliminary and subject to change pending additional information that may come to Great Plains Energy’s knowledge and restructuring decisions made.

The following represents the preliminary adjustments to the assets acquired and liabilities assumed:

(Amounts in Millions)		
Total preliminary estimated purchase price (Note 1)	$	1,739.4
Less: Book value of Aquila assets acquired and liabilities assumed		1,671.5
Excess of purchase price over net book value of assets acquired	$	67.9
Adjustments to goodwill related to:		
Elimination of historical goodwill	$	111.0
Tangible assets		20.0
Regulatory assets-pensions		(21.6)
Receivables, net		(3.3)
Other current liabilities		28.8
Long-term debt		104.7
Deferred tax liabilities		(168.8)
Total adjustments		70.8
Total adjustment to goodwill	$	138.7

In Great Plains Energy's opinion, the fair value of assets, liabilities and long-term debt assumed will approximate book value in a rate-regulated acquisition. Great Plains Energy's management analyzed the Merger Agreement for potential intangible assets and none were identified.

Pursuant to SFAS No. 142, "Goodwill and Other Intangible Assets", goodwill is not amortized; rather, impairment tests are performed at least annually or more frequently if circumstances indicate an impairment may have occurred. If an impairment exists, the goodwill is immediately written down to its fair value through a current charge to retained earnings. Accordingly, the goodwill arising from the acquisition will be subject to an impairment test at least annually.

E—The historical equity of Aquila is eliminated in this pro forma adjustment.

F—Represents the pro forma adjustment to record the fair value of the Great Plains Energy common shares outstanding exchanged in the acquisition.

G—Represents the pro forma adjustment to record the fair value of the Adjusted Aquila stock options converted to Great Plains Energy stock options.

H—This pro forma adjustment accrues the estimated remaining direct costs of the acquisition, or anticipated transaction-related expenses of Great Plains Energy to be included in the estimated purchase price for the acquisition, which include financial advisory, legal and other professional service fees.

I—The pro forma adjustment eliminates goodwill previously recorded by Aquila primarily related to Aquila's purchase of St. Joseph Light & Power Company.

J—Represents the pro forma adjustments to accrue expenses related to Aquila executives and other employees as a result of the acquisition change in control and severance.

K—The cash consideration paid to Aquila shareholders in the acquisition is reflected in this pro forma adjustment as if the acquisition occurred on March 31, 2008.

L—Represents the pro forma adjustments to deferred taxes and income tax expense related to Federal and State net operating loss carryforwards (NOLs). An adjustment of $88.4 million was included to reduce the valuation allowance on NOLs and decrease income tax expense $32.2 million for the three months ended March 31, 2008 and $70.2 million for the year ended December 31, 2007, to reflect the combined company's net tax liability and ability to utilize NOLs. The merger transaction will result in a change in ownership within the definitions of Section 382 of the Internal Revenue Code. Based on currently available information, the Section 382 limitation is expected to limit the combined company's ability to utilize Federal and State NOLs. In addition, the combined company will not be able to utilize State NOLs in states where the company will no longer have operations. The adjustments could be materially affected by finalization of the consolidated company's tax position after the July 14, 2008 close.

M—This pro forma adjustment represents the recording of a regulatory asset by Great Plains Energy of certain unrecognized pension prior service costs and actuarial gains/losses that had previously been included in accumulated other comprehensive income by Aquila. These unrecognized pension costs were eliminated in purchase accounting in connection with the elimination of Aquila's historical equity as described in Note E. These pension costs are included as a purchase accounting adjustment because they are expected by Great Plains Energy to be recovered through rates in connection with the acquisition of Aquila.

N—Represents the pro forma adjustment to reflect the net tax liability of the combined company pursuant to FASB Interpretation No. 39, "Offsetting of Amounts Related to Certain Contracts-an interpretation of APB Opinion No. 10 and FASB Statement No. 105".

O— Represents the pro forma adjustment to record the estimated fair value of Adjusted Aquila long-term debt. The adjustment was determined based on quoted market prices at March 31, 2008, and applicable state regulatory treatment for certain debt issuances, and will be amortized as a reduction of interest expense over the remaining term of the debt.

P— This pro forma adjustment represents adjustments to conform various Aquila accounting policies to those of Great Plains Energy.

Q— This pro forma adjustment represents adjustments to record an estimate of certain exit costs expected to be incurred in accordance with EITF Issue No 95-3, "Recognition of Liabilities in Connection with a Purchase Business Combination" and estimated in accordance with EITF Issue No 98-1, "Valuation of Debt Assumed in a Purchase Business Combination".

R— This pro forma adjustment represents the recording of a regulatory asset to defer non-labor transition costs and amortize over a five-year period beginning with rates effective after the first post-transaction rate cases currently anticipated to be summer 2009. This adjustment also reclassifies the related incurred expenses, net of tax, included in the income statements for the periods presented.

S— Represents the pro forma adjustment to record the estimated fair value of the Aquila corporate headquarters facility expected to be sold after close of the transaction. The adjustment was determined based on Great Plains Energy's estimates of fair value based on broker estimates, indicating a fair value of approximately $26.0 million. This analysis is significantly affected by assumptions regarding the current market for the building. The $20.0 million adjustment reflects the difference between the fair value of the facility at $26.0 million and the $46.0 million book value of the facility at March 31, 2008. Great Plains Energy management believes this to be an appropriate estimate of the fair value of the facility. The adjusted value could be materially affected by changes in fair value prior to the recording of the acquisition.

5. Unaudited Pro Forma Earnings (Loss) per Share

The pro forma weighted average number of basic shares outstanding is calculated by adding Great Plains Energy's weighted average number of basic shares of common stock outstanding for the three months ended March 31, 2008 or the year ended December 31, 2007 and Aquila's weighted average number of basic shares of common stock outstanding for the same period multiplied by the exchange ratio of 0.0856:

	Three months ended March 31, 2008		For the year ended December 31, 2007	
(Amounts in Thousands, except per share data)	**Weighted Average Shares**	**Loss per share**	**Weighted Average Shares**	**Earnings per share**
Basic:				
Great Plains Energy	85.9		84.9	
Conversion of Aquila to Great Plains Energy	32.2		32.2	
Pro forma	118.1	$ (0.06)	117.1	$ 0.70
Diluted:				
Great Plains Energy	85.9		85.2	
Conversion of Aquila to Great Plains Energy	32.2		32.2	
Pro forma	118.1	$ (0.06)	117.4	$ 0.69