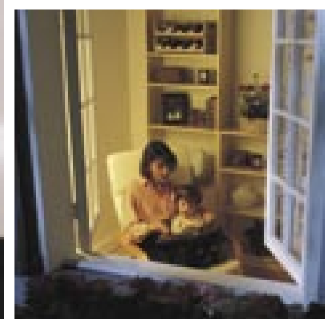
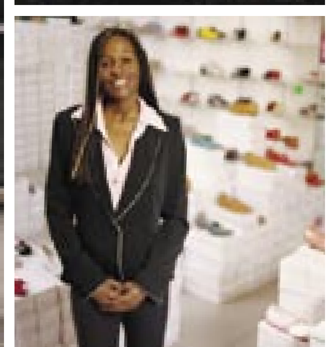
Aquila

2004 Annual Report





Providing Energy For Better Living.℠

Aquila in the Community

A look back at a few 2004 Aquila employee activities to help improve the quality of life in the communities we serve.

Clockwise From Top:
Kansas City, MO – Fundraising for the less fortunate
Kansas City, MO – Neighborhood improvement project
Webster City, IA – Delivering meals to senior citizens
Great Bend, KS – Helping with electric car competition for high school students
Rochester, MN – Food program assistance
Platte City, MO – Natural gas fire training for local emergency workers
Guttenberg, IA – Volunteer firefighter

Cover Photo:
Aquila's James Reed was one of about 1,000 employees and contractors who worked around the clock to restore electric service to Missouri and Kansas customers following a January 2005 ice storm. Photo: Terry Weckbaugh

Letter to Shareholders

In 2004, your company made significant progress in its repositioning strategy, executing on our plan to strengthen our credit profile, improve cash flow and increase operational efficiency. To date, Aquila has completed more than 30 major initiatives which have contributed to ensuring that Aquila remains a safe, reliable provider of energy, committed to meeting the current and future needs of its customers.

Our major financial initiatives in 2004 included:

- Eliminating more than $550 million of liabilities by terminating four long-term gas supply contracts;
- Raising more than $980 million by completing the sale of independent power plants and Canadian utility businesses, after repaying related debt and transaction costs;
- Raising $446.6 million from the issuance of common stock and mandatorily convertible securities;
- Completing two new five-year unsecured financings—a $110 million revolving credit facility and a $220 million term loan facility—and a new six-month revolving credit facility secured by accounts receivable;
- Receiving rate increases totaling $55.3 million in Missouri, Colorado and Nebraska;
- Exiting the Aries tolling agreement and reaching an agreement, closed in February 2005, to exit the Batesville tolling agreement; and
- Early retirement of the company's $430 million secured loan.

Last year also marked the launch of Aquila's Six Sigma process improvement program to strengthen our customer service and operational efficiency. An established method for improving the quality of services and operations, Six Sigma has already produced some early wins and is expected to begin having a measurable impact on our operations this year and in 2006.

Driving this progress is our dedicated team of employees. Aquila's employees have risen to the challenges of the last few years with superb spirit and professionalism. In reviewing the many aspects of our company, it is important to keep in mind that Aquila's employees rank among its most important assets. Their continued commitment to our customers and the communities we serve underscore Aquila's vision of "providing energy for better living."

Firmer Financial Ground

Aquila ended 2004 on much firmer financial ground. Our net loss narrowed in 2004 to $292.5 million, or a fully diluted loss of $1.13 per share, from 2003's net loss of $336.4 million, or a fully diluted loss of $1.73 a share. Sales rose in 2004 to $1.71 billion from $1.67 billion in 2003. (Per-share results for the 2004 year and fourth quarter reflect the issuance of 46.0 million common shares and 13.8 million mandatorily convertible securities in late August 2004.)

Importantly, Aquila's credit profile improved significantly in 2004. Total debt and long-term gas contracts, net of unrestricted cash, fell to $2.19 billion at the end of 2004, nearly half the level of $4.08 billion at September 30, 2002. Year-end liquidity totaled $485 million, which included $225 million in cash, $110 million undrawn on the revolving credit, and $150 million of remaining capacity on the accounts-receivable facility.

Despite these advances, we are not satisfied with our progress mitigating the utility earnings volatility created by weather and fuel costs. In 2005, we have stepped up our efforts to mitigate earnings volatility while continuing to seek appropriate rate increases and improve operational efficiency.

Accelerating Aquila's Repositioning Plan

To achieve our goals of stronger performance and enhanced shareholder value, we must also accelerate our repositioning plan so we can take advantage of significant positive trends in the industry. There is growing acknowledgement of the country's need to invest in utility infrastructure. At the same time, financial markets regard this trend as an investment opportunity and increasingly value utilities for their relative earnings stability and yield. Our goal is to ensure that Aquila participates fully in these positive trends.

Further debt reduction holds the key to Aquila's ability to accelerate its repositioning plan and realize its growth opportunity in the years to come. Our debt level remains too high for a utility our size, and our interest expense consumes too much of our cash. Additional reductions in our debt levels and improvement in our credit profile would give Aquila better access to capital markets on more favorable terms, allowing the company to more cost-effectively fund investments in its rate base to meet customer needs and drive future earnings.

We estimate that the company has the opportunity to invest approximately $650 million over the next five years in generation, transmission and natural gas and electric distribution capacity, as well as required environmental upgrades, to strengthen our utility business and improve earnings. These investments would put Aquila on a path to achieving its goal of average annual growth of 3 percent to 5 percent in post-divestiture rate base earnings before interest and taxes (EBIT.)

On March 14 we outlined our plan to accelerate our repositioning strategy and further reduce debt. We are considering the sale of select utility and non-core assets. The utilities under consideration for divestiture are Aquila's natural gas operations in Michigan, Minnesota, and Missouri; electric operations in Colorado and Kansas; and St. Joseph Light & Power in Missouri. The other utilities Aquila operates are electric properties in Missouri (former Missouri Public Service) and gas properties in Iowa, Nebraska, Kansas and Colorado. The non-core assets considered for sale include three merchant peaking plants and Everest Connections. The company also plans a settlement of its Elwood toll contracts.

The proceeds from the sales of select utility assets and non-core assets will be used to retire debt and other liabilities.

A Disciplined Strategy

I want to emphasize that Aquila intends to remain an integrated, multi-state utility, and will continue to take a disciplined approach to executing our strategy. The elements of our accelerated repositioning plan are the result of extensive analysis of our opportunities, taking into account the potential impact of our decisions on our customers, communities, employees and shareholders.

Our decision on whether to sell an asset will be based on a comparison of the value the market offers versus the value we can build by continuing to own and operate that business. We may ultimately decide to divest only some of the utilities under consideration for sale.

As we pursue our accelerated repositioning plan, we are keenly aware that our divestiture plans create uncertainty for our employees. We believe, however, that ultimately our employees will have the opportunity to work for a strong company – whether that's Aquila or another company that purchases one of our assets going forward. Over the next few weeks I will be traveling to Aquila locations in each of our seven states to meet with as many employees as possible to explain our plans and listen to their concerns and suggestions. We pledge to move as quickly as possible to make key decisions and communicate them. The management team and I are also working to brief our regulators and meet with community leaders to keep them informed of our progress.

Board of Directors

We welcomed Patrick J. Lynch to our Board of Directors in May 2004. He is a retired senior vice president and chief financial officer of Texaco, Inc. His financial expertise and counsel have proved highly valuable as the Board worked to reduce our liabilities.

We offer our appreciation and thanks to John R. (Jack) Baker, a director since 1971, who has decided to retire from the Board in May when his term expires. Jack's tireless service to Aquila has included 43 years as an employee of the company, during which he held many positions in accounting, finance and corporate development. He played a key role as Senior Vice President, Corporate Development, from 1985 to 1992. After retiring as Vice Chairman in 1995, Jack then served another decade as a director. We will greatly miss his warmth and wise counsel.

Management Changes

On our management team, Christopher M. Reitz was appointed Interim General Counsel and Corporate Secretary in February 2005. He succeeds Leslie J. Parrette, Jr., who has taken a senior position at another company.

Chris joined Aquila in 2000 as Senior Corporate Counsel and later was named Assistant General Counsel and Assistant Secretary. He previously worked as an attorney with Blackwell Sanders Peper Martin LLP, Sprint and Cerner Corporation. He has a bachelor's degree in business and accounting and a J.D. degree in law from the University of Kansas.

Outlook

As we enter into this next phase of our repositioning plan, Aquila's strategy in the months ahead can be summed up in six objectives:

- Maintain its focus on operating an integrated, multi-state utility.
- Consider the sale of select utility and non-core assets, applying proceeds to reduce debt.
- Significantly reduce Aquila's debt levels and strengthen its credit profile.
- Gain access to the capital markets on improved terms, allowing the company to more cost-effectively fund investments in its rate base to meet customer needs.
- Continue to improve operational efficiency and lower earnings variability.
- Actively work with regulators and legislators to address rate and fuel cost issues.

Aquila has traveled a challenging road in our two-and-a-half years of repositioning efforts. Thanks to the initiatives we have completed, our company is now well placed to accelerate its repositioning plans and lay a firm foundation for future growth. We're confident that our strategy will lead to enhanced shareholder value while strengthening Aquila's standing as a reliable, safe provider of energy.

Sincerely,

Richard C. Green

Richard C. Green
Chairman and Chief Executive Officer
March 14, 2005

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

We anticipate significant additional capital expenditures in order to satisfy our long-term power generation and transmission needs and to comply with environmental rules and regulations. Some important factors that could cause actual results to differ materially from those anticipated include:

We may not receive the approvals required to participate in the planned construction of additional generating capacity.

Environmental rules and regulations could change such that we are not required to make anticipated capital expenditures for environmental compliance.

Our goal is to be on a path to achieve an average annual EBIT growth on post-divestiture rate base of 3 percent to 5 percent and move further toward investment grade metrics. Some important factors that could cause actual results to differ materially from those anticipated include:

Our actual allowed rate of return on our expected capital investments may be lower than our internal projections.

We may not achieve operational efficiencies in our businesses and our plan to sell utility assets could result in stranded overhead costs that would reduce our EBIT.

We are planning to regain access to the capital markets on improved terms, allowing us to fund investments in our rate base and meet customer needs. Some important factors that could cause actual results to differ materially from those anticipated include:

Our strategy to improve our credit standing may not be successful.

We may not receive shareholder approval to issue additional shares of our common stock.

We intend to sell certain regulated utility assets and our interests in three merchant peaking facilities and Everest Connections, as well as terminate the Elwood toll contracts. Some important factors that could cause actual results to differ materially from those anticipated include:

We may receive bids for assets at prices that are inadequate or insufficient for accomplishing our targeted goals.

Regulatory commissions may refuse to approve some or all of the contemplated divestitures.

The counterparty to the Elwood toll contracts may be unwilling to terminate or restructure these contracts, or we may not find a third party willing to assume this obligation upon acceptable terms.

We will attempt to improve operating efficiencies, seek appropriate rate increases and lower earnings volatility. Some important factors that could cause actual results to differ materially from those anticipated include:

Our process improvement initiative may fail or not produce the desired results.

Legislative initiatives designed to lower volatility associated with weather and fuel may fail.

Regulatory agencies may refuse to approve some or all of our rate increase requests.

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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2004

or

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

For the transition period from ____________ to ____________

Commission file number: 1-03562

AQUILA, INC.
(Exact name of registrant as specified in its charter)

Delaware	**44-0541877**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

20 West Ninth Street, Kansas City, Missouri 64105
(Address of principal executive offices)

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

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

Title of each class	Name of each exchange on which registered
Common Stock, par value $1.00 per share	**New York Stock Exchange**
7.875% Quarterly Interest Bonds, due March 1, 2032	**New York Stock Exchange**
Premium Income Equity Securities, due September 15, 2007	**New York Stock Exchange**

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part 3 of this Form 10-K or any amendment to this Form 10-K. ☐

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

The aggregate market value of the voting stock held by non-affiliates of the Registrant, based upon the closing sale price of the Common Stock on June 30, 2004 as reported on the New York Stock Exchange, was approximately $654,409,600. Shares of Common Stock held by each officer and director and by each person who owns 5% or more of the outstanding Common Stock have been excluded in that such persons may be deemed to be affiliates. This determination of affiliate status is not necessarily a conclusive determination for other purposes.

Title	Outstanding at March 7, 2005
Common Stock, par value $1.00 per share	**241,771,033**
Documents Incorporated by Reference: Proxy Statement for 2005 Annual Shareholders Meeting	**Where Incorporated: Part 3**

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Glossary of Terms and Abbreviations

APB—Accounting Principles Board.

Aquila Merchant—Aquila Merchant Services, Inc., our merchant energy subsidiary.

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

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

CFTC—Commodity Futures Trading Commission.

CO_2—Carbon Dioxide.

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

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

Energy Act—Energy Policy Act of 1992.

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

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

EWG—Exempt Wholesale Generator, an independent power project certified by the FERC.

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

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

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

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

Fitch—Fitch Ratings, a leading global rating agency.

FPA—Federal Power Act.

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

GWh—Gigawatt-hour.

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

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

kWh—Kilowatt-hour.

LIBOR—London Inter-Bank Offering Rate.

Mcf—One thousand cubic feet.

MGP—Manufactured Gas Plant.

MMBtu—One million Btu's.

MMcf—One million cubic feet.

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

MW—Megawatt, one thousand Kilowatts.

Mwh—Megawatt-hour.

NOx—Nitrogen oxide.

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

NYMEX—New York Mercantile Exchange.

NYSE—New York Stock Exchange.

NYSEG—New York State Electric and Gas Corp.

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

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

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

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

RTO—Regional Transmission Organization.

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

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

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

SO_2—Sulfur dioxide.

Part I

Item 1. Business

History and Organization

Aquila, Inc. (Aquila or the company, which may be referred to as "we," "us" or "our") is primarily an integrated electric and natural gas utility headquartered in Kansas City, Missouri. We began as Missouri Public Service Company in 1917 and reincorporated in Delaware as UtiliCorp United Inc. in 1985. In March 2002, we changed our name to Aquila, Inc. As of December 31, 2004, we had 3,192 employees in the United States. Our business is organized into two groups: Domestic Utilities, which comprises our regulated utility operations, and Merchant Services, which comprises our unregulated energy activities. All other operations are included in Corporate and Other, including costs that are not allocated to our operating businesses; our controlling investment in a broadband company operating in Kansas City, Everest Connections; and our former investments in Australia, New Zealand and the United Kingdom. Substantially all of our revenues are generated by the Domestic Utilities group.

Our electric utilities include 2,075 MW of generation and 20,888 pole miles of electric transmission and distribution lines. Our gas utilities include 721 miles of intrastate gas transmission pipelines and 19,356 miles of gas distribution mains and service lines. The Domestic Utilities group generated revenues of $1.8 billion in the year ended December 31, 2004 and had total assets of $3.2 billion at December 31, 2004.

Until recently, our operations also included significant international utility investments and Merchant Services was a much larger component of our business. In 2002, we began to reposition our business to concentrate on our Domestic Utilities and reduce our financial obligations. As part of that repositioning, we sold all of our international investments and a substantial portion of our Merchant Services assets. Additionally, we wound down most of our Merchant Services energy trading portfolio. Our remaining Merchant Services group principally owns, operates, and contractually controls non-regulated power generation assets in the United States. See Management's Discussion and Analysis for further discussion of our strategic and financial repositioning.

Access to Company Information and Officer Certifications

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

Our Chief Executive Officer and Chief Financial Officer have filed with the SEC, as exhibits to our annual report on Form 10-K, the certifications required by Section 302 of the Sarbanes Oxley Act regarding the quality of our public disclosure. Our Chief Executive Officer certified to the NYSE following our 2004 annual shareholder meeting that he was not aware of violations by us of the NYSE corporate governance listing standards.

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

Business Group Summary

Segment information for the three years ended December 31, 2004 is included in Note 20 to the Consolidated Financial Statements.

I. Domestic Utilities

Domestic Utilities generates, transmits and distributes electricity to approximately 452,646 customers in Colorado, Kansas and Missouri. Our electric generating facilities and purchase power contracts supply electricity principally to our own distribution systems. Additionally, we sell excess power to other utilities and marketing companies. Approximately 65% of our electric customers are located in Missouri. Domestic Utilities also distributes natural gas to approximately 910,116 customers in Colorado, Iowa, Kansas, Michigan, Minnesota, Missouri and Nebraska. Approximately 46% of our utility operations, based on the book value of our regulated assets, are located in Missouri.

Electric Generating Facilities

As of December 31, 2004, our owned or leased interests in electric generation plants were as follows:

Unit	Location	Year Installed	Unit Capability (MW)	Fuel
Missouri:				
Sibley #1-3	Sibley	1960, 1962, 1969	502	Coal
Ralph Green #3	Pleasant Hill	1981	69	Gas
Nevada	Nevada	1974	20	Oil
Greenwood #1-4	Greenwood	1975-1979	241	Gas/Oil
KCI #1-2	Kansas City	1970	31	Gas
Lake Road #1, 3	St. Joseph	1951, 1962	30	Gas/Oil
Lake Road #2, 4	St. Joseph	1957, 1967	122	Coal/Gas
Lake Road #5	St. Joseph	1974	62	Gas/Oil
Lake Road #6-7	St. Joseph	1989, 1990	40	Oil
Iatan	Iatan	1980	121	Coal
Kansas:				
Judson Large #4	Dodge City	1969	142	Gas
Arthur Mullergren #3	Great Bend	1963	96	Gas
Cimarron River #1-2	Liberal	1963, 1967	72	Gas
Clifton #1-2	Clifton	1974	71	Gas/Oil
Jeffrey #1-3	St. Mary's	1978, 1980, 1983	354	Coal
Colorado:				
W.N. Clark #1-2	Canon City	1955, 1959	43	Coal
Pueblo #6	Pueblo	1949	20	Gas
Pueblo #5	Pueblo	1941, 2001	9	Gas
AIP Diesel	Pueblo	2001	10	Oil
Diesel #1-5	Pueblo	1964	10	Oil
Diesel #1-5	Rocky Ford	1964	10	Oil
Total			2,075	

We are constructing a 315-megawatt, natural gas-fired, combustion turbine generation plant near Peculiar, Missouri. We expect to complete this facility during the summer of 2005.

The following table shows Domestic Utilities' overall fuel mix and generation capability for the past three years:

Fuel Source—In Megawatts (MW)	**2004**	**2003**	**2002**
Coal	1,020	1,020	1,020
Gas	439	439	444
Oil	90	90	92
Coal and gas	122	122	122
Gas and oil	404	404	414
Total generation capability	2,075	2,075	2,092

At December 31, 2004, Domestic Utilities had 4,650 miles of electric transmission lines and 16,238 miles of electric distribution lines, 721 miles of intrastate gas transmission pipelines and 19,356 miles of gas distribution mains and service lines.

The following table summarizes sales, volumes and customers for our electric utility business:

	2004	**2003**	**2002**
Sales (in millions)			
Residential	$ 305.3	$ 292.2	$ 275.5
Commercial	218.4	200.9	190.2
Industrial	124.1	113.2	100.5
Other	111.5	91.2	100.7
Total	$ 759.3	$ 697.5	$ 666.9
Volumes Generated and Purchased (GWh)			
Coal	6,476	6,880	6,553
Gas	420	519	590
Coal/Gas	689	646	638
Gas/Oil	20	98	173
Total generated	7,605	8,143	7,954
Purchased	5,739	4,670	5,453
Total generated and purchased	13,344	12,813	13,407
Company use	(19)	(16)	(23)
Line loss	(962)	(964)	(1,011)
Total	12,363	11,833	12,373
Volumes (GWh)			
Residential	4,063	4,107	4,075
Commercial	3,454	3,391	3,343
Industrial	2,605	2,570	2,459
Other	2,241	1,765	2,496
Total	12,363	11,833	12,373

	2004	2003	2002
Customers at Year End			
Residential	387,365	381,033	374,697
Commercial	61,016	60,531	59,087
Industrial	456	457	467
Other	3,809	3,869	3,714
Total	452,646	445,890	437,965
Average annual volume per residential customer (kWh)	10,582	10,850	10,952
Average annual sales per residential customer	$ 795	$ 772	$ 741
Average residential sales per kWh (cents)	7.51	7.12	6.76
Units of Fuel Used in Generation			
Coal—thousand tons	4,367	4,529	4,287
Natural gas—Mmcf	6,142	8,070	10,631
Average Cost of Fuel			
Coal—per ton	$ 22.96	$ 21.04	$ 20.62
Natural gas—per Mcf	5.96	5.02	3.06

The following table summarizes sales, volumes and customers for our gas utility business:

	2004	2003	2002
Sales (in millions)			
Residential	$ 655.2	$ 620.1	$ 490.3
Commercial	284.7	263.5	195.2
Industrial	48.0	40.3	34.8
Other	44.1	45.6	44.8
Total	$ 1,032.0	$ 969.5	$ 765.1
Volumes (Mcf)			
Residential	68,748	74,507	72,454
Commercial	33,171	34,889	33,322
Industrial	6,863	6,612	7,974
Transportation	105,929	111,570	120,974
Other	265	417	403
Total	214,976	227,995	235,127
Customers at Year End			
Residential	817,331	807,853	796,207
Commercial	82,186	81,485	81,180
Industrial	2,339	2,227	2,300
Other	8,260	9,212	10,840
Total	910,116	900,777	890,527

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 Domestic Utilities' peak seasons.

Operations	Peak
Gas network operations	November through March
Electric network operations	July and August

Competition

We currently have limited competition for the retail distribution of electricity and natural gas in our service areas. While various restructuring and competitive initiatives have been discussed in the states in which our utilities operate, only Michigan has adopted rules for retail competition for residential customers. Residential retail gas customers in Michigan were able to choose their service provider beginning in June 2002, but no competitors have emerged. As a result of several factors, including the energy crisis in California, many states have either discontinued or delayed implementation of retail deregulation initiatives. However, we do face competition from independent marketers for the sale of natural gas to our industrial and commercial customers.

Regulation and Rates

State Regulation

Our utility operations are subject to the jurisdiction of the public service commissions in the states in which they operate. The commissions oversee services and facilities, rates and charges, accounting, valuation of property, depreciation rates and various other matters. Certain commissions also have jurisdiction over the creation of liens on property located in their state to secure bonds or other securities.

On May 7, 2003, the State Corporation Commission of the State of Kansas issued an order in connection with its investigation into the affiliated transactions between our regulated utilities and our other businesses. On June 26, 2003, the Kansas Commission modified that order. The May 7, 2003 and June 26, 2003 orders are filed as exhibits to our 2003 Annual Report on Form 10-K. Among other things, the orders provide that without the approval of the Kansas Commission, we may not:

- pledge for the benefit of our current and prospective lenders any regulated utility assets presently devoted to serving Kansas retail customers;
- invest any money in new non-utility businesses or invest in any existing business except in the ordinary course of business or to fulfill an existing financial, contractual or operational obligation;
- incur any new or modify any existing indebtedness other than routine, short-term borrowings incurred in the ordinary course of business for working capital needs;
- pay any dividends; or

• enter into any contract or agreement that: (1) alienates, conveys or creates an interest in our assets (e.g., through issuing stock or debt or arranging other securitization), including any agreement to modify an existing obligation to alienate, convey or create an interest in our assets, or (2) relates to products or services not required for the provision of continuing utility operations.

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

The following summarizes our recent rate case activity:

(In millions)	**Type of Service**	**Date Requested**	**Date Approved**	**Amount Requested**	**Amount Approved**
Minnesota *(1)*	Gas	8/2000	7/2003	$ 9.8	$ 5.7
Iowa *(2)*	Gas	6/2002	2/2003	9.3	4.3
Michigan *(3)*	Gas	8/2002	3/2003	14.3	8.4
Colorado *(4)*	Electric	10/2002	6/2003	23.4	16.0
Nebraska *(5)*	Gas	6/2003	1/2004	9.9	6.2
Missouri *(6)*	Electric	7/2003	4/2004	80.9	37.5
Missouri *(7)*	Gas	8/2003	4/2004	6.4	3.4
Colorado *(8)*	Electric	12/2003	8/2004	11.4	8.2
Kansas *(9)*	Electric	6/2004	1/2005	19.2	7.4
Kansas *(10)*	Gas	11/2004	Pending	6.2	Pending

(1) This rate increase had been collected on an interim basis since October 2000. We refunded over-collected interim rates to our Minnesota customers in February 2004.

(2) An interim increase of $5.6 million went into effect in September 2002 and we completed a refund to our Iowa gas customers of over-collected amounts in May 2003.

(3) The new Michigan rates went into effect in March 2003. This increase was net of a separate depreciation case docket, which reduced our annual rates by $.7 million. That decrease relates to our depreciation rates and reduced cash flow and had little impact on earnings.

(4) The new Colorado rates went into effect in June 2003.

(5) We have been collecting interim rates in Nebraska since October 2003 based on an interim rate increase of $9.9 million. In April 2004, we refunded the difference between the interim rate increase implemented in October 2003 and the final settlement amount to our Nebraska customers.

(6) The Missouri electric settlement included a two-year Interim Energy Charge (IEC) that allows us to recover variable generation and purchased power costs up to a specified amount per Mwh specific to each of our Missouri regulatory jurisdictions. The IEC rate per unit sold is $13.98/Mwh for St. Joseph Light & Power and $19.71/Mwh for Missouri Public Service. If the amounts collected under the IEC exceed our average cost incurred for the two-year period, we will refund the excess to our customers with interest. This fuel and purchased power cost recovery mechanism represents $18.5 million of the

$37.5 million rate increase. Also, as part of the settlement we agreed not to seek a general increase in our Missouri electric rates that would be effective in less than two years from the current rate increase, unless certain significant events occur that impact our operations. The rate increase went into effect April 22, 2004.

(7) The Missouri gas rate increase went into effect May 3, 2004 for our Missouri Public Service operations and July 1, 2004 for our St. Joseph Light & Power operations.

(8) The Colorado electric settlement included the modification of our Incentive Clause Adjustment to provide for the recovery of 100% of the variability of energy costs from our electric customers in Colorado, which is an increase from 75% recovery.

(9) This increase is effective March 1, 2005. We have filed for reconsideration of certain items included in the Commission's order.

(10) This application is primarily to recover infrastructure improvements and increased operating and maintenance costs. We expect hearings to be held by May 2005 with rates effective in August 2005.

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

In our regulated electric business in 2004, we generated approximately 57% of the power that we sold and we purchased the remaining 43% through long-term contracts or in the open market. The regulatory provisions for recovering power costs vary by state. In Kansas and Colorado, we have an Energy Cost Adjustment and an Incentive Clause Adjustment, respectively, that serve a purpose similar to the PGAs for our gas utilities. To the extent that our fuel and purchased power energy costs vary from the energy cost built into our tariffs, the difference is passed through to the customer. In Missouri, we do not have the ability to adjust the rates we charge for electric service to offset all or part of any increase or decrease in prices we pay for natural gas, coal or other fuel we use in generating electricity (i.e., a fuel adjustment mechanism). As a result, our electric earnings can fluctuate more in Missouri than in our other electric rate jurisdictions. As described more fully above, the Missouri Commission approved a settlement agreement in April 2004 for our electric operations that establishes our right to recover costs up to $13.98/Mwh in our St. Joseph Light & Power operations and $19.71/Mwh in our Missouri Public Service operations for a two-year period. If our actual costs are higher than those allowed costs, then we cannot recover the excess costs through rates. If our actual costs are less than those allowed costs, then we must refund the difference to our customers, except to the extent actual costs are below $12.64/Mwh for our St. Joseph Light & Power operations and $16.65/Mwh for our Missouri Public Service operations. Since the rate increase went into effect pursuant to the settlement agreement, our actual costs have exceeded the allowed costs by approximately $1.8 million through December 31, 2004.

Federal Regulation

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

In December 1999, the FERC issued Order 2000 addressing some significant regional electricity transmission issues. Among other things, Order 2000 required transmission-owning utilities, including Aquila, that did not already participate in an independent system operator (ISO) to file plans detailing their participation in an organization that will control the transmission facilities within a region. We have made the filings required by Order 2000, and are otherwise in compliance with the order, but our transmission facilities are not yet controlled by a regional transmission organization.

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

Environmental Matters

General

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

- the protection of the environment; and

- the safety and health of personnel and the public.

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

- the protection of air and water quality;

- the identification, generation, storage, handling, transportation, disposal, record-keeping, labeling, reporting of, and emergency response in connection with hazardous and toxic materials and wastes, including asbestos;

- the protection of plant and animal species and minimization of noise emissions; and

- safety and health standards, practices and procedures that apply to the workplace and to the operation of our facilities.

Water Issues

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

316(b) Fish Impingement Requirements

In July 2004, the EPA issued new rules requiring power plants with cooling water intake structures to undertake studies and implement technologies to minimize fish kills resulting from water withdrawal. We have three power plants that may be affected by these rules and are in discussion with the EPA concerning the application of this rule to those facilities. Aquila is currently working with state and federal agencies involved with the Missouri River regulations to determine compliance options and benefits to Missouri River fish populations.

Missouri River Levels

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

Air Emissions

Our facilities are subject to the Clean Air Act and many state and local laws and regulations relating to the protection of air quality. These laws and regulations cover, among other pollutants, those contributing to the formation of ground-level ozone, carbon monoxide, SO_2, NOx and particulate matter. In addition, CO_2 is also included as a potential emission that may be regulated. Fossil-fueled power generating facilities emit each of the foregoing pollutants and, accordingly, are subject to substantial regulation and enforcement oversight by various governmental agencies.

Clean Air Act

Title IV of the Clean Air Act (CAA) created an SO_2 allowance trading program as part of the federal acid rain program. Each allowance gives the owner the right to emit one ton of SO_2. At the end of each year, each emitting unit must have enough allowances to cover its emissions for that year. Allowances may be traded so that affected units that expect to emit more SO_2 than their allowances may purchase allowances from other affected units that expect to emit less than their allocated allowances. The allowance allocation is based on historical operating data. Our facilities emit SO_2 in excess of their allocated allowances. Therefore, we must purchase additional allowances to stay in compliance. Allowance prices have more than tripled in price during 2004 and we are continuing to evaluate the cost of purchasing allowances versus adding pollution control equipment.

Multi-pollutant regulations

Approximately 55% of our generating capacity is coal-fired. The EPA has issued proposed regulations (Interstate Air Quality Rule) with respect to SO_2, NOx and mercury emissions from coal-fired power plants. These new rules, if adopted, would require significant reductions in these emissions from our power plants in phases, beginning as early as 2008. The rules have been placed on hold while the EPA awaits the possibility of obtaining similar reductions under legislation that has been introduced in 2005. The EPA has stated that if legislation is not approved in early 2005, they will proceed with finalizing the Interstate Air Quality Rule. Multi-pollutant legislation has been introduced in the 2005 Congressional session and is currently being reviewed, but generally requires reductions similar to the EPA proposed rules. The proposed mercury regulations contain a number of options and the final control requirements are uncertain. We anticipate additional capital costs to comply with the mercury rules.

New Source Review

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

In January 2004, Westar Energy, Inc. received a notification from the EPA that it had violated the EPA's NSR requirements and Kansas environmental regulations by making modifications to the Jeffrey Energy Center without obtaining the proper permits. The Jeffrey Energy Center is a large coal-fired power plant located in Kansas that is 84% owned by Westar and operated exclusively by Westar. We have a 16% interest in the Jeffrey Energy Center and are generally responsible for this portion of its operating costs and capital expenditures. The electric generation plants we own or lease are described in the table at Item 1, page 6. It is possible that Westar could be subject to an enforcement action by the EPA and required to make significant capital expenditures to install additional pollution controls at the Jeffrey Energy Center. Aquila would potentially be responsible for 16% of those costs.

Global Climate

Future initiatives regarding greenhouse gas emissions and global warming continue to be the subject of debate. The Kyoto Protocol, which includes, among other things, targets for limiting CO_2 emissions, was signed by the United States, but then rejected by the current administration. Additional pressure for regulating CO_2 emissions may come from other countries that have ratified the protocol. Several legislative representatives have stated the desire to include carbon dioxide caps as part of multi-pollutant legislation. Coal-fired power plants are significant sources of CO_2 emissions. Therefore, any mandated federal greenhouse gas reductions or caps on CO_2 emissions could have a material impact.

Solid Waste

Various materials used at our facilities are subject to disposal regulations. Our coal facilities generate ash that is sent to a permitted landfill or is utilized either in roofing material, road construction or as flowable fill. The useful life of the permitted landfill at our Sibley location is set to expire in 2006. Therefore, we have begun investigating options for this waste disposal. Until an option is chosen the future cost increase cannot be determined, but is not believed to be material.

Past Operations

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

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

As of December 31, 2004, we estimate probable costs of future investigation and remediation on our identified MGP sites and retained liabilities to be $6.6 million. This is our best estimate based upon a comprehensive review of the potential costs associated with conducting investigative and remedial actions at our identified sites, as well as the likelihood of whether such actions will be necessary. There are also additional costs that we consider to be less likely but still ''reasonably possible'' to be incurred at these sites. Based upon the results of studies at these sites and our knowledge and review of potential remedial actions, it is reasonably possible that these additional costs could exceed our best estimate by approximately $9.0 million. This estimate could change materially once we have investigated further. It could also be affected by the actions of environmental agencies and the financial viability of other responsible parties. Ultimate liability also may be affected significantly if we are held responsible for parties unable to contribute financially to the cleanup effort.

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

II. Merchant Services

Merchant Services consists principally of our interests in gas-fired merchant power plants and our remaining wholesale energy trading business. Our merchant power plants are exempt wholesale generators that do not have dedicated customers and are designed to operate only during periods of peak demand in the geographic area in which the plant is located. Because we currently believe that the fuel and start-up costs of operating our merchant power plants will exceed the revenues that would be generated from the power sold, we believe that for the foreseeable future we will have limited ability to generate power from these plants at a gross profit. Annual operating and maintenance costs of these plants are approximately $9.0 million. In addition, we make annual capacity payments of approximately $37.3 million on our Elwood tolling contracts. We have sold capacity in three of these plants which will partially offset these costs in 2005 and 2006.

The table below shows information about our Merchant Services power plants as of December 31, 2004:

Plant & Location	Location	Type of Investment	Capacity (MW)	Heat Rates	Date in Service
Batesville Unit No. 3 *(a)*	Mississippi	Toll Contract	281	7.7	August 2000
Elwood Energy L.L.C.	Illinois	Toll Contracts	609	10.7	July 2001
Coahoma Power Plant	Mississippi	Contractually Controlled	340	11.9	September 2002
Clay County Power Plant	Illinois	Owned	340	11.9	November 2002
Piatt County Power Plant	Illinois	Owned	510	12.0	June 2003
Total Capacity (MW)			2,080		

(a) We had a toll contract ending in February 2021, including an anticipated extension at our option, for 281 MW of the output of the Batesville plant. We sold all of this capacity to South Mississippi Electric Power Association (SMEPA) under a power sales contract. In February 2005, we terminated our power sales contract and assigned our rights and obligations under the toll contract to SMEPA. We received approximately $16.3 million in connection with this agreement.

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

Competition

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

Regulation

Natural Gas Marketing Regulation

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

Power Marketing Regulation

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

Power Generation Regulation

In 1992, Congress passed the Energy Act to promote further competition in the development of new wholesale power generation sources by encouraging the development of independent power projects that are certified by the FERC as EWGs. Our owned and contractually controlled merchant power plants are certified by the FERC as EWGs. The owners or operators of EWGs are exempt from the provisions of PUHCA, but not from the FPA. The Energy Act also provided the FERC with extensive new authority to order electric utilities to provide other electric utilities and independent power projects with access to their transmission systems.

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

Our Executive Team

Name	Age	Position
Richard C. Green (Rick)	50	President, Chief Executive Officer and Chairman
Keith G. Stamm	44	Senior Vice President and Chief Operating Officer
Rick J. Dobson	46	Senior Vice President and Chief Financial Officer
Leo E. Morton	59	Senior Vice President and Chief Administrative Officer
Christopher M. Reitz (Chris)	39	Interim General Counsel and Corporate Secretary
Sally C. McElwreath	64	Senior Vice President, Corporate Communications
Brock A. Shealy	43	Senior Vice President, Corporate Compliance Officer
Jon R. Empson	59	Senior Vice President, Regulated Operations
Robert L. Poehling (Bob)	41	Senior Vice President, Energy Resources

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

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

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

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

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

Rick joined Aquila Merchant in 1989 as Vice President and Controller. In 1995, he left Aquila to serve as Vice President and Controller for ProEnergy in Houston, Texas. He rejoined Aquila Merchant in 1997 and served as Vice President Financial Management until November 2002, when he was appointed Interim Chief Financial Officer of Aquila, Inc. In May 2003, Rick was appointed Senior Vice President and Chief Financial Officer of Aquila. Prior to joining our company, Rick served in a management position with Arthur Andersen LLP.

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

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

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

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

Sally C. McElwreath (B.A., Social Sciences; M.B.A., Public Relations, Pace University)

Sally joined our company in 1994 as Senior Vice President, Corporate Communications. She left the company in 2001 and returned in the same position in June 2003. Prior to joining our company, she was Vice President, Corporate Communications for Macmillan Inc. and for The Travel Channel; Director of Marketing Communications for TransWorld Airlines; and Manager of Corporate Communications for United Airlines beginning in 1971. Prior to 1971, she held various positions with ARCO and Sinclair Oil Corporation. Sally also served as a public affairs officer in the U.S. Naval Reserve, attaining the rank of captain.

Brock A. Shealy (A.B., Psychology; Drury College; J. D., University of Missouri-Kansas City)

Brock joined our company in August 1999 as Director, Employee and Labor Relations. He transferred to what is now Aquila Merchant in August 2000 and became Vice President, Human Resources in January 2001. He was named Chief Administrative Officer for Aquila Merchant's European operations in December 2001, and became a director of Aquila Energy Limited and its European affiliates in January 2002. He was appointed our Senior Vice President and Corporate Compliance Officer in August 2003. Prior to joining our company, Brock was a partner with the law firm of Blackwell Sanders Peper Martin LLP.

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

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

Robert L. Poehling (B.S., Business, University of Nebraska)

Bob joined our company in 1991 and served in various operating and management positions until 1996 when he was appointed Vice President, General Manager of an affiliated merchant company in Australia. In 1999, he was appointed Senior Vice President of Aquila Merchant. In December 2003, Bob was appointed as our Senior Vice President, Energy Resources.

Item 2. Properties

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

In addition, we lease or own various real property and facilities relating to our regulated and non-regulated electricity generation assets. Our principal assets are generally described under ''Domestic Utilities'' and ''Merchant Services.'' Certain of these properties are encumbered by liens securing loans made to us. See Note 13 to the Consolidated Financial Statements for a description of the liens.

Item 3. Legal Proceedings

Litigation

AMS Shareholder Lawsuit

A consolidated lawsuit was filed against us in federal court in Missouri in connection with our recombination with our Aquila Merchant subsidiary that occurred pursuant to an exchange offer completed in January 2002. The suit raised allegations concerning the lack of independent members on the board of directors of Aquila Merchant to negotiate the terms of the exchange offer on behalf of the public shareholders of Aquila Merchant. This lawsuit is scheduled for trial in May 2005. We believe we have strong defenses and will defend this case vigorously. We cannot predict with certainty whether we will incur any liability, nor can we estimate the damages, if any, that might be incurred in connection with this lawsuit. However, given the nature of the claims, an adverse outcome could have a material adverse effect on our financial condition, results of operations and cash flows.

Price Reporting Litigation

On August 18, 2003, Cornerstone Propane Partners filed suit in the Southern District of New York against 35 companies, including Aquila, that allegedly manipulated natural gas prices and futures prices on NYMEX through misreporting of natural gas trade data in the physical market. The suit does not specify alleged damages and was filed on behalf of all parties who bought and sold natural gas futures and options on NYMEX from 2000 to 2002. On September 24, 2004, the court denied Aquila's motion to dismiss along with similar motions filed by most of the other defendants. We will defend this case vigorously as we believe we have strong defenses to the plaintiff's claims. We cannot predict with certainty whether we will incur any liability, nor can we estimate the damages, if any, that might be incurred in connection with this lawsuit. However, given the nature of the claims, an adverse outcome could have a material adverse effect on our financial condition, results of operations and cash flows.

On June 7, 2004, the City of Tacoma filed suit against 56 companies, including Aquila, for allegedly conspiring to manipulate the California power market in 2000 and 2001 in violation of the Sherman Act. This case was dismissed in February 2005. It is not certain whether the plaintiff will appeal this ruling.

On July 8, 2004, the County of Santa Clara and the City and County of San Francisco each filed suit against seven energy trading companies, including Aquila, in the Superior Court of San Diego alleging manipulation of the California natural gas market in 2000 through 2002. Since that date 13 other counties, cities and other parties have filed similar complaints making nearly identical allegations. These lawsuits allege violations of the Cartwright Act, the Sherman Act, and the California Unfair Competition Law and unjust enrichment. The lawsuits have been designated *In re Natural Gas Anti-Trust Cases V* and assigned to a Coordination Motion Judge in the Superior Court of San Diego to determine whether they are complex and should be coordinated. Aquila is also a defendant in the *Utility Savings & Refund Services, LLP v. Reliant Energy Services, Inc., et al.* lawsuit filed November 30, 2004 in the U.S. District Court for the Eastern District of California alleging violations of the Sherman Act, the Cartwright Act, and the California Unfair Competition Law. We cannot predict with certainty whether we will incur any liability, nor can we estimate the damages, if any, that might be incurred in connection with these lawsuits. However, given the nature of the claims, an adverse outcome could have a material adverse effect on our financial condition, results of operations and cash flows.

Enron Bankruptcy Litigation

On March 7, 2005, we reached an agreement with Enron Corp. and certain of its affiliates (Enron). Under this agreement, we will pay $28 million to Enron to settle all outstanding claims between Enron and Aquila associated with the various bankruptcy filings of Enron in December 2001 and two lawsuits filed by Enron Canada Corp. in January 2003. In 2001, we reserved for substantially all of our then outstanding receivables from Enron, which resulted in a charge of $66.8 million. This charge did not reflect potential gains we would record in the event we were successful in netting certain obligations to Enron against these receivables. Approximately $33.5 million of liabilities remained on our books related to contracts with Enron after the 2001 charge. The settlement is subject to final approval the bankruptcy court. As a result of the settlement, we reduced our net liability to Enron by approximately $6 million, or $3.7 million after tax.

Lender Litigation

On October 5, 2004 and October 15, 2004, lawsuits were filed against us by our lenders alleging that we were obligated to pay a ‘‘make whole’’ amount when we prepaid the $430 million three-year secured term loan in September 2004. We believe that our termination of the term loan required us to pay a prepayment penalty of $8.7 million. The plaintiff lenders have sued us for breach of contract for their proportionate share of the difference between their prepayment calculation and the $8.7 million, which in the aggregate is approximately $20.6 million. We believe we have strong defenses and will defend these cases vigorously. We cannot predict with certainty whether we will incur any liability, nor can we estimate the damages, if any, that might be incurred in connection with these lawsuits. However, given the nature of the claims, an adverse outcome could have a material adverse effect on our financial condition, results of operations and cash flows.

ERISA Litigation

On September 24, 2004, a lawsuit was filed in the U.S. District Court for the Western District of Missouri against us, the Board of Directors and certain members of management alleging they violated the ERISA and are responsible for losses that participants in the Aquila 401(k) plan experienced as a result of the decline in the value of their Aquila stock held in the Aquila 401(k) plan. A number of similar lawsuits alleging that the defendants breached their fiduciary duties to the plan participants in violation of ERISA by concealing information and/or misleading employees who held Aquila stock through the Aquila 401(k) plan were subsequently filed against us. The suits also seek damages for the plan's losses resulting from the alleged breaches of fiduciary duties. On January 26, 2005 the court ordered that each of these lawsuits must all be consolidated into a single case captioned, *In re Aquila ERISA Litigation,* and gave the plaintiffs 45 days to file an amended consolidated complaint. We believe we have strong defenses and will defend this case vigorously. We cannot predict with certainty whether we will incur any liability, nor can we estimate the damages, if any, that might be incurred in connection with this lawsuit. However, given the nature of the claims, an adverse outcome could have a material adverse effect on our financial condition, results of operations and cash flows.

As described in Item 1. Business—Environmental Matters of this report, we are involved in the remediation of certain properties under the oversight of federal and state environmental agencies.

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

There were no matters submitted to a vote of security holders in the fourth quarter of 2004.

Part II

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

Our common stock (par $1) is listed on the NYSE under the symbol ILA. Through March 15, 2002, the symbol was UCU. At March 7, 2005, we had approximately 34,000 common shareholders of record. Information relating to market prices of common stock on the NYSE and cash dividends on common stock is set forth below. On March 7, 2005, the reported last sale price of the common stock on the NYSE was $4.06 per share.

Market Price Per Share

	High	Low	Cash Dividends
2004 Quarters			
Fourth	$3.80	$3.00	—
Third	3.87	2.25	—
Second	4.86	3.05	—
First	4.75	3.41	—
2003 Quarters			
Fourth	$4.37	$3.17	—
Third	3.85	2.16	—
Second	3.22	1.63	—
First	2.50	1.07	—

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

Item 6. Selected Financial Data

In millions, except per share amounts	2004	2003	2002	2001	2000
Sales	$1,711.0	$1,674.0	$ 2,041.1	$ 3,375.8	$ 2,806.7
Gross profit	496.8	549.9	549.1	1,408.6	1,204.8
Earnings (loss) from continuing operations *(a)*	(349.2)*(b)*	(356.0)*(c)*	(1,725.4)*(d)*	196.8 *(e)*	186.2 *(f)*
Basic earnings (loss) per common share—					
Continuing operations	(1.35)	(1.83)	(10.67)	1.76	2.00
Diluted earnings (loss) per common share—					
Continuing operations	(1.35)	(1.83)	(10.67)	1.70	1.99
Cash dividends per common share	—	—	.775	1.20	1.20
Total assets	4,777.3	7,719.1	9,376.0	11,966.5	14,026.9
Short-term debt	—	—	287.8	445.0	306.7
Long-term debt (including current maturities)	2,371.9	2,706.0	2,626.5	2,439.0	2,467.0
Common shareholders' equity	1,130.5	1,359.3	1,607.9	2,551.6	1,799.6

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

(a) Depreciation and amortization expense included (in millions) $13.1 and $8.1 of goodwill amortization for the years ended December 31, 2001 and 2000, respectively. Goodwill amortization was not recorded in the years ended December 31, 2004, 2003 and 2002 as a result of the implementation of a new accounting standard that discontinued the amortization of goodwill beginning January 1, 2002. Additionally, included in earnings from equity method investments for those periods was approximately (in millions) $17.6 and $10.5, respectively, of goodwill amortization.

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

(c) Included in earnings (loss) from continuing operations for the year ended December 31, 2003, are (a) a $105.5 million termination payment regarding our 20-year tolling agreement for the Acadia power plant; (b) an $87.9 million impairment charge on our equity method investments in 12 independent power plants; and (c) $28.2 million of restructuring charges from exit from interest rate swaps related to our Clay County and Piatt County construction financing arrangements and additional severance and retention payments related to the continued wind-down of our energy trading operations and the restructuring of Everest Connections.

(d) Included in earnings (loss) from continuing operations for the year ended December 31, 2002, are (a) a $696.1 million impairment charge on our investment in Quanta Services; (b) a $247.5 million impairment charge on our investment in Midlands Electricity; (c) a $127.2 million impairment charge on our investment in Multinet Gas and AlintaGas; (d) a $227.6 million impairment charge related to our 96% investment in Everest Connections; (e) a $181.2 million write-down of Merchant Services' goodwill; (f) other impairment charges and losses on sale of assets of $91.9 million, primarily as a result of our decision to sell non-core assets to improve our liquidity position; and (g) $210.2 million of restructuring charges from our exit from the wholesale energy trading business and the restructuring of our domestic utility business. We also recorded a $130.5 million gain on the sale of our shares of UnitedNetworks.

(e) In the year ended December 31, 2001, we (a) recorded a $110.8 million gain on the sale of 5.75 million shares of Aquila Merchant Services, Inc. Class A common stock (net income reflects our 80% ownership of Aquila Merchant from April 27, 2001 to December 31, 2001); (b) wrote off exposure related to the Enron bankruptcy of $35.0 million in Merchant Services and $31.8 million in Domestic Utilities; (c) recorded charges of $16.5 million in our communications business; and (d) recorded charges of $11.5 million in our Australian networks related to valuation allowances on certain deferred taxes and collectibility of certain receivables.

(f) In the year ended December 31, 2000, we recorded $19.4 million of reserves for impairments and other charges relating to investments in retail assets in the United Kingdom, certain information technology assets, corporate intangibles and our construction of fiber-optic communications networks. We also recorded a $44.0 million gain on the sale of a 34% interest in Uecomm Limited to the public.

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

See Forward-Looking Information and Risk Factors beginning on page 65.

Strategic and Financial Repositioning Overview

Overview

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

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

This repositioning plan was developed to focus on building and maintaining the generation, transmission and distribution infrastructure necessary to provide our utility customers with safe and reliable service, while increasing the returns on invested capital in jurisdictions that lag behind those of our peers. We intend to focus on improving our returns through future rate activities and our recently initiated six sigma process improvement program, which we believe will bring our returns closer to those of our peers by the end of 2007.

Asset Divestures and Strengthen Credit Profile

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

Following an extensive review and discussion with outside advisors on our stand-alone regulated utility strategy, we have retained investment banking advisors to conduct a competitive sale process for certain regulated utility assets. Due to regulatory and price uncertainties associated with the sale of regulated assets, we intend to concurrently conduct a competitive bidding process for utility assets having an aggregate net plant book value of approximately $874 million. The utilities that will be included in the competitive bidding process are our gas operations in Michigan, Minnesota and Missouri and our electric operations in Kansas, Colorado and our St. Joseph, Missouri service territory. At the conclusion of this process, we expect to enter into one or more definitive sale agreements to sell a subset of the offered properties. We will not determine which assets to sell until the conclusion of the competitive bidding process. Among other considerations, our decision will be based on the comparison of the value of the offers versus the value we can build by continuing to own and operate these assets, execution risk through the regulatory approval process, and the opportunity to support the growth of our remaining operations.

We expect to use the proceeds from the sale of regulated utility assets to retire debt and other liabilities. We currently have more than $700 million of debt obligations that are, or are expected to be callable at par or at a reasonable fixed contractual fee. Having the ability to repurchase debt securities at fixed prices allows us to deploy the proceeds from utility asset divestures efficiently in order to reduce debt and improve our credit profile.

We will also be focused on the divesture of our non-regulated assets and contractual requirements. This includes the continued analysis of the timing of our divesture of the remaining three peaking facilities and Everest Connections. Additionally, we will continue to pursue the exit of our Elwood tolling contract commitments. The proceeds from the sale of the peaking facilities and Everest Connections will be applied towards the exit of our Elwood tolling contract or to retire debt.

Historical Review of Repositioning Efforts

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

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

- Began the wind-down of our Merchant Services trading portfolio in North America and Europe;

- Sold our natural gas storage facilities in both North America and the United Kingdom;

- Sold substantially all of our merchant loan portfolio;

- Sold our gas gathering and processing business located primarily in Texas and Oklahoma;

- Reduced our investment in Quanta Services, Inc. (which builds and maintains networks that carry energy and telecommunications) from 38% to 10.2%;

- Sold our equity investment in regulated utility operations in New Zealand; and

- Eliminated our quarterly dividend.

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

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

- Sold our remaining 10.2% investment in Quanta Services, Inc.;
- Sold our Australian investments;
- Signed an agreement to sell our United Kingdom utility investment, which we completed in January 2004;
- Entered into a $430 million three-year secured term loan;
- Terminated our capacity payment obligations under our Acadia tolling agreement;
- Signed agreements to sell our Canadian utility businesses, which we completed in the second quarter of 2004;
- Signed agreements to sell our equity investment in 13 independent power plants, which we completed in the first half of 2004;
- Pursued rate increases for certain of our gas and electric operations; and
- Continued the wind-down of our wholesale energy trading businesses in North America and Europe.

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

- Sold our investment in a merchant power plant development project in the United Kingdom;
- Settled rate cases relating to our Missouri and Colorado electric and Missouri and Nebraska gas utility operations and pursued rate relief for our Kansas electric and gas utility operations;
- Terminated our capacity payment obligations under our Aries tolling agreement and exited our investment in the Aries merchant power plant;
- Received a distribution on our investment in the BAF Energy cogeneration project;
- Renewed our 364-day letter of credit facility;
- Sold a non-strategic natural gas system located in eastern Missouri;
- Terminated four long-term natural gas supply contracts;
- Issued 46.0 million shares of common stock and $345 million of mandatorily convertible senior notes, raising $446.6 million in net proceeds;

- Retired the $430 million three-year secured term loan due in April 2006;
- Entered into a $220 million five-year unsecured term loan and a $110 million five-year revolving credit facility; and
- Entered into a $150 million six-month revolving credit facility secured by the accounts receivable of our regulated operations.

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

LIQUIDITY AND CAPITAL RESOURCES

Working Capital Requirements

The most significant activity impacting working capital is the purchase of natural gas for our gas utility customers. We could experience significant working capital requirements during peak months of the winter heating season due to higher natural gas consumption, potential periods of high natural gas prices and our current requirement to prepay certain gas commodity suppliers and pipeline transportation companies. Under a stressed weather and commodity price environment, we believe this working capital peak could be as high as $350 million. We anticipate using the combination of our $110 million five-year unsecured revolving credit facility, $150 million secured accounts receivable facility and cash on hand to meet the peak winter working capital requirements of our business.

Cash Flows

Cash Flows from Operating Activities

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

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

Our 2003 cash flows from operations were negative due to significant cash impacts resulting primarily from our non-investment grade credit rating and the continued exit from our wholesale energy trading business. Our negative 2003 cash flows were driven by the following events and factors:

- During 2003, we had significant working capital requirements due to our non-investment grade credit rating and the resulting changes in vendor payment terms.

- We were required to post significant collateral in 2003 due to our non-investment grade credit rating and increased natural gas prices. Some of our collateral from 2002 was returned to us as we continued to exit our energy trading businesses. However, we were required to cash collateralize our letters of credit under our new letter of credit facility.

- We made a $105.5 million payment to terminate our Acadia tolling contract in connection with our restructuring effort to return to operating as a domestic utility.

- We made other restructuring payments of $61.3 million in 2003 for severance, retention and other related charges due to our continued exit from the wholesale energy trading business, primarily for severance that had been accrued in 2002 and due to our restructuring of Everest Connections.

- Higher gas prices in 2003 resulted in increased cash payments for the purchase of gas inventory for our utilities.

- Offsetting cash outflows was the receipt of approximately $261 million of income tax refunds received during the year and depreciation.

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

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

Cash Flows from Investing Activities

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

Cash flows provided from investing activities increased in 2003 compared to 2002. This increase mainly stemmed from reduced capital expenditures in 2003, primarily in the merchant business, as merchant plant construction was significantly completed in 2002. We also made a significant investment in Midlands Electricity in 2002, which did not recur in 2003. In addition, in December 2002 we sold our merchant loan portfolio which generated net cash outflows in 2002. These decreased cash outflows were partially offset by a decrease in cash received from the sale of assets and subsidiary stock in 2003 compared to 2002.

Cash Flows from Financing Activities

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

Cash flows from financing activities decreased in 2003 compared to 2002. Our 2003 net cash used for financing activities reflects the repayment of short-term borrowings and from the reduction of long-term debt.

Cash flows from financing activities in 2002 came primarily from our issuance of common stock and senior notes. In January 2002, we issued 12.5 million shares of common stock to the public, which raised approximately $277.7 million in net proceeds. We also sold $287.5 million of 7.875% senior notes due in March 2032. The issuance of 37.5 million common shares and $500.0 million of senior notes in July 2002 raised approximately $764 million. We used the proceeds of these issuances primarily to replace the liquidity formerly provided by our accounts receivable sale programs that were terminated in 2002 and to retire debt and company-obligated preferred securities.

Current Credit Ratings

Credit ratings impact our ability to obtain short- and long-term financing, the cost of such financing and vendor payment terms, including collateral and prepayment requirements. Our financial flexibility is limited because of restrictive covenants and other terms that are typically imposed on non-investment grade borrowers. As of December 31, 2004, our senior unsecured long-term debt ratings, as assessed by the three major credit rating agencies, were as follows:

Agency	Rating	Commentary
Moody's	B2	Stable Outlook
S&P	B –	Negative Outlook
Fitch	B –	Stable Outlook

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

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

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

Collateral Positions

As of December 31, 2004, we had posted collateral for the following in the form of cash or cash collateralized letters of credit:

In millions	
Trading positions	$125.3
Utility cash collateral requirements	164.6
Elwood tolling contract	37.9
Insurance and other	25.3
Total Funds on Deposit	$353.1

Collateral requirements for our remaining trading positions will fluctuate based on the movement in commodity prices and our credit rating. Changes in collateral requirements based on price movements will vary depending on the magnitude of the price movement and the current position of our trading portfolio. We will receive our posted collateral related to the trading positions as these transactions settle in the future.

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

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

Contractual Obligations

Our contractual cash obligations include maturities of long-term debt, cash payments for our two remaining long-term gas contracts, minimum payments on operating leases and regulated power, gas and coal purchase contracts, as well as the Elwood tolling contracts and merchant gas transportation obligations. See Notes 13, 14 and 21 to the Consolidated Financial Statements for further discussion of these obligations.

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

In millions	**2005**	**2006**	**2007**	**2008**	**2009**	**Thereafter**	**Total**
Long-term debt obligations *(a)*	$ 42.0	$ 89.3	$ 43.3	$ 2.6	$421.5	$1,428.2	$2,026.9
Long-term gas contracts	22.1	23.4	23.9	2.0	—	—	71.4
Lease and maintenance obligations	29.3	24.1	22.3	23.6	22.5	94.7	216.5
Elwood tolling contracts	37.3	37.3	37.3	37.4	37.4	267.7	454.4
Merchant gas transportation obligations	9.2	8.5	5.4	5.4	5.4	23.3	57.2
Regulated purchase obligations	330.9	280.3	249.3	205.4	178.1	582.6	1,826.6
Total	$470.8	$462.9	$381.5	$276.4	$664.9	$2,396.5	$4,653.0

(a) Long-term debt obligations maturing in 2007 does not include the non-cash, mandatory conversion of $345.0 million of PIES to common stock on September 15, 2007.

Long-Term Gas Contracts

We accounted for the advance cash payments we received under these contracts as liabilities. We reduce our obligation for these long-term gas contracts as the gas is delivered to the customer under the units of revenue method. If we were to default on these obligations, or were unable to perform on them, we would be required to pay the issuers of the surety bonds or the counterparties on these arrangements approximately $69.6 million. This amount is greater than the long-term gas contract balance on our Consolidated Balance Sheet due to our use of the units of revenue method versus a present value method applied under the default provisions of the contractual agreements. We do not intend to terminate these remaining contracts.

Elwood Tolling Contracts

Because it is generally expected that the fuel and start-up costs of operating the Elwood power plant will exceed the revenues that would be generated from the power sales, during the foreseeable future, we believe that our capacity to generate power from the Elwood power plant will largely be unutilized. Before including existing forward sales contracts, we expect to incur pretax losses and negative operating cash flows of approximately $37.3 million in 2005 related to these contracts. We are attempting to terminate or restructure this obligation.

Off-Balance Sheet Arrangements

The term ''off-balance sheet arrangement'' generally means any transaction, agreement or other contractual arrangement to which an entity that we do not consolidate is a party, under which we have (i) any obligation arising under a guarantee contract, derivative instrument or variable interest; or (ii) a retained or contingent interest in assets transferred to such entity or similar arrangement that serves as credit, liquidity or market risk support for such assets. As of December 31, 2004, we have obligations under certain off-balance sheet arrangements that have or are reasonably likely to have a current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that may be material to investors. These are discussed below.

Merchant Loan Portfolio

In connection with our former portfolio of merchant loans to energy-related businesses, we entered into commodity and interest rate swaps with the borrowers. Because of increases in natural gas prices and declines in interest rates, these swaps have increased in market value. When we sold substantially all of the portfolio of loans, we retained these swaps. As part of the sale agreement, we agreed that in the event these borrowers fail to meet their note obligations to the buyer of the portfolio, we could be required to share a portion of any proceeds we receive on these swaps with the buyer. In 2004, we paid $6.0 million to the buyer of the portfolio out of $10.7 million of swap proceeds collected. As of December 31, 2004, we have collected $28.0 million related to the remaining swaps, of which we have reserved $5.0 million to cover this obligation. The value of the unsettled portion of these swaps, which expire by December 2006, was $28.5 million at December 31, 2004.

Equity Put Rights

Certain minority owners of Everest Connections had the option to sell their ownership units to us if Everest Connections did not meet certain financial and operational performance measures as of December 31, 2004 (target-based put rights). If the target-based put rights were exercised, we would have been obligated to purchase up to 4.0 million and 4.75 million ownership units at a price of $1.00 and $1.10 per unit, respectively, for a total potential cost of $9.2 million. As a result of our reduced funding of this business, management assessed the likelihood of achieving these metrics and during 2002 recorded a probability-weighted expense of $7.1 million. In 2004, we achieved the operating targets related to 4.0 million and 1.5 million of ownership units at a price of $1.00 and $1.10 per unit, respectively. Therefore, we reversed $4.5 million of this reserve. We did not achieve the targets related to 3.25 million of ownership units at a price of $1.10 per unit. The holders of these target-based put rights exercised their options and were paid $3.6 million for their ownership units in February 2005. As of December 31, 2004, we had fully reserved for this obligation. The minority owners of 9.5 million ownership units also have the option to sell their ownership units to us at fair market value (market-based put rights). The market-based put rights expire on December 31, 2005. We have not provided for this potential obligation as the exercise would represent an equity transaction at fair value. We do not believe based on current estimates of fair value that these market-based put rights are a material contingent obligation.

Capital Expenditures

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

	Actual	Estimated Future Cash Requirements		
In millions	**2004**	**2005**	**2006**	**2007**
Domestic Utilities	$146.6	$223.6	$179.0	$196.0
Canadian utilities	72.8	–	–	–
Everest Connections	14.0	7.5	11.7	3.5
Corporate and Other	8.5	6.6	1.3	1.2
Total capital expenditures	$241.9	$237.7	$192.0	$200.7

Our estimated Domestic Utilities capital expenditures increase significantly in 2005 from 2004, primarily because of approximately $64.3 million of additional capital expenditures on our South Harper Peaking Facility and related transmission system upgrades. In addition, 2006 and 2007 capital expenditures include the anticipated cost of additional emissions control equipment at our generating facilities.

Iatan 2

Our 2005 power supply plan indicates the need for additional base-load capacity after 2009. There is generally a five- to seven-year lead time required between the decision to proceed with a coal-fired generating project and the completion of development, permitting, construction and performance testing of such a project. Kansas City Power & Light Company has presented their plan for the construction of up to 800 MW of coal-fired generating capacity at the existing Iatan site in Weston, Missouri, through a series of workshops to the Missouri Public Service Commission (MPSC) and other interested parties. The additional 800 MW generating capacity is planned for commercial operation prior to summer 2010. On March 2, 2005, we filed an experimental regulatory plan with the MPSC outlining certain regulatory principles needed in order to facilitate our equity participation in 150 MW of the proposed new Iatan facility. The table presented above does not include the additional capital expenditures that would be associated with this participation.

Regulatory Approvals Required for Financing

We are required to obtain the prior approval of the FERC, Kansas Corporation Commission and Colorado Public Utilities Commission prior to issuing long-term debt or stock. We currently have approval from the FERC, Kansas Commission and Colorado Commission to issue up to $238 million of securities in the form of any combination of common stock and long-term debt that is mandatorily convertible into our common stock. We do not have approvals to incur additional long-term debt.

We are also required to obtain the prior approval of the FERC to issue short-term debt. We have obtained their approval to have outstanding up to $350 million of additional secured or unsecured short-term debt. We must obtain the prior approval of the Kansas Corporation Commission to issue short-term debt except as required to meet our working capital requirements.

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

Restriction on Ability to Issue Common Stock

Our certificate of incorporation authorizes us to issue up to 400 million shares of common stock, 20 million shares of Class A Common Stock and 20 million shares of preferred stock. Of the 400 million shares of common stock authorized to be issued, approximately 391.6 million shares have either been issued or reserved for issuance in connection with the conversion of our PIES or pursuant to employee compensation plans. Accordingly, unless our certificate of incorporation is amended with the approval of our shareholders, our ability to raise capital through the sale of common stock is severely restricted.

FINANCIAL REVIEW

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

The use of EBIT as a performance measure is not meant to be considered an alternative to net income or cash flows from operating activities, which are determined in accordance with GAAP. In addition, our use of EBIT may not be comparable to similarly titled measures used by other entities.

See page 65 for cautionary statements and risk factors concerning forward-looking statements contained in this analysis.

In millions, except per share amounts	Year Ended December 31, 2004	2003	2002
Earnings (Loss) Before Interest and Taxes:			
Domestic Utilities	$ 159.1	$ 175.1	$ 125.8
Merchant Services	(438.7)	(415.5)	(677.9)
Corporate and Other	(24.5)	12.4	(1,133.2)
Total EBIT	(304.1)	(228.0)	(1,685.3)
Interest expense	258.4	273.1	232.9
Income tax benefit	(213.3)	(145.1)	(192.8)
Loss from continuing operations	(349.2)	(356.0)	(1,725.4)
Earnings (loss) from discontinued operations, net of tax	56.7	19.6	(327.0)
Cumulative effect of accounting change, net of tax	—	—	(22.7)
Net loss	$(292.5)	$(336.4)	$(2,075.1)
Diluted earnings (loss) per share:			
Continuing operations	$ (1.35)	$ (1.83)	$ (10.67)
Discontinued operations	.22	.10	(2.02)
Cumulative effect of accounting change	–	–	(.14)
Net loss	$ (1.13)	$ (1.73)	$ (12.83)

Key Factors Impacting Continuing Operating Results

Our total loss before interest and taxes increased significantly in 2004 compared to 2003. Key factors affecting 2004 results were as follows:

- Domestic Utilities EBIT decreased $16.0 million primarily due to increased cost of natural gas used for fuel, higher purchased power cost and unfavorable weather for both the electric utility and the gas utility, partially offset by rate increases in Nebraska, Colorado and Missouri.
- The continued wind-down of our energy trading businesses resulted in a $23.2 million increase in losses before interest and taxes from Merchant Services, driven primarily by the losses associated with the termination of four long-term gas contracts.
- In Corporate and Other, we recorded $42.1 million of foreign currency gains in 2003 related to favorable movements in the Australian and New Zealand dollar against the U.S. dollar. We recorded $11.9 million of foreign currency gains in 2004 related to the wind-down of our Canadian merchant subsidiaries.

Cumulative Effect of Accounting Change

In October 2002, the EITF reached a consensus to rescind EITF No. 98-10, ‘‘Accounting for Contracts Involved in Energy Trading and Risk Management Activities.’’ By rescinding EITF 98-10, all contracts that would have otherwise been accounted for under EITF 98-10 and that do not fall within the scope of SFAS No. 133, ‘‘Accounting for Derivative Instruments and Hedging

Activities'' (SFAS 133), should no longer be marked-to-market through earnings. We elected to adopt this requirement in October 2002 and thus reversed $37.5 million (or $22.7 million on an after-tax basis) of earnings previously recognized.

Restructuring Charges

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

	Year Ended December 31,		
In millions	**2004**	**2003**	**2002**
Domestic Utilities:			
Severance costs	$—	$—	$ 15.9
Disposition of corporate aircraft	—	—	5.1
Total Domestic Utilities	—	—	21.0
Merchant Services:			
Interest rate swap reductions	—	23.1	6.2
Severance costs	.7	—	30.6
Retention payments	—	2.2	30.5
Lease agreements	—	(.2)	38.5
Write-down of leasehold improvements and equipment	—	—	58.8
Loss on termination of aggregator loan program	—	—	9.0
Disposition of corporate aircraft	—	—	2.0
Other	—	(.4)	4.4
Total Merchant Services	.7	24.7	180.0
Corporate and Other severance costs	.2	3.5	9.2
Total restructuring charges	$ .9	$28.2	$210.2

Net Loss on Sale of Assets and Other Charges

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

	Year Ended December 31,		
In millions	**2004**	**2003**	**2002**
Domestic Utilities:			
Gas distribution system	$ —	$ .9	$ 9.0
Other	—	(2.2)	—
Total Domestic Utilities	—	(1.3)	9.0
Merchant Services:			
Aries power project and tolling agreement	46.6	—	—
Termination of long-term gas contracts	156.2	—	—
Red Lake gas storage development project	8.9	—	—
Acadia tolling agreement	—	105.5	—
Turbine contracts	—	(5.1)	42.1
Independent power plants	(6.1)	87.9	—
Investment in BAF Energy	(9.1)	—	—
Enron bankruptcy	(6.0)	—	—
Marchwood development project	(5.0)	—	—
Merchant Services goodwill	—	—	181.2
Exit from Lodi gas storage investment	—	—	21.9
Termination of Cogentrix acquisition	—	—	12.2
Other	—	.8	9.7
Total Merchant Services	185.5	189.1	267.1
Corporate and Other:			
Quanta Services	—	—	696.1
Everest Connections and other communication investments	(4.5)	1.1	227.6
Midlands	(3.3)	4.0	247.5
Australia	—	1.8	127.2
Turbines impairment	10.6	—	—
Other	—	—	(3.0)
Total Corporate and Other	2.8	6.9	1,295.4
Total net loss on sale of assets and other charges	$188.3	$194.7	$1,571.5

During 2004, 2003 and 2002, we also incurred net (gains) losses on asset sales and other charges of $(74.0) million, $47.5 million and $438.2 million, respectively, that are reflected in discontinued operations and are not included in the table above.

Discontinued Operations

As further discussed in Note 6 to the Consolidated Financial Statements, we have reported the results of operations of the following assets in discontinued operations in the Consolidated Statements of Income: (i) our Texas natural gas storage facility, our Texas and Mid-Continent natural gas pipeline systems, including our natural gas and natural gas liquids processing assets and our ownership interest in the Oasis Pipe Line Company, our West Virginia coal terminal and our merchant loan portfolio that were all sold in 2002 and early 2003, and (ii) our Canadian network businesses that we sold in May 2004 and our consolidated independent power plants, Lake Cogen and Onondaga, that we sold in March 2004.

Operating results of discontinued operations are as follows:

	Year Ended December 31,		
In millions	**2004**	**2003**	**2002**
Sales	$130.9	$322.4	$ 571.4
Cost of sales	25.1	64.0	225.5
Gross profit	105.8	258.4	345.9
Operating expenses:			
Operating expense	56.7	141.9	197.9
Net loss (gain) on sale of assets and other charges	(74.0)	47.5	438.2
Depreciation and amortization expense	—	8.6	82.2
Total operating expenses	(17.3)	198.0	718.3
Other income (expense):			
Equity in earnings of investments	—	—	5.3
Other income (expense)	2.7	(16.0)	57.5
Total other income (expense)	2.7	(16.0)	62.8
Earnings (loss) before interest and taxes	125.8	44.4	(309.6)
Interest expense	14.7	23.9	22.3
Earnings (loss) before income taxes	111.1	20.5	(331.9)
Income tax expense (benefit)	54.4	.9	(4.9)
Earnings (loss) from discontinued operations	$ 56.7	$ 19.6	$(327.0)

2004 versus 2003

Sales, Cost of Sales and Gross Profit

Sales and cost of sales decreased $191.5 million and $38.9 million, respectively, resulting in a gross profit decrease of $152.6 million in 2004 compared to 2003. Sales, cost of sales and gross profit for our Canadian network business decreased $126.0 million, $21.2 million and $104.8 million, respectively, primarily due to the sale of these businesses in May 2004. Canadian utility sales, cost of sales and gross profit in June 2003 through December 2003 were $170.4 million, $23.3 million and $147.1 million, respectively. These decreases were partially offset by the March 2003 decision by the Alberta Energy Utilities Board (AEUB) to reduce our 2002 and 2003 customer billing rates. The AEUB decision resulted in an adjustment that reduced our first quarter 2003 sales and gross profit by approximately $33.7 million. Sales, cost of sales and gross profit for Lake Cogen and Onondaga were lower in 2004 by $65.2 million, $17.8 million and $47.4 million, respectively, due to the sale of these businesses in early March 2004 and a price dispute settlement that increased Lake Cogen's 2003 sales by $5.7 million.

Operating Expense

Operating expense decreased $85.2 million in 2004 compared to 2003 primarily due to the sale of our consolidated independent power plants in March 2004 and our Canadian utility businesses in May 2004.

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

In 2004, net gain on sale of assets and other charges of $74.0 million consisted of a $65.6 million gain related to the sale of our Canadian utility businesses in May 2004, and an $8.4 million gain related to the sale of our consolidated independent power plants, Lake Cogen and Onondaga, in March 2004. In 2003, the $47.5 million net loss and other charges was related to the impairment charge taken on our consolidated independent power plants. In the third quarter of 2003, we decided to proceed with their sale and therefore wrote them down to their estimated fair value less costs to sell, which was less than their carrying value.

Depreciation and Amortization Expense

Depreciation and amortization expense decreased $8.6 million in 2004 compared to 2003. The elimination of depreciation from our Canadian utility businesses, due to their classification as held for sale in accordance with SFAS 144, decreased depreciation expense $21.4 million. SFAS 144 requires that depreciation expense no longer be recorded for those assets classified for accounting purposes as held for sale. The decrease was offset by the $15.2 million adjustment in the first quarter of 2003 related to the decision by the AEUB to reduce the depreciation rates on most of our distribution assets in Alberta.

Other Income (Expense)

Other income increased $18.7 million in 2004 compared to 2003, primarily due to 2003 costs including an $18.5 million charge related to a currency put option purchased to protect us from unfavorable currency movements on the Canadian asset sale proceeds and $3.2 million of foreign currency losses related to U.S. dollar denominated debt issued by our Canadian subsidiaries.

Income Tax Expense

Income tax expense increased $53.5 million in 2004 compared to 2003. The 2004 income tax expense on pretax income from discontinued operations was primarily the result of taxes associated with the gain on the sale of our Canadian utility businesses. The effective tax rate on the pretax gain on sale of our Canadian utility businesses is substantially higher than the statutory federal tax rate due to the following factors. The U.S. taxes reflect the partial deduction of Canadian taxes, including withholding taxes, from the U.S. taxable income instead of the full utilization of foreign tax credits. Taxes on the sale also reflect our inability to fully utilize the tax loss on the sale of the Alberta business against the tax gain on the sale of the British Columbia business. Offsetting the 2004 income tax expense was the reversal of $11.1 million of valuation allowances provided in 2003 related to the impairment of our investments in independent power plants. This valuation allowance was reversed in 2004 when the final sale structure was determined and an updated estimate of expected capital losses was completed. In addition, our former Alberta utility recognized income taxes using the flow-through method. As a result, the elimination of depreciation in 2004 and the adjustment of depreciable lives due to the 2003 regulatory decision increased pretax income but had no impact on income tax expense.

2003 versus 2002

Sales, Cost of Sales and Gross Profit

Sales and cost of sales decreased $249.0 million and $161.5 million, respectively, resulting in a gross profit decrease of $87.5 million in 2003 compared to 2002. These decreases were primarily due to the sale of our gas gathering and pipeline assets and our coal terminal in the fourth quarter of 2002 and early 2003. In addition, sales and gross profit for our Canadian network businesses decreased $12.9 million and $20.6 million, respectively, due to the decision by the AEUB to decrease our 2002 and 2003 customer billing rates.

Operating Expense

Operating expense decreased $56.0 million in 2003 compared to 2002 primarily due to the sale of our gas gathering and pipeline assets, merchant loan portfolio and coal terminal in 2002 and early 2003.

Net Loss on Sale of Assets and Other Charges

Net loss on sale of assets and other charges consisted of $47.5 million related to our consolidated independent power plants, Lake Cogen and Onondaga. In the third quarter of 2003, we decided to proceed with the sale of these assets and therefore wrote them down to estimated fair value less costs to sell, which was less than their carrying value. The 2002 net loss on sales of assets and other charges included a $240.3 million loss on the sale of our gas gathering and pipeline assets, a $184.0 million loss on the sale of our merchant loan portfolio, a $6.6 million impairment of our coal terminal, a $4.3 million pretax gain on sale of our gas storage assets, a $6.4 million impairment charge on a Canadian power plant and $5.2 million of other impairment charges.

Depreciation and Amortization Expense

Depreciation and amortization expense decreased $73.6 million in 2003 compared to 2002. When we classified our Canadian utility as held for sale, we stopped recording depreciation expense for that business. This decreased depreciation expense by $20.5 million. Approximately $23.2 million of the decrease in depreciation and amortization was due to the sale of our gas gathering and pipeline assets and our coal terminal in the fourth quarter of 2002 and early 2003. The remaining decrease was primarily due to the AEUB's decision to reduce the depreciation rates on most of our distribution assets in Alberta.

Equity in Earnings of Investments

Equity in earnings of investments decreased $5.3 million due to the sale of our investment in the Oasis Pipe Line Company in the fourth quarter of 2002.

Other Income

Other income decreased $73.5 million in 2003 compared to 2002, primarily due to the sale of our merchant loan portfolio in the fourth quarter of 2002. This business generated $45.5 million of other income in 2002. In 2003, we incurred an $18.5 million charge related to a currency put option purchased to protect us from unfavorable currency movements on the Canadian asset sale proceeds and $3.2 million of foreign currency losses related to U.S. dollar denominated debt issued by our Canadian subsidiaries.

Income Tax Benefit

Income tax benefit decreased $5.8 million primarily due to pretax income in 2003 compared to a pretax loss in 2002 and the AEUB decision discussed above. This decision decreased sales and depreciation; however, only the sales impact is tax-effected for Canadian regulatory purposes. In 2002, $190.9 million of our losses were treated as capital losses for income tax purposes. Because capital losses can only offset capital gains, and we do not have sufficient capital gains in prior years to offset all of these losses, nor can we be assured of generating future capital gains, we recorded a $75.4 million valuation allowance against our capital loss carryforward. In addition, the 2002 impairment charges and net loss on sale of assets included the effects of $31.9 million of goodwill and other intangibles that were not deductible for income tax purposes. These benefits were offset by income tax expense that was recorded for our Canadian operations. Due to our decision to sell this business, we could no longer represent that cash from this business would be permanently reinvested. Therefore, additional deferred tax was recorded to account for taxes associated with bringing asset sales proceeds back to the United States. In addition, approximately $28.0 million of the 2003 impairment charge on our consolidated independent power plants was expected to be a capital loss for which we provided additional valuation allowances.

Three-Year Review—Domestic Utilities

Domestic Utilities is made up of our electric and gas regulated utility businesses, which operate as Aquila in Colorado, Iowa, Kansas, Michigan, Minnesota, Missouri and Nebraska.

	Year Ended December 31,		
Dollars in millions	**2004**	**2003**	**2002**
Sales:			
Electricity—regulated	$ 759.3	$ 697.5	$ 666.9
Natural gas—regulated	1,032.0	969.5	765.1
Natural gas—non-regulated	7.1	14.6	323.7
Other—non-regulated	27.2	30.2	47.1
Total sales	1,825.6	1,711.8	1,802.8
Cost of sales:			
Electricity—regulated	384.7	331.3	308.4
Natural gas—regulated	741.2	671.0	496.1
Natural gas—non-regulated	4.9	11.6	296.1
Other—non-regulated	14.0	13.3	24.7
Total cost of sales	1,144.8	1,027.2	1,125.3
Gross profit	680.8	684.6	677.5
Operating expenses:			
Operating expense	399.1	383.0	400.1
Restructuring charges	—	—	21.0
Net loss (gain) on sale of assets and other charges	—	(1.3)	9.0
Depreciation and amortization expense	126.4	129.2	124.6
Total operating expenses	525.5	510.9	554.7
Other income (expense):			
Other income	3.8	1.4	3.0
Earnings before interest and taxes	$ 159.1	$ 175.1	$ 125.8
Electric sales and transportation volumes (GWh)	12,363	11,833	12,373
Gas sales and transportation volumes (Mcf)	214,976	227,995	235,127
Electric customers	452,646	445,890	437,965
Gas customers	910,116	900,777	890,527

2004 versus 2003

Sales, Cost of Sales and Gross Profit

Sales and cost of sales for the Domestic Utilities businesses increased $113.8 million and $117.6 million, respectively, resulting in a gross profit decrease of $3.8 million in 2004 compared to 2003. These changes were primarily due to the following factors:

- Regulated electric utility sales and cost of sales increased $61.8 million and $53.4 million, respectively, in 2004 compared to 2003, for a net increase in gross profit of $8.4 million. Sales and gross profit increased by $36.4 million due to rate increases in Colorado effective in July 2003 and in Missouri effective in April 2004, plus $5.6 million of additional margin from an increase in customers. These were partially offset by a $25.7 million increase in cost of sales due to the higher cost of fuel and purchased power, net of offsetting derivative hedge positions in 2004 and 2003. Unfavorable weather also decreased gross profit by $6.1 million. In addition, 2003 electric cost of sales included $2.3 million of favorable adjustments resulting from the settlement of purchased power pricing disputes that did not recur in 2004.

- Sales and cost of sales for our regulated gas utilities increased $62.5 million and $70.2 million, respectively, in 2004 compared to 2003, for a net decrease in gross profit of $7.7 million. Sales and cost of sales increased due to an 18% increase in natural gas prices. However, because gas purchase costs for our gas utility operations are passed through to our customers, the change in gas prices did not have a corresponding impact on gross profit. Regulated gas margins decreased $11.4 million due to unfavorable weather and lower usage per customer in 2004 compared to 2003. Regulated gas margins in 2003 included a $1.9 million favorable change in reserved funds released upon conclusion of multi-year gas cost recovery filings that did not recur in 2004. The overall decline in gas margins due to volume and weather was partially offset by $6.6 million in rate increases in Nebraska and Missouri and $1.9 million of increased margins from customer growth.

- Non-regulated gas sales, cost of sales and gross profit decreased $7.5 million, $6.7 million and $.8 million, respectively, in 2004 compared to 2003, primarily as the result of the sale of certain non-regulated gas pipeline and gathering operations in August 2003.

- Non-regulated other sales decreased $3.0 million and cost of sales increased $.7 million for a net decrease in gross profit of $3.7 million, primarily as a result of a decrease in appliance service contracts and increased costs of servicing existing contracts.

Operating Expense

Operating expense increased $16.1 million in 2004 compared to 2003, as a result of a number of cost increases. The most significant of these was outside services and materials costs, which increased $6.1 million, and labor and other compensation costs, which increased $5.3 million due to additional customer service representatives, apprentice linemen, increased pension costs and compliance costs in 2004 compared to 2003.

Depreciation and Amortization Expense

Depreciation and amortization expense decreased $2.8 million in 2004 compared to 2003, primarily due to the adjustments to depreciation rates resulting from recent rate cases.

2003 versus 2002

Sales, Cost of Sales and Gross Profit

Sales and cost of sales for the Domestic Utilities businesses decreased $91.0 million and $98.1 million, respectively, resulting in a gross profit increase of $7.1 million in 2003 compared to 2002. These changes were primarily due to the following factors:

- Regulated electric utility sales and cost of sales increased $30.6 million and $22.9 million, respectively, in 2003 compared to 2002, for a net increase in gross profit of $7.7 million. Sales and gross profit increased by $9.5 million due to a rate increase in Colorado effective in July 2003 and $7.7 million of additional margin from favorable weather and customer growth. These increases were offset by a $4.5 million decrease in margin from off-system sales and a $5.3 million increase in cost of sales due to the higher cost of natural gas used to fuel our power plants, net of offsetting derivative positions.

- Sales and cost of sales for our regulated gas utilities increased $204.4 million and $174.9 million, respectively, in 2003 compared to 2002, for a net increase in gross profit of $29.5 million. Sales and cost of sales increased due to a 33% increase in natural gas prices. However, because gas purchase costs for our gas utility operations are passed through to our customers, the change in gas prices did not have a corresponding impact on gross profit. Gross profit for our regulated gas utilities increased primarily due to $14.1 million in rate increases in Michigan, Iowa and Nebraska, a $6.3 million change in reserved funds released upon conclusion of multi-year gas cost recovery filings in various states and customer growth of $2.4 million.

- Non-regulated gas sales, cost of sales and gross profit decreased $309.1 million, $284.5 million and $24.6 million, respectively, in 2003 compared to 2002, primarily as the result of the sale of our non-regulated retail gas operations on September 30, 2002.

- Other non-regulated gross profit was lower by $5.5 million in 2003, primarily due to the sale of our off-system appliance repair business in January 2003.

Operating Expense

Operating expense decreased $17.1 million in 2003 compared to 2002, primarily due to approximately $15.6 million of lower labor, benefits and administrative expenses resulting from the restructuring of our domestic utility operations.

Restructuring Charges

Restructuring charges decreased $21.0 million in 2003 compared to 2002. As a result of the restructuring of our Domestic Utilities business to more closely align it with our state service areas, we incurred $21.0 million in restructuring costs in 2002, primarily in the form of severance for terminated employees and the disposition of our corporate aircraft operation.

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

As further discussed in Note 5 to the Consolidated Financial Statements, Domestic Utilities incurred a $9.0 million asset impairment charge related to a local natural gas distribution system deemed unrecoverable in one of our regulatory jurisdictions in 2002, compared to a net $1.3 million gain in 2003 on several minor asset dispositions and impairments.

Depreciation and Amortization Expense

Depreciation and amortization expense increased $4.6 million in 2003 compared to 2002, primarily due to the adjustment of depreciation rates in one jurisdiction in December 2002.

Earnings Trend

The recent settlement of our electric and gas rate cases in Missouri is expected to increase annual sales approximately $37.5 million and $3.4 million, respectively. However, our costs of natural gas used for fuel and purchased power have exceeded the level of costs recovered under the IEC discussed on page 10. If these costs remain above the IEC base cost for the two-year period, we will not recover the excess. A portion of the rate increase is to cover increased costs in the 12-month test period such as additional staffing to improve customer service. To the extent that operating costs increase or decrease subsequent to the test period, the impact of the change will affect our operating results.

Our power supply agreement with Aries, which provides up to 500 MW of power, expires in June 2005. We plan to replace this power with the construction of the South Harper Peaking Facility, a 315-megawatt combustion turbine generation plant near Peculiar, Missouri, and by entering into power purchase agreements. The construction of South Harper is expected to require additional capital expenditures of approximately $44.8 million. In addition, transmission system upgrades of $19.5 million will be required. To the extent the cost of this replacement power exceeds the cost of power recovered in rates under the Aries agreement, and until such cost is recovered in a subsequent rate case, our earnings could be adversely affected.

On December 22, 2003, one of our coal suppliers declared a partial force majeure event due to a labor strike at the mine and gave us formal notice they would be unable to fully perform their contract obligations for the then following 60 to 90 days. This force majeure condition continued throughout 2004 with Aquila receiving approximately 30% of its contracted low-sulfur, high-Btu volumes. Although force majeure conditions are expected to improve in 2005, we continue to plan for and have secured substantial quantities of alternate supply through spot purchases, despite a general decrease in availability of comparable coal on the spot market. These substitute supplies of coal are typically of higher sulfur content and therefore require the purchase of additional SO_2 emission allowances at a time when the cost of such allowances is substantially higher than historical levels. In the event we continue to replace our original contracted coal supply with the substitute coal supply during 2005, our operating results could be adversely affected.

Merchant Services

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

Three-Year Review—Merchant Services

In millions	Year Ended December 31, 2004	2003	2002
Sales	$(152.9)	$ (70.0)	$ 225.4
Cost of sales	57.1	87.3	362.8
Gross loss	(210.0)	(157.3)	(137.4)
Operating expenses:			
Operating expense	32.2	94.0	146.2
Restructuring charges	.7	24.7	180.0
Net loss on sale of assets and other charges	185.5	189.1	267.1
Depreciation and amortization expense	17.4	31.8	15.5
Total operating expenses	235.8	339.6	608.8
Other income:			
Equity in earnings of investments	1.9	53.7	52.8
Other income	5.2	27.7	15.5
Earnings (loss) before interest and taxes	$(438.7)	$(415.5)	$(677.9)

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

2004 versus 2003

Sales, Cost of Sales and Gross Loss

Gross loss for our Merchant Services operations for 2004 was $210.0 million, primarily due to the following factors:

- Approximately $22.6 million was a non-cash loss related to the discounting of our trading portfolio, primarily driven by our long-term gas contracts. After updating the future cash flow stream based on the new forward natural gas prices, we discount the future cash flows of our price risk management assets based on our counterparties' credit standing, versus our future cash flows of our price risk management liabilities that are discounted based on our current credit standing. In prior periods, primarily in 2002, when our credit standing deteriorated compared to our counterparties' that make up the vast majority of our price risk management assets, we recorded non-cash earnings related to the discounting of our price risk management assets and liabilities. During 2004, the benchmark indices we use to determine the discount rate appropriate for our credit standing decreased, resulting in the partial reversal of the previous earnings and assets recorded. Due to the settlement of four of our long-term gas contracts, the future impact of non-cash mark-to-market movements described above will be significantly reduced.

- In 2004, we incurred margin losses of $30.3 million resulting from the difference between revenue recognized on our long-term gas contracts and the net cost of gas delivered under these contracts.

- During 2004, we made fixed capacity payments evenly throughout the year that entitled us to generate power at merchant power plants owned by others. For 2004, we recorded net margin loss associated with these agreements of $36.9 million. The cost to purchase natural gas to fuel these power plants generally exceeded the value of the power that could be generated. Accordingly, we did not generate material revenues. Capacity payments were lower in 2004 compared to 2003 because we terminated our Acadia capacity contract in the second quarter of 2003 and our Aries capacity contract in the first quarter of 2004.

- The settlement of our price risk management assets and liabilities associated with four of our long-term gas contracts resulted in non-cash, mark-to-market losses of approximately $40.3 million related to the discounting of our trading portfolio. We discount the future cash flows of our price risk management assets based on our counterparties' credit standing, versus our future cash flows of our price risk management liabilities that are discounted based on our current credit standing. This resulted in the recording of a net asset related to these four long-term contracts and their corresponding commodity hedges of approximately $40.3 million prior to our settlement. Additionally, we recorded a margin loss of approximately $16.5 million for margin recorded on these long-term contracts and approximately $7.1 million related to replacement gas payments we made under the termination provisions of these contracts.

- We incurred approximately $23.9 million of costs to manage our remaining natural gas hedge positions related to the Onondaga swap derivative sold in connection with the sale of our independent power plants, cash flow hedge option premium expirations, the exit of other hedges related to previous contracts and settlements of various open positions during 2004.

- Our remaining gross loss for 2004 mainly stems from mark-to-market losses and unfavorable settlements of approximately $32.4 million, related to a long-term power supply transaction with NYSEG and our remaining stream flow transaction which expires in 2006. In May 2004, we settled our obligation under the long-term power supply contract with NYSEG by making a cash payment of $37.7 million to a third party that assumed our obligations under this contract.

Gross loss for our Merchant Services operations for 2003 was $157.3 million, primarily due to the following factors:

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

- In 2003, we incurred margin losses of $45.9 million, resulting from the difference between revenue recognized on our long-term gas contracts and the net cost of gas delivered under these contracts.

- During 2003, we made fixed capacity payments evenly throughout the year that entitled us to generate power at merchant power plants owned by others. For 2003, we recorded net margin loss associated with these agreements of $56.3 million. The cost to purchase natural gas to fuel these power plants generally exceeded the value of the power that could be generated. Accordingly, we did not generate material revenues.

- In 2003, we incurred approximately $47.9 million of unfavorable settlements of our highly structured stream flow and long-term power supply transactions and our continued wind-down of our European trading operations.

- We recorded a $25.6 million non-cash loss related to the sale of our capacity under certain long-term gas transportation agreements at substantially less than our future commitments. Although the loss was recognized for accounting purposes, the cash associated with the loss will be paid out over the term of the contracts.

- We recognized approximately $29.3 million of net mark-to-market losses on natural gas hedge positions related to the Onondaga swap derivative and other hedges related to previous contracts.

- The remaining $7.2 million of gross loss primarily relates to mark-to-market losses on alternative risk contracts and settlements of various open positions during 2003.

Operating Expense

Operating expense decreased $61.8 million primarily due to $26.5 million of expense accrued in 2003 related to our January 2004 settlement with the CFTC, and lower labor and other costs related to continued reductions in staff as part of the wind-down of our Merchant operations.

Restructuring Charges

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

Net Loss on Sale of Assets and Other Charges

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

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

Depreciation and Amortization Expense

Depreciation and amortization expense decreased $14.4 million in 2004 compared to 2003, primarily due to the elimination of the amortization of premiums associated with our equity method investments in independent power plants, resulting from the impairment of our investments in these plants in September 2003.

Equity in Earnings of Investments

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

Other Income (Expense)

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

2003 versus 2002

Sales, Cost of Sales and Gross Loss

The significant factors causing the gross loss of $157.3 million in 2003 are discussed above.

Gross loss for our Merchant Services operations for 2002 was $137.4 million. The following describes the major components of the 2002 gross loss:

- Approximately $125.8 million of this loss related to balancing counterparty positions, reducing open positions and terminating existing contracts as a result of our decision to exit the wholesale energy trading business.

- In 2002, we incurred margin losses of $45.0 million, resulting from the difference between revenue recognized on our long-term gas contracts and the net cost of gas delivered under these contracts.

- We made fixed capacity payments evenly throughout 2002 that entitled us to generate power at merchant power plants owned by others. For 2002, we recorded net margin loss associated with these agreements of $22.7 million.

- We recognized approximately $25.7 million of net mark-to-market losses on natural gas hedge positions related to the Onondaga swap derivative and other hedges related to previous contracts.

- Partially offsetting the losses discussed above were approximately $30.2 million of non-cash earnings related to the discounting of our trading portfolios, primarily driven by long-term gas contracts.

- Also offsetting the losses described above was gross profit of $51.6 million from the optimization of the energy-trading portfolio prior to the June 17, 2002 announcement of our exit from wholesale energy trading.

Operating Expense

Operating expense decreased $52.2 million primarily due to labor and benefit savings, lower corporate costs resulting from the restructuring of this business in 2002 and related operating cost reductions resulting from the exit from our wholesale energy trading operations in 2002, partially offset by $26.5 million of expense accrued in 2003 related to our January 2004 settlement with the CFTC and a $9.8 million write-down of our remaining merchant note receivable in 2003.

Restructuring Charges

Restructuring charges decreased $155.3 million in 2003 compared to 2002. This decrease stemmed primarily from significant charges taken in 2002. In connection with the exit from our wholesale energy trading business in 2002, we incurred $173.8 million of restructuring charges. These charges included $61.1 million of severance and retention payments to terminated employees, $58.8 million of leasehold improvements and equipment that were expensed when we vacated the related leased properties, $38.5 million of lease costs connected to future lease commitments, $9.0 million of losses associated with the exit from our retail aggregator loan business and $6.4 million of other charges.

Partially offsetting the decrease were restructuring charges of $23.1 million and $6.2 million during 2003 and 2002, respectively, relating to the termination of our remaining interest rate swaps associated with the construction financings for our Clay County and Piatt County power plants. As debt related to these facilities was retired earlier than anticipated, the notional amount of our swaps exceeded our outstanding debt. We therefore reduced our position and realized the loss associated with the cancelled portion of the swaps.

Net Loss on Sale of Assets and Other Charges

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

For 2002, net loss on sale of assets and other charges consisted primarily of an impairment charge of $181.2 million related to goodwill associated with Merchant Services that became unrealizable due to our exit from this business, $42.1 million relating to the expected loss associated with either the sale or contract termination of four electric turbines that were sold or returned to the manufacturer in 2003, $21.9 million related to our exit from the Lodi gas storage investment, $12.2 million related to fees and expenses associated with the termination of our proposed Cogentrix acquisition, and $9.7 million of other impairments.

Depreciation and Amortization Expense

Depreciation and amortization expense increased $16.3 million in 2003 compared to 2002. Approximately $12.3 million of this increase was due to a decrease in the estimated amortizable life of certain plant premiums relating to our acquisition of GPU International in December 2000. In addition, the start of commercial operations at three owned power plants contributed an additional $9.6 million of depreciation and amortization expense in 2003. These increases were partially offset by decreased depreciation related to excess leasehold improvements and equipment that were expensed when we vacated the related leased properties.

Other Income (Expense)

Other income increased $12.2 million in 2003 primarily due to two items. On January 12, 2004, the Eighth Circuit Court of Appeals overturned a prior adverse decision of the United States Tax Court regarding the proper depreciable life of certain of our natural gas gathering and pipeline assets. As a result of the appeals court's decision, we reversed the accrual of $7.7 million of interest expense in 2003 that would have been payable had the Internal Revenue Service prevailed in the dispute. We also realized foreign currency translation gains of $12.5 million on the wind-down of our European merchant operations.

Current Operating Developments

ICE Sale

In February 2005, we sold our 4.5% interest in IntercontinentalExchange, Inc. (ICE), which owns a web-based commodity exchange platform, to other shareholders in ICE for approximately $13.8 million. This transaction resulted in a pretax gain of approximately $9.3 million.

Batesville Tolling Contract

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

Earnings Trend and Impact of Changing Business Environment

The merchant energy sector has been negatively impacted by the increase in generation capacity that became operational in 2002 and 2003. This increase in supply has placed downward pressure on power prices and subsequently the value of unsold merchant generation capacity. Because it is generally expected that the fuel and start-up costs of operating our merchant power plants will exceed the revenues that would be generated from the power sold, we believe that during the foreseeable future we will have limited ability to generate power at a gross profit. We will continue to have operating and maintenance cost associated with our owned merchant generation plants, whether the facilities are being utilized to generate power or are idle. Additionally, we will be required to make capacity payments related to our tolling agreements with Elwood and expect to incur pretax losses and negative operating cash flows of approximately $37.3 million in 2005 related to this arrangement. We are attempting to terminate or restructure this obligation. We have sold capacity in three of these plants which will partially offset these costs in 2005 and 2006. As a result of the above factors and our change in strategy, we do not expect Merchant Services to be profitable in the next two to three years.

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

We began winding down and terminating our trading positions with our various counterparties during the third quarter of 2002. However, it will take a number of years to complete the wind-down. Because most of our trading positions are hedged, we should experience limited fluctuation in earnings or losses other than the impacts from counterparty credit, the discounting or accretion of interest, or the termination or liquidation of additional trading contracts. We have one remaining highly customized actuarial-based contract in Merchant Services which expires in 2006. There may be earnings volatility associated with this contract due to its highly customized nature and our inability to completely hedge the associated risk. Using a long-term value at risk methodology, with a 95% confidence level, we estimate $22.2 million of total volatility (potential earnings or losses) related to this contract.

Corporate Matters

Corporate and Other EBIT

The table below summarizes EBIT for Corporate and Other, which contains the retained costs of the company that are not allocated to our operating businesses, and our 96% owned subsidiary, Everest Connections, a communications business which provides local and long-distance telephone, cable television and high-speed Internet service to areas of greater Kansas City. Additionally, our results for the year ended December 31, 2002 includes our ownership interest in Quanta Services, Inc., a provider of field services to electric utilities, telecommunications and cable television companies, and governmental entities. We began decreasing our ownership interest in Quanta Services in July 2002 and sold our remaining shares in February 2003.

Also included are our former equity method investments in Australia, New Zealand and the United Kingdom, each of which has been sold. Our Australian investments included a 33.8% interest in United Energy Limited (UEL), an electric distribution company in the Melbourne area; a 25.5% interest in Multinet Gas, a gas distribution company in the Melbourne area; and a 45.0% interest, held jointly with UEL, in AlintaGas Limited, a gas distribution company in Western Australia. We sold our Australian investments in May and July 2003. Our United Kingdom investment consisted of an indirect 79.9% interest in Aquila Sterling Limited, the holding company for Midlands Electricity, an electric distribution company in central England. We sold our United Kingdom investment in January 2004. Our results for the year ended December 31, 2002, includes the earnings from our investment in UnitedNetworks Limited, a New Zealand gas and electric distribution company that we sold in October 2002.

We sold our former Canadian utility businesses in May 2004 and the results of these operations have been reclassified as discontinued operations and are not included below (see Note 6 to the Consolidated Financial Statements).

	Year Ended December 31,		
In millions	**2004**	**2003**	**2002**
Sales	$ 38.3	$32.2	$ 12.9
Cost of sales	12.3	9.6	3.9
Gross profit	26.0	22.6	9.0
Operating expenses:			
Operating expense	52.2	72.6	63.6
Restructuring charges	.2	3.5	9.2
Net loss on sale of assets and other charges	2.8	6.9	1,295.4
Depreciation and amortization expense	6.5	3.7	15.7
Total operating expenses	61.7	86.7	1,383.9
Other income (expense):			
Equity in earnings of investments	.2	15.9	114.1
Gain on sale of subsidiary stock	—	—	130.5
Minority interest in loss of subsidiaries	—	—	7.8
Other income (expense)	11.0	60.6	(10.7)
Earnings (loss) before interest and taxes	$(24.5)	$12.4	$(1,133.2)

2004 versus 2003

Sales, Cost of Sales and Gross Profit

Sales, cost of sales and gross profit increased $6.1 million, $2.7 million and $3.4 million, respectively, in 2004 compared to 2003, primarily due to an increase in customers and higher average sales to residential and business customers at Everest Connections.

Operating Expense

Operating expense decreased $20.4 million in 2004 compared to 2003, due to a $14.2 million decrease in insurance and other costs associated with having non-investment grade credit ratings. Consulting fees decreased $8.2 million in 2004 due to the completion of our restructuring efforts in 2003. In addition, the sale of our international investments in Australia and the United Kingdom decreased operating expenses $12.5 million. These decreases were partially offset by an $8.8 million increase in costs associated with the settlement of the appraisal rights shareholder lawsuit in 2004 and $4.9 million of additional costs related to the exit of our international networks investment in 2004.

Restructuring Charges

Restructuring charges decreased $3.3 million in 2004 compared to 2003. This was primarily due to $2.1 million of severance and other related costs that were paid in 2003 in connection with the restructuring of Everest Connections, and $.9 million of executive severance that was paid in 2003.

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

The 2004 net loss on sale of assets and other charges of $2.8 million is mainly due to the $10.6 million impairment on three natural gas combustion turbines that were held for future construction by one of our non-regulated subsidiaries and have now been transferred to our Missouri electric operations at their current fair value. The impairment was partially offset by the reversal of our Everest Connections target-based put rights liability of $4.5 million due to the meeting of certain financial and operational performance measures, and the $3.3 million gain we recorded in connection with the sale of our interest in Midlands Electricity in January 2004. The Midlands Electricity investment was written down to its estimated fair value in 2002 and again in September 2003. However, due to strengthening of the British pound exchange rate in the fourth quarter of 2003 and in early 2004, we realized a gain on the closing of the sale. The 2003 loss on sale of assets of $6.9 million was related to the impairment charge taken on our investment in Midlands Electricity in September 2003 and the net loss on the sale of our interests in AlintaGas, United Energy and Multinet Gas in Australia in May and July 2003.

Depreciation and Amortization Expense

Depreciation and amortization expense increased $2.8 million primarily due to customer equipment additions resulting from Everest Connections customer growth and network expansion.

Equity in Earnings of Investments

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

Other Income (Expense)

Other income decreased $49.6 million, mainly due to $42.1 million of foreign currency gains recognized in 2003 related to favorable movements in the Australian and New Zealand dollar against the U.S. dollar, and $12.3 million of foreign currency gains recognized in the second quarter of 2003 due to the strengthening of the Canadian dollar on U.S. dollar obligations at a former Canadian finance subsidiary not included in discontinued operations. We had an $11.9 million gain on foreign currency related to the wind-down of our Canadian merchant subsidiaries in 2004. Additionally in 2004, we realized a $1.9 million gain on the early redemption of the note payable issued in connection with our acquisition of Midlands, which was offset by $1.8 million in fees paid to lenders in connection with the waiver and amendment of financial covenants under our retired secured term loan. These gains in 2004 were partially offset by $8.7 million of prepayment penalties and fees we paid in association with the retirement of the secured term loan.

2003 versus 2002

Sales, Cost of Sales and Gross Profit

Sales, cost of sales and gross profit increased $19.3 million, $5.7 million and $13.6 million, respectively, in 2003 compared to 2002, primarily due to an increase in customers at Everest Connections.

Operating Expense

Operating expense increased $9.0 million in 2003 compared to 2002, primarily due to an additional $12.5 million of restructuring consulting fees and $21.4 million of increased insurance and other costs associated with having non-investment grade credit ratings. This increase was partially offset by $3.7 million of costs incurred in 2002 associated with retiring debt and company-obligated preferred securities and $6.5 million of cost savings in Everest Connections associated with the restructuring of its operations in 2003. In addition, our losses on investments associated with the cash surrender value of certain life insurance policies were greater in 2002 than in 2003. We also incurred approximately $5.5 million of expenses in 2002 primarily related to the proxy contest for control of Quanta Services.

Restructuring Charges

Restructuring charges decreased $5.7 million in 2003 compared to 2002. This decrease was primarily due to $8.9 million of executive severance costs recorded in 2002 in connection with the separation agreements with our former Chief Executive Officer and Chief Financial Officer, partially offset by the restructuring of the operations of Everest Connections in the first half of 2003. This resulted in the termination of approximately 160 employees and $2.1 million of severance and related restructuring costs.

Net Loss on Sale of Assets and Other Charges

Net loss on sale of assets and other charges for 2003 included a $1.8 million pretax loss on the sale of our interests in AlintaGas, United Energy and Multinet Gas in Australia and a $4.0 million impairment charge related to our investment in Midlands resulting from the sale agreement with Powergen. In 2002, we recorded impairment charges of $127.2 million related to our investment in Multinet Gas and AlintaGas and $247.5 million related to our investment in Midlands. The 2002 impairments also included of $696.1 million of impairment losses related to our investment in Quanta Services and $227.6 million of impairment losses related to Everest Connections and other communication technology investments. See Note 5 to the Consolidated Financial Statements for further explanation.

Depreciation and Amortization Expense

Depreciation and amortization expense decreased $12.0 million primarily due to the reduced depreciable asset base at Everest Connections resulting from the impairment charge recorded in the fourth quarter of 2002.

Equity in Earnings of Investments

Equity in earnings of investments decreased $98.2 million in 2003 compared to 2002. This decrease was primarily due to the sale of our interest in UnitedNetworks Limited in New Zealand in October 2002, which contributed equity earnings of $30.9 million in 2002, the 2003 sale of our Australian investments which contributed $39.2 million of equity earnings in 2002 compared to $16.1 million in 2003, and not recording equity earnings in 2003 from our Midlands investment due to regulatory limitations on cash payments by Midlands to its owners. In 2003, we received no cash dividends or management fees from Midlands, which would have enabled us to recognize earnings on this investment. Our share of undistributed net earnings from Midlands was $55.9 million in 2003. During 2002, we recorded equity earnings of $41.9 million related to our Midlands investment.

Gain on Sale of Subsidiary Stock

In October 2002, we sold our shares in our New Zealand utility business in a public tender offer and realized a gain of $130.5 million.

Minority Interest in Loss of Subsidiaries

Minority interest in loss of subsidiaries decreased $7.8 million in 2003 compared to 2002 due to the reduction of Everest Connections' minority capital balances to zero in October 2002. In accordance with Everest Connections' limited liability company agreement, losses were allocated first to the membership units held by minority owners until their capital accounts were depleted. After all minority accounts were reduced to zero, losses were allocated to us. As a result, we recorded all of Everest Connections' losses in 2003.

Other Income (Expense)

Other income increased $71.3 million, mainly due to $42.1 million of foreign currency gains in 2003 resulting from favorable movements in the Australian and New Zealand dollar against the U.S. dollar. In addition, 2002 included $5.9 million of foreign exchange and interest rate hedge losses relating to our original planned financing structure that was not consummated in connection with our Midlands acquisition, and more than $4.0 million of losses related to technology-related fund investments. This increase was also due to $12.3 million of foreign currency gains recognized in the second quarter of 2003 due to the strengthening of the Canadian dollar on U.S. dollar obligations of a former Canadian finance subsidiary not included in discontinued operations.

Interest Expense and Income Tax Benefit

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

	Year Ended December 31,		
In millions	**2004**	**2003**	**2002**
Interest expense	$ 258.4	$ 273.1	$ 232.9
Income tax benefit	$(213.3)	$(145.1)	$(192.8)

2004 versus 2003

Interest Expense

Interest expense decreased $14.7 million in 2004 compared to 2003. The decrease was primarily the result of the following:

- Lower interest costs of $8.3 million related to the retirement of debt associated with our international utility investments and power generation;
- Decreased interest expense and fees on short-term borrowings and letter of credit facilities of approximately $6.8 million; and

- Decreased amortization of debt issue costs of $9.3 million mainly associated with the 364-day secured credit facility and the three-year secured term loan in 2003.

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

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

Income Tax Benefit

The income tax benefit increased $68.2 million in 2004 compared to 2003, primarily due to increased pretax losses, the decrease in net valuation allowances provided on capital losses and the accrual of non-deductible fines and penalties in 2003.

2003 versus 2002

Interest Expense

Interest expense increased $40.2 million in 2003 compared to 2002. The increase was primarily the result the following:

- Higher interest costs of $41.8 million related to the $500.0 million of 14.875% senior notes issued in July 2002;

- The borrowing in the second quarter of 2003 of $430.0 million under our three-year secured term loan that resulted in $26.7 million of additional interest expense; and

- Amortization of debt issue costs of $11.5 million mainly associated with the 364-day secured credit facility and the three-year secured term loan.

These increases were offset in part by the retirement of our prior revolving credit facility, debt outstanding in Australia, New Zealand and the United Kingdom in late 2002 and early 2003, and the conversion of the premium equity participating securities to common equity in November 2002.

Income Tax Benefit

The income tax benefit decreased $47.7 million in 2003 compared to 2002, primarily as a result of lower losses before income taxes in 2003 compared to 2002, and due to the removal of our permanent investment elections in Australia and Canada in 2002. Also impacting 2003 income tax benefits were a valuation allowance on anticipated capital losses associated with the sale of our equity method independent power plants, a valuation allowance on certain state tax loss carryforwards and a non-deductible fine. Tax benefits were not recognized on a significant amount of the 2002 losses as a result of valuation allowances provided on capital losses and certain non-deductible expenses.

OTHER ITEMS

Critical Accounting Policies and Estimates

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

Energy Trading and Derivative Accounting

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

- We have variability in our mark-to-market earnings due to changes in the market price for gas and/or power. Our portfolio is valued from current and expected future gas and power prices. Changes in these prices can cause fluctuations in our earnings.

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

We also have other activities in our utility operations that are accounted for under SFAS 133. The majority of these activities consist of the purchasing of gas, power and coal for our utility operations, which fall under the normal purchases and sales exception. These activities require that management make certain judgments regarding the election of the normal purchases and sales exceptions.

Unbilled Utility Revenues

Sales related to the delivery of energy are generally recorded when service is rendered or energy is delivered to customers. However, the determination of sales is based on reading customers' meters, which occurs systematically throughout the month. At the end of each month, an estimate is made of the amount of energy delivered to customers after the date of the last meter reading. The unbilled revenue is calculated each month based on estimated customer usage, weather factors, line losses and applicable customer rates. Total unbilled revenues at December 31, 2004 were $138.1 million.

Impairment of Long-Lived Assets

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

During 2004, we evaluated the carrying value of three power peaking plants we own. As of December 31, 2004, the carrying value of these plants was $467.7 million. We performed this evaluation due to reduced spark spreads and an oversupply of generation that we expect will continue for the foreseeable future. This situation has prevented these plants from firing and, in turn, has created losses for us. It is forecasted that these losses will continue for the next few years. We separately tested the cash flows for each plant based on estimated margin contributions and forecasted operating expenses over their remaining plant lives. These peaking plants were placed into service in 2002 and 2003 and we depreciate these facilities over 35 years. In evaluating future estimated margin contributions, we used external price curves based on four different future price environments. In each environment, we calculated an average margin contribution based on a multi-simulation scenario analysis and then equally weighted each price environment. Based on this analysis and the level of probability we would sell these assets, the undiscounted probability weighted cash flows for these plants exceeded their current book value. Therefore, under SFAS 144 no impairment was required as of December 31, 2004. We have evaluated these assets as held and used. If at some future date we determine these assets are held for sale, based on current market values, we would likely record a material impairment charge.

Goodwill and Other Intangible Assets

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

We believe that the accounting estimate related to determining the fair value of goodwill, and thus any impairment, is a critical accounting estimate because: (1) it is highly susceptible to change from period to period because it requires us to make cash flow assumptions about future sales, operating costs and discount rates over an indefinite life; and (2) the impact of recognizing an impairment could be material. Management's assumptions about future sales margins and volumes require significant judgment because actual margins and volumes have fluctuated in the past and are expected to continue to do so. In estimating future margins and expenses, we use our internal budgets. We develop our budgets based on anticipated customer growth, rate cases, inflation and weather trends. Total goodwill at December 31, 2004 was $111.0 million.

Regulatory Accounting Implications

We currently record the economic effects of regulation in accordance with the provisions of SFAS No. 71 ''Accounting for the Effects of Certain Types of Regulation'' (SFAS 71). Accordingly, our balance sheet reflects certain costs as regulatory assets. We are required to periodically assess the probable recovery of our regulatory assets. We expect our rates will continue to be based on historical costs for the foreseeable future. However, if we no longer qualified for treatment under SFAS 71, we would make adjustments to the carrying value of our regulatory assets and liabilities and would be required to recognize them in current period earnings. Total regulatory assets and liabilities at December 31, 2004 were $126.8 million and $88.3 million, respectively. See Note 11 to the Consolidated Financial Statements for further details.

Valuation of Deferred Tax Assets

We are required to assess the ultimate realization of deferred tax assets generated from net operating losses and capital losses incurred on the sale of assets using a ''more likely than not'' assessment of realization. This assessment takes into consideration tax planning strategies within our control, including assumptions regarding the availability and character of future taxable income. As of December 31, 2004, we have recorded $304.7 million of valuation allowances against deferred tax assets for which the ultimate realization of the tax asset is mainly dependent on the availability of future capital gains and taxable income in certain states. The ultimate amount of deferred tax assets realized could be materially different from that recorded, as impacted by changes in federal income tax laws and upon the generation of future capital gains or state taxable income to enable us to realize the related tax assets.

As of December 31, 2004, we had approximately $460.7 million of federal net operating loss carryforwards originating in 2003 and $418.4 million of estimated federal net operating losses originating in 2004. 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 federal net operating loss carryforward expires in 2024 and cannot be carried back due to losses in the carryback years. We did not record valuation allowances against the deferred tax assets related to federal net operating losses. This determination was based on our assessment that it is more likely than not that we will realize these deferred assets during the carryforward period. This assessment considered the forecasted reversal of existing temporary differences and taxable income expected to be generated in the carryforward period and potential IRS audit adjustments in 2001.

Pension Plans

Our reported costs of providing non-contributory defined pension benefits (described in Note 19 to the Consolidated Financial Statements) are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience.

Pension costs, for example, are impacted by actual employee demographics (including age, compensation levels and employment periods), the level of contributions we make to the plan and earnings on plan assets. Changes made to the provisions of the plan may also impact current and future pension costs. Pension costs may also be significantly affected by changes in key actuarial assumptions, including anticipated rates of return on plan assets and the discount rates used in determining the projected benefit obligation and pension costs. Pension plan assets are primarily made up of equity and fixed income investments. Fluctuations in actual equity market returns as well as changes in general interest rates may result in increased or decreased pension costs in future periods. Likewise, changes in assumptions regarding current discount rates and expected rates of return on plan assets could also increase or decrease recorded pension costs. As of September 30, 2004, our average assumed discount rate was 6.00% and our average expected return on plan assets was 8.50%.

The following chart reflects the sensitivities associated with a change in certain actuarial assumptions by the indicated percentage. While the chart below reflects an increase in the percentage for each assumption, we and our actuaries expect that the inverse of this change would impact the projected benefit obligation (PBO) at December 31, 2004, and our estimated annual pension cost (APC) on the income statement for 2005 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%	$(10.9)	$(1.1)
Rate of return on plan assets	.25%	–	(.7)

Significant Balance Sheet Movements

Total assets decreased by $2,941.8 million since December 31, 2003. This decrease is primarily due to the following:

- Cash decreased $376.6 million. See our Consolidated Statement of Cash Flows for analysis of this decrease.
- Restricted cash decreased $226.4 million, primarily due to the release of cash that had been previously restricted for a large counterparty's customer funds on deposit of $248.7 million, partially offset by $20.6 million of additional cash we restricted for the resolution of a dispute over the early retirement of the $430 million three-year secured term loan.

- Funds on deposit decreased $29.4 million, primarily due to the return of margin deposits paid to counterparties in connection with the continued wind-down of our wholesale energy-trading portfolio, offset in part by additional requirements by our suppliers of natural gas that we post additional margin deposits as a result of our non-investment grade credit rating.

- Accounts receivable decreased $135.0 million, primarily due to lower volumes of natural gas and electricity delivered due to the continued wind-down of wholesale energy trading business, offset in part by increased natural gas prices since December 31, 2003.

- Price risk management assets decreased $542.6 million, primarily due to the termination of four long-term gas contracts and related hedges in 2004 and a reduction in the number of wholesale energy trading contracts, partially offset by an increase in natural gas prices since December 31, 2003.

- Investments in unconsolidated subsidiaries decreased by $311.4 million, primarily due to the sale of our investment in Midlands Electricity and our equity method investments in independent power plants.

- Deferred charges decreased by $79.8 million, primarily due to the elimination of deferred income tax regulatory assets in connection with the sale of our Canadian utility businesses.

- Current and non-current assets of discontinued operations decreased $1,280.7 million, primarily due to the sale of our Canadian utility businesses and our consolidated independent power plants.

Total liabilities decreased by $2,713.0 million and common shareholders' equity decreased by $228.8 million since December 31, 2003. These changes are primarily attributable to the following:

- Accounts payable decreased by $112.6 million, primarily due to lower volumes of natural gas and electricity delivered due to the continued wind-down of our wholesale energy trading business, offset in part by increased natural gas prices since December 31, 2003.

- Other accrued liabilities decreased by $52.7 million, primarily due to the settlement with the CFTC regarding the reporting of our natural gas trading information to publications that compile and report index prices and the settlement of our appraisal rights litigation.

- Price risk management liabilities decreased $434.0 million, primarily due to the termination of four long-term gas contracts and related hedges in 2004, and a reduction in the number of trading contracts, partially offset by an increase in natural gas prices since December 31, 2003.

- Customer funds on deposit decreased $255.3 million, primarily due to the return of a large counterparty's deposit after the underlying contracts associated with the counterparty were settled in 2004.

- Short-term and long-term debt, including current maturities of long-term debt, together decreased by $334.1 million, primarily due to the retirement of the three-year secured term loan, the repayment of the 6.875% and 7.00% series of senior notes, and the early retirement of the Midlands acquisition note payable. These decreases were partially offset by the issuance of the PIES and five-year $220 million unsecured term loan.

- Deferred income taxes and credits decreased $228.2 million, primarily due to deferred tax benefits on 2004 net operating losses, and the sale of our investments in Midlands Electricity and Canadian utility businesses.

- Long-term gas contracts, including the current portion of long-term gas contracts, decreased $623.2 million, primarily due to the termination of our obligations under four long-term gas contracts in 2004.

- Deferred credits decreased $94.6 million, primarily due to the elimination of deferred income tax regulatory liabilities in connection with the sale of our Canadian utility businesses.

- Current and non-current liabilities of discontinued operations decreased by $555.9 million, primarily due to the sale of our Canadian utility businesses and our consolidated independent power plants.

- Common shareholders' equity decreased $228.8 million, primarily as a result of the $292.5 million net loss in 2004 and other comprehensive income losses due to the sale of our investments in Midlands Electricity and Canadian utility businesses offset in part by the issuance of 46.0 million shares of common stock for approximately $112.3 million.

New Accounting Standards

In 2004, the FASB issued a revised Interpretation No. 46, ''Consolidation of Variable Interest Entities,'' a new SFAS and a FASB Staff Position that had potential impacts on our financial results: SFAS No. 123R, ''Share-Based Payments,'' and FASB Staff Position No. 106-2, ''Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003.'' In 2002, the Emerging Issues Task Force issued EITF No. 02-3, ''Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities'' (EITF 02-3). See Notes 1, 2 and 19 to the Consolidated Financial Statements for further discussion.

Effects of Inflation

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

Forward-Looking Information and Risk Factors

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

- We expect to complete construction of a 315-megawatt, natural gas-fired generation facility near Peculiar, Missouri this summer. Some important factors that could cause actual results to differ materially from those anticipated include:

  - The construction of our South Harper Peaking Facility could be delayed by weather.

    - The construction of our South Harper Peaking Facility could be delayed or barred by an adverse outcome of litigation pending against us.

- We expect our utility rates to be increased in certain states where we have utility operations. Some important factors that could cause actual results to differ materially from those anticipated include:

    - Regulatory commissions may refuse to approve some or all of the utility rate increases we have requested or may request.

    - The timing of utility rate increases approved by regulatory commissions is often beyond our control and, until final approval is received, our earnings will continue to be impacted.

- We anticipate significant additional capital expenditures in order to satisfy our long-term power generation and transmission needs and comply with environmental rules and regulations. Some important factors that could cause actual results to differ materially from those anticipated include:

    - We may not receive the approvals required to participate in the planned construction of additional generating capacity at the Iatan facility near Weston, Missouri, or to complete the South Harper Peaking Facility.

    - Environmental rules and regulations could change such that we are not required to make anticipated capital expenditures for environmental compliance.

    - We may not receive shareholder approval to issue additional shares of our common stock, which may be required to fund part of our anticipated future capital expenditures.

- We believe that the anticipated capital costs of environmental compliance will be allowed for recovery in future rate cases. Some important factors that could cause actual results to differ materially from those anticipated include:

    - Regulatory commissions may refuse to allow us to recover in rates part or all of the capital costs related to environmental compliance.

    - Changes in applicable law or regulation may prohibit us from recovering in rates part or all of the capital costs related to environmental compliance.

- We intend to execute our long-term strategic plan, including the sale of certain regulated utility assets and our interests in three Merchant peaking facilities and Everest Connections, as well as the termination of the Elwood tolling contract, which we expect to help bring our returns closer to those of our peers by the end of 2007. Some important factors that could cause actual results to differ materially from those anticipated include:

    - We may receive bids for assets at prices that are inadequate or insufficient for accomplishing our targeted goals.

    - Regulatory commissions may not approve some or all of the contemplated divestitures.

    - We may not be able to retire indebtedness and our other long-term obligations on reasonable terms with the proceeds raised by additional asset sales.
    - We may not be able to improve returns on our Domestic Utilities business if our business process improvement initiative does not create significant savings over the next three years or, even if it does generate significant savings, we may not be allowed by regulatory commissions to retain such savings for the benefit of our shareholders.
    - The counterparty to the Elwood tolling contract may be unwilling to terminate or restructure this contract, or we may not find a third party willing to assume this obligation upon acceptable terms.
- We anticipate that our current revolving credit capacity and available cash will be sufficient to fund our winter needs and working capital requirements. Some important factors that could cause actual results to differ materially from those anticipated include:
    - Our access to revolving credit capacity depends on maintaining compliance with loan covenants. If we violate these covenants, we may lose revolving credit capacity and not have sufficient cash available for our winter needs.
    - Unanticipated increases in the price of natural gas that we purchase for our utility customers could exhaust our liquidity in the winter months.
    - Counterparties may default on their obligations to supply commodities or return collateral to us or to meet their obligations under commercial contracts, including those designed to hedge against movements in commodity prices.
- We will attempt to improve operating cash flows by improving our operating efficiencies, increasing utility rates and cost recovery, retiring debt and long-term liabilities, and completing the wind-down of our Merchant Services business. Some important factors that could cause actual results to differ materially from those anticipated include:
    - We may not recover a significant portion of the fuel and purchase power costs we incur to provide utility services in our largest jurisdiction, Missouri.
    - We may not be able to improve returns on our Domestic Utilities business if our business process improvement initiative does not create significant savings over the next three years or, even if it does generate significant savings, we may not be allowed by regulatory commissions to retain such savings for the benefit of our shareholders.
    - Counterparties may default on their obligations to supply commodities or return collateral to us or to meet their obligations under commercial contracts, including those designed to hedge against movements in commodity prices.
    - The counterparty to the Elwood tolling contract may be unwilling to terminate or restructure this contract, or we may not find a third party willing to assume this obligation upon acceptable terms.

- We believe that we have strong defenses to litigation pending against us. Some important factors that could cause actual results to differ materially from those anticipated include:

  - Judges and juries can be difficult to predict and may, in fact, rule against us.

  - Our positions may be weakened by adverse developments in the law or the discovery of facts that hurt our cases.

- We do not expect that the annual limitations on net operating losses would cause any of our net operating losses to expire unutilized for purposes of reducing our taxes. Some important factors that could cause actual results to differ materially from those anticipated include:

  - Changes in the tax law could result in our tax net operating losses going unutilized.

  - The failure to generate sufficient income could result in our tax net operating losses going unutilized.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Market Risk—Utility Operations

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

In our regulated electric business in 2004, we generated approximately 57% of the power that we sold and we purchased the remaining 43% through long-term contracts or in the open market. The regulatory provisions for recovering power costs vary by state. In Kansas and Colorado, we have an Energy Cost Adjustment and an Incentive Clause Adjustment, respectively, that serve a purpose similar to the PGAs for our gas utilities. To the extent that our fuel and purchased power energy costs vary from the energy cost built into our tariffs, the difference is passed through to the customer. In Missouri, we do not have the ability to adjust the rates we charge for electric service to offset all or part of any increase or decrease in prices we pay for natural gas, coal or other fuel we use in generating electricity (i.e., a fuel adjustment mechanism). As a result, our exposure to commodity price changes is concentrated in the Missouri electric operations resulting in greater earnings volatility from year to year there than in our other electric rate jurisdictions.

We have taken several measures to mitigate the commodity price risk exposure in our Missouri electric operations. One of these measures is contracting for a diverse supply of coal to meet 94% of our native load fuel requirements of coal-fired generation in 2005 and 87% in 2006 through 2007, respectively. We are currently receiving reduced volumes on one of these coal contracts because of a declared partial force majeure that occurred in 2004. The price risk associated with our natural gas and on-peak spot market purchased power requirements is also mitigated through a dollar-cost averaging hedging plan using NYMEX futures contracts and options. This is a multi-year hedging plan. As of December 31, 2004, we had financial contracts in place to price hedge approximately 66% of our on-peak natural gas and natural gas equivalent purchased power price exposure for 2005.

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

Market Risk—Trading

We are exposed to market risk, including changes in commodity prices, interest rates and currency exchange rates. To manage the volatility relating to these exposures, we enter into various derivative transactions in accordance with our policy approved by the Board of Directors. Our trading portfolios consist primarily of natural gas, electricity, coal and interest rate contracts that are settled by the delivery of the commodity or cash. These contracts take many forms, including futures, forwards, swaps and options. As we are winding down our trading portfolio, most of our positions have been hedged to limit our exposure to the above risks.

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

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

The average value-at-risk (VaR) for all commodities during 2004 was $2.4 million. Our Board of Directors sets our VaR limit. We are currently limited to $3.0 million for the remaining commodity trading portfolio and a $5.0 million target for the aggregate book that includes the first 18 months of Merchant Services asset positions. In addition to VaR, we also apply other risk control measures that incorporate volumetric limits by commodity, loss limits, durational limits and application of stress testing to our various risk portfolios. Additionally, we have one remaining highly customized actuarial-based contract, which expires in September 2006, with life-of-contract VaR of approximately $22.2 million at December 31, 2004.

All merchant interest and foreign currency risks are monitored within the commodity portfolios and value-at-risk calculation. The merchant commodity portfolios are valued on a mark-to-market basis that requires that the trading book be discounted on a net present value basis utilizing risk adjusted current interest rates based on our credit standing and those of our counterparties. Because interest rate movements impact the value of our trading portfolio, we actively hedge our interest rate exposures to limit these fluctuations.

Certain Trading Activities

We engage in price risk management activities for both trading and non-trading activities. Transactions carried out in connection with trading activities that are derivatives under SFAS 133 are accounted for under the mark-to-market method of accounting. Through October 2002, these contracts were accounted for under EITF 98-10 which also required the use of the mark-to-market method. Under SFAS 133, our energy commodity trading contracts, including physical transactions (mainly gas and power) and financial instruments, are recorded at fair value. As part of the valuation of our portfolio, we value the credit risks associated with the financial condition of counterparties and the time value of money. We primarily use quoted market prices from published sources or comparable transactions in liquid markets to value our contracts. If actively quoted market prices are not available, we contact brokers and other external sources or use comparable transactions to obtain current values of our contracts. In addition, the market prices or fair values used in determining the value of the portfolio are our best estimates utilizing information such as historical volatility, time value, counterparty credit and the potential impact on market prices of liquidating our positions in an orderly manner over a reasonable period of time under current market conditions. When market prices are not readily available or determinable, certain contracts are recorded at fair value using an alternative approach such as model pricing.

The changes in fair value of our trading and other contracts for 2004 are summarized below:

In millions	**Total**
Fair value at December 31, 2003	$ 130.0
Reduction in fair value during the year	(154.0)
Contracts realized or cash settled	45.4
Fair value at December 31, 2004	$ 21.4

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

In millions	**2005**	**2006**	**2007**	**2008**	**Thereafter**	**Total**
Prices actively quoted	$(12.4)	$13.8	$—	$—	$—	$ 1.4
Prices provided by other external sources	—	—	18.4	—	—	18.4
Priced based on models and other valuation methods	—	(5.4)	—	1.9	5.1	1.6
Net price risk management assets (liabilities)	$(12.4)	$ 8.4	$18.4	$ 1.9	$ 5.1	$21.4

Credit Risk

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

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

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

The following table details our credit exposures at December 31, 2004, associated with our forward positions within our trading portfolio and our billed receivables (excluding residential customers), netted by counterparty where master netting agreements exist and by collateral to the extent any is held.

In millions	**Investment Grade**	**Non-investment Grade**	**Total**
Utilities and merchants	$ 37.3	$138.1	$175.4
Financial institutions	113.2	—	113.2
Oil and gas producers	.1	—	.1
Commercial and industrial	—	3.2	3.2
Total	$150.6	$141.3	$291.9

In our Domestic Utilities business, approximately 54% of our sales are to residential customers. Therefore, our credit risk associated with these sales is relatively low. See pages 7 and 8 under Properties for a breakout of our customers by type.

Currency Rate Exposure

We have substantially wound down our United Kingdom and Canadian merchant trading businesses, which are included in our Merchant Services segment, and have sold our international utility businesses in Canada, Australia, New Zealand and the United Kingdom. Our remaining currency rate exposure relates only to approximately $58.5 million of cash held in foreign countries, a limited trading portfolio in Canada and the resolution of outstanding tax obligations and receivables.

Interest Rate Exposure

We have approximately $275.1 million in unhedged variable rate financial obligations. A 100-basis-point change in the variable rate financial instruments would affect net income by approximately $1.7 million.

Item 8. Financial Statements and Supplementary Data

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Aquila, Inc.
Consolidated Statements of Income

In millions, except per share amounts	Year Ended December 31, 2004	2003	2002
Sales:			
Electricity—regulated	$ 759.3	$ 697.5	$ 666.9
Natural gas—regulated	1,032.0	969.5	765.1
Electricity—non-regulated	9.1	4.8	345.3
Natural gas—non-regulated	(106.5)	(39.2)	217.1
Other—non-regulated	17.1	41.4	46.7
Total sales	1,711.0	1,674.0	2,041.1
Cost of sales:			
Electricity—regulated	384.7	331.3	308.4
Natural gas—regulated	741.2	671.0	496.1
Electricity—non-regulated	56.8	80.4	362.6
Natural gas—non-regulated	4.9	18.5	296.1
Other—non-regulated	26.6	22.9	28.8
Total cost of sales	1,214.2	1,124.1	1,492.0
Gross profit	496.8	549.9	549.1
Operating expenses:			
Operating expense	483.5	549.6	609.9
Restructuring charges	.9	28.2	210.2
Net loss on sale of assets and other charges	188.3	194.7	1,571.5
Depreciation and amortization expense	150.3	164.7	155.8
Total operating expenses	823.0	937.2	2,547.4
Other income (expense):			
Equity in earnings of investments	2.1	69.6	166.9
Minority interest in loss of subsidiaries	—	—	7.8
Gain on sale of subsidiary stock	—	—	130.5
Other income	20.0	89.7	7.8
Total other income	22.1	159.3	313.0
Interest expense	258.4	273.1	232.9
Loss from continuing operations before income taxes	(562.5)	(501.1)	(1,918.2)
Income tax benefit	(213.3)	(145.1)	(192.8)
Loss from continuing operations	(349.2)	(356.0)	(1,725.4)
Earnings (loss) from discontinued operations, net of tax	56.7	19.6	(327.0)
Cumulative effect of accounting change, net of tax	—	—	(22.7)
Net Loss	$ (292.5)	$ (336.4)	$(2,075.1)
Basic and diluted earnings (loss) per common share:			
Continuing operations	$ (1.35)	$ (1.83)	$ (10.67)
Discontinued operations	.22	.10	(2.02)
Cumulative effect of accounting change	—	—	(.14)
Net loss	$ (1.13)	$ (1.73)	$ (12.83)

See accompanying notes to consolidated financial statements.

Aquila, Inc.
Consolidated Balance Sheets

In millions	December 31, 2004	December 31, 2003
Assets		
Current assets:		
Cash and cash equivalents	$ 225.1	$ 601.7
Restricted cash	22.8	249.2
Funds on deposit	353.1	382.5
Accounts receivable, net	463.4	598.4
Inventories and supplies	155.0	149.4
Price risk management assets	124.9	311.0
Prepaid pension	98.7	108.0
Other current assets	105.8	86.7
Current assets of discontinued operations	—	231.9
Total current assets	1,548.8	2,718.8
Property, plant and equipment, net	2,777.4	2,752.7
Investments in unconsolidated subsidiaries	1.5	312.9
Price risk management assets	136.1	492.6
Goodwill, net	111.0	111.0
Deferred charges and other assets	202.5	282.3
Non-current assets of discontinued operations	—	1,048.8
Total Assets	$4,777.3	$7,719.1
Liabilities and Shareholders' Equity		
Current liabilities:		
Current maturities of long-term debt	$ 42.0	$ 414.8
Accounts payable	375.6	488.2
Accrued interest	66.6	89.0
Other accrued liabilities	193.7	246.4
Price risk management liabilities	137.3	290.1
Current portion of long-term gas contracts	15.0	84.8
Customer funds on deposit	24.2	279.5
Current liabilities of discontinued operations	—	368.5
Total current liabilities	854.4	2,261.3
Long-term liabilities:		
Long-term debt, net	2,329.9	2,291.2
Deferred income taxes and credits	148.0	376.2
Price risk management liabilities	102.3	383.5
Long-term gas contracts	32.9	586.3
Deferred credits	179.3	273.9
Non-current liabilities of discontinued operations	—	187.4
Total long-term liabilities	2,792.4	4,098.5
Common shareholders' equity	1,130.5	1,359.3
Total Liabilities and Shareholders' Equity	$4,777.3	$7,719.1

See accompanying notes to consolidated financial statements.

Aquila, Inc.
Consolidated Statements of Common Shareholders' Equity

In millions, except per share amounts	Year Ended December 31, 2004	2003	2002
Common stock: authorized 400,000,000 at December 31, 2004, 2003 and 2002, par value $1 per share, 241,739,573 shares issued at December 31, 2004 (195,252,630 at December 31, 2003 and 193,782,782 at December 31, 2002); authorized 20,000,000 shares of Class A common stock, par value $1 per share, none issued			
Balance beginning of year	$ 195.3	$ 193.8	$ 115.9
Issuance of shares in public offerings	46.0	—	50.0
Issuance of shares through Premium Equity Participating Security conversion	—	—	11.7
Issuance of shares through Aquila Merchant exchange offer	—	—	12.6
Issuance of shares under compensation arrangements	.4	1.5	3.6
Balance end of year	241.7	195.3	193.8
Premium on capital stock:			
Balance beginning of year	3,161.3	3,158.6	2,047.0
Issuance of shares in public offerings	66.3	—	498.9
Issuance of shares through Premium Equity Participating Security conversion	—	—	238.3
Issuance of shares through Aquila Merchant exchange offer	—	—	314.3
Issuance of shares under compensation arrangements	1.0	2.7	60.1
Balance end of year	3,228.6	3,161.3	3,158.6
Retained earnings (deficit):			
Balance beginning of year	(2,047.9)	(1,711.5)	479.3
Net loss	(292.5)	(336.4)	(2,075.1)
Other	(.2)	—	—
Dividends on common stock, ($.775 per share in 2002)	—	—	(115.7)
Balance end of year	(2,340.6)	(2,047.9)	(1,711.5)
Treasury stock, at cost, 251 shares at December 31, 2004 (129 shares at December 31, 2003 and 7,443 shares at December 31, 2002)	—	—	—
Accumulated other comprehensive income (loss)	.8	50.6	(33.0)
Total Common Shareholders' Equity	$ 1,130.5	$ 1,359.3	$ 1,607.9

See accompanying notes to consolidated financial statements.

Aquila, Inc.
Consolidated Statements of Comprehensive Income

In millions	Year Ended December 31, 2004	2003	2002
Net loss	$(292.5)	$(336.4)	$(2,075.1)
Other comprehensive income (loss), net of related tax:			
Foreign currency adjustments:			
Foreign currency translation adjustments, net of deferred tax expense (benefit) of $(14.5) million and $50.3 million for 2004 and 2003, respectively	(22.0)	96.2	42.6
Reclassification of foreign currency (gains) losses to income due to sale of businesses and other, net of deferred tax (expense) benefit of $(26.2) million and $(9.5) million for 2004 and 2003, respectively	(41.0)	(14.9)	31.4
Total foreign currency adjustments	(63.0)	81.3	74.0
Cash flow hedges:			
Unrealized gains (losses) on hedging instruments during the period, net of deferred tax expense (benefit) of $(1.0) million, $(.4) million and $(10.9) million for 2004, 2003 and 2002, respectively	(1.6)	(1.6)	(27.2)
Unrealized gains (losses) on hedging instruments of equity method investments, net of deferred tax expense (benefit) of $(5.6) million and $(1.7) million for 2003 and 2002, respectively	—	(7.6)	(13.6)
Reclassification of net losses (gains) on hedging instruments to net income, net of deferred tax benefit (expense) of $.8 million, $9.1 million and $2.4 million for 2004, 2003 and 2002, respectively	1.3	15.0	3.8
Reclassification of net losses on hedging instruments to net income due to sale of businesses, net of deferred tax benefit (expense) of $(.6) million for 2002	—	—	9.5
Reclassification of net losses to income on cash flow hedges in equity method investments due to sale, net of deferred tax benefit (expense) of $5.5 million and $1.8 million for 2004 and 2003, respectively	9.1	3.4	8.6
Total cash flow hedges	8.8	9.2	(18.9)
Held for sale securities:			
Unrealized gain on securities held for sale	—	—	7.3
Reclassification of net losses (gains) on sales of securities to income	—	(7.3)	—
Total held for sale securities	—	(7.3)	7.3
Decrease (increase) in minimum pension liability, net of deferred tax (benefit) expense of $2.7 million and $(2.7) million for 2004 and 2003, respectively	4.4	.4	(4.8)
Other comprehensive income (loss)	(49.8)	83.6	57.6
Total Comprehensive Loss	$(342.3)	$(252.8)	$(2,017.5)

See accompanying notes to consolidated financial statements.

Aquila, Inc.
Consolidated Statements of Cash Flows

In millions	Year Ended December 31, 2004	2003	2002
Cash Flows From Operating Activities:			
Net loss	$ (292.5)	$(336.4)	$(2,075.1)
Adjustments to reconcile net loss to net cash used for operating activities:			
Depreciation and amortization expense	150.3	173.3	238.0
Gain on sale of subsidiary stock	—	—	(130.5)
Restructuring charges	.9	28.2	210.2
Cash paid for restructuring and other charges	(171.2)	(166.8)	(95.2)
Net loss on sale of assets and other charges	114.3	242.2	2,009.8
Foreign currency gains	(13.0)	(53.7)	—
Net changes in price risk management assets and liabilities	107.9	52.8	297.5
Deferred income taxes and investment tax credits	(194.7)	(126.7)	88.2
Equity in earnings of investments	(2.1)	(69.6)	(172.2)
Dividends and fees from investments	1.5	48.6	91.9
Minority interests in loss of subsidiaries	—	—	(7.8)
Changes in certain assets and liabilities, net of effects of acquisitions and divestitures:			
Restricted cash	232.9	(99.6)	(171.7)
Funds on deposit	43.7	(118.5)	(132.3)
Accounts receivable/payable, net	27.4	(100.4)	38.9
Accounts receivable sales programs	—	—	(297.5)
Inventories and supplies	(10.4)	(14.8)	126.7
Prepaid pension and other current assets	(13.1)	248.4	(162.5)
Deferred charges and other assets	20.8	22.1	81.7
Accrued interest and other accrued liabilities	(107.8)	106.7	(352.6)
Customer funds on deposit	(235.9)	35.7	124.6
Deferred credits	(8.0)	7.4	(45.1)
Other	7.5	(11.2)	38.0
Cash used for operating activities	(341.5)	(132.3)	(297.0)
Cash Flows From Investing Activities:			
Additions to utility plant	(219.4)	(247.2)	(266.9)
Merchant capital expenditures	—	(20.5)	(168.5)
Net increases in merchant loans	—	—	(41.5)
Investments in international businesses	—	—	(216.7)
Investments in communication services	(14.0)	(12.2)	(101.0)
Cash proceeds on sale of assets and subsidiary stock	1,267.9	905.7	1,115.8
Merchant investment in unconsolidated subsidiary	—	(44.5)	—
Other	(8.2)	(16.6)	23.6
Cash provided from investing activities	1,026.3	564.7	344.8

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

In millions	Year Ended December 31, 2004	2003	2002
Cash Flows From Financing Activities:			
Issuance of common stock	112.3	—	548.9
Retirement of company-obligated preferred securities	—	—	(100.0)
Issuance of long-term debt	551.2	412.0	1,146.9
Retirement of long-term debt	(943.9)	(492.8)	(989.7)
Short-term borrowings, net	(215.0)	(57.9)	(280.3)
Cash paid on long-term gas contracts	(623.1)	(81.6)	(79.8)
Cash dividends paid	—	—	(115.7)
Other	1.3	3.7	.7
Cash provided from (used for) financing activities	(1,117.2)	(216.6)	131.0
Increase (decrease) in cash and cash equivalents	(432.4)	215.8	178.8
Cash and cash equivalents at beginning of year (includes $55.8 million, $55.6 million and $45.0 million of cash included in current assets of discontinued operations in 2004, 2003 and 2002, respectively)	657.5	441.7	262.9
Cash and Cash Equivalents at End of Year (includes $55.8 million and $55.6 million of cash included in current assets of discontinued operations in 2003 and 2002, respectively)	$ 225.1	$ 657.5	$ 441.7
Supplemental cash flow information:			
Interest paid, net of amount capitalized	$ 299.7	$ 276.9	$ 216.8
Income taxes paid (refunded), net	21.1	(241.0)	(65.7)

See accompanying notes to consolidated financial statements.

Aquila, Inc.
Notes to Consolidated Financial Statements

Note 1: Summary of Significant Accounting Policies

Description of Business

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

Domestic Utilities operates primarily as Aquila in the distribution and transmission of electricity and natural gas to retail and wholesale customers in seven states. Our electric generation facilities and purchase power contracts supply electricity to our own distribution systems in three states. We also sell a small amount of excess power to wholesale customers outside our service areas. During peak periods, we buy energy in the wholesale market for our utility load.

Our Merchant Services business operates as Aquila Merchant Services, Inc. (Aquila Merchant), which, until we began to wind down these operations during the second quarter of 2002, marketed natural gas, electricity and other commodities throughout North America and Western Europe. This segment also included our capital services business. We sold substantially all of the assets of our capital services business in December 2002 and now report its results as discontinued operations. Aquila Merchant currently owns or contractually controls non-regulated merchant power plants. Our former investments in 13 independent power plants were sold in the first quarter of 2004. Two of these plants that were consolidated are reported in discontinued operations. Merchant Services also formerly owned natural gas and gas liquids gathering, transportation, storage and processing assets, which were sold in 2002. These operations are also reported as discontinued operations.

Corporate and Other includes the costs of the company that are not allocated to our operating businesses. Corporate and Other also includes our communications business, Everest Connections, which provides local and long-distance telephone, cable television and high-speed Internet service to areas of greater Kansas City, and our former investment in Quanta Services, Inc. (Quanta Services). Quanta Services provides specialized construction and maintenance services to the utility, telecommunications and cable television industries. We sold our investment in Quanta Services in late 2002 and early 2003. We also formerly had investments in Australia, New Zealand and the United Kingdom. We sold our investment in New Zealand in October 2002, our investments in Australia in the second and third quarters of 2003, and our investment in the United Kingdom in January 2004.

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

Use of Estimates

The preparation of these financial statements in conformity with accounting principles generally accepted in the United States required that we make certain estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of December 31, 2004 and 2003, and the reported amounts of sales and expenses during the three years ended December 31, 2004. Significant items subject to such estimates and assumptions include the carrying value of property, plant and equipment; the valuation of derivative instruments; valuation allowances for receivables and deferred income taxes; and assets and liabilities related to employee benefits. Actual results could differ materially from those estimates and assumptions.

Principles of Consolidation

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

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

Issuances of Subsidiary Stock

In accordance with SEC Staff Accounting Bulletin No. 51, we record the difference between the carrying amount of the parent's investment in a subsidiary and the underlying net book value of the subsidiary, after a subsidiary stock issuance, as a gain or loss in our consolidated financial statements.

Property, Plant and Equipment

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

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. In accordance with SFAS No. 142, ''Goodwill and Other Intangible Assets'' (SFAS 142), we no longer amortize goodwill effective January 1, 2002. These balances are tested annually for impairment and if impaired, written off against earnings at that time. We completed an initial assessment of the realizability of our goodwill and determined that as of January 1, 2002, no goodwill impairments existed. Our annual assessment date is November 30. At December 31, 2004, 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	Domestic Utilities	Merchant Services	Corporate and Other	Total Continuing Operations	Total Discontinued Operations
Balance, December 31, 2001	$109.0	$ 6.2	$ 26.6	$ 141.8	$ 211.8
Repurchase of Aquila Merchant shares *(a)*	—	189.0	—	189.0	29.7
Merchant Services impairment *(b)*	—	(181.2)	—	(181.2)	(5.3)
Everest Connections impairment *(b)*	—	—	(21.6)	(21.6)	—
Sales of businesses *(c)*	—	(14.0)	(5.0)	(19.0)	(48.1)
Exchange rate change and other	2.0	—	—	2.0	.5
Balance, December 31, 2002	111.0	—	—	111.0	188.6
Exchange rate change and other	—	—	—	—	40.9
Balance, December 31, 2003	111.0	—	—	111.0	229.5
Sales of businesses *(c)*	—	—	—	—	(218.2)
Exchange rate change	—	—	—	—	(11.3)
Balance, December 31, 2004	$111.0	$ —	$ —	$ 111.0	$ —

(a) See Note 15 for discussion of the goodwill that was recorded on the repurchase of Aquila Merchant in January 2002. We allocated $189.0 million of that amount to our wholesale energy trading operations and independent power plants in Merchant Services continuing operations and $29.7 million to our gas gathering and pipeline assets and our gas storage facility, which are included in discontinued operations, based upon expected future cash flows.

(b) See Note 5 for further discussion of the basis for the impairment charges taken against allocated goodwill in Merchant Services and Everest Connections.

(c) See Notes 5 and 6 for further discussion of the net loss on sale of assets and other charges including the goodwill allocated to our gas gathering and pipeline assets and our gas storage facility, our investment in Lockport Energy and our investment in New Zealand.

Sales Recognition

Utility Activities

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

Trading Activities

Transactions carried out in connection with trading activities that meet the definition of a derivative under SFAS No. 133, ''Accounting for Derivative and Hedging Activities'' (SFAS 133), are accounted for under the mark-to-market method of accounting. Through October 2002, these contracts were accounted for under EITF No. 98-10, ''Accounting for Contracts Involved in Energy Trading and Risk Management Activities'' (EITF No. 98-10), which also required the use of the mark-to-market method. See Note 2 for further discussion regarding changes in the accounting for energy trading contracts in 2002. Under SFAS 133, our energy commodity trading contracts, including both physical transactions and financial instruments, are recorded net in sales at fair value and shown on our Consolidated Balance Sheets as price risk management assets and price risk management liabilities. As part of the valuation of our portfolio, we value our credit risks associated with the financial condition of counterparties and the time value of money. We use quoted market prices from published sources or comparable transactions in liquid markets to value our contracts. If actively quoted market prices are not readily available, we contact brokers or other external sources or use comparable transactions to obtain current values of our contracts. When market prices are not readily available or determinable, certain contracts are valued at fair value using an alternate approach such as model pricing. In addition, the market prices or fair values used in determining the value of our portfolio are our best estimates utilizing information such as historical volatility and the potential impact on market prices of liquidating our positions in an orderly manner over a reasonable period of time under current market conditions. When the market value of the portfolio changes (primarily due to the effect of price changes, newly originated transactions and the settlement of existing transactions), the change is immediately recognized as a gain or loss. We record the resulting unrealized gains or losses as price risk management assets or price risk management liabilities, respectively.

Weather Derivatives

As part of our wholesale energy trading business, we historically entered into weather derivative contracts. However, due to our decision to exit this business, we no longer do so. We accounted for our weather derivatives in accordance with EITF No. 99-2, ''Accounting for Weather Derivatives.'' This standard requires that weather derivatives entered into for trading or speculative activities be accounted for at fair value, with subsequent changes in fair value reported in earnings.

Our utility business also uses weather derivatives to offset inherent weather risks, but not for trading or speculative purposes. EITF No. 99-2 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 that we have on deposit with counterparties consist primarily of margin requirements related to commodity purchases, commodity swaps and futures contracts. Pursuant to individual contract terms with counterparties, deposit amounts required will vary with changes in market prices, credit provisions and various other factors. In connection with our 364-day letter of credit agreement, we are required to secure all letters of credit issued with cash deposits. See Note 12 for further discussion. These are identified as funds on deposit in our Consolidated Balance Sheets. Interest is earned on most funds on deposit. We also hold funds on deposit from counterparties in the same manner. These are identified as customer funds on deposit in our Consolidated Balance Sheets.

Inventories

Our inventories consist primarily of natural gas in storage, coal, materials and supplies that are valued at weighted average cost.

Regulatory Matters

Our regulated utility operations are subject to the provisions of SFAS No. 71, ''Accounting for the Effects of Certain Types of Regulation'' (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 11 for further discussion.

Long-Term Gas Contracts

We were paid in advance on certain long-term gas contracts for the future delivery of gas to municipal utilities over the subsequent 10 to 12 years. We accounted for these contracts as long-term obligations. We recognize the reduction of our obligations on these long-term gas contracts as gas is delivered to the customer under the units of revenue method, which matches the revenue recognized with the forecasted volumes of gas to be delivered. See Note 14 for further discussion.

Income Taxes

We use the liability method to reflect income taxes on our financial statements. We recognize deferred tax assets and liabilities by applying enacted tax rates and regulations to the differences between the carrying value of existing assets and liabilities and their respective tax basis and capital loss and tax credit carryforwards. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that the change is enacted. We amortize deferred investment tax credits over the lives of the related properties. We assess the realizability of deferred tax assets for capital and operating loss carryforwards and provide valuation allowances when we determine it is more likely than not that such losses will not be realized within the applicable carryforward period. See Note 18 for further discussion.

Environmental Matters

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

Stock Based Compensation

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

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

In millions, except per share amounts	**2004**	**2003**	**2002**
Net loss:			
As reported	$(292.5)	$(336.4)	$(2,075.1)
Premium Income Equity Securities (PIES) adjustment (Note 13)	9.4	—	—
Loss available for common shares	(283.1)	(336.4)	(2,075.1)
Total stock-based employee compensation expense determined under fair value method, net of related tax	(9.3)	(5.4)	(6.2)
Pro forma net loss	$(292.4)	$(341.8)	$(2,081.3)
Basic and diluted loss per share:			
As reported	$ (1.13)	$ (1.73)	$ (12.83)
Pro forma	(1.16)	(1.76)	(12.87)

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:

	2004	**2003**	**2002**
Weighted average fair value per share	$ 2.25	$ .85	$ 1.03
Expected volatility	83%	55%	52%
Risk-free interest rate	3.40%	3.53%	3.53%
Expected lives	3.7 years	7 years	7 years
Dividend yield	—	—	—

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

In December 2004, the FASB issued SFAS No. 123R, ''Share-Based Payments,'' that would require all companies to expense the value of employee stock options in periods beginning after June 15, 2005. Based on the small number of options that are expected to be unvested at that date, we do not expect the impact of this standard to have a material effect on our financial statements.

Cash and Cash Equivalents

Cash includes cash in banks and temporary investments with an original maturity of three months or less. As of December 31, 2004 and 2003, our cash held in foreign countries was $58.5 million and $104.6 million, respectively.

Currency Adjustments

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

Reclassifications

Certain prior year amounts in the consolidated financial statements have been reclassified where necessary to conform to the 2004 presentation. In particular, as discussed in Note 6, certain assets that have been classified as held for sale and the results of operations from those assets have been reclassified as discontinued operations in the accompanying balance sheets and statements of income for all periods presented.

Note 2: New Accounting Standards

Variable Interest Entities

In December 2003, the FASB issued a revised Interpretation No. 46, ''Consolidation of Variable Interest Entities, an interpretation of ARB No. 51.'' This interpretation addresses the consolidation by business enterprises of variable interest entities as defined in the interpretation. The interpretation applies immediately to companies that have entities considered to be special-purpose entities. Other public companies are required to apply this interpretation by the end of the first reporting period that ends after March 31, 2004. The adoption of this interpretation did not have a material effect on our financial statements.

Energy Trading Activities

In June 2002, the EITF reached a consensus in EITF No. 02-3 that all realized and unrealized gains and losses on energy trading contracts be shown net on the income statement whether or not they are settled physically. The adoption of this standard required the reclassification of all prior period sales and cost of sales to reflect the net gains and losses on energy trading contracts. This requirement became effective for financial statements issued for periods beginning after December 15, 2002. We adopted this requirement as of September 30, 2002. The adoption of this requirement had no impact on our gross profit, but did result in a reduction of sales and cost of sales for all periods presented in the financial statements.

In October 2002, the EITF met again and reached a consensus to require that all energy trading contracts that do not fall within the scope of SFAS 133 no longer be marked-to-market through earnings, but be accounted for on the accrual basis of accounting. The consensus was effective for all new contracts executed after October 25, 2002, and required that a cumulative effect of an accounting change be recognized for all contracts executed prior to October 25, 2002. We elected early adoption of this requirement on October 1, 2002. The cumulative effect of this change was reported in 2002 in the Consolidated Statements of Income as an additional loss before income taxes of $37.5 million, or $22.7 million after tax.

Note 3: Risk Management

Overview

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

Trading Activities

During the second half of 2002, we began exiting from the wholesale energy trading business. Because of this decision, we liquidated many of our energy trading contracts in the market. However, we were not able to liquidate all of our contracts. We are no longer a market maker and no longer trade to take advantage of market trends and arbitrage opportunities. Trading activities now consist of optimizing assets we own or contractually control.

Prior to the decision to exit this business, we traded energy commodity contracts daily. Our trading activities attempted to match our portfolio of physical and financial contracts to current or anticipated market conditions. Within the trading portfolio, we took certain positions to hedge physical sale or purchase contracts and to take advantage of market trends and conditions. We continue to use all forms of financial instruments, including futures, forwards, swaps and options, to help hedge our remaining portfolio. Each type of financial instrument involves different risks. We believe financial instruments help us manage our remaining contractual commitments and reduce our exposure to changes in market prices.

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

Market Risk

Our price risk management activities involve commitments to purchase or sell financial instruments or commodities at fixed prices at future dates. The contractual amounts and terms of these financial instruments at December 31, 2004 are below:

	December 31, 2004		
Dollars in millions	**Fixed Price Payor**	**Fixed Price Receiver**	**Maximum Term in Years**
Energy Commodities:			
Natural gas *(trillion Btu's)*	337	224	5
Electricity *(megawatt-hours)*	1,379,404	1,348,431	1
Crude oil *(barrels)*	140,000	140,000	1
Financial Products:			
Interest rate instruments	$2.6	$1.9	16

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 contracts are discounted to December 31, 2004, 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, 2004, and the average value for the year ended December 31, 2004:

	Price Risk Management Assets		Price Risk Management Liabilities	
In millions	Average Value	December 31, 2004	Average Value	December 31, 2004
Natural gas	$615.2	$221.3	$504.6	$195.4
Electricity	48.3	29.0	59.5	26.6
Coal	11.2	7.2	3.5	–
Other	9.5	3.5	26.9	17.6
Total	$684.2	$261.0	$594.5	$239.6

Our price risk management assets are concentrated with ten counterparties representing 76% of the total asset value of the portfolio. This concentration of customers may impact our overall exposure to credit risk, either positively or negatively, as the counterparties may be similarly affected by changes in economic, regulatory or other conditions.

Hedging Activities

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

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

Cash Flow Hedges

Changes in the fair value of a derivative that is highly effective, that is designated and qualifies as a cash flow hedge are recorded in OCI to the extent that the derivative is effective as a hedge. We recorded a $8.8 million decrease in OCI related to cash flow hedges in 2004, net of both taxes and reclassifications to earnings.

Normal Purchases and Sales Exception

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

Regulated Commodity Management

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

In 2004, our regulated electric business generated approximately 57% of the power that we sold and purchased the remaining 43% through long-term contracts or in the open market. The regulatory provisions for recovering power costs vary by state. In Kansas and Colorado, we have an Energy Cost Adjustment and an Incentive Clause Adjustment, respectively, that serve a purpose similar to that of the PGAs for the gas utilities. To the extent that our fuel and purchased power energy costs vary from the energy cost built into our tariffs, the difference is passed through to the customer. In Missouri, there is no provision to pass through changes in costs except through a rate case filing. We are, however, currently operating under a two-year settlement agreement that allows us to recover such costs up to a specified amount per Mwh specific to each of our Missouri service territories. The settlement rate per unit sold is $13.98/Mwh for our St. Joseph Light & Power operations and $19.71/Mwh for our Missouri Public Service operations. Our actual costs since the rate increase went into effect pursuant to the settlement agreement on April 22, 2004 have exceeded the amount allowed under the settlement by approximately $1.8 million through December 31, 2004. If the amounts collected under the settlement agreement exceed our cost incurred for the two-year period, we will be required to refund the excess with interest to our customers. We will not recover the excess of the actual costs over the settlement rate. Variability in the cost of natural gas and coal used for the production of electricity and the price of power purchased in the open market can impact the stability of utility earnings. We manage this commodity risk through a purchasing strategy designed to minimize the effect of variability in energy costs on earnings.

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

Note 4: Restructuring Charges

In connection with our continued exit from Merchant Services and the restructuring of our Domestic Utilities, we have recorded the following restructuring charges:

	Year Ended December 31,		
	2004	2003	2002
Domestic Utilities:			
Severance costs	$—	$—	$ 15.9
Disposition of corporate aircraft	—	—	5.1
Total Domestic Utilities	—	—	21.0
Merchant Services:			
Interest rate swap reductions	—	23.1	6.2
Severance costs	.7	—	30.6
Retention payments	—	2.2	30.5
Lease agreements	—	(.2)	38.5
Write-down of leasehold improvements and equipment	—	—	58.8
Loss on termination of aggregator loan program	—	—	9.0
Disposition of corporate aircraft	—	—	2.0
Other	—	(.4)	4.4
Total Merchant Services	.7	24.7	180.0
Corporate and Other severance costs	.2	3.5	9.2
Total restructuring charges	$ .9	$28.2	$210.2

Severance Costs and Retention Payments

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

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

We incurred $55.7 million of total severance costs in 2002 related to the restructuring of Domestic Utilities in order to more closely align it with its regulatory service areas and the decision to exit our energy trading business in Merchant Services. These actions resulted in the termination of approximately 1,205 energy trading employees, 500 Domestic Utilities employees and 75 Corporate employees in 2002. These charges were expensed and accrued in 2002 and paid out bi-weekly over the term of the severance benefit. In addition, certain employees in wholesale energy trading operations had retention agreements in 2002 to ensure an orderly exit from this business. During 2002, we paid approximately $30.5 million of retention payments to these employees.

Disposal of Corporate Aircraft

The $7.1 million charge for disposal of corporate aircraft in 2002 primarily included the termination of applicable lease agreements and losses associated with the sale of our corporate aircraft.

Interest Rate Swap Reductions

We incurred $23.1 million and $6.2 million of restructuring charges in 2003 and 2002, respectively, to exit interest rate swaps related to our Clay County and Piatt County construction financing arrangements. As debt related to these facilities was paid down, the notional amount of our interest rate swaps exceeded the outstanding debt. As a result, we reduced our swap position and realized the loss associated with the cancelled portion of the swaps.

Aggregator Loan Program

During the year ended December 31, 2002, we incurred a $9.0 million loss on the negotiated termination of certain aggregator loans to substantially complete our exit from that business.

Lease Agreements

During 2002, we recorded a $38.5 million restructuring charge for operating leases for various office facilities used in the wholesale energy trading operations that we determined would no longer be used. This charge represented the estimated future net lease costs of these facilities after estimated sublease recoveries.

Leasehold Improvements and Equipment

During 2002, we wrote down $58.8 million of leasehold improvements and equipment in our wholesale energy trading business that were no longer realizable based on our best estimate of their fair value.

Restructuring Reserve Activity

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

	Year Ended December 31,		
In millions	**2004**	**2003**	**2002**
Severance and Retention Costs:			
Accrued severance and retention costs at beginning of period	$ .9	$ 16.6	$ —
Additional expense during the period	.9	5.7	86.2
Cash payments during the period	(1.0)	(21.4)	(69.6)
Accrued severance and retention costs at end of period	$ .8	$ .9	$ 16.6
Other Restructuring Costs:			
Accrued other restructuring costs at beginning of period	$16.0	$ 32.6	$ —
Additional expense during the period	—	22.5	46.0
Cash payments during the period	(9.0)	(39.1)	(13.4)
Accrued other restructuring costs at end of period *(a)*	$ 7.0	$ 16.0	$ 32.6

(a) The majority of this liability represents costs accrued for future unused office space with various lease terms through 2010, net of anticipated subleases.

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

Pretax net loss (gain) on sale of assets and other charges we recorded for the years ended December 31, 2004, 2003 and 2002 are shown below. After-tax losses in the following paragraphs are reported after giving consideration to the effects of non-deductible goodwill or intangibles and capital loss carryback and carryforward limitations. As a result, the net tax effect may differ substantially from our expected statutory tax rates. The after-tax losses (gains) discussed below are based on current estimates of the tax treatment of these transactions and may be adjusted after detailed allocation of the purchase price for tax purposes and the filing of tax returns including these sales.

	Year Ended December 31,		
	2004	**2003**	**2002**
Domestic Utilities:			
Gas distribution system	$ —	$ .9	$ 9.0
Other	—	(2.2)	—
Total Domestic Utilities	—	(1.3)	9.0
Merchant Services:			
Aries power project and tolling agreement	46.6	—	—
Termination of long-term gas contracts	156.2	—	—
Red Lake gas storage development project	8.9	—	—
Acadia tolling agreement	—	105.5	—
Turbine contracts	—	(5.1)	42.1
Independent power plants	(6.1)	87.9	—
Investment in BAF Energy	(9.1)	—	—
Enron bankruptcy	(6.0)	—	—
Marchwood development project	(5.0)	—	—
Merchant Services goodwill	—	—	181.2
Exit from Lodi gas storage investment	—	—	21.9
Termination of Cogentrix acquisition	—	—	12.2
Other	—	.8	9.7
Total Merchant Services	185.5	189.1	267.1
Corporate and Other:			
Quanta Services	—	—	696.1
Everest Connections and other communication investments	(4.5)	1.1	227.6
Midlands	(3.3)	4.0	247.5
Australia	—	1.8	127.2
Turbines impairment	10.6	—	—
Other	—	—	(3.0)
Total Corporate and Other	2.8	6.9	1,295.4
Total net loss on sale of assets and other charges	$188.3	$194.7	$1,571.5

During 2004, 2003 and 2002, we also incurred net loss (gain) on sale of assets and other charges of $(74.0) million, $47.5 million and $438.2 million, respectively, relating to our discontinued operations. These charges are reflected in discontinued operations and are not included in the table above. See Note 6 for further discussion.

Gas Distribution System

In the course of evaluating the need for rate relief in one of our gas jurisdictions in 2002, it became evident that certain costs would not be recoverable in rates. This was further supported by commission orders. Accordingly, we assessed this asset in accordance with SFAS 144 using an undiscounted cash flow test. This test indicated that the asset was impaired. We then performed a probability-weighted discounted cash flow analysis to estimate the fair value of this asset and recorded an impairment charge for the excess of the asset carrying value over fair value. In 2003, we agreed to sell these assets to another utility. As a result, we recorded pretax charges of $.9 million and $9.0 million, or $.6 million and $5.5 million after tax, in 2003 and 2002, respectively, related to this system.

Aries Power Project and Tolling Agreement

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

Termination of Long-Term Gas Contracts

As discussed in more detail in Note 14, we terminated four of our long-term gas supply contracts resulting in payments of $712.9 million and pretax losses of $156.2 million, or $97.6 million after tax in 2004.

Red Lake Storage Development Project

In January 2002, we acquired the Red Lake property for development of two salt cavern natural gas storage facilities with a combined working capacity of 12 Bcf. In December 2004, we decided to proceed with the potential sale of this property and signed a letter of intent with a third party for less than the carrying value of our investment. As a result, we recorded a pretax impairment charge of $8.9 million, or $5.6 million after tax. We are in the process of conducting due diligence with the prospective buyer. The value of this asset may be adjusted further based on the outcome of the potential sale or future regulatory actions by the FERC.

Acadia Tolling Agreement

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

Turbine Contracts

As discussed in Note 12, we had a contract to acquire four General Electric turbines. Our intent was to place these turbines into future power plant development projects. However, due to the restructuring of our business and change in our business strategy, we made the decision in the fourth quarter of 2002 to cease these development projects and to sell these turbines or return them to the manufacturer. As a result, we incurred a $42.1 million pretax charge, or $25.5 million after tax, related to the expected loss on sale or contract termination related to these turbines.

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

Independent Power Plants

In November 2003, we agreed to sell our interests in 12 independent power plants. Two of the power plants were consolidated on our balance sheet. Therefore, in accordance with SFAS No. 144, ''Accounting for the Impairment or Disposal of Long-Lived Assets'' (SFAS 144), we have reported the results of operations and assets of these two plants in discontinued operations. See Note 6 for further explanation.

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

Investment in BAF Energy

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

Enron Bankruptcy

On March 7, 2005, we reached an agreement with Enron Corp. and certain of its affiliates (Enron). Under this agreement, we will pay $28 million to Enron to settle all outstanding claims between Enron and Aquila associated with the various bankruptcy filings of Enron in December 2001 and two lawsuits filed by Enron Canada Corp. in January 2003. In 2001, we reserved for substantially all of our then outstanding receivables from Enron, which resulted in a charge of $66.8 million. This charge did not reflect potential gains we would record in the event we were successful in netting certain obligations to Enron against these receivables. Approximately $33.5 million of liabilities remained on our books related to contracts with Enron after the 2001 charge. The settlement is subject to final approval the bankruptcy court. As a result of the settlement, we reduced our net liability to Enron by approximately $6 million, or $3.7 million after tax.

Marchwood Development Project

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

Merchant Services Goodwill

In connection with our decision to exit our wholesale energy trading operations, we assessed our ability to realize the goodwill associated with our Merchant Services business. This assessment was based on our best estimate of the value of this business in a liquidation, which we determined was less than the carrying value of its net assets. Because future earnings or sufficient sales proceeds could no longer support this asset, we wrote off the entire $181.2 million of unamortized goodwill in 2002.

Exit from Lodi Gas Storage Investment

In August 2001, Aquila Merchant and a partner acquired a 12 Bcf gas storage facility under construction near Lodi, California. In October 2002, we exited our investment in the Lodi project due to our exit from the wholesale energy trading business. We owned 50% of WHP Acquisition Company LLC, a company jointly established with an affiliate of ArcLight Energy Partners Fund I, L.P. in 2001 to purchase Western Hub Properties LLC, the developer of the Lodi gas storage project. Under the settlement, WHP Acquisition Company LLC redeemed Aquila Merchant's ownership interest for cash payments totaling $5.0 million over a five-year period. We were also released from all of our guarantee obligations relating to this transaction. We recorded a pretax loss on this transaction of $21.9 million pretax or $21.6 million after-tax.

Termination of Cogentrix Acquisition

In August 2002, we terminated the purchase agreement we signed in April 2002 to acquire Cogentrix Energy, Inc., an independent power producer. We agreed with Cogentrix that due to the uncertainty of the electric power market, the deterioration of the creditworthiness of some of Cogentrix's customers and our exit from the wholesale energy trading business, proceeding with the transaction was impractical and not in either company's best interest. In connection with the termination of this transaction we expensed legal, consulting and termination fees of $12.2 million, or $7.4 million after tax.

Merchant Services—Other

Included in other impairments for Merchant Services are three additional impairments or losses. In December 2002, we recorded a $4.2 million impairment charge on one of our equity investments in a non-regulated power plant based on an other-than-temporary decline in fair value of this investment. In September 2002, we completed the sale of our 16.58% interest in the Lockport Energy facility for $37.5 million. We recorded a $1.1 million pretax loss and a $5.8 million after-tax loss on this sale. In October 2002, we sold our Hole House natural gas storage assets in the United Kingdom for $36.9 million. In connection with this sale, we recorded a pretax and after-tax loss on disposal of $.9 million.

Quanta Services

At June 30, 2002, the cost basis in our 38% equity investment in Quanta Services was approximately $26.69 per share and was significantly above the trading price of Quanta Services' stock. On July 1, 2002, Quanta Services announced that it had reduced its earnings forecast due to a continued decline in the telecommunications industry, reduced utility construction spending and financial difficulties surrounding Quanta Services' two largest customers. Quanta Services' share price dropped to approximately $3.00 per share after this announcement. Because of these factors and the termination of our proxy contest for control of Quanta Services in May 2002, we concluded that there was an other-than-temporary decline in the fair value of this investment. Accordingly, in the second quarter of 2002 we wrote the investment down by $692.9 million before tax, or $627.3 million after tax, to its estimated fair value of $3.00 a share, or $87.7 million in total.

In the second half of 2002, we sold approximately 17.6 million shares of Quanta Services stock at an average price of $2.75 per share for an additional pretax and after-tax loss of $3.2 million, reducing our ownership percentage from 38% to 10.2%. As a result, we accounted for this asset as an available-for-sale security in accordance with SFAS No. 115, ''Accounting for Certain Investments in Debt and Equity Securities'' (SFAS 115). Accordingly, at December 31, 2002, we recorded a $7.3 million increase in our investment and other comprehensive income to write our investment up to $3.50 per share, the market price of Quanta Services' common stock at December 31, 2002. We sold our remaining 11.6 million shares in February 2003 at a net price of $2.90 per share.

Everest Connections and Other Communication Investments

Due to liquidity concerns and our renewed focus on our utility operations, we made a decision in the fourth quarter of 2002 to reduce the future funding for the network build-out of Everest Connections to levels necessary to complete construction in progress, serve existing customers and limit growth to the addition of customers on our existing network. We evaluated Everest Connections' strategic alternatives and chose to restructure the business so that going forward it is self-funded from operations. As a result of this change in strategy, we assessed this asset in accordance with SFAS 144 using an undiscounted cash flow test. This test indicated that the asset was impaired. We then performed a probability-weighted discounted cash flow analysis and used other market methods to estimate the fair value of this asset and recorded an impairment charge of $175.8 million before tax, or $107.6 million after tax, for the excess carrying value over fair value.

We also assessed the realizability of Everest Connections' recorded goodwill and other intangibles in accordance with SFAS 142. This test indicated that the goodwill was impaired as the carrying value of the business after the asset impairment above was greater than the enterprise fair value. We then performed a probability-weighted discounted cash flow analysis and used other market methods to estimate the fair value of the assets and liabilities other than goodwill and intangibles. This assessment indicated that the goodwill of $21.6 million was fully impaired. We therefore recorded a pretax and after-tax impairment charge in 2002 of $21.6 million to write off the goodwill balance.

During 2002, we determined that certain cost and equity method investments in our communication technology-related businesses were impaired based on continuing losses in these businesses, their continued failure to achieve operational goals, the inability of these businesses to obtain additional capital, and our assessment of their long-term prospects. Accordingly, in June 2002 we recorded a $23.1 million pretax impairment charge, or $13.9 million after-tax, relating to these investments.

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

Midlands

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

In 2002, we recorded a pretax and after-tax impairment charge of $247.5 million to record an other-than-temporary decline in this investment, which we purchased in May 2002. See Note 10 for further discussion. The purchase price was based on our ability to hold the investment long-term, which would allow us to use this investment as a base to extract synergies in future acquisitions and to continue to develop certain of its non-regulated businesses. However, our liquidity situation in 2002 caused us to revise our strategic view of this investment. As a result, in August 2002, we initiated a bid process for the sale of our interest in Midlands Electricity. We received offers in early December and were in negotiations with prospective buyers. Our evaluation of those offers indicated that this investment was impaired. The impairment stemmed from our inability to hold the investment long-term and thus realize the benefits anticipated in our original analysis. This impairment charge was determined based on the estimated fair value of this investment based on current market information, which included offers obtained during the bid process, and was consistent with a corresponding impairment charge taken in the financial statements of the underlying business.

Australia

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

In 2002, we recorded a pretax impairment charge of $127.2 million, or $93.0 million after tax, to record an other-than-temporary decline in our investments in Multinet and AlintaGas in Australia. Approximately $109 million of this pretax charge related to the Multinet business and the remaining impairment charge was related to our investment in AlintaGas. Our liquidity situation and change in strategic direction in 2002 caused us to change our intention to hold these investments long-term. As a result, we considered the current market value of these businesses, which included an offer to purchase our interest in these businesses, as well as an impairment charge taken in the financial statements of the underlying businesses, to assess the realizability of our investment.

Turbines Impairment

In December 2004, we determined that the carrying value of three Westinghouse Siemens natural gas combustion turbines held for future construction by one of our non-regulated subsidiaries was impaired. These turbines were transferred from the non-regulated subsidiary to our Missouri regulated electric division for the construction of a 315-megawatt, natural gas peaking generation plant near Peculiar, Missouri. Missouri affiliate transaction rules require that such transfers be made at the lower of fair market value or fully distributed cost. We obtained an appraisal of the fair value of the turbines, which was less than the carrying value of the turbines and related costs. As a result, we recorded a pretax impairment charge of approximately $10.6 million, or $6.5 million after tax. This transfer is subject to the final determination of the Missouri Public Service Commission which is expected in 2005.

Note 6: Discontinued Operations

We have sold the assets discussed below, which are considered discontinued operations in accordance with SFAS 144. The only remaining asset that had been classified as held for sale in 2003 was a merchant note receivable which was not sold with our merchant loan business in 2002. Due to our unsuccessful efforts to sell this note in 2004, we determined that the asset and its associated results from operations should be reclassified as held for use under the provisions of SFAS 144. As a result, we reclassified $10.4 million of assets to deferred charges and other assets as of December 31, 2003. Additionally, we reclassified pretax losses (income) of $8.8 million and $(1.5) million, or $5.4 million and $(.9) million after tax, to continuing operations for the years ended December 31, 2003 and 2002, respectively.

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

Canada

On May 31, 2004, we completed the sale of our Canadian utility operations in Alberta and British Columbia to two wholly-owned subsidiaries of Fortis Inc., a Canadian energy company, for approximately $1.08 billion (CDN$1.476 billion), including the assumption of debt of $113 million (CDN$155 million) by the purchasers. The closing proceeds include $85 million (CDN$116 million) of adjustments for working capital and capital expenditures as provided under the sales agreements. We recorded a pretax gain from this sale of $65.6 million, or $9.1 million after tax, including final working capital and capital expenditure adjustments.

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

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

Independent Power Plants

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

Gas Storage Facility

In August 2002, we agreed to sell our Texas natural gas storage facility for $180.0 million. After pricing adjustments, this transaction closed in the fourth quarter of 2002 for $160.4 million. We recorded a pretax and after-tax gain of $4.3 million.

Gas Gathering and Pipeline Assets

In August 2002, we agreed to sell our Texas and Mid-Continent natural gas pipeline systems, including our natural gas and natural gas liquids processing assets, and our ownership interest in the Oasis Pipe Line Company, for $262.9 million. The transaction closed in October 2002. In connection with this sale, we recorded a pretax loss of $240.3 million, or $152.0 million after tax.

Merchant Loan Portfolio

Historically, we provided capital to energy-related businesses seeking financing for energy projects. After we made the decision to exit the wholesale energy trading business, we decided to sell our loan portfolio because this business was no longer a part of our core strategy. We sold substantially all of the loan portfolio in December 2002 for $258.5 million. In connection with this sale, we recorded a pretax loss of $184.0 million, or $193.6 million after tax.

Coal Terminal

During the fourth quarter of 2002, we decided to dispose of Aquila Dock, Inc., our coal terminal in West Virginia. As a result of the expected disposition of this business, we recorded an estimated pretax impairment charge of $6.6 million and after-tax loss of $4.9 million to reduce the carrying value of the assets to their fair value less estimated selling costs. We sold this facility in February 2003.

Summary

We have reported the results of operations from these assets in discontinued operations for the three years ended December 31, 2004 in the Consolidated Statements of Income. The related assets and liabilities included in the sale of these businesses, as detailed below, have been reclassified as current and non-current assets and liabilities of discontinued operations on the December 31, 2003 Consolidated Balance Sheets as follows:

In millions	**December 31, 2003**
Current assets of discontinued operations:	
Cash and cash equivalents	$ 55.8
Funds on deposit	46.3
Accounts receivable, net	58.3
Price risk management assets	34.5
Other current assets	37.0
Total current assets of discontinued operations	$ 231.9
Non-current assets of discontinued operations:	
Property, plant and equipment, net	$ 752.1
Price risk management assets	45.8
Goodwill, net	229.5
Other non-current assets	21.4
Total non-current assets of discontinued operations	$1,048.8
Current liabilities of discontinued operations:	
Current maturities of long-term debt	$ 22.8
Short-term debt	215.0
Accounts payable	39.0
Other current liabilities	91.7
Total current liabilities of discontinued operations	$ 368.5
Non-current liabilities of discontinued operations:	
Long-term debt, net	$ 133.9
Deferred credits	53.5
Total non-current liabilities of discontinued operations	$ 187.4

Operating results of discontinued operations are as follows:

In millions	Year Ended December 31, 2004	2003	2002
Sales	$130.9	$322.4	$ 571.4
Cost of sales	25.1	64.0	225.5
Gross profit	105.8	258.4	345.9
Operating expenses:			
Operating expense	56.7	141.9	197.9
Impairment charges and net loss (gain) on sale of assets	(74.0)	47.5	438.2
Depreciation and amortization expense	—	8.6	82.2
Total operating expense	(17.3)	198.0	718.3
Other income (expense):			
Equity in earnings of investments	—	—	5.3
Other income (expense)	2.7	(16.0)	57.5
Total other income (expense)	2.7	(16.0)	62.8
Interest expense	14.7	23.9	22.3
Earnings (loss) before taxes	111.1	20.5	(331.9)
Income tax expense (benefit)	54.4	.9	(4.9)
Earnings (loss) from discontinued operations	$ 56.7	$ 19.6	$(327.0)

Note 7: Restricted Cash

Our restricted cash on the Consolidated Balance Sheets is comprised of the following:

In millions	December 31, 2004	2003
Restricted customer funds on deposit	$ 1.0	$248.7
Escrow for prepayment penalty dispute	20.6	—
Other	1.2	.5
Total	$22.8	$249.2

A large counterparty required us to segregate the customer funds on deposit that it had advanced to us from our daily cash accounts. This amount was considered ''restricted cash'' and was not available for day-to-day operations. In September 2004, the underlying contracts with this counterparty were settled and we returned the funds it had deposited with us from our restricted cash.

Certain lenders have contested our retirement of the $430 million three-year secured term loan and are seeking additional prepayment penalties of approximately $20.6 million. As a result, we have deposited $20.6 million with the term loan facility agent and classified the amount as restricted cash. See Note 21 for further discussion.

Note 8: Accounts Receivable

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

In millions	December 31, 2004	2003
Merchant Services accounts receivable	$193.1	$369.4
Domestic Utilities accounts receivable	157.6	137.0
Other accounts receivable	5.3	6.4
Allowance for doubtful accounts	(30.7)	(36.7)
Unbilled utility revenue	138.1	122.3
Total	$463.4	$598.4

In 2004, we entered into a $150 million six-month secured revolving credit facility. Borrowings under this facility are secured by the accounts receivable generated by our regulated utility operations in Colorado, Kansas, Michigan, Missouri and Nebraska. There were no borrowings under this facility at December 31, 2004. See Note 12 for further discussion.

In October 2003, we pledged receivables from certain of our merchant gas customers as collateral support for a margining agreement with one of our significant gas suppliers. The total of these pledged receivables was $33.2 million at December 31, 2004.

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

Note 9: Property, Plant and Equipment

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

In millions	December 31, 2004	2003
Electric utility	$ 2,264.4	$ 2,185.4
Gas utility	1,249.7	1,222.0
Non-regulated electric power generation	494.9	494.9
Communications	77.4	60.2
Corporate and other	286.4	364.4
Electric and gas utility plant—construction in process	132.3	44.1
	4,505.1	4,371.0
Less—accumulated depreciation and amortization	(1,727.7)	(1,618.3)
Total property, plant and equipment, net	$ 2,777.4	$ 2,752.7

Our property, plant and equipment includes acquisition-related adjustments that are being amortized over useful lives not exceeding 40 years. Net amounts included in electric utility and gas utility that are not included in our rate base were $59.3 million and $64.0 million at December 31, 2004 and 2003, respectively.

	Composite Depreciation Rates		
	2004	2003	2002
Electric utility	2.8%	3.1%	3.3%
Gas utility	2.9%	3.0%	3.4%
Non-regulated electric power generation	2.8%	2.8%	2.9%
Communications	9.0%	8.5%	10.4%
Corporate and other	11.6%	11.7%	9.3%

Jointly Owned Electric Utility Plant

We own an 8% interest and lease another 8% interest in a coal-fired plant (Jeffrey Energy Center) with generating capacity of approximately 2,200 megawatts, operated by Westar Energy, Inc. We also own an 18% interest in a 670-megawatt coal-fired plant (Iatan) operated by Kansas City Power & Light Company. At December 31, 2004, our investments in the Jeffrey and Iatan plants totaled $194.9 million and related accumulated depreciation was $119.5 million. Our pro rata share of Jeffrey Energy Center's and Iatan's operating costs are included in our Consolidated Statements of Income.

Asset Retirement Obligations

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

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

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

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 $1.1 million as of December 31, 2004.

Depreciation rates approved by regulatory commissions in certain states include a provision for the cost of future removal of assets for which there is no legal removal obligation. Concurrent with the adoption of SFAS 143, the net provision for these ''non-legal'' removal costs has been reclassified from accumulated depreciation, where it has been recorded previously, to a regulatory liability. See Note 11 for further discussion.

Note 10: Investments in Unconsolidated Subsidiaries

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

			Investment at December 31,		**Equity Earnings— Year Ended December 31,**		
In millions	**Effective Ownership at 12/31/04**	**Country**	**2004**	**2003**	**2004**	**2003**	**2002**
Independent power plant partnerships	Sold	U.S. & Jamaica	$—	$200.6	$ 1.9	$56.4	$ 52.1
Midlands Electricity plc *	Sold	United Kingdom	—	75.1	—	—	41.9
United Energy Limited	Sold	Australia	—	—	—	10.9	29.1
Multinet Gas *	Sold	Australia	—	—	—	5.0	3.0
AlintaGas Limited *	Sold	Australia	—	—	—	.2	7.1
UnitedNetworks Limited	Sold	New Zealand	—	—	—	—	30.9
Quanta Services, Inc. *	Sold	United States	—	—	—	—	2.4
Other	Various	United States	1.5	37.2	.2	(2.9)	.4
Total			$ 1.5	$312.9	$ 2.1	$69.6	$166.9

* *These businesses recorded significant impairment charges during 2002. We have reflected our proportionate share in our net loss on sale of assets and other charges in our Consolidated Statements of Income as described in Note 5.*

Independent Power Plant Partnerships

As of December 31, 2003, we owned interests in 14 independent power plants located in eight states and Jamaica. These investments are aggregated because the individual investments are not significant. In 2002, we sold our interests in one of these projects, Lockport Energy, resulting in a $1.1 million pretax loss. In 2003, we decided to proceed with the sale of our remaining investments in independent power plants and evaluated the carrying value of these equity method investments based on the bids received and other internal valuations. The results of this assessment indicated that these investments were impaired. Therefore, we recorded a pretax impairment charge of $87.9 million, or $69.9 million after tax, to reduce the carrying value of our investments to their estimated fair value. In January 2004, we sold our interest in one of these plants. In March 2004, we closed the sale of our interests in 12 plants for approximately $256.9 million and paid approximately $4.1 million in transaction costs. As the actual proceeds realized were greater than estimated when we recorded the 2003 impairment charges, we recorded a pretax gain of $6.1 million, or $22.6 million after tax, in 2004. Two of the power plants, Lake Cogen Ltd. (Lake Cogen) and Onondaga Cogen Ltd. Partnership (Onondaga), were consolidated on our balance sheet. The remaining 10 plants were equity method investments that did not qualify for reporting as discontinued operations under SFAS 144 and were therefore included in continuing operations and in the investment table above.

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

Midlands Electricity plc

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

Midlands is the fourth-largest regional electricity company in the United Kingdom, serving approximately 2.4 million network customers through a 38,000-mile distribution network. Pursuant to an operating services agreement, we provided management and operating services to Midlands in exchange for a management fee.

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

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

In August 2002, Aquila and FirstEnergy initiated a bid process for the sale of Midlands. We received offers in early December and were in negotiations with prospective buyers at December 31, 2002. As a result of those offers, our own internal analysis and the corresponding impairment charge at the investment level, we recorded a $247.5 million pretax and after-tax impairment charge to write this investment down to its estimated fair value. See Note 5 for further discussion.

In October 2003, we and FirstEnergy Corp. agreed to sell 100% of the shares in ASL, the owner of Midlands Electricity plc, to a subsidiary of Powergen UK plc for approximately

£36 million. As a result of this agreement and our analysis of fair value surrounding this investment, in the third quarter of 2003 we recorded a $4.0 million pretax and after-tax impairment charge to write this investment down to its estimated fair value. We completed the sale of ASL in January 2004, received proceeds of $55.5 million and paid approximately $7.6 million in transaction fees. We recorded a pretax and after-tax gain from this sale of approximately $3.3 million in the first quarter of 2004 due to strengthening in the British pound exchange rate in the fourth quarter of 2003 and early 2004.

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

In millions	**December 31, 2003**
Assets:	
Current assets	$ 241.3
Non-current assets	2,821.0
Total assets	$3,062.3
Liabilities and Equity:	
Current liabilities	$ 198.3
Non-current liabilities	2,705.5
Equity	158.5
Total liabilities and equity	$3,062.3

	Year Ended December 31,	
In millions	**2003**	**2002**
Operating Results:		
Sales	$623.3	$ 605.5
Costs and expenses	543.2	818.2
Net Income (Loss)	$ 80.1	$(212.7)

United Energy Limited, Multinet Gas and AlintaGas Limited

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

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

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

In July 2002, UEL and Ikon sold their combined 50% interest in Pulse Energy, a retail electric and gas company. Through our 33.8% ownership in United Energy and our 25.5% ownership in Ikon, we had an approximately 15% ownership in Pulse. UEL also sold its interests in EdgeCap, a marketing and trading business, and Utili-Mode, a provider of back office support services for UEL and others. The sales of these three businesses closed in the third quarter of 2002 and resulted in a $3.0 million pretax and after-tax gain.

As discussed in Note 5, we recorded a pretax impairment charge of $127.2 million, or $93.0 million after tax, related to our investments in Multinet Gas and AlintaGas during the fourth quarter of 2002.

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

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

In millions	**Seven Months Ended July 31, 2003**	**Year Ended December 31, 2002**
Operating Results:		
Sales	$157.3	$238.6
Costs and expenses	126.4	202.1
Net income	$ 30.9	$ 36.5

UnitedNetworks Limited

Our New Zealand investment represented our interest in UnitedNetworks Limited (UNL), New Zealand's largest electric distribution company. We acquired our interests in the companies that became UNL between 1993 and 1998. In April 2000, UNL expanded its presence in the New Zealand energy market by purchasing the natural gas distribution network and North Island contracting business of Orion New Zealand Limited for approximately $274 million.

Our New Zealand investments were reflected on a consolidated basis from October 1998 to June 2000. In June 2000, we sold a portion of our New Zealand investment to a private equity investor (minority shareholder), reducing our effective ownership in UNL to approximately 62%. In connection with the transaction, the minority shareholder received substantive participating and protective rights. These rights included: the right to enforce 50% board representation at all times; supermajority rights requiring 80% of the vote of the board and shareholders regarding disposal of shares, capital expenditures, guarantees, securities issuances, amendments to by-laws, mergers and acquisitions, dividends and dissolution; and simple majority rights requiring 51% of the vote regarding employment contracts, business plan and financial budget approval, disposal of property or investments, material capital expenditures, legal proceedings, tax claims and appointment of the chairman of the board. We therefore did not consolidate these operations for financial statement purposes. In April 2001, additional shares of UNL were sold in New Zealand to the public for net proceeds of approximately $41 million, reducing our effective interest in UNL to 55.5%.

In October 2002, through a public tender offer in New Zealand, VECTOR Limited acquired all of the outstanding shares of UNL, in which we had a 70.2% indirect interest, for a purchase price of NZ$9.90 per share. The sale resulted in US$489.1 million of net cash proceeds to us that we used to retire debt and pay associated income taxes. Prior to closing this transaction, we repurchased our minority partner's 14.7% stake in UNL for approximately US$38.5 million. We recorded a pretax gain of $130.5 million, or $28.0 million after tax, in the fourth quarter of 2002 as a result of the sale of UNL shares.

Following is the summarized financial information for UNL. The balance sheets as of December 31, 2004 and 2003 and the income statements for the 2004 and 2003 periods are not included because we sold our investment in 2002:

In millions	**Nine Months Ended September 30, 2002**
Operating Results:	
Sales	$164.6
Costs and expenses	119.0
Net income	$ 45.6

Quanta Services, Inc.

Between 1999 and 2001, we acquired voting convertible preferred and common stock of Quanta Services, Inc. for approximately $719 million. Our fully converted beneficial voting interest in Quanta Services was approximately 38% at December 31, 2001. As discussed in Note 5, during 2002 we determined that there was an other-than-temporary decline in the fair value of our Quanta Services investment and accordingly wrote this asset down by $692.9 million to its estimated fair value of $3.00 a share. During the second half of 2002, we sold approximately 17.6 million shares at an average price of $2.75 per share for an additional loss of $3.2 million, reducing our ownership from 38% to 10.2%. As a result, we accounted for this investment as an available-for-sale security in accordance with SFAS 115. Accordingly, at December 31, 2002, we recorded a $7.3 million increase in our investment and other comprehensive income to write our investment up to $3.50 a share, the market value of Quanta Services' stock at December 31, 2002. We sold our remaining 11.6 million shares of Quanta Services in February 2003 at a net price of $2.90 per share.

We used Quanta Services as a construction contractor in our utility and communications businesses. These services were contracted under competitive bids at Quanta Services' standard rates for comparable services. The cost of such services was $24.8 million in 2002.

Following is the summarized financial information for Quanta Services. The balance sheets as of December 31, 2004 and 2003 and the income statements for the 2004 and 2003 periods are not included because we sold our remaining investment in February 2003:

In millions	**Year Ended December 31, 2002**
Operating Results:	
Sales	$1,750.7
Costs and expenses	2,370.3
Net loss	$ (619.6)

Aries Power Project

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

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

In millions	**December 31, 2003**
Assets:	
Current assets	$ 277.1
Non-current assets	1,163.3
Total assets	$1,440.4
Current liabilities	$ 329.0
Non-current liabilities	599.0
Equity	512.4
Total liabilities and equity	$1,440.4

In millions	Year Ended December 31, 2003	2002
Operating Results:		
Sales	$912.6	$1,026.8
Costs and expenses	750.2	1,050.9
Net income (loss)	$162.4	$ (24.1)

Note 11: Regulatory Assets

Federal, state or local authorities regulate certain of our utility operations. Our financial statements therefore include the economic effects of rate regulation in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS 71). This means our Consolidated Balance Sheets show some assets and liabilities that would not be found on the balance sheets of a non-regulated company.

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

In millions	December 31, 2004	2003
Regulatory Assets:		
Under-recovered gas costs	$ 41.6	$ 14.9
Income taxes	58.1	62.3
Environmental	7.6	10.0
Regulatory accounting orders	8.9	10.1
Other	10.6	9.8
Total regulatory assets	$126.8	107.1
Regulatory Liabilities:		
Cost of removal	72.5	69.7
Income taxes	5.9	11.1
Revenue subject to refund	2.6	10.1
Over-recovered gas costs	—	17.7
Pensions	6.6	2.3
Other	.7	.6
Total regulatory liabilities	88.3	111.5
Net regulatory (liabilities) assets	$ 38.5	$ (4.4)

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

- Under-recovered gas costs represent the cost of gas delivered to our gas utility customers in excess of that allowed in current rates. We do not earn a return on these costs which are collected from customers in future periods of less than one year as rates are periodically adjusted.

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

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

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

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

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

- Cost of removal represents the estimated cumulative net provision for future removal costs included in depreciation expense.

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

- Revenue subject to refund represents revenues collected from customers under interim rate orders that we expect to return to customers. This amount is estimated by management based on the particular facts and circumstances of the cases and the historical actions of the regulatory jurisdictions.

- Over-recovered gas costs represent the cost of gas paid by gas utility customers in allowed rates in excess of actual costs incurred. These costs will be returned to customers in future periods as rates are periodically adjusted.

- Pensions represent the cumulative excess of pension costs recovered in rates over pension expense recorded under SFAS 87. We expect to refund this amount to customers in future periods.

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 12: Short-Term Debt

We had no short-term borrowings outstanding on December 31, 2004 or 2003.

Letter of Credit Facility

In April 2004, we extended a 364-day letter of credit agreement with a commercial bank for an additional 364 days. Under terms of the agreement, the bank committed to issue letters of credit under the facility subject to a limit of $100.0 million outstanding at any one time. All letters of credit issued are fully secured by cash deposits with the bank. At December 31, 2004, $71.1 million of letters of credit were outstanding under this facility. Additionally, we have other letters of credit outstanding of approximately $6.6 million as of December 31, 2004.

Six-Month Secured Revolving Credit Facility

On October 22, 2004, we completed a $125 million secured revolving credit facility (the AR Facility). On December 1, 2004, we amended this facility to increase the maximum borrowing limit to $150 million. Proceeds may be used for working capital and other general corporate purposes. The facility is secured by the accounts receivable generated by our regulated utility operations in Colorado, Kansas, Michigan, Missouri and Nebraska. The six-month facility expires April 22, 2005. We expect to extend or replace this facility prior to its maturity. Borrowings under the AR Facility bear interest at the LIBOR plus 2.50%. 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 term loan and revolving credit facilities discussed in Note 13. There were no borrowings under this AR Facility at December 31, 2004.

Note 13: Long-Term Debt

This table summarizes our long-term debt:

In millions	December 31, 2004	December 31, 2003
First Mortgage Bonds:		
9.44% Series, due annually through 2021 *(a)*	$ 19.1	$ 20.2
Secured Term Loan:		
LIBOR plus 5.00%, due April 11, 2006 (retired September 2004)	—	430.0
Unsecured Term Loan:		
LIBOR plus 5.75% (8.26% at December 31, 2004), due September 19, 2009	220.0	—
Senior Notes:		
7.0% Series, due July 15, 2004	—	250.0
6.875% Series, due October 1, 2004	—	150.0
9.03% Series, due December 1, 2005	19.1	19.1
6.70% Series, due October 15, 2006	85.9	85.9
8.2% Series, due January 15, 2007	36.9	36.9
7.625% Series, due November 15, 2009	199.0	199.0
9.95% Series, due February 1, 2011	250.0	250.0
7.75% Series, due June 15, 2011	197.0	197.0
14.875% Series, due July 1, 2012	500.0	500.0
8.27% Series, due November 15, 2021	80.9	80.9
9.0% Series, due November 15, 2021	5.0	5.0
8.0% Series, due March 1, 2023	51.5	51.5
7.875% Series, due March 1, 2032	287.5	287.5
Medium Term Notes:		
Various, 7.77%*, due 2005-2023	40.0	40.0
Mandatorily Convertible Notes:		
6.75% Series, mandatorily convertible on September 15, 2007 into common shares at a conversion rate of 8.0386 to 9.8039 shares per $25 par value convertible note	345.0	—
Convertible Subordinated Debentures:		
6.625%, due July 1, 2011 (convertible into 149,556 common shares at $15.79 per share)	2.3	2.6
Other:		
Note Payable, 8.15%, due annually through 2008 (retired February 2004)	—	75.5
Other notes and obligations 4.63%*, due 2005-2028 *(a)*	32.7	24.9
Total long-term debt	2,371.9	2,706.0
Less current maturities	42.0	414.8
Long-term debt, net	$2,329.9	$2,291.2
Fair value of long-term debt, including current maturities *(b)*	$2,757.6	$2,940.8

* *Weighted average interest rate.*

(a) *Approximately $46.2 million of our long-term debt, including $27.1 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 the company 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
2005	$ 42.0
2006	89.3
2007 *(a)*	388.3
2008	2.6
2009	421.5
Thereafter	1,428.2
Total	$2,371.9

(a) Includes the non-cash, mandatory conversion of $345.0 million of PIES to common stock on September 15, 2007.

Mandatorily Convertible Senior Notes

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

If the mandatory conversion had occurred on December 31, 2004, the average closing price of our common stock for the 20-day trading period used to determine the conversion rate would have been $3.50. Using that rate, we would have converted each security into 8.0386 shares of our common stock. The fair value of those shares would have been $409.3 million as of December 31, 2004.

Senior Notes Rating Triggers

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

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

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

Three-Year Secured Term Loan

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

The three-year facility was secured by (i) $430.0 million of first mortgage bonds issued under a new indenture that constitutes a lien on our existing and future Michigan, Nebraska, Iowa and Colorado utility network assets, (ii) a pledge of the equity of two wholly-owned subsidiaries that indirectly held our Canadian utility businesses, and (iii) a pledge of the equity of a wholly-owned subsidiary that indirectly held our interests in independent power plants.

The $430.0 million secured term loan became immediately due and payable in September 2004 when we did not complete an exchange offer, tender offer, refinancing or other retirement transaction with regard to 80% of our $150.0 million, 6.875% senior note series due October 1, 2004, at least two weeks prior to its maturity date. We paid our lenders an early termination fee of 2%, or $8.7 million, pursuant to this provision. We also wrote off $10.3 million of unamortized debt issue costs. Certain lenders participating in the term loan are contesting the terms of the prepayment and seeking to require us to pay additional prepayment penalties of approximately $20.6 million. We have deposited $20.6 million with the term loan facility agent pending resolution of this dispute. The liens against our regulated utility assets in Michigan, Nebraska, Iowa and Colorado that were pledged as collateral on the term loan have been released. See Note 21 for discussion of litigation relating to this dispute.

Five-Year Unsecured Term Loan and Revolving Credit Facility

In September 2004, we completed a $220 million 364-day unsecured term loan and a $110 million 364-day unsecured revolving credit facility. The facilities automatically extended to September 2009 when we received extension approval from the FERC and various state public utility commissions (Five-Year Facilities). We borrowed the full amount of the term loan and received $211.3 million of net proceeds after upfront fees and expenses on the two facilities. We had not drawn on the revolving credit facility as of December 31, 2004. The Five-Year Facilities bear interest at the LIBOR plus 5.75%, subject to reduction if our credit rating improves. Among other restrictions, the Five-Year Facilities contain the following financial covenants with which we were in compliance as of December 31, 2004:

(1) We are required to maintain a ratio of total debt to total capital (expressed as a percentage) of not more than 90% from December 31, 2004 through September 30, 2007; 75% from December 31, 2007 through September 30, 2008; 70% from December 31, 2008 through June 30, 2009; and 65% thereafter.

(2) We must maintain a trailing 12-month ratio of earnings before interest, taxes, depreciation and amortization (EBITDA), as defined in the agreement, to interest expense of no less than 1.0 to 1.0 from December 31 2004 to September 30, 2005; 1.1 to 1.0 from December 31, 2005 through September 30, 2006; 1.3 to 1.0 from December 31, 2006 through September 30, 2007; 1.4 to 1.0 from December 31, 2007 through September 30, 2008; 1.6 to 1.0 from December 31, 2008 through June 30, 2009; and 1.8 to 1.0 thereafter.

(3) We must maintain a trailing 12-month ratio of debt outstanding to EBITDA of no more than 9.5 to 1.0 from December 31, 2004 to September 30, 2005; 8.5 to 1.0 from December 31, 2005 through September 30, 2006; 7.5 to 1.0 from December 31, 2006 through September 30, 2007; 6.0 to 1.0 from December 31, 2007 through September 30, 2008; 5.5 to 1.0 from December 31, 2008 through June 30, 2009; and 5.0 to 1.0 thereafter.

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

Note Payable

In connection with the acquisition of our interest in Midlands Electricity from FirstEnergy Corp., described in Note 10, we issued a note payable to the seller, FirstEnergy, for a portion of the purchase price. This note required us to make annual payments of $19.0 million through May 2008. The note obligation was recorded at its net present value at the date of acquisition, discounted at our incremental borrowing rate at that time of 8.15%. In 2003, FirstEnergy sold this note to two unrelated third parties and removed the requirement that we repay the note on an undiscounted basis if we sold our interest in Midlands.

In February 2004, we paid $78.6 million to extinguish this note payable and accrued interest, resulting in other income related to this transaction of approximately $1.9 million.

Credit Ratings

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

As of December 31, 2004, our senior unsecured long-term debt ratings, as assessed by the three major credit rating agencies, were as follows:

Agency	Rating	Outlook
Moody's	B2	Stable Outlook
S&P	B–	Negative Outlook
Fitch	B–	Stable Outlook

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

Secured Financing

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

In addition, we are required to obtain prior approval from the FERC before we can issue long-term or short-term debt. We currently have authority from the FERC to have up to $350 million of additional short-term, unsecured debt outstanding. Our authority to issue short-term debt expires in March 2006. The FERC recently issued an order in which it announced that any future debt authorization orders would prohibit companies subject to its jurisdiction from using their utility properties as collateral for loans unless the loan proceeds will be used to support their utility operations.

Except in limited circumstances, holders of our senior notes and bonds, which represent the majority of our unsecured obligations, do not have the right to restrict our use of collateral or to be equally or ratably secured if we provide collateral to other creditors. Our five-year facilities prohibit us from pledging our assets as collateral except in certain circumstances.

Note 14: Long-Term Gas Contracts

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

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

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

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

In millions	**Long-Term Gas Contract Settlement *(a)***	**Long-Term Gas Contract Margin Loss *(b)***	**Total Long-Term Gas Contract Cash Payments *(c)***
2005	$15.0	$ 7.1	$22.1
2006	15.7	7.7	23.4
2007	15.8	8.1	23.9
2008	1.4	.6	2.0
Total	$47.9	$23.5	$71.4

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

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

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

We accounted for the cash payments in advance related to these contracts as long-term obligations. We reduce our obligation on these long-term gas contracts as gas is delivered to the customer under the units of revenue method. If we were to default on the two remaining contracts, or were unable to perform on them, we would be required to pay the issuers of the surety bonds or the counterparties on these arrangements approximately $69.6 million. This amount is greater than the long-term gas contract balance on our Consolidated Balance Sheet due to our use of the units of revenue method versus a present value method applied under default provisions based on contractual agreements.

Note 15: 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.

Aquila Merchant Equity Offering

An initial public offering of 19,975,000 Class A Aquila Merchant common shares, including an over-allotment of 2,475,000 shares, closed in April 2001. The offering price was $24.00 per share and we raised approximately $446 million in net proceeds. Of the 19,975,000 shares, Aquila Merchant sold 14,225,000 new shares and we sold 5,750,000 previously issued shares. Upon completion of the offering, we owned approximately 80% of Aquila Merchant's outstanding shares.

In January 2002, we completed an exchange offer and merger in which we acquired all the outstanding publicly-held shares of Aquila Merchant in exchange for shares of Aquila common stock. The public shareholders of Aquila Merchant received .6896 shares of Aquila common stock in a tax-free exchange for each outstanding share of Aquila Merchant Class A common stock. Aquila Merchant shareholders holding approximately 1.7 million shares of Aquila Merchant Class A shares exercised dissenters' rights to request an appraisal of the fair value of their shares with respect to the merger. In June 2004, we paid approximately $38 million, including interest from 2002, to settle this litigation. This resulted in the recognition of additional expense of $8.8 million including litigation costs in 2004.

We accounted for this transaction as a purchase. The total purchase price of $369.7 million was determined based upon the market price of the approximately 12.6 million Aquila common shares issued in the exchange, an estimated liability to dissenting shareholders at the same market price and transaction costs. The purchase price exceeded our proportionate interest in the fair value of the net assets of Aquila Merchant by approximately $218.7 million, which was classified as goodwill. We wrote off all of this goodwill in 2002 in connection with the sale of assets or through impairment charges. See Note 1 for further discussion.

Equity Offerings

In January 2002, we sold 12.5 million shares of our common stock to the public, including an over-allotment of 1.5 million shares, which raised approximately $277.7 million in net proceeds. These proceeds were used to reduce short-term debt and for general corporate purposes. In July 2002, we sold an additional 37.5 million shares of our common stock to the public, raising approximately $271.2 million in net proceeds. We used the proceeds of this offering to repay borrowings under the revolving credit facility and to increase our liquidity. In August 2004, we sold 46.0 million shares of our common stock to the public, including an over-allotment option of 6.0 million shares, which raised $112.3 million in net proceeds. We used the proceeds of this offering to retire long-term debt and reduce other long-term liabilities.

Premium Equity Participating Security Units

In November 2002, we issued approximately 11.7 million shares of our common stock to settle substantially all of our purchase contracts related to our premium equity participating security units (PEPS). Each PEPS unit had an issue price of $25 and consisted of a contract to purchase shares of our common stock on, or prior to, November 16, 2002 and a preferred security of UtiliCorp Capital Trust I. Each purchase contract yielded 2.40% per year, paid quarterly, on the $25 stated amount of the PEPS unit. Each trust preferred security yielded 7.35% per year, paid quarterly, on the $25 stated amount of the PEPS Unit, until November 16, 2002. These trust preferred securities were cancelled upon the issuance of common stock to settle the purchase contracts.

Suspension of Dividend

In November 2002, the Board of Directors suspended the annual dividend on common stock for an indefinite period. This decision followed a detailed analysis of the company's current financial condition, its liquidity forecast and its earnings prospects after completion of the asset sales program discussed above. Currently one 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.

Stockholder Rights Plan

Our Board of Directors has adopted a rights plan and declared a dividend distribution of one right for each outstanding share of our common stock. The rights become exercisable if a person acquires beneficial ownership of 15% or more of our outstanding common stock. If the rights were exercised, the value of the shares of our common stock held by the acquiring person would be substantially diluted. The purpose of the rights plan is to encourage a person desiring to acquire 15% or more of our outstanding common stock to negotiate the terms of their acquisition with our Board of Directors.

Dividend Reinvestment and Common Stock Purchase Plan

Our Dividend Reinvestment and Common Stock Purchase Plan (the Stock Plan) has been suspended until we obtain authorization of additional shares. Previously we offered current and potential shareholders the option to participate in the Stock Plan. The Stock Plan allowed participants to purchase up to $10,000 per month of common stock at the average market price on the date of the transaction, with minimal sales commissions. The Stock Plan also allowed members to reinvest dividends into additional common shares at a 5% discount. For the years ended December 31, 2003 and 2002, 608,074 and 2,188,427 shares were issued, respectively, under the Stock Plan.

Employee Stock Purchase Plan

Purchases have been suspended under our Employee Stock Purchase Plan until we obtain authorization of additional shares. Participants in this plan had the opportunity to buy shares of common stock at a reduced price through regular payroll deductions and/or lump sum deposits of up to 20% of the employee's base salary, but not more than $25,000 annually. Contributions were credited to the participant's account throughout an option period. At the end of the option period, the participant's total account balance was applied to the purchase of common stock. The shares were purchased at 85% of the lower of the market price on the first day or the last day of the option period. Participants must have been enrolled in the Plan as of the first day of an option period in order to participate in that option period. For the years ended December 31, 2003 and 2002, 665,254 and 281,394 shares were purchased, respectively, under the Employee Stock Purchase Plan.

Retirement Investment Plan

A defined contribution plan, the Retirement Investment Plan (Savings Plan), covers all of our full-time and eligible part-time employees. Participants may generally elect to contribute up to 50% of their annual pay on a before- or after-tax basis subject to certain limitations. The company generally matches contributions up to 6% of pay. Participants may direct their contributions into various investment options. Through 2002, all matching contributions made by the company were in Aquila stock. Effective in 2003, our matching contributions were made in cash and invested as directed by the employee. Company contributions were $8.4 million, $8.1 million and $11.5 million during the years ended December 31, 2004, 2003 and 2002, respectively. The Savings Plan also includes a discretionary contribution fund to which the company historically contributed stock equal to 3% of base wages for eligible full-time employees. Beginning in 2003, these contributions are made in cash and invested as directed by the employee. Vesting occurs ratably over five years of employment with distribution upon termination of employment. All dividends are reinvested in the respective investment elections. For 2004, 2003 and 2002, compensation expense (in millions) of $4.3, $4.9 and $5.9, respectively, was recognized, which approximates 3% of eligible employees' base wages. Any Aquila common shares that have been elected by the employee related to this program are classified as outstanding when calculating earnings per share.

Long-Term Incentive Plan

Our Long-Term Incentive Plan (LTIP) enables the company to reward key executives who have an ongoing company-wide impact. Eligible executives are awarded performance units based on experience and responsibilities in the company. Incentives earned are based on a comparison of our total shareholder return over three years to a specific group of companies with operations similar to ours. Incentives have been paid in cash, restricted stock, restricted stock units or deferred compensation agreements funding stock option grants based on the executives' total shareholdings of company common stock and their elections. No new grants have been provided to senior executive officers since the performance cycle beginning in 2002. We currently have only one outstanding grant to junior executives for the 2003 through 2005 performance cycle. Total compensation expense for the years ended December 31, 2004 and 2003, was $.7 million and $.4 million, respectively.

Omnibus Incentive Compensation Plan

In 2002, the Board and our shareholders approved the Omnibus Incentive Compensation Plan. This plan authorizes the issuance of 9,000,000 shares of Aquila common stock as stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance units, stock awards, cash-based awards and annual incentive awards to all eligible employees and directors of the company. All equity-based awards are issued under this plan. Stock options under this plan and preceding plans have generally been granted at market prices with one to three year vesting terms and have been exercisable for seven to 10 years from the date of grant. In December 2004, we granted fully vested stock options for approximately 1.9 million shares to all employees other than senior executive officers of the company. These options are exercisable for seven years from the date of grant. As of December 31, 2004, we have approximately 4.9 million shares of common stock available for issuance under this plan and preceding plans.

Summary of Stock Options

This table summarizes all stock option activity:

	2004	2003	2002
Shares:			
Beginning balance	8,558,048	8,908,508	6,118,123
Granted	1,900,760	408,300	1,789,152
Converted from Merchant plan	—	—	2,641,369
Exercised	(472,591)	(85,577)	(270,028)
Cancelled	(348,118)	(673,183)	(1,370,108)
Ending balance	9,638,099	8,558,048	8,908,508
Weighted average prices:			
Beginning balance	$20.22	$20.75	$22.37
Granted price	3.75	1.44	1.83
Converted price	—	—	34.82
Exercised price	4.06	3.04	24.14
Cancelled price	21.57	17.15	29.49
Ending balance	$17.73	$20.22	$20.75

This table summarizes all outstanding and exercisable stock options as of December 31, 2004:

	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	1,409,266	4.99	$ 1.77	1,235,866	$ 1.81
$3.75	1,899,210	6.99	3.75	1,899,210	3.75
$18.16-24.90	4,257,182	3.46	21.55	4,257,182	21.55
$28.13-39.52	2,072,441	5.59	33.51	1,606,024	33.73
Total	9,638,099			8,998,282	

No restricted stock awards were granted during 2004 or 2003. As of December 31, 2004, we had 453,326 restricted stock awards outstanding.

Note 16: Accumulated Other Comprehensive Income (Loss)

The table below reflects the activity for accumulated other comprehensive income (loss) for 2002, 2003 and 2004:

In millions	Foreign Currency Adjustments	Cash Flow Hedges	Held for Sale Securities	Minimum Pension Liability	Accumulated Other Comprehensive Income (Loss)
Balance December 31, 2001	$(91.5)	$ .9	$ —	$—	$(90.6)
2002 change	74.0	(18.9)	7.3	(4.8)	57.6
Balance December 31, 2002	(17.5)	(18.0)	7.3	(4.8)	(33.0)
2003 change	81.3	9.2	(7.3)	.4	83.6
Balance December 31, 2003	63.8	(8.8)	—	(4.4)	50.6
2004 change	(63.0)	8.8	—	4.4	(49.8)
Balance December 31, 2004	$ .8	$ —	$ —	$—	$ .8

Note 17: Earnings (Loss) Per Share

The table below shows how we calculated diluted earnings (loss) per share and diluted shares outstanding. Basic earnings (loss) per share and basic weighted average shares are the starting point in calculating the dilutive measures. To calculate basic earnings (loss) per share, divide earnings (loss) available for common shares by weighted average shares outstanding, without adjusting for dilutive items. Weighted average shares used in basic earnings per share includes 110.9 million shares issuable on the conversion of the mandatorily convertible Premium Income Equity Securities (PIES) from August 24, 2004, the date of issuance of the PIES. See Note 13 for further discussion. Diluted earnings (loss) per share are calculated by dividing earnings (loss) available for common shares, after assumed conversion of dilutive securities, by weighted average shares outstanding, adjusted for the effect of dilutive securities. As a result of the net losses in

2004, 2003 and 2002, the potential issuances of common stock were anti-dilutive and therefore not included in the calculation of diluted earnings (loss) per share.

	Year Ended December 31,		
In millions, except per share amounts	**2004**	**2003**	**2002**
Loss from continuing operations	$(349.2)	$(356.0)	$(1,725.4)
Interest and debt amortization costs associated with the PIES	9.4	—	—
Loss available for common shares from continuing operations	(339.8)	(356.0)	(1,725.4)
Interest on convertible bonds	—	—	—
Loss available for common shares from continuing operations	(339.8)	(356.0)	(1,725.4)
Earnings (loss) from discontinued operations	56.7	19.6	(327.0)
Cumulative effect of accounting change	—	—	(22.7)
Loss available for common shares	$(283.1)	$(336.4)	$(2,075.1)
Basic and diluted earnings (loss) per share:			
Loss available for common shares from continuing operations	$ (1.35)	$ (1.83)	$ (10.67)
Earnings (loss) from discontinued operations	.22	.10	(2.02)
Cumulative effect of accounting change	—	—	(.14)
Net loss available for common shares	$ (1.13)	$ (1.73)	$ (12.83)
Weighted average number of common shares used in basic and diluted earnings (loss) per share	251.35	194.75	161.72

Note 18: Income Taxes

Loss from continuing operations before income taxes consisted of:

	Year Ended December 31,		
In millions	**2004**	**2003**	**2002**
Domestic	$(560.8)	$(491.9)	$(1,851.4)
Foreign	(1.7)	(9.2)	(66.8)
Total	$(562.5)	$(501.1)	$(1,918.2)

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

In millions	Year Ended December 31, 2004	2003	2002
Current:			
Federal	$ —	$ (34.5)	$(366.1)
Foreign	(.5)	2.5	76.7
State	—	(6.1)	(65.0)
Deferred:			
Federal	(172.6)	(45.6)	(189.8)
Foreign	—	(.6)	80.6
State	(30.6)	(8.1)	(33.7)
Change in valuation allowance	(8.1)	(51.0)	306.2
Investment tax credit amortization	(1.5)	(1.7)	(1.7)
Income tax benefit from continuing operations	(213.3)	(145.1)	(192.8)
Income tax expense (benefit) from discontinued operations:			
Current	36.3	20.6	68.6
Deferred (net of valuation allowance of $(11.1) million, $11.1 million and $75.4 million in 2004, 2003 and 2002, respectively)	18.1	(19.7)	(73.4)
Income tax expense (benefit) from discontinued operations	54.4	.9	(4.8)
Income tax benefit on cumulative effect of accounting change	—	—	(14.8)
Total	$(158.9)	$(144.2)	$(212.4)

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

In millions	December 31, 2004	December 31, 2003
Deferred Tax Assets:		
Alternative minimum tax credit carryforward	$ 103.6	$ 103.6
Net operating loss carryforward	359.7	81.4
Mark-to-market losses	8.1	23.4
Accrued bonuses and deferred compensation	14.9	16.1
Allowance for doubtful accounts	11.6	14.4
Asset impairments	25.4	58.6
Realized capital loss carryforward for income tax purposes	275.4	187.3
Unrealized capital losses	17.3	140.6
Other	12.5	25.5
Less: valuation allowance	(304.7)	(341.7)
Total deferred tax assets	523.8	309.2
Deferred Tax Liabilities and Credits:		
Accelerated depreciation and other plant differences:		
Regulated	301.0	283.0
Non-regulated	35.9	24.9
Reserve for contingent tax liabilities	244.0	208.7
Basis difference in international investments	—	30.0
Currency translation adjustment	.5	40.8
Pension costs	38.2	46.8
Regulatory asset	52.2	51.2
Total deferred tax liabilities and credits	671.8	685.4
Deferred income taxes and credits, net	$ 148.0	$ 376.2

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

	December 31, 2004	December 31, 2003	December 31, 2002
Statutory Federal Income Tax Rate	(35.0)%	(35.0)%	(35.0)%
Tax effect of:			
State income taxes, net of federal benefit	(3.8)	(3.4)	(3.3)
Revocation of permanent foreign reinvestments	—	—	6.2
Change in valuation allowance	(1.5)	(10.2)	16.0
Reserve for contingent tax liabilities	(.9)	17.1	—
Goodwill	—	—	3.7
Other	3.3	2.5	2.3
Effective Income Tax Rate	(37.9)%	(29.0)%	(10.1)%

Tax Credits

At December 31, 2004 and 2003, we had alternative minimum tax credit carryforwards of $103.6 million. These credits do not expire and can be used to decrease future cash tax payments. In addition, at December 31, 2004 and 2003, we had general business tax credit carryforwards of $6.7 million. The substantial majority of the general business credits expire in 2018, after which time they become a deduction against taxable income instead of a credit against tax. We did not record valuation allowances against the deferred tax asset related to the general business credits as we believe that more likely than not they will be utilized.

Capital Loss Carryforwards

As of December 31, 2004, we had approximately $716.3 million of net realized capital loss carryforwards available for federal income tax purposes that expire in 2007 through 2009 and recognized impairment charges of $45.1 million that we expect to realize (for income tax purposes) as capital losses when the assets are sold. The tax benefit of these carryforwards and impairments is reflected on our balance sheet as a deferred tax asset of $292.7 million. We assessed the likelihood that all or a portion of the deferred tax assets relating to the remaining capital losses would not be realized. This assessment included consideration of positive and negative factors, including our current financial position and results of operations, projected future taxable income, including projected capital gains, and available tax planning strategies. As a result of such assessment, we determined that it was more likely than not that deferred tax assets relating to capital losses would not be realized. Therefore, we have established a full valuation allowance of $292.7 million against these tax benefits.

Net Operating Loss Carryforwards

As of December 31, 2004, we had approximately $460.7 million of federal net operating loss carryforwards originating in 2003 and $418.4 million of estimated federal net operating losses originating in 2004. 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 federal net operating loss carryforward expires in 2024 and cannot be carried back due to losses in the carryback years. At December 2004 and 2003, we had recorded deferred tax benefits of $359.7 million and $81.4 million, respectively, related to our cumulative net operating loss carryforwards. Included in these amounts are deferred tax benefits of $52.0 million and $41.9 million, respectively, related to state net operating losses. The state net operating loss carryforwards expire in various years.

We did not record valuation allowances against the deferred tax assets related to the federal net operating losses as we believe it is more likely than not that sufficient taxable income to utilize these losses during the carryforward period will be generated from continuing operations, including the reversal of deferred tax liabilities on our regulated business plus income from the sale of assets. However, we recorded a valuation allowance of $13.8 million in 2003 and an additional valuation allowance of $15.9 million in 2004 against the state net operating loss benefits. Also, in 2004, $17.8 million of state net operating loss benefits and related valuation allowance was written off because we no longer operate in certain states. At December 2004, our valuation allowance related to state net operating losses was $11.9 million. This valuation allowance is necessary because we believe that it is more likely than not that we will not realize the deferred tax assets related to these state net operating losses during the applicable carryforward periods. This assessment considered the decline in future business activity in certain states and the taxable income we expect to generate in the applicable state carryforward periods.

As a result of the PIES offering and concurrent common stock offering, which closed on August 24, 2004, we may be limited in our ability to utilize certain of our net operating losses and general business credit carryforwards to offset future taxable income and tax liability, respectively. The Internal Revenue Code imposes an annual limitation on the use of a corporation's tax attributes if a corporation undergoes an ownership change for tax purposes during a three-year test period. The PIES and common stock offerings, in conjunction with additional transactions in our company stock during the testing period, may constitute an ownership change for this purpose.

If an ownership change is determined to have occurred, our ability to use the general business credits, the net operating loss carryforward from 2003, and the net operating loss generated through August 24, 2004, would be subject to an annual limitation. In such case, the amount of net operating loss subject to the limitation would not be determined until the 2004 tax return is filed and such determination would be subject to audit by the IRS. Based on our current estimate of the total net operating losses at August 24, 2004, and our current estimate of the annual limitation, we do not expect that the annual limitation would cause any of our net operating losses or general business credits to expire unutilized. Thus, we have not established a valuation allowance against the tax benefits of the net operating losses or general business credits existing at August 24, 2004.

We also have significant capital loss and minimum tax credit carryforwards that would be subject to the annual limitation described above. However, a full valuation allowance has already been provided against the tax benefits from the capital loss carryforwards and the minimum tax credit carryforwards do not expire. Therefore, no additional valuation allowance is required due to the potential ownership change annual usage limitation.

Reserve for Contingent Tax Liabilities

As of December 31, 2004 and 2003, we had recorded in deferred tax liabilities $244.0 million and $208.7 million, respectively, of cumulative tax provisions for tax deduction or income positions taken in prior tax returns that we believe were properly treated on such tax returns but for which it is reasonably likely that these deductions or income positions will be challenged when the returns are audited. The tax returns containing these tax deductions or income positions are currently under audit or will likely be audited. The reserve is included in deferred tax liabilities because the timing of the resolution of these audits is uncertain and if the positions taken on the tax returns are not ultimately sustained, we may be required to make cash payments plus interest and/or utilize our net operating loss carryforwards, alternative minimum tax credit carryforwards, and/or general business credit carryforwards.

Revocation of Permanent Foreign Reinvestments

Due to our need for capital and our change in business strategy to transition the company to a domestic regulated utility with some non-regulated generation, we sold our New Zealand investments in 2002, our Australian investments in 2003 and our Canadian investments in 2004. As a result, we could no longer represent that cash from our international investments would be permanently invested outside the United States. Therefore, additional deferred tax of $148.3 million was recorded in 2002 to account for the estimated taxes that arose when we brought asset sale proceeds back to the United States.

Goodwill

Included in 2002 impairment charges and net loss on sales of assets was $200.5 million of Merchant Services goodwill which was not deductible for income tax purposes and therefore does not result in the recognition of a tax benefit.

Note 19: 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 accrue the cost of post-retirement benefits during an employee's service. We fund the net periodic post-retirement benefit costs to the extent that they are tax-deductible. For measurement purposes, projected benefit obligations and the fair value of plan assets were determined as of September 30, 2004 and 2003.

On December 8, 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act) became effective. The Act expands Medicare, primarily by offering a prescription drug benefit to Medicare-eligible retirees starting in 2006, as well as a federal subsidy to sponsors of retiree healthcare plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. Our actuaries have determined that the benefits provided under our other post-retirement benefit plans are actuarially equivalent to the Medicare Part D benefits under the Act for current retirees. Therefore, we will qualify for the 28% federal subsidy. We have recognized the effect of the Act on our other post-retirement benefit obligations and costs in our financial statements, beginning July 1, 2004 in accordance with FASB Staff Position No. 106-2, ''Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003.'' Based on a remeasurement of the plans at April 1, 2004, the effect of the Act on the accumulated post-retirement benefit obligation was a decrease of $10.1 million, which we expect to amortize to reduce net periodic benefit costs in future periods. The effect of the Act on net periodic benefit cost was a decrease of $.7 million for 2004.

The following table shows the funded status of our pension and post-retirement benefit plans and the amounts included in the Consolidated Balance Sheets and Consolidated Statements of Income:

	Pension Benefits		Other Post-retirement Benefits	
Dollars in millions	**2004**	**2003**	**2004**	**2003**
Change in Projected Benefit Obligation:				
Benefit obligation at start of year	$330.4	$301.7	$ 81.1	$ 74.5
Service cost	7.8	8.0	.2	.3
Interest cost	19.4	19.2	4.7	4.8
Plan participants' contribution	—	—	2.3	2.0
Actuarial (gain) loss	(4.7)	17.7	(12.3)	7.4
Curtailment loss	—	—	—	(.2)
Benefits paid	(15.3)	(16.2)	(7.8)	(7.7)
Projected benefit obligation at end of year	$337.6	$330.4	$ 68.2	$ 81.1
Change in Plan Assets:				
Fair value of plan assets at start of year	$288.4	$248.4	$ 14.3	$ 13.7
Actual return on plan assets	39.7	52.4	.2	.9
Employer contribution	0.8	3.8	4.9	5.4
Plan participants' contribution	—	—	2.3	2.0
Benefits paid	(15.3)	(16.2)	(7.8)	(7.7)
Fair value of plan assets at end of year	$313.6	$288.4	$ 13.9	$ 14.3
Funded status:				
Funded status	$ (24.0)	$ (42.0)	$(54.3)	$(66.8)
Unrecognized transition amount	(1.5)	(2.6)	12.4	13.9
Unrecognized net actuarial loss	90.9	119.4	14.8	29.5
Unrecognized prior service cost	12.0	13.1	3.3	2.5
Accumulated regulatory gain/loss adjustment	10.6	10.8	(1.0)	(.1)
Net amount recognized before SFAS 71 regulatory liability	88.0	98.7	(24.8)	(21.0)
SFAS 71 regulatory liability	(6.6)	(2.3)	—	—
Net amount recognized	$ 81.4	$ 96.4	$(24.8)	$(21.0)
Amounts Recognized in the Consolidated Balance Sheets:				
Prepaid benefit cost	$ 98.7	$108.0	$ —	$ —
Accrued benefit liability	(18.1)	(17.2)	(24.8)	(21.0)
SFAS 71 regulatory liability	(6.6)	(2.3)	—	—
Intangible asset	7.4	7.9	—	—
Net amount recognized	$ 81.4	$ 96.4	$(24.8)	$(21.0)
Reconciliation of Net Amount Recognized:				
Net amount recognized at start of year	$ 96.4	$106.2	$(21.0)	$(19.1)
Net periodic benefit cost before curtailments and regulatory expense adjustments	(11.3)	(14.5)	(7.8)	(7.4)
Curtailment (gain) loss	—	(.3)	—	.2
Contributions	.8	3.8	4.9	5.4
Regulatory gain/loss adjustment	(.2)	3.5	(.9)	(.1)
SFAS 71 regulatory adjustment	(4.3)	(2.3)	—	—
Net amount recognized at end of year	$ 81.4	$ 96.4	$(24.8)	$(21.0)
Weighted Average Assumptions as of September 30:				
Discount rate for expense	6.00%	6.75%	6.00%	6.75%
Discount rate for disclosure	6.00%	6.00%	6.00%	6.00%
Expected return on plan assets for expense	8.50%	9.50%	7.00%	8.50%
Expected return on plan assets for disclosure	8.50%	8.50%	7.00%	8.50%
Rate of compensation increase	4.40%	4.15%	n/a	n/a

For measurement purposes, to calculate the annual rate of increase in the per capita cost of covered health benefits for each future fiscal year, we used a graded rate for non-prescription drug medical costs starting at 9% in 2005 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 13% in 2005 and decreasing 1% annually until the rate levels out at 5% for years 2013 and thereafter.

	Pension Benefits			**Other Post-retirement Benefits**		
In millions	**2004**	**2003**	**2002**	**2004**	**2003**	**2002**
Components of Net Periodic Benefit Cost:						
Service cost	$ 7.8	$ 8.0	$ 8.8	$ .2	$ .3	$ .4
Interest cost	19.4	19.2	19.5	4.7	4.8	5.8
Expected return on plan assets	(23.9)	(22.9)	(25.9)	(1.0)	(1.2)	(1.0)
Amortization of transition amount	(1.2)	(1.2)	(1.6)	1.5	1.6	1.7
Amortization of prior service cost	1.1	1.1	1.0	.7	.7	.5
Recognized net actuarial (gain) loss	8.1	10.3	2.8	1.7	1.2	1.7
Net periodic benefit cost before curtailments and regulatory expense adjustments	11.3	14.5	4.6	7.8	7.4	9.1
Curtailment (gain) loss	—	.3	.2	—	(.2)	2.5
Regulatory gain/loss adjustment	.2	(3.5)	(1.9)	.9	.1	—
SFAS 71 regulatory adjustment	4.3	2.3	—	—	—	—
Net periodic benefit cost after curtailments and regulatory expense adjustments	$ 15.8	$ 13.6	$ 2.9	$ 8.7	$ 7.3	$11.6

In our most recent settlement with the Missouri Public Service Commission (the Commission), we agreed to recover our Missouri-related pension funding at an agreed-upon annual amount for ratemaking purposes. This settlement determines the annual amount we will recover and recognize as pension expense beginning in the second quarter of 2004. As ordered by the Commission, the difference between the agreed-upon expense for ratemaking purposes and the amount determined under SFAS No. 87, ''Employers' Accounting for Pensions,'' will be recognized as a regulatory asset or liability in accordance with SFAS 71. The impact of this settlement on net periodic benefit cost was an increase of $4.3 million for 2004.

The funded status for those individual plans that have obligations in excess of plan assets and the corresponding amounts recognized in the Consolidated Balance Sheets for the plans are summarized below:

In millions	**2004**	**2003**
Projected Benefit Obligations in Excess of Plan Assets:		
Fair value of plan assets at end of year	$313.6	$288.4
Projected benefit obligation at end of year	337.6	330.4
Funded status	$ (24.0)	$ (42.0)
Accumulated Benefit Obligations in Excess of Plan Assets:		
Fair value of plan assets at end of year	$ —	$ —
Accumulated benefit obligation at end of year	18.1	17.2
Funded status *(a)*	$ (18.1)	$ (17.2)

(a) The SERP is reflected as an unfunded accumulated benefit obligation as plan assets are not netted against the obligations for non-qualified plans. We have segregated approximately $4.2 million of assets for the SERP as of December 31, 2004. 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 $311.2 million and $300.4 million at September 30, 2004, and 2003, respectively.

We engaged benefit plan consultants to assist in the development of a statement of pension plan investment objectives and to perform a study modeling expectations of future returns of numerous portfolios using historic rates of return. The rate of return assumption we used was a result of selecting the model portfolio from the study that best fit our pension plan long-term investment objectives. As a result of a related asset allocation study, in November 2004 we changed our portfolio of qualified pension plan assets from a mix of 77% equity and 23% fixed income securities to a mix of 69% equity and 31% fixed income securities to be achieved over a three month period ending February 1, 2005. At the same time, we shifted certain equity assets from passive to more active management to enhance the long-term investment performance.

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, 2004 and 2003, along with the long-term targets and target ranges, are as follows:

	Plan Assets at September 30,		**Plan Asset Allocation Targets**	
	2004	**2003**	**Long-Term**	**Range**
Asset Category:				
Core fixed income	14.6%	14.9%	15.0%	5.0-25.0%
High yield bonds	8.2	8.0	8.0	6.0-10.0
Large cap equities	32.2	31.5	32.0	27.0-37.0
Mid cap equities	9.9	5.8	10.0	8.0-12.0
Small cap equities	10.2	13.9	10.0	8.0-12.0
International equities	13.0	12.6	12.5	10.0-15.0
Emerging markets equities	2.7	2.7	2.5	0.0-5.0
Real estate	7.8	7.6	7.5	5.0-10.0
Private equity	1.3	1.1	2.5	0.0-5.0
Cash	.1	1.9	—	—
Total	100.0%	100.0%	100.0%	100.0%

Our other post-retirement benefit plan assets at December 31, 2004 and 2003 were 100% invested in short-term debt instruments and cash equivalents.

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

The following chart reflects the sensitivities associated with a change in certain actuarial assumptions by the indicated percentage. While the chart below reflects an increase in the percentage for each assumption, we and our actuaries expect that the inverse of this change would impact the projected benefit obligation (PBO) at December 31, 2004, and our estimated annual pension cost (APC) on the income statement for 2005 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%	$(10.9)	$(1.1)
Rate of return on plan assets	.25%	—	(.7)

Our health care plans are contributory, with participants' contributions adjusted annually. The life insurance plans are non-contributory. In estimating future health care costs, we have assumed future cost-sharing changes. The expense recognition for health care costs does not necessarily match the cost estimates due to certain differences in regulatory accounting at our domestic utility operations. 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 2005.

	1 Percentage-Point	
In millions	**Increase**	**Decrease**
Effect on total of service and interest cost components	$ .3	$ (.3)
Effect on post-retirement benefit obligation	5.4	(4.7)

Based on actuarial projections, we expect to contribute $.8 million and $6.1 million to our defined benefit pension plans and other post-retirement benefit plans, respectively, in 2005. No discretionary contributions are planned in 2005.

In February 2005, we amended our pension and other post-retirement benefit plans to bring our benefits into line with our regulated utility peers. The effects of these amendments on our projected (pension) benefit obligation and accumulated post-retirement benefit obligation were increases of $21.9 million and $24.9 million, respectively, as of our most recent measurement date, September 30, 2004.

Following are estimated future benefit payments, which reflect expected future service, as appropriate, as well as the plan amendments approved in February 2005. 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:			
2005	$ 16.6	$ 6.7	$—
2006	17.5	7.5	(.9)
2007	18.7	8.2	(1.0)
2008	19.8	8.6	(1.1)
2009	21.4	9.0	(1.2)
2010-2014	130.3	46.7	(6.2)

Note 20: Segment Information

We have restated our financial reporting segments to reflect the significant changes in our business over the last two years, including the continuing wind-down of our wholesale energy trading operations and the sale of our merchant loan portfolio, natural gas pipeline, gathering and storage assets, investments in international utility networks and investment in Quanta Services, Inc. We now manage our business in two operating segments: Domestic Utilities and Merchant Services. Domestic Utilities consists of our regulated electricity and natural gas utility operations in seven states. Merchant Services includes our remaining investments in merchant power plants, our commitments under merchant capacity tolling obligations, our commitments under long-term gas contracts and the remaining contracts from our wholesale energy trading operations. All other operations are included in Corporate and Other, including the costs of the company that are not allocated to our operating businesses, our investment in Everest Connections, and our former investments in Quanta Services, Australia and the United Kingdom. Each segment is managed based on operating results, expressed as earnings before interest and taxes. Generally, decisions on finance, dividends and taxes are made at the Corporate level. The current and non-current assets of our consolidated independent power plants and our Canadian utility businesses are included in Merchant Services and Corporate and Other, respectively.

Business Lines

	Year Ended December 31,		
In millions	**2004**	**2003**	**2002**
Sales: *(a)*			
Domestic Utilities	$1,825.6	$1,711.8	$1,802.8
Merchant Services	(152.9)	(70.0)	225.4
Corporate and Other	38.3	32.2	12.9
Total	$1,711.0	$1,674.0	$2,041.1

(a) For the years ended December 31, 2004, 2003 and 2002, respectively, the following (in millions) have been reclassified to discontinued operations and are not included in the above amounts: Corporate and Other sales related to our former Canadian utility businesses of $122.9, $248.8 and $261.8; Merchant Services sales of $8.0, $73.6 and $309.6.

	Year Ended December 31,		
In millions	**2004**	**2003**	**2002**
Earnings (Loss) Before Interest and Taxes (EBIT): *(a)*			
Domestic Utilities	$ 159.1	$ 175.1	$ 125.8
Merchant Services *(b)*	(438.7)	(415.5)	(677.9)
Corporate and Other *(b)*	(24.5)	12.4	(1,133.2)
Total EBIT	(304.1)	(228.0)	(1,685.3)
Interest expense	258.4	273.1	232.9
Loss from continuing operations before income taxes	$(562.5)	$(501.1)	$(1,918.2)

(a) Included in EBIT for each segment for the years ended December 31, 2004, 2003 and 2002, respectively, is equity in earnings of investments as follows (in millions): Merchant Services, $1.9, $53.7 and $52.8; and Corporate and Other, $.2, $15.9 and $114.1.

(b) For the years ended December 31, 2004, 2003 and 2002, respectively, the following (in millions) have been reclassified to discontinued operations and are not included in the above amounts: Merchant Services EBIT of $7.0, $(30.1) and $(379.5); and Corporate and Other EBIT relating to our former Canadian utility businesses of $118.8, $74.5 and $69.9.

In millions	Year Ended December 31, 2004	2003	2002
Depreciation and Amortization Expense: *(a)*			
Domestic Utilities	$126.4	$129.2	$124.6
Merchant Services	17.4	31.8	15.5
Corporate and Other	6.5	3.7	15.7
Total	$150.3	$164.7	$155.8

(a) For the years ended December 31, 2003 and 2002, respectively, the following depreciation and amortization expense (in millions) have been reclassified to discontinued operations and are not included in the above amounts: Merchant Services $.4 and $24.1; and Corporate and Other relating to our former Canadian utility businesses $8.2 and $58.1.

In millions	December 31, 2004	2003
Identifiable Assets: *(a)*		
Domestic Utilities	$3,215.7	$3,060.2
Merchant Services *(b)*	1,080.6	2,717.8
Corporate and other *(b)*	481.0	1,941.1
Total	$4,777.3	$7,719.1

(a) Included in identifiable assets for each segment as of December 31, 2004 and 2003, respectively, are investments in unconsolidated subsidiaries as follows (in millions): Domestic Utilities, $.1 and $.1; Merchant Services, $— and $234.0; and Corporate and Other, $1.4 and $78.8.

(b) Included in identifiable assets as of December 31, 2003, are current and non-current assets of discontinued operations as follows (in millions): Merchant Services, $118.1; and Corporate and Other related to our former Canadian utility businesses, $1,162.6.

In millions	Year Ended December 31, 2004	2003	2002
Capital Expenditures: *(a)*			
Domestic Utilities	$146.6	$125.5	$154.5
Merchant Services	—	20.5	168.5
Corporate and other	95.3	140.5	222.3
Total	$241.9	$286.5	$545.3

(a) Included in the years ended December 31, 2004, 2003 and 2002, respectively, are capital expenditures of discontinued operations as follows (in millions): Merchant Services, $—, $.3 and $33.9; and Corporate and Other relating to our former Canadian utility businesses, $72.8, $121.7 and $112.4.

Geographical Information

In millions	Year Ended December 31, 2004	2003	2002
Sales: *(a)*			
United States	$1,711.0	$1,696.0	$2,077.0
Canada	1.3	7.0	(33.1)
Other international	(1.3)	(29.0)	(2.8)
Total	$1,711.0	$1,674.0	$2,041.1

(a) For the years ended December 31, 2004, 2003 and 2002, respectively, the following (in millions) sales have been reclassified to discontinued operations and are not included in the above amounts: United States sales of $8.0, $73.6, and $309.6; Canada sales of $122.9, $248.8, and $261.8.

In millions	December 31, 2004	2003
Long-Lived Assets: *(a)*		
United States	$2,778.9	$2,990.6
Other international *(b)*	—	75.0
Total	$2,778.9	$3,065.6

(a) Includes property, plant and equipment, net and investments in unconsolidated subsidiaries.

(b) Long-lived assets totaling $752.1 million related to our former Canadian utility businesses as of December 31, 2003 have been reclassified to discontinued operations and are not included in the above amounts.

Note 21: Commitments and Contingencies

Capital Expenditures

We have made certain construction commitments in connection with our 2005 capital expenditure plan. During 2005, we estimate that our total capital expenditures will be approximately $237.7 million.

Commitments

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

In millions	**2005**	**2006**	**2007**	**2008**	**2009**	**Thereafter**	**Total**
Future minimum payments—							
Facilities and equipment	$ 17.7	$ 13.5	$ 11.7	$ 11.5	$ 9.6	$ 23.8	$ 87.8
Jeffrey Energy Center	11.6	10.6	10.6	12.1	12.9	70.9	128.7
Elwood tolling contracts	37.3	37.3	37.3	37.4	37.4	267.7	454.4
Merchant gas transportation obligations	9.2	8.5	5.4	5.4	5.4	23.3	57.2
Regulated business purchase obligations:							
Purchased power obligations	128.5	110.4	116.5	118.9	121.5	270.4	866.2
Purchased gas obligations	111.6	97.2	70.6	38.5	27.1	113.9	458.9
Coal contracts	90.8	72.7	62.2	48.0	29.5	198.3	501.5

Future minimum payments

Future minimum payments primarily relate to operating leases of coal rail cars, vehicles and office space over terms of up to 20 years. In connection with our exit from the wholesale energy trading business we have leases of office space and other facilities that we no longer need. In 2002, we recorded restructuring charges for the cost of these minimum lease commitments on such space as discussed in Note 4. Rent expense for the years 2004, 2003 and 2002 was (in millions), $16.2, $22.4 and $25.4, respectively.

We have an operating lease of an 8% interest in the Jeffrey Energy Center through 2019. The lease contains certain fixed price and fair market value purchase and renewal options. The lease payments vary by year but are recognized as lease expense on a straight-line basis of approximately $10.4 million annually.

Elwood tolling contracts

In connection with our merchant power generation business, we have entered into two power purchase agreements through 2017 for a portion of the total output of the Elwood power plant owned by others. This agreement is treated as an operating lease for accounting purposes.

Merchant gas transportation obligations

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

Regulated business purchase obligations

In 2004, our electric utility operations generated 57% of the power delivered to their customers. Our electric utility operations purchase coal and natural gas, including transportation capacity, as fuel for its generating power plants under long-term contracts through 2020. These operations also purchase power and gas to meet customer needs under short-term and long-term purchase contracts.

Contingent Obligations

Merchant Loan Portfolio

In connection with our former portfolio of merchant loans to energy-related businesses, we entered into commodity and interest rate swaps with the borrowers. Because of increases in natural gas prices and declines in interest rates, these swaps have increased in market value. When we sold the portfolio of loans we retained these swaps. As part of the sale agreement, we agreed that in the event these borrowers fail to meet their note obligations to the buyer of the portfolio, we could be required to share a portion of any proceeds we receive on these swaps with the buyer. In 2004, we paid $6.0 million to the buyer of the portfolio out of $10.7 million of swap proceeds collected. As of December 31, 2004 we have collected $28.0 million related to the remaining swaps, of which we have reserved $5.0 million to cover this obligation. The value of the unsettled portion of these swaps, which expire by December 2006, was $28.5 million at December 31, 2004.

Guarantees

We have entered into contracts that contain guarantees to outside parties that could require performance or payment under certain conditions. These guarantees have been grouped based on similar characteristics and are described below.

We have entered into various agreements that require letters of credit for financial assurance purposes. These letters of credit are available to fund the payment of such obligations. At December 31, 2004, we had $77.7 million of letters of credit outstanding with expiration dates generally ranging from one month to 12 months.

In the normal course of business, we guarantee certain payment obligations of our wholly-owned subsidiaries including certain operating leases as discussed above.

Equity Put Rights

Certain minority owners of Everest Connections had the option to sell their ownership units to us if Everest Connections did not meet certain financial and operational performance measures as of December 31, 2004 (target-based put rights). If the target-based put rights were exercised, we would have been obligated to purchase up to 4.0 million and 4.75 million ownership units at a price of $1.00 and $1.10 per unit, respectively, for a total potential cost of $9.2 million. As a result of our reduced funding of this business, management assessed the likelihood of achieving these metrics and during 2002 recorded a probability-weighted expense of $7.1 million. In 2004, we achieved the operating targets related to 4.0 million and 1.5 million of ownership units at a price of $1.00 and $1.10 per unit, respectively. Therefore, we reversed $4.5 million of this reserve. We did not achieve the targets related to 3.25 million of ownership units at a price of $1.10 per unit. The holders of these target-based put rights exercised their options and were paid $3.6 million for their ownership units in February 2005. As of December 31, 2004, we had fully reserved for this obligation. The minority owners of 9.5 million ownership units also have the option to sell their ownership units to us at fair market value (market-based put rights.) The market-based put rights expire on December 31, 2005. We have not provided for this potential obligation as the exercise would represent an equity transaction at fair value. We do not believe based on current estimates of fair value that these market-based put rights are a material contingent obligation.

Legal

AMS Shareholder Lawsuit

A consolidated lawsuit was filed against us in federal court in Missouri in connection with our recombination with our Aquila Merchant subsidiary that occurred pursuant to an exchange offer completed in January 2002. The suit raised allegations concerning the lack of independent members on the board of directors of Aquila Merchant to negotiate the terms of the exchange offer on behalf of the public shareholders of Aquila Merchant. This lawsuit is scheduled for trial in May 2005. We believe we have strong defenses and will defend this case vigorously. We cannot predict with certainty whether we will incur any liability, nor can we estimate the damages, if any, that might be incurred in connection with this lawsuit. However, given the nature of the claims, an adverse outcome could have a material adverse effect on our financial condition, results of operations and cash flows.

Price Reporting Litigation

On August 18, 2003, Cornerstone Propane Partners filed suit in the Southern District of New York against 35 companies, including Aquila, that allegedly manipulated natural gas prices and futures prices on NYMEX through misreporting of natural gas trade data in the physical market. The suit does not specify alleged damages and was filed on behalf of all parties who bought and sold natural gas futures and options on NYMEX from 2000 to 2002. On September 24, 2004, the court denied Aquila's motion to dismiss along with similar motions filed by most of the other defendants. We will defend this case vigorously as we believe we have strong defenses to the plaintiff's claims. We cannot predict with certainty whether we will incur any liability, nor can we estimate the damages, if any, that might be incurred in connection with this lawsuit. However, given the nature of the claims, an adverse outcome could have a material adverse effect on our financial condition, results of operations and cash flows.

On June 7, 2004, the City of Tacoma filed suit against 56 companies, including Aquila, for allegedly conspiring to manipulate the California power market in 2000 and 2001 in violation of the Sherman Act. This case was dismissed in February 2005. It is not certain whether the plaintiff will appeal this ruling.

On July 8, 2004, the County of Santa Clara and the City and County of San Francisco each filed suit against seven energy trading companies, including Aquila, in the Superior Court of San Diego alleging manipulation of the California natural gas market in 2000 through 2002. Since that date 13 other counties, cities and other parties have filed similar complaints making nearly identical allegations. These lawsuits allege violations of the Cartwright Act, the Sherman Act and the California Unfair Competition Law and unjust enrichment. The lawsuits have been designated *In re Natural Gas Anti-Trust Cases V* and assigned to a Coordination Motion Judge in the Superior Court of San Diego to determine whether they are complex and should be coordinated. Aquila is also a defendant in the *Utility Savings & Refund Services, LLP v. Reliant Energy Services, Inc., et al.* lawsuit filed November 30, 2004 in the U.S. District Court for the Eastern District of California alleging violations of the Sherman Act, the Cartwright Act, and the California Unfair Competition Law. We believe we have strong defenses and will defend these cases vigorously. We cannot predict with certainty whether we will incur any liability, nor can we estimate the damages, if any, that might be incurred in connection with these lawsuits. However, given the nature of the claims, an adverse outcome could have a material adverse effect on our financial condition, results of operations and cash flows.

Enron Bankruptcy Litigation

On March 7, 2005, we reached an agreement with Enron Corp. and certain of its affiliates (Enron). Under this agreement, we will pay $28 million to Enron to settle all outstanding claims between Enron and Aquila associated with the various bankruptcy filings of Enron in December 2001 and two lawsuits filed by Enron Canada Corp. in January 2003. In 2001, we reserved for substantially all of our then outstanding receivables from Enron, which resulted in a charge of $66.8 million. This charge did not reflect potential gains we would record in the event we were successful in netting certain obligations to Enron against these receivables. Approximately $33.5 million of liabilities remained on our books related to contracts with Enron after the 2001 charge. The settlement is subject to final approval the bankruptcy court. As a result of the settlement, we reduced our net liability to Enron by approximately $6 million, or $3.7 million after tax.

Lender Litigation

On October 5, 2004 and October 15, 2004, lawsuits were filed against us by our lenders alleging that we were obligated to pay a ‘‘make whole’’ amount when we prepaid the $430 million three-year secured term loan in September 2004. We believe that our termination of the term loan required us to pay a prepayment penalty of $8.7 million. The plaintiff lenders have sued us for breach of contract for their proportionate share of the difference between their prepayment calculation and the $8.7 million, which in the aggregate is approximately $20.6 million. We believe we have strong defenses and will defend these cases vigorously. We cannot predict with certainty whether we will incur any liability, nor can we estimate the damages, if any, that might be incurred in connection with this lawsuit. However, given the nature of the claims, an adverse outcome could have a material adverse effect on our 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, the Board of Directors and certain members of management alleging they violated the ERISA and are responsible for losses that participants in the Aquila 401(k) plan experienced as a result of the decline in the value of their Aquila stock held in the Aquila 401(k) plan. A number of similar lawsuits alleging that the defendants breached their fiduciary duties to the plan participants in violation of ERISA by concealing information and/or misleading employees who held Aquila stock through the Aquila 401(k) plan were subsequently filed against us. The suits also seek damages for the plan's losses resulting from the alleged breaches of fiduciary duties. On January 26, 2005 the court ordered that each of these lawsuits must all be consolidated into a single case captioned, *In re Aquila ERISA Litigation,* and gave the plaintiffs 45 days to file an amended consolidated complaint. We believe we have strong defenses and will defend these cases vigorously. We cannot predict with certainty whether we will incur any liability, nor can we estimate the damages, if any, that might be incurred in connection with this lawsuit. However, given the nature of the claims, an adverse outcome could have a material adverse effect on our financial condition, results of operations and cash flows.

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, 2004, we estimate probable costs of future investigation and remediation on our identified MGP sites and retained liabilities to be $6.6 million. This is our best estimate based upon a comprehensive review of the potential costs associated with conducting investigative and remedial actions at our identified sites, as well as the likelihood of whether such actions will be necessary. There are also additional costs that we consider to be less likely but still ''reasonably possible'' to be incurred at these sites. Based upon the results of studies at these sites and our knowledge and review of potential remedial actions, it is reasonably possible that these additional costs could exceed our best estimate by approximately $9.0 million. This estimate could change materially once we have investigated further. It could also be affected by the actions of environmental agencies and the financial viability of other responsible parties. Ultimate liability also may be affected significantly if we are held responsible for parties unable to contribute financially to the cleanup effort.

The EPA proposed two regulations in December 2003 that would affect our coal-fired power plants by requiring reductions in emissions of sulfur dioxide, nitrogen oxide and mercury. The rules are in proposed form only and are subject to change. If adopted as proposed, we estimate that we could be required to make capital expenditures of $100 million to $400 million to comply with the regulations. We estimate the costs for 2005 to be approximately $1 million. This estimate could change materially once the regulations are finalized and we have investigated further. We believe these costs would likely be allowed for recovery in future rate cases.

Note 22: Quarterly Financial Data (Unaudited)

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

	2004 Quarters				2003 Quarters			
In millions, except per share amounts	First	Second	Third	Fourth	First	Second	Third	Fourth
Sales	$553.2	$335.3	$ 322.4	$500.1	$522.8	$ 367.4	$ 322.0	$461.8
Gross profit	121.3	113.0	131.5	131.0	109.6	147.8	128.7	163.8
Loss from continuing operations	(84.6)	(67.1)	(116.5)	(81.0)	(64.1)	(105.1)	(144.1)	(42.7)
Earnings (loss) from discontinued operations	32.8	23.8	.1	—	12.2	24.5	(25.8)	8.7
Net loss	$ (51.8)	$ (43.3)	$(116.4)	$ (81.0)	$ (51.9)	$ (80.6)	$(169.9)	$ (34.0)
Basic and diluted earnings (loss) per common share: *(a)*								
From continuing operations	$ (.43)	$ (.34)	$ (.44)	$ (.21)	$ (.33)	$ (.54)	$ (.74)	$ (.22)
From discontinued operations	.17	.12	—	—	.06	.13	(.13)	.04
Net income (loss)	$ (.26)	$ (.22)	$ (.44)	$ (.21)	$ (.27)	$ (.41)	$ (.87)	$ (.18)

(a) The sum of the quarterly earnings per share amounts may differ from that reflected in Note 17 due to the weighting of common shares outstanding during each of the respective periods.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Aquila, Inc.:

We have audited the accompanying consolidated balance sheets of Aquila, Inc. and subsidiaries as of December 31, 2004 and 2003, and the related consolidated statements of income, common shareholders' equity, comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2004. In connection with our audits of the consolidated financial statements, we also have audited the financial statement schedule, ''Schedule II—Valuation and Qualifying Accounts,'' for each of the years in the three-year period ended December 31, 2004. These consolidated financial statements and the financial statement schedule are the responsibility of the company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Aquila, Inc. and subsidiaries as of December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2004 in conformity with United States generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Aquila, Inc.'s internal control over financial reporting as of December 31, 2004 based on criteria established in *Internal Control—Integrated Framework*, issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 11, 2005 expressed an unqualified opinion on management's assessment of, and the effective operation of, internal control over financial reporting.

/s/ KPMG LLP
Kansas City, Missouri

March 11, 2005

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Aquila, Inc.:

We have audited management's assessment, included in the Management's Report on Internal Control Over Financial Reporting appearing under Item 9A, that Aquila, Inc. (the Company) maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control—Integrated Framework*, issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Aquila, Inc.'s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

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

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that Aquila, Inc. maintained effective internal control over financial reporting as of December 31, 2004 is fairly stated, in all material respects, based on criteria established in *Internal Control—Integrated Framework*, issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Also, in our opinion, Aquila, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004 based on criteria established in *Internal Control—Integrated Framework*, issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Aquila, Inc. and subsidiaries as of December 31, 2004 and 2003, and the related consolidated statements of income, common shareholders' equity, comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2004, and our report dated March 11, 2005 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP
Kansas City, Missouri

March 11, 2005

Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

Not Applicable.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

Our Chief Executive Officer (CEO) and Chief Financial Officer (CFO) are responsible for establishing and maintaining the company's disclosure controls and procedures. These controls and procedures were designed to ensure that material information relating to the company and its subsidiaries are communicated to the CEO and the CFO. We evaluated these disclosure controls and procedures as of the end of the period covered by this report under the supervision of our CEO and CFO. Based on this evaluation, our CEO and CFO concluded that our disclosure controls and procedures are effective in timely alerting them to material information required to be included in our periodic reports filed with the Securities and Exchange Commission. There has been no change in our internal controls over financial reporting during the period covered by this report that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under the framework in *Internal Control—Integrated Framework*, our management concluded that our internal control over financial reporting was effective as of December 31, 2004.

Our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2004, has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their report which is included herein.

Item 9B. Other Information

Not Applicable.

Part III

Items 10, 11, 12 and 13. Directors and Executive Officers of the Company, Executive Compensation, Security Ownership of Certain Beneficial Owners and Management, and Certain Relationships and Related Transactions

Information regarding these items appears in our proxy statement and is hereby incorporated by reference in this Annual Report on Form 10-K. For information regarding our executive officers, see ''Our Executive Team'' in Part 1, Item 1 of this Form 10-K.

Equity Compensation Plan Information

The following table provides information as of December 31, 2004 about our compensation plans under which shares of stock have been authorized.

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights *(a)*	Weighted-average exercise price of outstanding options, warrants and rights *(b)*	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) *(c)*
Equity compensation plans approved by security holders	9,312,769	$17.50	4,907,966
Equity compensation plans not approved by security holders	325,330 *(c)*	$24.02	—
Total	9,638,099		4,907,966

(a) Includes 1,650,691 options issued upon conversion of Merchant Services options in connection with our acquisition of the minority interest in Merchant Services. These options have a weighted average price of $34.81 per share.

(b) These shares are available for issuance under our 2002 Omnibus Incentive Compensation Plan. Awards may be in the form of stock options, restricted stock awards, stock appreciation rights, stock awards or other forms of equity based compensation.

(c) Options issued under a broad-based employee stock option plan that has since been terminated.

Item 14. Principal Accountant Fees and Services

Information regarding this item appears in our proxy statement and is hereby incorporated by reference in this Annual Report on Form 10-K.

Part IV

Item 15. Exhibits, Financial Statement Schedules

The following documents are filed as part of this report:

(a)(1) Financial Statements:

The consolidated financial statements required under this item are included under Item 8.

(a)(2) Financial Statement Schedules

Schedule II—Valuation and Qualifying Accounts for the years 2004, 2003 and 2002 on page 151.

All other schedules are omitted because they are not applicable or the required information is shown in the financial statements or notes thereto.

(a)(3) List of Exhibits*

The following exhibits relate to a management contract or compensatory plan or arrangement:

10(a)(7)	Annual and Long-Term Incentive Plan.
10(a)(8)	First Amendment to Annual and Long-Term Incentive Plan.
10(a)(9)	Form of Severance Compensation Agreement (change in control agreement) of Certain Executives.
10(a)(10)	Life Insurance Program for Officers.
10(a)(11)	Supplemental Executive Retirement Plan, Amended and Restated, effective January 1, 2001.
10(a)(12)	Employment Agreement for Richard C. Green
10(a)(13)	Amended and Restated Capital Accumulation Plan.
10(a)(14)	First Amendment to the Amended and Restated Capital Accumulation Plan.
10(a)(15)	Second Amendment to the Amended and Restated Capital Accumulation Plan.
10(a)(16)	Severance Compensation Agreement (change in control agreement) dated as of March 16, 2001, by and between Aquila Merchant Services, Inc. (formerly Aquila, Inc.) and Keith Stamm.
10(a)(17)	Aquila, Inc. 2002 Omnibus Incentive Compensation Plan.
10(a)(18)	Executive Security Trust Amended and Restated as of April 4, 2002.
10(a)(19)	Supplemental Executive Retirement Agreement, by and between Aquila, Inc. (formerly UtiliCorp United Inc.) and John R. Baker, dated as of May 7, 1990.

* *Incorporated by reference to the Index to Exhibits.*

(b) Exhibits

The Index to Exhibits follows on page 152.

AQUILA, INC.
SCHEDULE II—VALUATION AND QUALIFYING ACCOUNTS

For the Three Years Ended December 31, 2004
(in millions)

Column A	Column B	Column C	Column D	Column E
Description	**Beginning Balance at January 1**	**Additions Charged to Expense**	**Deductions from Reserves for Purposes for Which Created**	**Ending Balance at December 31**
Allowance for Doubtful Accounts				
2004	$36.7	$12.6	$(18.6)	$30.7
2003	28.3	18.3	(9.9)	36.7
2002	58.8	13.5	(44.0)	28.3
Maintenance Reserves *(a)*				
2004	$ 4.0	$ 3.5	$ (3.9)	$ 3.6
2003	3.1	2.8	(1.9)	4.0
2002	3.2	2.6	(2.7)	3.1
Other Reserves *(b)*				
2004	$26.3	$32.2	$(36.9)	$21.6
2003	18.5	45.1	(37.3)	26.3
2002	17.6	37.5	(36.6)	18.5
Restructuring Reserves *(c)*				
2004	$16.9	$ .9	$(10.0)	$ 7.8
2003	49.2	28.2	(60.5)	16.9
2002	—	96.0	(46.8)	49.2

(a) Costs to be incurred related to scheduled maintenance outages on regulated generating facilities are accrued in advance of the scheduled outage consistent with current regulatory treatment.

(b) Includes reserves for self-insurance, environmental claims and other.

(c) Includes restructuring reserves for severance, lease and other costs.

AQUILA, INC.
INDEX TO EXHIBITS

Exhibit Number	Description
*3(a)	Restated Certificate of Incorporation of the company. (Exhibit 3(a) to the company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2002.)
*3(b)	Amended and Restated By-laws of the company. (Exhibit 3(b) to the company's Annual Report on Form 10-K for the year ended December 31, 2001.)
*4(a)	Long-term debt instruments of the company in amounts not exceeding 10% of the total assets of the company and its subsidiaries on a consolidated basis will be furnished to the Commission upon request.
*4(b)	Form of Rights Agreement between the company and UMB Bank, N.A. (as successor to First Chicago Trust Company of New York), as Rights Agent. (Exhibit 4 to the company's Form 10-Q for the period ended September 30, 1996.)
*4(c)	Amendment to Rights Agreement. (Exhibit 4(d) to the company's Post Effective Amendment No. 1 to Registration Statement on Form S-3 No. 333-29657 filed March 15, 2002.)
*10(a)(1)	Indenture, dated as of August 24, 2001, between Aquila, Inc. and BankOne Trust Company, N.A., as Trustee. (Exhibit 4(d) to the company's Registration Statement on Form S-3 (File No. 333-68400) filed August 27, 2001.)
*10(a)(2)	First Supplemental Indenture to the August 24, 2001 Indenture, dated February 28, 2002, between Aquila, Inc. and BankOne Trust Company, N.A., as Trustee. (Exhibit 4 to the company's Current Report on Form 8-K filed February 27, 2002.)
*10(a)(3)	Third Supplemental Indenture to the August 24, 2001 Indenture, between the Company and J.P. Morgan Trust Company (Exhibit 4 to the company's Current Report on Form 8-K filed August 20, 2004.)
*10(a)(4)	$110 million Revolving Credit Agreement among the company, the lenders and Credit Suisse First Boston dated September 20, 2004. (Exhibit 10.1 to the company's Current Report on Form 8-K filed on September 21, 2004.)
*10(a)(5)	$220 million Credit Agreement among the company, the lenders and Credit Suisse First Boston dated September 20, 2004. (Exhibit 10.2 to the company's Current Report on Form 8-K filed on September 21, 2004.)
*10(a)(6)	Financing Agreement between the company and Union Bank of California dated October 22, 2004. (Exhibit 10.1 to the company's Current Report on Form 8-K filed on October 28, 2004.)
*10(a)(7)	Annual and Long-Term Incentive Plan. (Exhibit 10(a)(3) to the company's Annual Report on Form 10-K for the year ended December 31, 1999.)
*10(a)(8)	First Amendment to Annual and Long-Term Incentive Plan. (Exhibit 10(a)(5) to the company's Annual Report on Form 10-K for the year ended December 31, 2001.)
*10(a)(9)	Form of Severance Compensation Agreement (change in control agreement) between the company and certain Executives of the company. (Exhibit 10(a)(7) to the company's Annual Report on Form 10-K for the year ended December 31, 2001.)

*10(a)(10)	Life Insurance Program for Officers. (Exhibit 10(a)(13) to the company's Annual Report on Form 10-K for the year ended December 31, 1995.)
*10(a)(11)	Supplemental Executive Retirement Plan, Amended and Restated, effective January 1, 2001. (Exhibit 10(a)(1) to the company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2001.)
*10(a)(12)	Employment Agreement for Richard C. Green (Exhibit 10.1 to the company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2002.)
*10(a)(13)	Amended and Restated Capital Accumulation Plan. (Exhibit 10(a)(14) to the company's Annual Report on Form 10-K for the year ended December 31, 2000.)
*10(a)(14)	First Amendment to the Amended and Restated Capital Accumulation Plan. (Exhibit 10(a)(2) to the company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2001.)
*10(a)(15)	Second Amendment to the Amended and Restated Capital Accumulation Plan. (Exhibit 10.4 to the company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2002.)
*10(a)(16)	Severance Compensation Agreement (change in control agreement) dated as of March 16, 2001, by and between Aquila Merchant Services, Inc. (formerly Aquila, Inc.) and Keith Stamm. (Exhibit 10.7 to Registration Statement No. 333-51718, filed April 18, 2001 by Aquila Merchant Services, Inc. (formerly Aquila, Inc.))
*10(a)(17)	Aquila, Inc. 2002 Omnibus Incentive Compensation Plan. (Exhibit 10.3 to the company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2002)
*10(a)(18)	Executive Security Trust Amended and Restated as of April 4, 2002. (Exhibit 10.5 to the company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2002.)
10(a)(19)	Supplemental Executive Retirement Agreement, by and between Aquila, Inc. (formerly UtiliCorp United, Inc.) and John R. Baker, dated as of May 7, 1990.
12	Ratio of Earnings to Fixed Charges.
14	Code of Ethics.
21	Subsidiaries of the company.
23	Consent of KPMG LLP.
31.1	Certification of Chief Executive Officer under Section 302.
31.2	Certification of Chief Financial Officer under Section 302.
32.1	Certification of Chief Executive Officer under Section 906.
32.2	Certification of Chief Financial Officer under Section 906.
*99.1	Order of the State Corporation Commission of the State of Kansas on Docket No. 02-UTCG-701-GIG, dated May 7, 2003. (Exhibit 99.1 to the company's Annual Report on Form 10-K for the year ended December 31, 2003.)
*99.2	Order of the State Corporation Commission of the State of Kansas on Docket No. 02-UTCG-701-GIG, dated June 26, 2003. (Exhibit 99.2 to the company's Annual Report on Form 10-K for the year ended December 31, 2003.)

* *Exhibits marked with an asterisk are incorporated by reference as indicated pursuant to Rule 12(b)-23.*

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized as of March 11, 2005.

Aquila, Inc.

By: /s/ RICHARD C. GREEN

Richard C. Green
President, Chief Executive Officer and Chairman of the Board of Directors

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated, as of March 11, 2005.

By: /s/ RICHARD C. GREEN Richard C. Green	President, Chief Executive Officer and Chairman of the Board of Directors (Principal Executive Officer)
By: /s/ RICK J. DOBSON Rick J. Dobson	Senior Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)
By: /s/ JOHN R. BAKER John R. Baker	Director
By: /s/ HERMAN CAIN Herman Cain	Director
By: /s/ DR. MICHAEL M. CROW Dr. Michael M. Crow	Director
By: /s/ IRVINE O. HOCKADAY, JR. Irvine O. Hockaday, Jr.	Director
By: /s/ HEIDI E. HUTTER Heidi E. Hutter	Director
By: /s/ DR. STANLEY O. IKENBERRY Dr. Stanley O. Ikenberry	Director
By: /s/ PATRICK J. LYNCH Patrick J. Lynch	Director
By: /s/ GERALD L. SHAHEEN Gerald L. Shaheen	Director

Exhibit 31.1

Aquila, Inc.
Chief Executive Officer
Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

I, Richard C. Green, certify that:

1. I have reviewed the annual report of Aquila, Inc. for the annual period ending December 31, 2004;
2. Based on my knowledge, the report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by the report;
3. Based on my knowledge, the financial statements, and other financial information included in the report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal controls over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this periodic report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weakness in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

March 11, 2005

/s/ RICHARD C. GREEN

Richard C. Green
Chairman, President and
Chief Executive Officer, Aquila, Inc.

Exhibit 31.2

Aquila, Inc.
Chief Financial Officer
Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

I, Rick J. Dobson, certify that:

1. I have reviewed the annual report of Aquila, Inc. for the annual period ending December 31, 2004;

2. Based on my knowledge, the report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by the report;

3. Based on my knowledge, the financial statements, and other financial information included in the report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal controls over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this periodic report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weakness in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

March 11, 2005

/s/ RICK J. DOBSON

Rick J. Dobson
Senior Vice President and Chief Financial Officer,
Aquila, Inc.

Exhibit 32.1

Aquila, Inc.
Chief Executive Officer
Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

I, Richard C. Green, certify that, to my knowledge:

1. Aquila, Inc.'s annual report on Form 10-K for the annual period ending December 31, 2004 accompanying this Certification, in the form filed with the Securities and Exchange Commission (the ''Report'') fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934 (the ''Exchange Act''); and

2. The information in the Report fairly presents, in all material respects, the financial condition and results of operations of Aquila, Inc.

Dated: March 11, 2005

/s/ RICHARD C. GREEN

Richard C. Green
Chairman, President and Chief Executive Officer
Aquila, Inc.

Exhibit 32.2

Aquila, Inc.
Chief Financial Officer
Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

I, Rick J. Dobson, certify that, to my knowledge:

1. Aquila, Inc.'s annual report on Form 10-K for the annual period ending December 31, 2004 accompanying this Certification, in the form filed with the Securities and Exchange Commission (the ''Report'') fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934 (the ''Exchange Act''); and

2. The information in the Report fairly presents, in all material respects, the financial condition and results of operations of Aquila, Inc.

Dated: March 11, 2005

/s/ RICK J. DOBSON

Rick J. Dobson
Senior Vice President and Chief Financial Officer
Aquila, Inc.

Management and Directors

Management Team

		Age/Year Joined Company
Richard C. Green	Chairman of the Board, President and Chief Executive Officer	50 / 1976
Keith G. Stamm	Senior Vice President and Chief Operating Officer	44 / 1983
Rick J. Dobson	Senior Vice President and Chief Financial Officer	46 / 1989
Jon R. Empson	Senior Vice President, Regulated Operations	59 / 1978
Sally C. McElwreath	Senior Vice President, Corporate Communications	64 / 1994
Leo E. Morton	Senior Vice President and Chief Administrative Officer	59 / 1994
Robert L. Poehling	Senior Vice President, Energy Resources	41 / 1991
Brock A. Shealy	Senior Vice President and Corporate Compliance Officer	43 / 1999
Randal P. Miller	Vice President, Finance and Treasurer	42 / 1988
Christopher M. Reitz	Interim General Counsel and Corporate Secretary	39 / 2000

Board of Directors

		Age/Year Joined Company
Richard C. Green	Chairman, President and Chief Executive Officer	50 / 1982
John R. Baker	Retired Vice Chairman	78 / 1971
Herman Cain	Chief Independent Director; Chief Executive Officer of T.H.E., Inc., a leadership consulting company, and Chairman of the Board of Godfather's Pizza, Inc., Omaha, NE	59 / 1992
Dr. Michael M. Crow	President of Arizona State University, Tempe, AZ	49 / 2003
Irvine O. Hockaday, Jr.	Retired President and Chief Executive Officer of Hallmark Cards, Inc., Kansas City, MO	67 / 1995
Heidi E. Hutter	Chief Executive Officer and a Principal of The Black Diamond Group, LLC, a merchant bank and advisory company, Austin, TX	46 / 2002
Dr. Stanley O. Ikenberry	Former President of the American Council on Education, Washington, DC	69 / 1993
Patrick J. Lynch	Retired Senior Vice President and Chief Financial Officer, Texaco, Inc., Houston, TX	67 / 2004
Gerald L. Shaheen	Group President of Caterpillar, Inc., Peoria, IL	59 / 2001

Committees of the Board

Committee chairmen are underlined.

Executive Committee: Green, Cain and Hockaday.
Exercises the authority of the Board on matters of an urgent nature that arise when the Board is not in session.

Audit Committee: Shaheen, Baker, Hutter and Lynch.
Retains independent accountants and preapproves their services. Reviews and approves audit plans, accounting policies, financial statements and reporting, and internal audit reports and controls.

Business Process Improvement Committee: Crow, Hockaday and Shaheen.
Oversees, monitors, evaluates, and makes recommendations regarding the formation, development, and operation of the company's business process improvement program.

Compensation and Benefits Committee: Hockaday, Crow and Ikenberry.
Evaluates the performance of the chief executive officer and establishes the compensation of the chief executive officer and other senior officers. Establishes and monitors management's administration of the company's retirement and employee benefit plans.

Nominating and Corporate Governance Committee: Ikenberry, Baker and Hockaday.
Identifies, considers and recommends to the Board nominees for director. Develops and recommends to the Board corporate governance principles applicable to Aquila. Oversees the annual evaluation of the Board and its committees.

Investor Information

www.aquila.com

Information you'll find on our website includes our news releases, annual reports, stock quotes, audio and graphics of management presentations, financial information, documents filed with the Securities and Exchange Commission such as Forms 10-K and 10-Q, and information about our products and services. Links make it easy to visit the home pages of our business units.

From time to time we also provide live webcasts of presentations to the investment community. For the quickest way to stay informed, sign up through the website to receive news releases, meeting notices and other types of information by e-mail as soon as they are released.

Annual Meeting

We will hold our 2005 annual meeting of Aquila shareholders in Kansas City, Missouri at 2:00 p.m. on Wednesday, May 4 at the Clarion Hotel at the Sports Complex (formerly the Adam's Mark Hotel), 9103 East 39th Street. We will host a reception with light refreshments before the meeting at 1:30. Free parking is available at the hotel.

You can vote your proxy for the annual meeting electronically. See "Electronic Proxy Voting" on this page for details on this easy process. We also encourage you to help us reduce costs and save trees by signing up to receive future annual reports electronically instead of by mail.

Regional Meetings

In April 2005, members of our management team will meet with shareholders in four metropolitan areas:

New York City	April 13
Boston, MA	April 14
Washington, D.C.	April 15
Philadelphia, PA	April 20

Shareholders in these areas will receive details on meeting time and location by mail. If you want additional information about attending one of the meetings, call 1-800-789-9189.

Stock Listings

The common shares of Aquila, Inc. are listed on the New York Stock Exchange. The company's trading symbol is ILA. At the end of 2004, Aquila had approximately 112,000 common shareholders and about 241.7 million shares outstanding.

Shareholder Inquiries

Our transfer agent is UMB Bank, n.a. Please call UMB for answers to questions about your account, including the transfer of shares. Here is how to reach them:

Toll-free:
1-866-235-0223
From outside the United States:
1-816-860-7786
Internet:
www.UMB.com/business/shareholder

You may contact Aquila Investor Relations toll-free at **1-800-487-6661**, or at 816-467-3579. You may also contact Investor Relations by e-mail through the Investors section of Aquila's website: **www.aquila.com.**

You can obtain our current stock price, news releases and other Aquila information by dialing toll-free-1-888-828-2000. By following the voice prompts, you can also get information about our shareholder services and transfer agent.

Mailing Addresses

Investor Relations
Aquila, Inc.
P.O. Box 13287
Kansas City, MO 64199-3287

Mail regarding the transfer of shares should be addressed to the transfer agent:
UMB Bank, n.a.
Securities Transfer Division
P.O. Box 410064
Kansas City, MO 64141-0064

Documents may also be delivered to UMB Securities Transfer Division, 928 Grand Blvd., 5th Floor, Kansas City, MO 64106.

Electronic Proxy Voting

There are several ways to cast your proxy vote. Each proxy card contains instructions to allow you to vote over the telephone or via the Internet. You may vote by telephone using a toll-free number. Just follow the voice prompts to vote on each issue shown on the proxy card. This takes only minutes. You may also vote online by accessing our secure Aquila shareholder voting site. The web address and instructions are shown on your 2005 proxy card.

When you vote online, you can also sign up to receive all future proxy materials, annual meeting notices and annual reports electronically. When doing this, you will be prompted to provide your e-mail address.

Online Account Access

You can review your Aquila stock account over the Internet, using information from your statement.

Log on to **www.UMB.com/business/shareholder** and choose Shareholder View to access your account. Have your stock account statement available and follow the online instructions.

This service allows you to check the current share price and total value of your account, obtain account and dividend history, or request investment plan information. It is available 24 hours a day.

You may request assistance at www.UMB.com/business/shareholder under Shareholder View, or by calling **1-866-235-0223.**

Investor Research

Analysts at the following investment firms currently follow Aquila and have issued research reports on our performance:

Equity Research
Credit Suisse First Boston
Lehman Brothers Inc.
Merrill Lynch & Co.
Robert W. Baird & Co.
UBS Warburg LLC
Value Line Publishing, Inc.

Debt Research
Credit Suisse First Boston
Deutsche Bank Securities, Inc.
Merrill Lynch & Co.
UBS Warburg LLC

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