



Aquila

2002 ***Annual Report***

Financial Results in Brief

In millions, except per share amounts	2002	2001	% Change
Sales	\$2,377.1	\$3,711.0	(36)%
Earnings (loss) before interest and taxes	(1,608.4)	642.8	
Earnings (loss) from continuing operations	(1,722.8)	245.3	
Earnings (loss) from discontinued operations	(329.6)	34.1	
Cumulative effect of accounting change	(22.7)	—	
Earnings (loss) available for common shares	(2,075.1)	279.4	
Diluted earnings per common share	\$(12.83)	\$ 2.42	
Cash dividends per common share	.775	1.20	(35)%
Book value per common share	8.30	22.01	(62)
Diluted average common shares outstanding	161.7	115.7	40
Total assets	\$9,259.2	\$11,966.5	(23)%
Total capitalization	4,837.6	5,777.2	(16)
Common equity as percent of capitalization	33.2%	44.2%	(25)

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Letter to Shareholders

On April 11, 2003, we completed new financing arrangements that will enable Aquila to proceed with its restructuring plan. Our goal is to restore the company's financial stability by returning our primary focus to our regulated utility networks in the United States.

You are probably all-too-familiar with the wrenching events of the past year that forced us to abandon our merchant energy strategy, sell non-core assets and return to our regulated utility roots. Our credit ratings fell below investment grade, charges and impairments wiped out years of earnings, we suspended our quarterly dividend, and our share price fell more than 90 percent.

That's more bad news than I've ever had to fit in one annual report, much less one paragraph. If there's a positive worth mentioning, it's this: We're on the road to a steady—though not speedy—recovery.

Why We Cut the Dividend

In June 2002, your board of directors voted to reduce the quarterly common dividend paid in September from \$.30 per share to \$.175, and the board suspended the dividend entirely the following quarter. I know that for many of you, this suspension reduced much-needed household income.

Once we restore business stability and again have positive financial results, the board will be able to consider reinstating a dividend at some point. In our current situation, though, we must devote that cash to our serious efforts to achieve a sustainable turnaround while continuing to maintain safe and reliable utility networks.

Finding the Road Back

During the past 16 years, we had actively pursued a merchant energy strategy that contributed significant profits, growth and diversification to the company. However, with the sudden deterioration of wholesale energy markets, increased credit rating standards and tightening capital markets, we saw in mid-2002 that the merchant business was no longer a viable area for Aquila. As fallout from the collapse of energy trading continued, we pushed to make rapid and radical changes to our business strategy.

In mid-2002, we became the first top-ten energy trader to announce that we would

completely exit the merchant energy business. At the same time, we began shutting down our North American and European trading operations and seeking buyers for other non-core businesses.

A critical step on the road back was the completion of our refinancing effort, which removes a large cloud of uncertainty about our future. As of mid-March 2003, we had \$595 million of debt and other maturing facilities that required refinancing by April 12, 2003. Now we have completed a step that not only provides the funds, but also allows the flexibility to execute our restructuring plan.

This repositioning will take some time to complete, and we will need to address challenges along the way. The impact of these conditions, evident in our 2002 financial results, will certainly continue through 2003 and into 2004. We recorded significant impairment charges in 2002 to reflect asset sales and the change in our strategy. We also took restructuring charges as we moved to close our energy trading business and exit certain other financial obligations.

In the second half of 2002, we sold \$1.3 billion in assets and reduced our net liabilities by \$1.0 billion as a result, primarily by reducing related obligations.

I have often talked with pride about our employees being shareholders, and I know that the events of the past year have been especially painful for them as employee-owners. Their resilience and continued commitment to getting Aquila through this difficult period reinforces my confidence in our ability to succeed.

Our original business of regulated utilities has not lost its inherent value, and we have redoubled our efforts to again realize that value for our customers and our shareholders.

Financial Results

Aquila's bottom line for 2002 was a fully diluted loss of \$12.83 per share, or a net loss of \$2.1 billion on sales of \$2.4 billion. Restructuring charges, impairment charges and net losses on sales of assets, losses within discontinued operations, and margin losses incurred during the wind-down of our merchant trading portfolio contributed the majority of the net loss.

These financial results are difficult for all of us. Unavoidably, the actions we

launched in 2002 to exit from the merchant energy business and begin implementing our financial restructuring, and the actions expected for the remainder of 2003, are all critical to building a fundamentally sound business foundation and repositioning on a solid utility business model.

Exiting Our Merchant Operations

After our decision to exit from the merchant business, we shut down its ongoing operations and began unwinding our trading portfolio in North America and Europe. By the end of 2002, we had substantially reduced our exposure to trading risk and our obligations to post collateral.

The exit from merchant activities also included selling our natural gas storage facilities, notes receivable loan portfolio, and gas gathering and processing business. As we continue the wind-down, we will still feel the negative impact from our remaining wholesale contracts and from tolling arrangements (under which we market electricity generated from natural gas we supply as fuel). However, we are already benefiting from our lower cash requirements due to the reduced level of trading activity.

Strengthening Our Balance Sheet and Improving Liquidity

Our financial restructuring plan is designed to strengthen our balance sheet and improve liquidity through asset sales, expense reductions and subsequent pay-down of debt.

In May 2002, we announced our intention to sell \$1 billion in non-strategic assets and reduce expenses by \$100 million. By March 2003 we had exceeded that goal, having completed \$1.3 billion in asset sales. We are actively pursuing the sale of our assets in Australia and have received unsolicited bids for our assets in the United Kingdom and Canada.

As we were working on our financial restructuring, our ability to meet our financial obligations in the short term was called into doubt by credit rating agencies. They repeatedly downgraded our credit ratings, making access to capital more difficult and costly.

We expect the new financing we have just completed—a major milestone in Aquila's restructuring plan and return to

stability—to provide sufficient liquidity to cover operational needs through June 2004. Our next significant need for outside capital relates to senior debt that matures in 2004, which we anticipate retiring through additional asset sales.

In addition to the new financing, we have taken other actions to improve our liquidity position. As I mentioned earlier, these unfortunately included suspension of our quarterly common dividend. Although painful for shareholders, this has been an important step that is helping us meet Aquila's short-term cash needs. Additionally, we halted spending on the build-out of Everest Connections' network and refocused its strategy so that unit could become self-funding and cash flow positive as soon as possible, a goal it has since achieved.

Even with our new financing and improvements made in 2002, however, we expect continuing pressure on liquidity as long-term gas delivery and power generation contracts will continue to generate significant losses and negative cash flows for a number of years.

Returning to Our Roots

As we work through these difficult financial results, we must keep our ultimate goal in mind: To refocus Aquila's business on its strengths and historic roots as an owner and operator of integrated utility operations and generation facilities in

North America. Our electric and natural gas utility operations are solid businesses with stable cash flow, modest load growth and above-average customer satisfaction. We are driving forward to enhance the value of these businesses for the benefit of all stakeholders—investors, customers and employees alike.

Even with strong operations in place, we continued to take actions to improve our utility businesses. In 2002, we reorganized our U.S. utility operations by state to improve efficiency even further and better align cost structures and services to specific state requirements. Additionally, we pursued a steady rate case strategy to ensure that the utility businesses are able to continue providing safe and reliable service to our customers while earning a reasonable rate of return on our investments.

Corporate Governance Enhancements

Embracing the goals put forth by the 2002 Sarbanes-Oxley legislation, the board of directors has reviewed Aquila's corporate governance practices and taken a number of steps to strengthen them further. These included selecting a presiding independent director, forming a new Nominating and Corporate Governance Committee, adopting new corporate governance principles and expanding our senior officer code of conduct.

For more information on our principles

and practices, I encourage you to read the separate section on corporate governance at the bottom of this page and to visit the new corporate governance section on our website at www.aquila.com.

Organizational Changes

The overall repositioning of the company in 2002 also resulted in changes in Aquila's senior management team and compensation plans. Along with the change in size and diversity of the business through asset sales and the exit from our merchant operations, we saw that we needed to reduce and restructure the executive staff.

In October 2002 we announced that Bob Green would leave Aquila as chief executive and a member of our board of directors. Subsequently, I reassumed chief executive duties, and Keith Stamm became chief operating officer. Also in October, Rick Dobson became interim chief financial officer when former chief financial officer Dan Streek left the company.

To be consistent with our corporate compensation philosophy, our executive compensation program was changed to reflect our dramatically reduced size and scope. Our revised compensation plans are designed to be comparable to pay packages at companies similar to today's Aquila—domestic utilities with about \$3 billion in sales—rather than larger, more diversified companies we considered comparable in previous years.

Update on Corporate Governance

At a meeting in November 2002, your board of directors considered ways to further strengthen Aquila's corporate governance practices. In a separate session, the board's independent directors appointed Herman Cain as the presiding independent director of the board.

The directors then formed a new Nominating and Corporate Governance Committee, chaired by independent director Stan Ikenberry and composed entirely of independent directors. The new committee oversees the development of comprehensive corporate governance guidelines for issues such as management succession planning, conflicts of interest, enhancements to our existing code of business conduct and online ethics training required of all employees.

This committee also oversees the evaluation of board members and executive officers, makes recommendations to the board regarding nominations of directors, committee assignments, the size of the board and whether or not to fill board vacancies.

In one of its first actions, the committee nominated Dr.

Michael M. Crow, president of the University of Arizona, for election as a director at the June 2003 annual meeting. His election would increase our board size to eight directors—seven of them independent. Dr. Crow previously was executive vice provost of Columbia University until taking his current post in July 2002.

Our Audit Committee, composed of independent directors and chaired by Gerald Shaheen, now meets at least monthly rather than quarterly. It has assumed responsibility for retaining the independent auditors and managing that relationship, including screening and preapproving all audit and permissible non-audit services that the auditors will provide the company.

Our directors have recently adopted new corporate governance principles and expanded our code of conduct applicable to senior officers and procedures for the anonymous reporting of accounting concerns. It also is revising the charters of each of the board's committees. These documents will be added to a new Corporate Governance section on our website at www.aquila.com.

This change reduces the total potential compensation that our executives can earn at any level of incentive goal achievement. In addition, participation of the executive officers in the annual incentive plan and long-term incentive plans has been suspended until Aquila's performance improves significantly.

For 2002 and 2003, Aquila's board and management put a number of salary and incentive restrictions in place due to the company's financial situation. Executive officers' base pay was frozen at 2002 levels. No stock options were granted to executives for 2002, and none will be granted to executive officers in 2003. The annual incentive plan was suspended for 2002 for Aquila's domestic management and professional employees, and merit increases for salaried employees have been eliminated for 2003.

I hope you will review the more detailed information about our revised compensation program, provided in the proxy statement accompanying this annual report.

Looking Forward

To say this past year has been a difficult one for Aquila would be a huge understatement. We have successfully begun implementing key aspects of our restructuring plan. Our move to exit the merchant energy business, the completion of \$1.3 billion in asset sales, reduction in expenses, and securing new funding all are significant steps toward building a solid foundation for the return to our traditional regulated utility base.

Despite these efforts, our work to restructure is far from over. During 2003 and 2004, we will continue to focus on achieving financial stability and strengthening our balance sheet and liquidity posi-

tion. However, over the long term our ultimate success will be driven by three key factors:

- 1. Capitalizing on the inherent value of our core utility operations.** Our outstanding customer satisfaction and safety ratings make Aquila a respected part of communities across our service area. By maintaining that commitment to provide superior customer service while running our operations safely and efficiently, we will build further value for shareholders and customers alike. At the same time, our historically strong relationships with state utility regulators are an asset in which we will continue to invest time and energy. We will work to ensure that Aquila continues to be able to secure rate relief that allows us to invest in and operate our facilities reliably and safely while providing a reasonable return to our shareholders.
- 2. Executing our restructuring plan.** Having secured a new source of funding, our plan to reposition on a solid utility model has a number of milestones we must accomplish. These include restructuring our tolling agreements, completing additional asset sales and reducing debt. Achieving these goals will bring us back toward financial health and enable us to leverage the value of our core utility operations.
- 3. Commitment to shareholders.** Above all, the ultimate factor enabling our success is the continued support of our shareholders, both inside and outside the company. As we restructure the business and restore our ability to deliver a healthy return to our shareholders, we

as a management team are committed to open, ongoing sharing of information—in times of challenge as well as success.

We will continue to face a difficult environment as we work through our repositioning plan. Our financial performance will continue to be impacted as we pursue further asset sales and resolve lingering merchant energy contracts and tolling arrangements at power plants. Additionally, we will continue to cooperate with regulatory officials as they complete their investigations into the causes and actions behind the recent turmoil in the energy markets.

The challenges we have faced thus far have been formidable, but we have made progress toward returning Aquila to its roots as a customer-focused, integrated utility. We are pursuing this vision for the future of Aquila and have a plan to accomplish it.

The support of our employees always has been, and will continue to be, a key element of our success. They are applying the same determination and energy they used to build Aquila into a *Fortune 500* enterprise to drive our current repositioning to again be a financially healthy, customer-focused utility that delivers real value to all of our shareholders.

With their help and support, I have no doubt that Aquila will reach that goal.

Sincerely,



Richard C. Green, Jr.
Chairman and Chief Executive Officer
April 11, 2003

What We Do

We own and operate regulated electricity and natural gas distribution networks in the United States and in three other countries, and non-regulated electricity generation in the U.S. Aquila also provides appliance services and operates communications networks.

OPERATIONS

MARKETS

United States

Energy Distribution Networks

Our electric and gas distribution utilities operate as **Aquila Networks**. We deliver energy through networks of wires and pipes serving seven states in the Mid-continent. Our operations serve territories with rates for service set by state or local regulators. We generate approximately 56% of the power we distribute. Our **ServiceOne**® subsidiary repairs and services appliances, heating and air conditioning equipment and other critical systems, primarily through service contracts and on-demand services.

We serve 438,000 electric distribution customers in three states: Missouri, Kansas and Colorado; and 891,000 gas distribution customers in seven states: Missouri, Kansas, Colorado, Nebraska, Iowa, Michigan and Minnesota. Our industrial and commercial gas customers in most of our states can choose their gas suppliers. We have a number of programs to provide smaller-volume customers in certain states with price-choice alternatives. ServiceOne serves about 110,000 contract customers in our utility territories in five states. It competes with local repair services and a few regional and national providers.

Power Generation

Aquila owns or controls approximately 3,626 megawatts (MW) of non-regulated power generation capacity. We have 21 projects in 11 states and Jamaica.

We currently serve utility and industrial clients in several parts of the United States. We compete with electric utilities and other independent power producers.

Communications Networks

Aquila owns 96% of **Everest Connections**, which provides local and long-distance telephone, cable television, high-speed Internet and data services to areas of Greater Kansas City. Everest began serving residential and business customers in the Kansas City market in 2001.

Competing directly against established local telephone and cable television providers, Everest has achieved market penetrations of more than 50% in areas where it has provided service for more than a year. Everest provides a bundled package of voice, video and data services.

International

Australia

United Energy, managed and 33.8%-owned by Aquila, is an electric distribution utility in Melbourne, Victoria. United Energy also manages the gas distribution of **Multinet Gas**, in which Aquila has a 25.5% interest. **Uecomm**, 66%-owned by United Energy, owns fiber-optic communications networks. **AlintaGas**, 45%-owned by Aquila and United Energy jointly, is the major supplier and distributor of natural gas in the state of Western Australia.

United Energy and Multinet Gas distribute energy to 578,000 electric customers and 630,000 gas customers in areas of metropolitan Melbourne, Victoria. Uecomm serves corporate, government and wholesale customers. AlintaGas has 463,000 gas distribution customers in Western Australia, including the city of Perth. Industrial and commercial retail gas customers in Western Australia can choose their supplier.

Canada

Aquila Networks Canada distributes electricity in Alberta and the southern interior of British Columbia. In British Columbia, it also generates hydroelectric power and manages the retail accounts of its distribution customers.

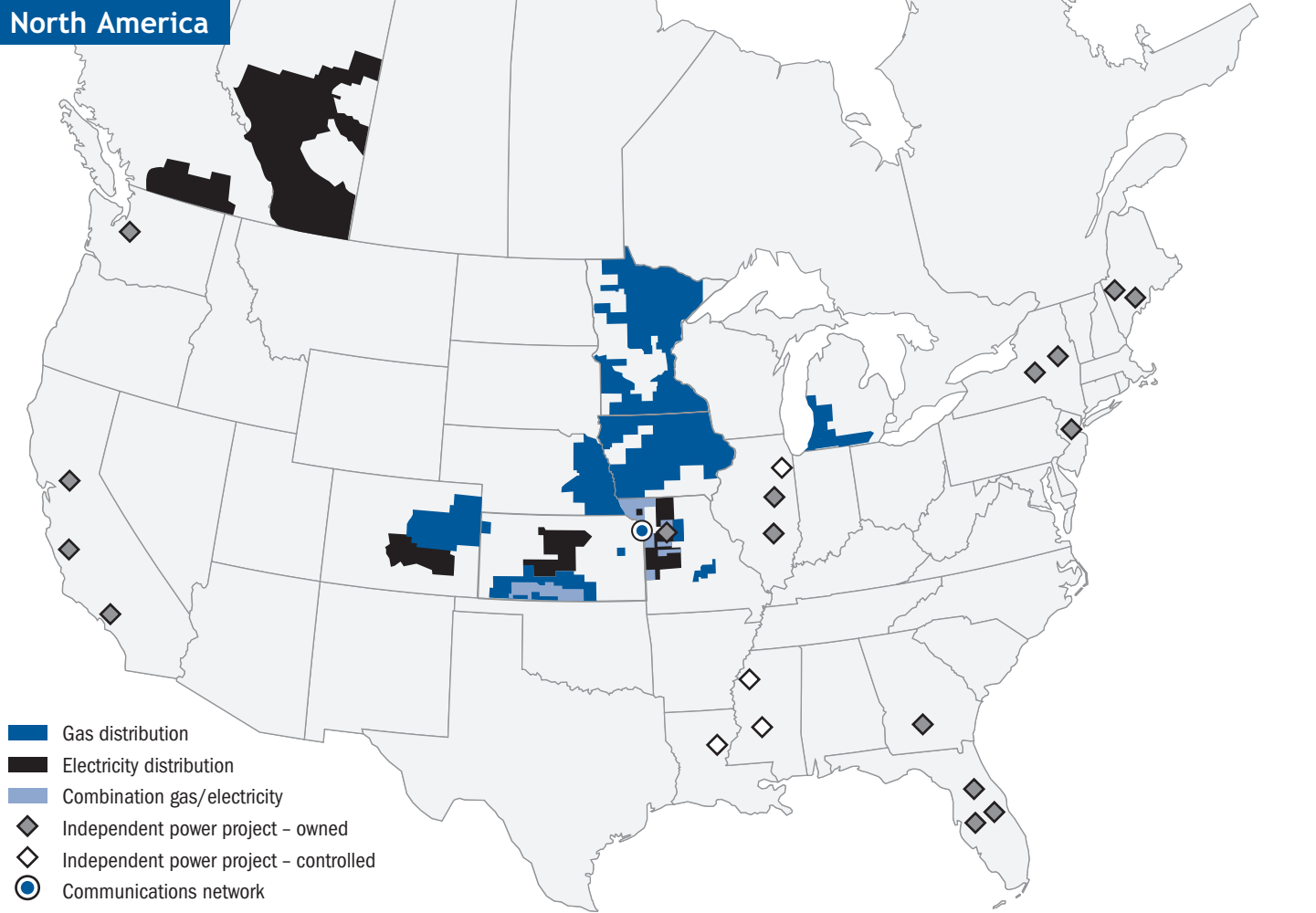
We provide electricity for 390,000 electric distribution customers in Alberta and 93,000 in British Columbia. In Alberta, we provide the power under long-term contract to the retailer. In our British Columbia territory, we are an integrated utility with no competition.

United Kingdom

We completed our acquisition of **Midlands Electricity** in May 2002. Located near Birmingham, England, Midlands operates an electric distribution network and holds interests in three independent power plants.

This utility distributes electricity under long-term contract to a retail power provider serving 2.3 million customers in and around the city of Birmingham, England. It is the fourth-largest regional electric company in the United Kingdom.

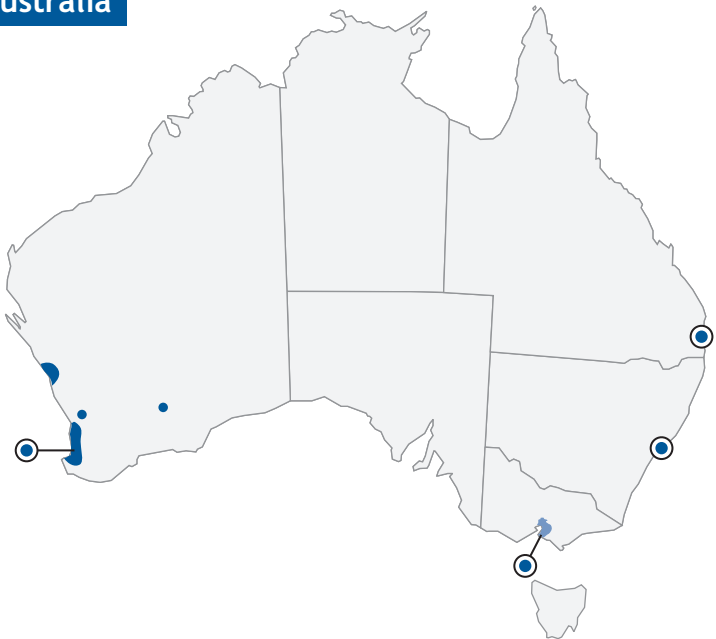
Where We Operate



United Kingdom



Australia



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 2003 annual meeting of Aquila shareholders in Kansas City, Missouri at 2:00 p.m. on Wednesday, June 4 at Starlight Theatre, 4600 Starlight Road. We will host a reception with light refreshments before the meeting at 1:30 p.m.

You can file 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.

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 2002, Aquila had approximately 115,000 common shareholders and about 193.8 million shares outstanding.

Sources of current investment research on Aquila, Inc. securities are shown on page vii.

Shares of United Energy Limited, managed and 33.8 percent owned by Aquila, are traded on the Australian Stock Exchange (ASE) under the symbol UEL.AX. Shares of Uecomm Limited, 66 percent owned by United Energy, are also traded on the ASE under the symbol UEC.AX. Shares of AlintaGas Limited, in which Aquila and United Energy jointly hold a 45 percent interest, are traded on the ASE under the symbol ALN.AX.

Direct Stock Purchases

Aquila's Common Stock Purchase Plan enables investors to acquire their first shares of our common stock directly from the company without expensive brokerage fees. (The minimum initial purchase for first-time buyers is \$250.)

- You may purchase \$50 or more in additional shares under the terms of our purchase plan, up to a maximum of \$10,000 per month.
- There is a nominal \$1 fee for each optional purchase.
- Other options include electronic payment for cash purchases and safekeeping of share certificates.
- The plan prospectus explains all of these points in full detail. You may download the prospectus and an enrollment form from www.aquila.com, or call **1-866-235-0223** toll-free to have them come by mail.

Shareholder Inquiries

Our transfer agent is UMB Bank, n.a. Please call UMB for answers to questions about your account, including the Common Stock Purchase Plan, direct investment service or the transfer of shares. Here is how to reach them:

Toll-free.	1-866-235-0223
From outside the United States	816-860-7786
Internet	www.umb.com/business/shareholder

You may contact Aquila Investor Relations toll-free at **1-800-487-6661**, or at **816-421-6600**. However, we usually refer to the transfer agent any calls about the transfer of shares, direct investment or cash purchases. 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., 13th Floor, Kansas City, MO 64106.

Electronic Proxy Voting

There are several ways to cast your proxy vote. Each proxy card contains instructions and a personal security number 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 2003 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 supply your e-mail address.

Online Account Access

You can review your Aquila stock account over the Internet, using your personal identification number (PIN).

Log on to **www.UMB.com/business/shareholder** and choose Shareholder View to access your account. Then use the account number shown on your statement. You may request a new PIN at www.UMB.com/business/shareholder under Shareholder View, or by calling **1-866-235-0223**. 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.

Investor Research

Analysts at the following investment firms currently follow Aquila and have issued research reports on our performance:

Equity Research

Banc of America Securities
Credit Suisse First Boston
Deutsche Banc Alex. Brown
Goldman Sachs & Co.
Lehman Brothers
Merrill Lynch & Co.
Morgan Stanley Dean Witter
Robert W. Baird & Co.
Salomon Smith Barney, Inc.
UBS Warburg LLC
Value Line Publishing, Inc.

Debt Research

Credit Suisse First Boston
Merrill Lynch & Co.
Prudential Fixed Income
UBS Warburg LLC

Officer and Director Changes

Management

Robert K. Green resigned as president and chief executive officer and as a director on October 1, 2002, after successfully launching Aquila's efforts to sell businesses and reduce expenses. Once the company was well on the way toward achieving both those goals, its reduced size called for a corresponding cut at the top level of management. At that time, Richard C. Green, Jr. resumed the positions of president and chief executive officer. Previously he was chief executive officer from 1996 through 2001, and president and chief executive officer from 1985 to 1996.

Keith Stamm became senior vice president and chief operating officer in October 2002. An engineer with strong experience in utility and power generation operations, he is responsible for domestic and international networks and the sale of our non-core assets. He was previously chief executive officer of Aquila Merchant Services and prior to that was CEO of United Energy in Australia.

Mike Jonagan was named senior vice president, Capacity Services in October 2002. Reporting to Stamm, he is responsible for the continuing wind-down of energy trading and manages Aquila's non-regulated generation assets in 11 states. Mike was previously chief executive officer of Domestic Networks after serving as chief operating officer of United Energy. He began his career at Aquila as an engineer in power generation more than 16 years ago.

Rick Dobson became interim chief financial officer in November 2002. A Certified Public Accountant, he leads all accounting, treasury and financial management activities for Aquila's U.S. and Canadian operations. He was vice president and controller of the company's energy merchant subsidiary for six years and later was vice president, risk management and accounting.

Dan Streek, CFO since August 2001 and previously CFO and treasurer of Aquila Merchant Services, left the company in November 2002. Dan played a key role helping Aquila through an extraordinary period of growth, change and finally restructuring.

Board of Directors

L. Patton Kline retired from Aquila's board in May 2002. He had been a director since 1986. Robert F. Jackson, Jr. retired from the board in October 2002 after serving for 21 years. The steady support and counsel these two provided for so many years will be missed.

Dr. Michael M. Crow has been nominated for election to your board of directors at the June 2003 annual meeting. His election would bring the number of directors to eight and the number of independent directors to seven. Dr. Crow has been president of the University of Arizona since July 2002 and previously was executive vice provost of Columbia University.

Officers and Directors

Leadership Team

		Age/Year Joined Company
Richard C. Green, Jr.	Chairman of the Board, President and Chief Executive Officer	48 / 1976
Keith G. Stamm	Senior Vice President and Chief Operating Officer	42 / 1983
Rick J. Dobson	Interim Chief Financial Officer	44 / 1989
Michael G. Jonagan	Senior Vice President, Capacity Services	41 / 1986
Leo E. Morton	Senior Vice President and Chief Administrative Officer	57 / 1994
Leslie J. Parrette, Jr.	Senior Vice President, General Counsel and Corporate Secretary	41 / 2000
C. E. Payne, Jr.	Senior Vice President and Chief Risk Officer	52 / 1995

Board of Directors

		Age/Year Joined Board
Richard C. Green, Jr.	Chairman, President and Chief Executive Officer	48 / 1982
John R. Baker	Retired Vice Chairman	76 / 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	57 / 1992
Irvine O. Hockaday, Jr.	Retired President and Chief Executive Officer of Hallmark Cards, Inc., Kansas City, MO	66 / 1995
Heidi E. Hutter	Chief Executive Officer and a Principal of The Black Diamond Group, LLC, a merchant bank and advisory company, New York, NY	45 / 2002
Dr. Stanley O. Ikenberry	Former President of the American Council on Education, Washington, DC	68 / 1993
Gerald L. Shaheen	Group President of Caterpillar, Inc., Peoria, IL	58 / 2001
Avis Green Tucker	Director Emeritus	87 / 1973

Committee chairmen are underlined.

Executive Committee: Green, Hockaday and Ikenberry.

When the Board is not in session, exercises the Board's authority to the extent delegated by the Board.

Audit Committee: Shaheen, Baker and Hutter.

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

Compensation Committee: Cain, Hockaday and Ikenberry.

Reviews policies, practices and procedures covering compensation of key employees. Establishes and administers compensation, retirement and employee benefit programs and plans.

Nominating and Corporate Governance Committee: Ikenberry, Baker and Hockaday.

Establishes corporate governance principles and oversees the evaluation process for the Board and senior management. Considers and recommends nominees for director, including those nominated by shareholders.

**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, 2002

or

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

For the transition period from _____ to _____

Commission file number: 1-03562

AQUILA, INC.

(Exact name of registrant as specified in its charter)

Delaware
(State or other jurisdiction of
incorporation or organization)

44-0541877
(I.R.S. Employer
Identification No.)

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

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

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

Title of each class	Name of each exchange on which registered
Common Stock, par value \$1.00 per share	New York Stock Exchange
Convertible Subordinated Debentures, 6 $\frac{7}{8}$ % due July 1, 2011	New York Stock Exchange
7.875% Quarterly Interest Bonds, due March 1, 2032	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, 2002 as reported on the New York Stock Exchange, was approximately \$1,020,976,000. 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 14, 2003)
Common Stock, par value \$1.00 per share	194,201,666
Documents Incorporated by Reference: Proxy Statement for 2003 Annual Shareholders Meeting	Where Incorporated: Part 3

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Part 1

Item 1. Business

History and Organization

Aquila, Inc. (the Company, which may be referred to as “we”, “us” or “our”) is a multinational energy provider 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. We operate regulated and non-regulated businesses in four countries. As of December 31, 2002, we had 4,710 employees, with 3,496 of them in the United States and the remaining 1,214 in Canada. Our business is organized into two groups: Global Networks Group, which consists of Domestic Networks and International Networks, and Merchant Services, which consists of Capacity Services and Wholesale Services:

- **Global Networks Group**—Our Domestic Networks business owns and operates regulated electric and natural gas operations in the United States, where we provide natural gas and/or electricity to approximately 1.3 million customers in Colorado, Iowa, Kansas, Michigan, Minnesota, Missouri and Nebraska. Domestic Networks also includes Everest Connections, our 96% owned domestic communications business. Our International Networks business owns and manages interests in electric, gas, and communications networks in Australia and the United Kingdom serving approximately 4.0 million customers. It also includes our wholly-owned electric generation, transmission and distribution properties serving approximately 483,000 customers in two Canadian provinces.
- **Merchant Services**—Merchant Services consists of Capacity Services, which owns, operates, and contractually controls our non-regulated electric power generation assets, and Wholesale Services, our North American and European commodity client and capital businesses.

The reports we file with the Securities and Exchange Commission are made available free of charge at our website www.aquila.com as soon as reasonably practicable after these reports are filed.

Strategic and Financial Repositioning

There have been significant changes in the energy industry during the two years ending December 31, 2002. These changes were primarily a result of lower prices in the power markets as new generation capacity continues to come online, the stabilization of commodity prices in California, the bankruptcy and near bankruptcy of several energy merchants, the tightening of the credit markets (for energy merchant companies in particular), and the lack of liquidity in forward energy markets as companies continue to exit and/or scale back their energy trading activities. In response to this escalating set of circumstances, we exited from our wholesale energy trading business and divested ourselves from the majority of our related activities and assets during 2002. Separately, we restructured our Domestic Networks Group to more closely align it with its regulatory service areas. Staff reductions due to the restructuring, including employees transferred with the sale of various businesses, consisted of approximately 1,205 Merchant Services employees, 75 Corporate employees and 550 Domestic Networks employees. With our exit from wholesale trading, we began to transition to a business comprised primarily of

our regulated utility business and our non-regulated power plants. As part of this transition, we took the following actions:

- The wind down of our Merchant Services trading portfolio in North America and Europe.
- The sale of our natural gas storage facilities in both North America and the United Kingdom.
- The sale of our notes receivable loan portfolio.
- The sale of our gas gathering and processing business located primarily in Texas and Oklahoma.
- The sale of our investment in Quanta Services, Inc. (a company specializing in building and maintaining networks used to carry energy and telecommunications) from 38% to 10.2%. We sold the remaining shares during the first quarter of 2003.
- The sale of our equity investment in our regulated utility operations in New Zealand.
- The initiation of negotiations to sell our Australian and United Kingdom investments.

Proceeds from these asset sales were used to pay down debt, fund restructuring charges and support our continuing operations. As part of our ongoing transition plan, our Board of Directors has suspended the payment of dividends on our common stock indefinitely. We now plan to operate primarily as a regulated utility with various investments in non-regulated power generation facilities.

We have experienced significant net losses and negative cash flows from operations in 2002. We have also experienced a number of credit downgrades and are currently rated as non-investment grade. This has caused us to post a substantial amount of cash or letters of credit as collateral on a number of our contractual agreements. As shown in our Consolidated Financial Statements, we had a retained deficit of \$1.7 billion as of December 31, 2002. In addition, as discussed in Notes 12 and 13 to the Consolidated Financial Statements, as a result of these losses, we were in violation of an interest coverage ratio covenant and a covenant that requires us to maintain a maximum debt to capitalization ratio.

On April 11, 2003, we closed on a three-year senior secured financing of \$430.0 million and a 364-day senior secured financing of \$100.0 million. The 364-day financing also includes an option under which we can during a 30-day period following closing, at our discretion, increase the size of the financing by up to \$100.0 million. Proceeds from the financings will be used to retire debt and support existing and future letters of credit. The secured financings will eliminate the covenant violations stated above. With the above financings, we believe we will have sufficient liquidity to cover our operational needs through June 2004. Our next significant need for outside capital relates to our need to retire senior notes maturing in 2004. We anticipate retiring these notes with proceeds from additional asset sales. In the event we are not successful in closing the asset sales, we would need to obtain a bridge loan to meet these obligations. Although no assurance can be given on the above actions, we expect to be successful in their execution.

Business Group Summary

Segment information for the three years ended December 31, 2002 is included in Note 22 to the Consolidated Financial Statements.

I. Global Networks Group

Our Global Networks Group is divided into two business segments: Domestic Networks and International Networks.

Domestic Networks

Our Domestic Networks businesses are engaged in the generation, transmission, distribution and sale of electricity to approximately 438,000 customers in Missouri, Kansas, and Colorado. Our electric generation facilities supply electricity to our own distribution systems. We also sell excess power to other utilities and marketing companies. We also distribute natural gas to approximately 891,000 customers in Missouri, Kansas, Colorado, Nebraska, Iowa, Minnesota, and Michigan. Domestic Networks also includes (a) our equity interest in Quanta Services, Inc., and (b) Everest Connections, our 96% owned domestic communications business which provides local and long-distance telephone, cable television, high-speed internet and data services to areas of greater Kansas City.

Divestitures

See Notes 5 and 20 to the Consolidated Financial Statements for a more detailed discussion of our divestitures described below.

Pipeline Operations

In January 2002, we completed the sale of an intrastate pipeline system in Missouri.

Quanta Services

During 2002, we sold approximately 17.6 million shares of Quanta Services, reducing our ownership percentage from 38% to approximately 10%. We sold our remaining 11.6 million shares during the first quarter of 2003.

Properties

As of December 31, 2002, our domestic electric generation plants included the following:

Unit	Location	Year Installed	Unit Capability (MW)	Fuel	2002 Net Generation (MW Hours)
Missouri:					
Sibley #1-3	Sibley	1960, 1962, 1969	512	Coal	3,061,409
Ralph Green #3	Pleasant Hill	1981	71	Gas	14,673
Nevada	Nevada	1974	20	Oil	(157)
Greenwood #1-4	Greenwood	1975-1979	251	Gas/Oil	105,988
KCI #1-2	Kansas City	1970	31	Gas	554
Lake Road #1, 3	St. Joseph	1951, 1962	30	Gas/Oil	45,423
Lake Road #2, 4	St. Joseph	1957, 1967	122	Coal/Gas	637,963
Lake Road #5	St. Joseph	1974	63	Gas/Oil	(558)
Lake Road #6-7	St. Joseph	1989, 1990	42	Oil	118
Iatan	Iatan	1980	121	Coal	729,187
Kansas:					
Judson Large #4	Dodge City	1969	145	Gas	304,339
Arthur Mullergren #3	Great Bend	1963	96	Gas	98,816
Cimarron River #1-2	Liberal	1963, 1967	72	Gas	109,059
Clifton #1-2	Clifton	1974	70	Gas/Oil	18,721
Jeffrey #1-3	St. Mary's	1978, 1980, 1983	344	Coal	2,499,635
Colorado:					
W.N. Clark #1-2	Canon City	1955, 1959	43	Coal	262,531
Pueblo #6	Pueblo	1949	20	Gas	43,575
Pueblo #5	Pueblo	1941, 2001	9	Gas	19,305
AIP Diesel	Pueblo	2001	10	Oil	364
Diesel #1-5	Pueblo	1964	10	Oil	1,801
Diesel #1-5	Rocky Ford	1964	10	Oil	837
Total			2,092		7,953,583

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

Fuel Source—In Megawatts (MW)	2002	2001	2000
Coal	1,137	1,184	1,174
Gas and oil	955	931	912
Total generation capability	2,092	2,115	2,086

At December 31, 2002, we had electric transmission and distribution lines as follows:

Description	Length (Miles)
Transmission lines	4,665
Distribution lines	15,448
Total	20,113

At December 31, 2002, our gas utility operations had 1,518 miles of gas gathering and transmission pipelines and 18,867 miles of distribution mains and service lines located throughout our service territories.

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

	2002	2001	2000
Sales (in millions)			
Residential	\$ 283.2	\$ 269.7	\$ 234.7
Commercial	190.2	186.6	162.6
Industrial	100.5	97.2	83.4
Other	100.7	122.2	93.8
Total	\$ 674.6	\$ 675.7	\$ 574.5
Volumes [Gigawatt Hours (one billion watt hours) (GWh)]			
Residential	4,075	3,847	3,137
Commercial	3,343	3,209	2,641
Industrial	2,459	2,326	1,873
Other	2,496	2,904	3,739
Total	12,373	12,286	11,390
Customers at Year End			
Residential	374,697	368,682	349,165
Commercial	59,087	57,939	54,901
Industrial	467	469	460
Other	3,714	3,836	3,967
Total	437,965	430,926	408,493

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

	2002	2001	2000
Sales (in millions)			
Residential	\$ 487.4	\$ 603.0	\$ 516.3
Commercial	195.2	258.0	213.8
Industrial	34.8	47.0	43.4
Other	44.8	56.3	53.0
Total	\$ 762.2	\$ 964.3	\$ 826.5
Volumes [Thousand Cubic Feet (Mcf)]			
Residential	72,454	66,858	72,648
Commercial	33,322	31,474	34,247
Industrial	7,974	7,664	8,247
Transportation	120,974	110,132	125,959
Other	403	431	607
Total	235,127	216,559	241,708
Customers at Year End			
Residential	796,207	783,409	773,017
Commercial	81,180	78,062	77,319
Industrial	2,300	2,226	2,361
Other	10,840	10,341	10,019
Total	890,527	874,038	862,716

We also had non-regulated commercial and industrial gas, appliance services and other sales (in millions) of \$378.9, \$570.0 and \$514.0 in the years ended December 31, 2002, 2001 and 2000, respectively.

Seasonal Variations of Business

Our domestic 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 peak seasons for our Domestic Networks businesses.

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, however, 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

Our domestic utility operations are subject to the jurisdiction of the public service commissions in the states in which they operate with respect to services and facilities, rates and charges, accounting, valuation of property, depreciation and various other matters. Certain commissions have jurisdiction over the creation of liens on property located in its state to secure bonds or other securities. Under the Federal Power Act (FPA), our wholesale transmission and sale of electric energy in interstate commerce and our generation facilities are subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC). FERC jurisdiction extends to, among other things, rates and charges in connection with such transmission and sale, the issuance of stock, long and short-term debt, the sale, lease or other disposition of such facilities, and accounting matters. The FPA and activities of the FERC are described more fully under the regulation discussion of our Merchant Services group.

The following summarizes our recent rate case activity:

<i>(In millions)</i>	Type of Service	Date Requested	Amount Requested	Amount Approved
Minnesota	Gas	8/2000	\$9.8	pending
Missouri	Electric	6/2001	49.4	\$ (4.3)
Iowa	Gas	6/2002	9.3	4.3
Michigan	Gas	8/2002	14.3	8.4
Colorado	Electric	10/2002	23.4	pending

We filed a Minnesota gas rate case in August 2000 for an increase of \$9.8 million. The case is pending before the Minnesota Utilities Commission with an interim rate increase of approximately \$5.2 million granted in October 2000. We expect a final settlement to be approved by the Commission in early summer 2003.

In June 2001, we filed for a \$49.4 million increase in our Missouri electric rates. Approximately \$39.0 million of the request related to anticipated increased fuel and purchased power costs that did not materialize. In February 2002, we reached a negotiated settlement with the Commission staff and all intervenors that resulted in a \$4.3 million annual rate reduction. The rate reduction was driven primarily by a \$16.0 million reduction in depreciation which reduced our cash flow but had little impact on earnings.

In June 2002, we filed for a \$9.3 million general rate increase in Iowa. We received approval to place an interim increase of \$5.6 million into effect, subject to refund. In February 2003, we reached a settlement with the Commission for an increase of \$4.3 million.

In August 2002, we filed for a \$14.3 million general rate increase in Michigan. We received approval to place an interim increase of \$8.2 million into effect as of December 2002. We reached a settlement with the Commission staff and other intervening parties for an increase of \$9.1 million. This settlement was approved by the Commission in March 2003 and the new rates have gone into effect. This increase was partially offset within a separate depreciation case docket whereby our annual rates were reduced by \$.7 million. This decrease relates to our depreciation rates, which reduced cash flow but had little impact on earnings.

In October 2002, we filed for a \$23.4 million increase in our Colorado electric rates. A hearing will be held in April 2003 and new rates are expected to become effective in June.

Our domestic regulated businesses produce, purchase and distribute power in three states and purchase and distribute gas in seven states. All of our gas distribution utilities have Purchased Gas Cost Adjustment (PGA) provisions that allow them to pass the 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.

In our regulated electric business, we generate approximately 56% of the power that we sell and purchase the remaining 44% through long-term contracts or in the open market. The regulatory provisions for recovering power costs vary by state. In Kansas, we have an Energy Cost Adjustment (ECA) that serves a similar purpose as the PGAs in place for the gas utility. 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. For Colorado, we have an Incentive Clause Adjustment (ICA) that provides for an equal sharing of the variability of energy costs between us and 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. In January 2003, legislation to provide a fuel adjustment clause was introduced in both the Missouri House and Senate. This legislation has now passed both the House and Senate Committees and has been submitted to the respective legislative chambers for passage. If passed and signed by the Governor, we will be able to file periodic fuel and purchase power adjustments.

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 discharge of pollutants into the air and water;
- 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, associated with our operations;

- the protection of animals and minimization of noise emissions; and
- safety and health standards, practices and procedures that apply to the workplace and to operation of our facilities.

Water Issues. The Federal Clean Water Act controls effluent 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 Environmental Protection Agency (EPA). All of our facilities that are required to have such permits either have them or have timely applied for extensions of expired permits and are lawfully operating under the prior permit.

In April 2002, the EPA proposed new rules for cooling water intake structures. The final action, expected by August 2003, may require environmental impact studies as a condition of permit renewals. At this time it is not known what impact, if any, this may have on operations.

In July 2000, the EPA issued final rules for the implementation of the Total Maximum Daily Load (TMDL) program of the Clean Water Act. While the EPA issued a proposed rule to withdraw the TMDL rules, their goal was to establish over the next 15 years, the maximum amounts of various pollutants that can be discharged into waterways while keeping those waterways in compliance with water quality standards. The establishment of TMDL values may eventually result in more stringent discharge limits in each facility's wastewater discharge permit. We will not know the future impact of the rule until the change is finalized.

Air Emissions. Our facilities are subject to the Federal Clean Air Act and many state laws and regulations relating to air pollution. These laws and regulations cover, among other pollutants, those contributing to the formation of ground-level ozone, carbon monoxide, sulfur dioxide, nitrogen oxides (NOx) and particulate matter. Our facilities generally emit these pollutants at levels within regulatory requirements. Fossil-fuel power generating facilities typically are major sources of air pollutants and are therefore subject to substantial regulation and enforcement oversight by the applicable governmental agencies. The Bush administration has introduced a Clear Skies Initiative that would require further reductions in sulfur dioxide, nitrogen oxides and mercury emissions from power plants. Until the legislation is developed and passed, we cannot determine the impact this action will have on our power plants. In 2003, several of our power plants will come under a NOx budget requirement. However, this will not significantly impact the business.

Carbon Dioxide. In November 1998, the United States became a signatory to the Kyoto Protocol to the United Nations Framework Convention on Climate Change. The Kyoto Protocol calls for developed nations to reduce their emissions of greenhouse gases, which are believed to contribute to global climate change. Carbon dioxide, a major byproduct of the combustion of fossil fuel, is considered to be a greenhouse gas. The Kyoto Protocol, however, will not become law in the United States until the U.S. Senate ratifies it. Aside from the Kyoto Protocol, the current administration has indicated it will not pursue limitations on carbon dioxide emissions. Nevertheless, bills continue to be introduced in Congress that include carbon dioxide emission limitations. Similarly, a number of states, primarily in the Northeast, are poised to include carbon dioxide limitations in state law. At this time there is no enforceable standard for carbon dioxide emissions, and it is unclear what effect, if any, current federal and state efforts to impose such a standard will have on our facilities.

Mercury. In December 2000, the EPA announced that it would regulate mercury emissions from coal- and oil-fired power plants. The EPA is expected to propose regulations by December 2003 and issue final regulations by December 2004. The impact of this action on our power plants cannot be determined until final regulations are issued.

Past Operations. Some federal and state laws authorize the EPA and other agencies to issue orders and compel responsible parties to clean up sites that are determined to present actual or potential threat to human health or the environment. We are named as a potentially responsible party at two disposal sites for Polychlorinated Biphenyls (PCBs). In addition, we have retained some environmental liability for several operations and investments we no longer own. We also own or have acquired liabilities from companies that once owned or operated 29 former manufactured gas plant sites. We estimate our ongoing program to remediate these sites will cost \$8.7 million.

In EPA Region VII, we and several other gas utilities were requested to provide information on past use of mercury regulators. We responded to the EPA's request and do not expect this inquiry to result in a material cost to us.

International Networks

The following discussion describes our International Networks businesses.

Australia

We have a 33.8% ownership interest in United Energy Limited (UEL), an electricity distribution utility serving 578,000 customers in Melbourne, Victoria. Under an operating services agreement with UEL, we manage the utility for a fee. UEL distributes and sells electricity, with the majority of its sales originating from the regulated distribution network business. We also have a 25.5% equity interest in Multinet Gas, a gas distribution business in Melbourne that serves approximately 630,000 accounts. In addition, we own a 50% interest in WA Gas Holdings Pty Ltd (WA Gas), which in turn owns 45% of AlintaGas Limited, the principal gas distribution and retail business in Western Australia. UEL owns the other 50% interest in WA Gas. AlintaGas serves approximately 463,000 customers. WA Gas has an operating services agreement with AlintaGas and receives a fee for management services provided under the agreement.

We are exploring the sale of our interest in the above properties and anticipate a sale being completed in 2003, however, there can be no assurance that this will occur.

New Zealand

In October 2002, through a public tender offer in New Zealand, VECTOR Limited acquired all of the outstanding shares of UnitedNetworks Limited (UNL), in which we had a 70.2% indirect interest. This tender resulted in an after tax gain of \$28.0 million. See Note 10 to the Consolidated Financial Statements for a more detailed discussion of this divestiture.

Canada

We own Aquila Networks Canada (British Columbia) Ltd. (ANCBC), a hydroelectric utility in British Columbia, Canada. ANCBC has four hydroelectric generation facilities with a capacity of 212 megawatts and approximately 4,243 miles of distribution and transmission lines that serve approximately 93,000 customers in south central British Columbia. ANCBC generates about half

of its power needs and acquires the rest through power purchase contracts. We also own Aquila Networks Canada (Alberta) Ltd. (ANCA). ANCA serves approximately 390,000 electric customers through 58,894 miles of low-voltage distribution lines representing 50% of Alberta's distribution network. As part of our restructuring initiatives, we plan to explore the possible sale of our Canadian operations.

As of December 31, 2002, our hydroelectric generation plants in British Columbia included the following:

Unit	Location	Year Installed	Unit Capability (MW)	2002 Net Generation (MW Hours)(a)
No. 1	Lower Bonnington	1924	44.4	239,857
No. 2	Upper Bonnington	1907	60.0	214,662
No. 3	South Slocan	1928	56.4	252,522
No. 4	Corra Linn	1932	51.3	201,848
Total			212.1	908,889

(a) As the result of the diversion of water upstream from our plants by another hydroelectric utility, we received another 597,733 MWh of power in 2002 as entitlement generation to compensate us for the power we otherwise would have been able to generate.

The following table summarizes sales, volumes and customers for our Canadian electric network transmission and distribution businesses:

	2002	2001(a)	2000(b)
Sales (in millions)	\$ 258.7	\$ 241.4	\$ 385.9
Volumes (GWh)	16,003	15,373	10,591
Customers at Year End	482,553	468,515	455,578

(a) Includes a full year of operations from ANCA, offset by the sale of its retail operations in January 2001.

(b) Includes sales, volumes and customers from ANCA after it was acquired in August 2000.

United Kingdom

In May 2002, we purchased from FirstEnergy Corporation a 79.9% equity interest in Avon Energy Partners Holding Company, the holding company for Midlands Electricity, a United Kingdom electric distribution network. FirstEnergy retained the remaining 20.1% of Avon. Although we have since written off substantially all of our investment, at the time of the

acquisition, the gross purchase price of the acquisition was valued at approximately \$262 million and was comprised of the following:

In millions

Initial payment	\$155
Transaction costs	20
Present value of promissory note to be paid in six annual payments of \$19 million beginning on May 8, 2003	87
Total value of purchase price	\$262

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. Midlands also owns a combined 884 megawatts of net generation capacity in the United Kingdom, Turkey and Pakistan.

In connection with the acquisition, FirstEnergy retained substantive participating and protective rights as the minority partner. We and FirstEnergy each have 50% voting power and an equal number of representatives on the Avon board of directors. Although we have the majority economic interest, FirstEnergy's participation in day-to-day business decisions is significant, including approval of executive compensation, additional capital contributions, budgets, and the dissolution of the company.

Recent downgrades in credit ratings assigned to the public debt in the Midlands ownership chain have 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 (Ofgem), now requires pre-approval of cash payments to the owners in the form of management fees or dividends. Accordingly, in 2003 and beyond, we intend to record equity earnings and management fees only to the extent of cash received.

In August 2002, Aquila and FirstEnergy initiated a process for the sale of Midlands with final binding bids due in December 2002. We received offers in early December and are currently in negotiations with the prospective buyer.

Seasonal Variations of Business

Our International Networks businesses are weather-sensitive. We have both summer- and winter-peaking assets. The table below shows the peak seasons for these businesses.

Location	Peak
Canada—Electric	November through March
Australia—Electric	December through March
Australia—Gas	June through September
United Kingdom—Electric	No peak season

Regulation

Our investments in electric and gas distribution businesses in foreign countries are subject to regulation by government-appointed agencies. In general, formal approvals are required to amend customer rate tariffs, issue long-term debt, undertake major capital construction or asset dispositions, establish property valuations, or change accounting policies.

Electric distribution businesses in British Columbia and Alberta, Canada, are regulated by the British Columbia Utilities Commission (BCUC) and by the Alberta Energy Utilities Board (AEUB), respectively. Customer rates are generally set for one- or two-year periods based on a forecasted cost of service. The BCUC has approved the use of an incentive-based ratemaking mechanism for the past several years. In British Columbia, only wholesale customers have the right of open access to transmission and alternate suppliers. Since January 2001, all customers in Alberta have access to alternate suppliers. We sold our Alberta retail supply business to an unaffiliated company in December 2000.

The electric and gas distribution businesses in Victoria, Australia, are regulated by that state's Essential Services Commission. Customer rates for use of the distribution systems are reset at five year intervals following an examination of the companies' historical and projected costs, return on invested capital, and other aspects of customer service. Those rates are adjusted annually after each reset interval, primarily by the rate of inflation minus a predetermined productivity factor. An efficiency carry-over mechanism provides for a five-year rolling adjustment for actual changes in operating and maintenance cost efficiencies. Gas rates were reset in January 2003 with a reduction of 2%. The next reset for electric rates will occur in January 2006. The final stage of full retail competition for electric customers was implemented in January 2002, and for gas customers in October 2002.

The gas distribution business in Western Australia is regulated by the Office of Gas Access Regulation. Refinement of the regulatory regime is in progress, following the privatization of the formerly government-owned gas utility in November 2000. The regulatory process for review of customer rates will likely reflect a number of the features of the Victoria model. The proportion of gas volumes used by industrial and large commercial customers compared to residential customers is very high. Because the company's franchise is not exclusive, other companies can construct pipelines that by-pass the incumbent network. The implementation of full retail gas competition is expected during 2003.

Electric distribution businesses in the United Kingdom are regulated by Ofgem. Full retail competition is in effect in the U.K. However, we do not participate in the retail supply business. Customer rates for use of the distribution systems are reset at five year intervals following an examination of the companies' historical costs, industry benchmark costs, return on invested capital, and customer service levels. Those rates are adjusted annually after each reset interval, primarily by the rate of inflation minus a predetermined productivity factor. The next reset for our electricity rates will be in April 2005.

The following highlights our recent rate case activity:

<i>(In millions)</i>	Type of Service	Date Requested	Amount Requested	Amount Approved
Alberta, Canada	Electric	12/2001	\$12.7	\$(21.0)
British Columbia, Canada	Electric	11/2002	4.9	4.2

In December 2001, we filed for an annual rate increase in Alberta of about \$30 million along with an application for a performance-based rate-setting mechanism. We subsequently modified that request and sought a \$12.7 million increase for 2002 and a \$6.0 million increase for 2003. In July 2002, an interim rate increase of approximately \$9.6 million was approved. Hearings were held in September and October 2002 and a final order was issued in February 2003, resulting in a decrease in rates of \$21.0 million for 2002, and no increase in rates in 2003 (2002 rates carried forward to 2003). Almost all of the reduction in rates related to depreciation on distribution assets (average asset lives were extended) and the related income tax effect. The decision did not adjust the allowed rate of return earned by the company and therefore, net income is not expected to be materially impacted by this decision. However, the decision is estimated to reduce annual cash flow from operations by approximately \$17.0 million for 2004 and beyond. With regard to 2003, cash flow from operations will be reduced by approximately \$33.0 million, which includes the effect of both the 2002 and 2003 reduction.

In November 2002, we filed a request for a \$4.9 million interim rate increase effective in January 2003 in British Columbia. Following a review process, the BCUC issued a final order in February 2003 approving a \$4.2 million rate increase.

Environmental Matters

Canada. Our Canadian operations are governed by environmental laws and regulations similar to those in the United States. In addition, the operation and maintenance of our hydroelectric generation facilities is governed by the Canadian Fisheries Act and provincial water permits and licenses. The Department of Fisheries and Oceans is moving towards stricter enforcement of the Fisheries Act, which might lead to higher compliance costs in the future.

II. Merchant Services

Merchant Services businesses operate as two business segments: Capacity Services and Wholesale Services. These businesses are operated through our wholly-owned subsidiary, Aquila Merchant Services, Inc. (Aquila Merchant).

Exchange Offer

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 1.8 million shares of Aquila Merchant Class A shares exercised dissenters' rights with respect to the merger.

Capacity Services

Our Capacity Services business owns, controls and operates energy-related assets. These assets historically complemented our Wholesale Services business by providing power, natural gas and coal supplies and an enhanced ability to structure innovative new products and services for clients. Following the asset sales discussed below, our remaining Capacity Services assets are comprised of non-regulated power generation assets.

Acquisitions and Divestitures

See Notes 5, 6 and 13 to the Consolidated Financial Statements for a more detailed discussion of the following acquisitions and divestitures.

Power Plant Construction

Piatt County Power Plant. In February 2002, we agreed to lease from a special purpose entity (SPE), a 510-megawatt power plant being constructed in Piatt County, Illinois. We expect construction to be completed in June 2003. In the fourth quarter of 2002, we repaid \$30.0 million of debt related to this project. Because of the debt repayment and the redemption of a portion of the SPE's equity, we consolidated the assets and related debt of the SPE onto our balance sheet, as it no longer qualified for off-balance sheet treatment. Concurrent with our new financings described in Notes 12 and 13 to the Consolidated Financial Statements, this debt was repaid in full during the second quarter of 2003.

Clay County Power Plant. In November 2000, we agreed to lease from an SPE a 340-megawatt power plant being constructed in Clay County, Illinois. The plant became operational in November 2002. In the fourth quarter of 2002, we repaid \$34.5 million of debt related to this project. Because of the debt repayment and the redemption of a portion of the SPE's equity, we consolidated the assets and related debt of the SPE onto our balance sheet, as it no longer qualified for off-balance sheet treatment. Concurrent with our new financings described in Notes 12 and 13 to the Consolidated Financial Statements, this debt was repaid in full during the second quarter of 2003.

Coahoma Power Plant. In September 2002, construction was completed on a 340-megawatt power plant that we own and operate in Clarksdale, Mississippi.

Termination of Cogentrix Acquisition

In August 2002, we agreed to terminate 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 current 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 interest.

Sale of Lockport Energy

In September 2002, we sold our 16.58% interest in the Lockport Energy facility, a 180-megawatt gas-fired power plant located approximately 30 miles north of Buffalo, New York.

Sale of Gas Gathering and Pipeline Assets

In October 2002, we sold our Texas and Oklahoma natural gas pipeline systems, including our natural gas and natural gas liquids processing assets, and our 50% ownership interest in the Oasis Pipe Line Company.

Sale of U.K. Gas Storage Assets

In October 2002, we sold our Hole House natural gas storage assets in the United Kingdom. The assets consisted principally of a natural gas storage facility in Cheshire, England.

Sale of Lodi Gas Storage

In October 2002, we sold our investment in the Lodi gas storage project in California. We owned 50% of WHP Acquisition Company LLC, a company jointly established in 2001 with an affiliate of ArcLight Energy Partners Fund I, L.P., to purchase Western Hub Properties LLC, the developer of the Lodi gas storage project.

Sale of Gas Storage Facility

In December 2002, we sold our Texas natural gas storage facility in Katy, Texas, one of the largest operating storage facilities in the Southwest.

Sale of Coal Terminal

In February 2003, we sold our coal terminal in West Virginia that provides blending and storage services, with annual capacity of approximately 5 million tons.

Properties

Contracted Power Plants

We own interests in a number of “qualifying facilities” (QFs) and “exempt wholesale generators” (EWGs) which have long-term contracts to sell power. QFs are small power producers or cogenerators (power producers that produce steam as a byproduct of the electricity generating process, for use in a second industrial process) that meet certain operating, efficiency and fuel-use standards set forth by the FERC. Electric utilities are required to purchase generating capacity and electric energy from QFs at a price approved by state regulatory bodies. EWGs are independent power projects that are exempt from the Public Utility Holding Company Act (PUHCA), but must obtain FERC approval for wholesale rates. Our EWGs have been granted market-based rate authority.

The table below shows information about our contracted power plants:

Plant and Location	Type of Investment	Percent Owned	Gross Capacity (MW)	Net Capacity (MW)	Fuel	Date in Service
Topsham Hydro Partners, Maine (QF)	Leveraged lease	50.00	14	7	Hydro	October 1987
Stockton CoGen Company, California (QF)	General partnership	50.00	60	30	Coal	March 1988
BAF Energy L.P., California (QF)	Limited partnership	23.11	120	28	Gas	May 1989
Rumford Cogeneration Company L.P., Maine (QF)	Limited partnership	24.30	85	21	Coal	May 1990
Koma Kulshan Associates, Washington (QF)	Limited partnership	49.75	14	7	Hydro	October 1990
Badger Creek Limited, California (QF)	Limited partnership	48.75	50	24	Gas	April 1991
Orlando Cogen Limited, L.P., Florida (QF)	Limited partnership	50.00	126	63	Gas	September 1993
Jamaica Private Power Company, Jamaica (EWG)	Limited liability company	24.09	58	14	Diesel	January 1998
Batesville Unit No. 3, Mississippi (EWG)	Toll Contract	—	279	279	Gas	August 2000
Lake Cogen Ltd., Florida (QF)	Limited partnership	99.90	110	110	Gas	July 1993
Mid-Georgia Cogen, L.P., Georgia (QF)	Limited partnership	50.00	296	148	Gas	June 1998
Pasco Cogen Ltd., Florida (QF)	Limited partnership	49.90	109	54	Gas	July 1993
Prime Energy Limited Partnership, New Jersey (QF)	Limited partnership	50.00	65	33	Gas	July 1989
Onondaga Cogen. Ltd. Partnership, New York (EWG)	Limited partnership	100.00	75	75	Gas	December 1993
Selkirk Cogen. Partners, L.P., New York (QF)	Limited partnership	19.90	345	69	Gas	March 1992/ September 1994
Total Capacity (MW)			1,806	962		

Merchant Power Plants

We own or control 2,664 MW of net power generation capacity from merchant facilities, including capacity under construction. Our merchant power plants generally do not have dedicated customers, because they are designed to operate only during periods of peak demand in the geographic area in which the plant is located. Generally these plants provide power to utilities when they experience unexpected outages or transmission difficulties or the demands of their customers exceed their regular power supply due to extreme weather.

The table below shows information about our merchant power plants:

Plant & Location	Type of Investment	Percent Owned	Gross Capacity (MW)	Net Capacity (MW)	Heat Rates(d)	Fuel	Date in Service
Aries L.L.C., Missouri (EWG)	Owned	50.00	580	290	7.1	Gas	June 2001/(a) May 2002
Elwood Energy L.L.C., Illinois (EWG)	Toll Contract	—	604	604	10.7	Gas	July 2001(b)
Acadia Power Plant, Louisiana (EWG)	Toll Contract	—	580	580	7.5	Gas	July 2002(c)
Coahoma Power Plant, Mississippi (EWG)	Owned	100.00	340	340	11.9	Gas	September 2002
Clay County Power Plant, Illinois (EWG)	Owned	97.2	340	340	11.9	Gas	November 2002
Piatt County Power Plant, Illinois (EWG)	Owned	94.9	510	510	12.0	Gas	June 2003*
Total Capacity (MW)			2,954	2,664			

* Estimated.

(a) Our Domestic Networks business currently has a contract to purchase up to 500 MW during the summer peak through May 2005.

(b) We have a 15-year contract for 604 MW of the output of the Elwood plant.

(c) We have a 20-year contract for 580 MW of the output of the Acadia plant.

(d) The measure of efficiency of converting fuel to electricity, expressed as BTU's of fuel per kilowatt-hour. The lower the heat rate, the more efficient the plant.

Natural Gas Assets

We owned significant natural gas gathering, transportation, processing and storage facilities located in Texas, Oklahoma and California. These assets were sold as part of our restructuring in the second half of 2002.

Competition

Our contracted power plants have agreements to sell all their power under long-dated, fixed-price contracts and therefore generally do not face competition. Generally, the purchasers of this power are regulated utilities with investment grade credit ratings. However, if the purchasers were to become bankrupt or default on the contracts, or if the purchase contracts were to be otherwise terminated, we would need to find replacement purchasers of the power from these facilities. Because our facilities are generally less efficient than the most modern power plants, we would have difficulty competing for new customers.

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. We continue to work in the market place to mitigate our costs, however, if significant events do not occur, we will incur significant losses related to these plants.

Wholesale Services

Although we are winding down the activities related to Wholesale Services, this business historically has represented a substantial portion of our income, expense, assets and liabilities. Because of the increased capital required to operate Wholesale Services, we began scaling back its activities during the second quarter of 2002. We stopped entering into new transactions and began liquidating our assets and liabilities related to this business during the third quarter. Nevertheless, because of the significance of this business to our historical operations and the continuing impact of the remaining obligations and risks associated with Wholesale Services, an understanding of these historical operations continues to be relevant.

Wholesale Services was functionally aligned as follows:

- Commodity Services—Marketing and trading of commodities;
- Client Services—Structured products and services; and
- Capital Services—Structured financing for energy-related businesses.

Commodity Services

We stopped growing our wholesale trading portfolio during the third quarter of 2002. Subsequent activity has been 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. These positions have been hedged to mitigate the exposure of price movements and will continue to be our assets and liabilities until the contracts are settled.

Power. We purchased electric power from generation facilities and sold it primarily to utilities, municipalities, cooperatives and other marketing companies.

Our power marketing and trading activities included trading electricity at various points of receipt, aggregating power supplies and arranging for transmission and delivery. We made transmission arrangements with non-affiliated interstate and intrastate transmission companies through a variety of means, including short-term and long-term firm and interruptible transmission agreements.

Natural Gas. We purchased natural gas from a variety of suppliers under daily, monthly, variable load, base load and term contracts that included either market-sensitive or fixed-price terms. We sold natural gas under sales agreements that had varying terms and conditions, most of which were intended to match seasonal and other changes in demand.

Our natural gas marketing activities included contracting to buy natural gas from suppliers at various points of receipt, aggregating natural gas supplies, arranging for their transportation, negotiating the sale of natural gas and matching natural gas receipts and deliveries based on volumes required by clients. We made transportation arrangements with affiliated and non-affiliated interstate and intrastate pipelines through a variety of means, including short-term and long-term firm and interruptible agreements. We also utilized our natural gas storage facilities and entered into various short-term and long-term firm and interruptible agreements for natural gas storage in order to offer peak delivery services to satisfy winter heating and summer electric generating demands.

We also entered into long-term gas transactions with municipalities, agreeing to deliver natural gas to them for an extended period of time (generally 10 to 12 years) at a fixed cost. The municipalities paid us in advance for the commodity. Between 1997 and 2000, we closed five of these transactions with an aggregate payment amount of approximately \$1 billion. Our obligation to deliver gas under these contracts has not changed, and we are committed to meeting those obligations. As of December 31, 2002, we had obligations of \$752.7 million on the balance sheet related to these contracts. We have substantially hedged our risk of changes in the price of natural gas to be delivered under these contracts.

Client Services

We offered products to help our clients manage multiple risks, including price, liquidity, credit, performance, volatility and weather risks. We used our access to current market information, trends, opportunities and threats, as well as the quantitative analytical and practical skills we developed in our marketing and trading business, to develop innovative products and services in order to better manage the risks of our clients.

Capital Services

Our Capital Services group provided capital structuring services to our clients by bundling structured financing with our commodity and capacity capabilities. Our structuring alternatives typically included traditional asset-based lending, revolving facilities, convertible preferred stock and volumetric production payments.

Our Capital Services earnings were derived from the spread between the price we charged our clients for funding and our cost for these funds. In addition, incremental value was created when we completed transactions that we otherwise might not have captured without our commodity capabilities. In December 2002, we sold substantially all our notes receivable in the loan portfolio as we exited from this business. See Note 6 to the Consolidated Financial Statements for a more detailed discussion of this divestiture.

Regulation

Natural Gas Marketing. The FERC has implemented regulations on the transportation and marketing of natural gas that are intended to induce interstate pipeline companies to provide non-discriminatory transportation services to producers, distributors and other shippers. The effect of the regulations has been the creation of an open access market for natural gas purchases and sales and the creation of a business environment that has fostered the evolution of various privately negotiated natural gas sales, purchase and transportation arrangements. Regulations in Canada have created a similar business environment in that country. The sale for resale of natural gas in North America has substantially completed its evolution to an open access market.

In Canada, certain federal and provincial regulatory authorities require parties to hold export or removal permits for transactions by which natural gas is to be exported from the jurisdiction in which it is produced. These requirements apply whether the natural gas is moved from one province to another or from a province to the United States. We hold permits for such purposes from the provinces of Alberta, British Columbia, Manitoba, Saskatchewan, Ontario and Quebec, and from the Canadian National Energy Board and the United States Department of Energy.

Other Natural Gas Regulatory Issues. Our natural gas purchases and sales are generally not regulated by the FERC or other regulatory authorities. However, we depend on the natural gas transportation and storage services offered by various pipeline companies that are regulated by the FERC and state regulatory authorities to enable the sale and delivery of our natural gas supplies.

Power Marketing Regulation. The Federal Power Act (FPA) and rules put out by 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. In April 1996, the FERC adopted Order 888 to expand transmission service and access and to provide alternative methods of pricing for transmission services. Order 888 was intended to open the FERC regulated interstate transmission grid in the continental United States to all qualified persons seeking transmission services. Owners of FERC regulated transmission facilities are required to provide non-discriminatory open access to those facilities with rates, terms and conditions that are materially comparable to those that the owner imposes on itself. Second generation implementation issues arising out of Order 888 abound. These include issues relating to power pool structures and transmission pricing.

In December 1999, the FERC issued Order 2000 addressing some of the significant regional transmission issues. Among other things, Order 2000 required transmission-owning utilities that do not already participate in an independent system operator (ISO) to file plans by October 2000, detailing their participation in an organization that will control the transmission facilities within a region. Utilities that already participated in an ISO had to submit filings in January 2001. Filings by many utilities and regional transmission entities are now on file and pending FERC review. Our electric marketing transactions may be impacted by the functioning of these new regional transmission organizations. Order 2000 allows significant flexibility in the structure and operation of these new organizations. We therefore cannot predict their impact on our power marketing business.

Power Generation Regulation. Historically in the United States, regulated and government-owned utilities have been the only significant producers of electricity for sale to third parties. The enactment of the Public Utility Regulatory Policies Act (PURPA) in 1978 encouraged non-utility companies to enter the electric power business by reducing their regulatory burdens. In addition, PURPA and its implementing regulations created unique opportunities for the development of cogeneration and small power production facilities by requiring utilities to purchase electricity generated by such facilities that meet certain requirements, referred to as “qualifying facilities.” As a result of PURPA, a significant market for electricity produced by independent power producers developed in the United States. The benefits and exemptions afforded by PURPA to qualifying facilities are important to us and our competitors.

The enactment in 1978 of PURPA and the adoption of regulations by the FERC and individual states provide incentives for the development of small power production and cogeneration facilities meeting FERC criteria concerning the facility’s size, fuel use, ownership and operating standards. In order to be a qualifying facility, a cogeneration facility must

(i) produce not only electricity but also a FERC-mandated quantity of useful thermal output, (ii) meet FERC-mandated operating and efficiency standards when using oil or natural gas as a fuel source and (iii) be not more than 50% owned by an electric utility or electric utility holding company, or any combination thereof. In order to be a qualifying facility, a small power production facility must meet the same ownership criteria as qualifying cogeneration facilities and must have as its primary energy source biomass, waste, renewable resources, geothermal resources or some combination thereof. Small power production facilities must have a capacity of no more than 80 MW, unless the primary energy source of the facility is solar, wind or waste, or the facility qualifies under FPA Section 3(17)(E), in which case there is no maximum plant size. Hydroelectric small power production facilities also may be PURPA qualifying facilities if, among other things, they impound or direct water by means of a new dam or diversion and meet FERC-specified environmental regulations.

PURPA provides two primary benefits to qualifying facilities. First, qualifying facilities are exempt from otherwise applicable requirements of PUHCA, the FPA and state laws respecting rate and financial regulation, except for state laws pertaining to sales of energy to a qualifying facility for the setting of avoided cost rates for purchases from the qualifying facility and establishing reliability procedures and standards. Second, PURPA requires that electric utilities purchase electricity generated by qualifying facilities at a price equal to the incremental cost the utility would have incurred to generate or purchase the power from another source (i.e., the utility's "avoided cost"). PURPA also requires the utility to sell back-up power to the qualifying facility on a non-discriminatory basis. The FERC regulations permit qualifying facilities and utilities to negotiate agreements for utility purchases of power at rates other than the purchasing utility's avoided cost. If Congress amends PURPA, the statutory requirement that an electric utility purchase electricity from a qualifying facility could be eliminated and even the validity and effect of existing contracts could be adversely affected. Moreover, although current legislative proposals specify the honoring of existing contracts, a repeal of the statutory purchase requirements of PURPA going forward could increase pressure to renegotiate existing contracts. Any changes that result in lower contract prices for qualifying facilities could have an adverse effect on our results of operations and financial position.

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 exempt wholesale generators (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, qualifying facilities and independent power projects with access to their transmission systems. However, the Energy Act does preclude the FERC from ordering transmission services to retail customers and prohibits "sham" wholesale energy transactions which appear to provide wholesale service, but actually are providing service to retail customers.

The FPA grants the FERC exclusive ratemaking 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. Although qualifying facilities under PURPA are exempt from the FPA's rate-making and rate approval requirements, independent power projects (including EWGs) must obtain FERC acceptance of their rates under FPA Section 205. Wholesale electricity sales related to power marketing activities are also subject to FERC acceptance on the basis that the rates either are cost-justified or are market-based. Independent power projects in which we have an interest and that are not qualifying facilities have been granted market-based rate authority and comply with the FPA requirements governing approval of wholesale rates.

Our Executive Team

<u>Name</u>	<u>Age</u>	<u>Position</u>
Richard C. Green, Jr. (Rick)	48	President, Chief Executive Officer and Chairman
Keith G. Stamm	42	Senior Vice President and Chief Operating Officer
Rick J. Dobson	44	Interim Chief Financial Officer
Leo E. Morton	57	Senior Vice President and Chief Administrative Officer
Leslie J. Parrette, Jr. (Les)	41	Senior Vice President, General Counsel and Corporate Secretary
C. E. Payne, Jr. (Cal)	52	Senior Vice President and Chief Risk Officer
Michael G. Jonagan (Mike)	41	Senior Vice President, Capacity Services

Richard C. Green, Jr. (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. 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 College)

Keith joined our company in 1983 as a staff engineer at our 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, a 33.8% owned foreign traded Australian company and currently serves as its Chairman. From January 2000 to November 2001, he served as Chief Executive Officer of Aquila Merchant Services, Inc. In November 2001, he was appointed President and Chief Operating Officer of our Global Networks Group. He also serves on the board of AlintaGas Limited, a 22.5% owned foreign traded Australian company. In October 2002, Keith became Chief Operating Officer of Aquila.

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

Rick joined Aquila Merchant Services 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 Services in 1997 and served as Vice President Financial Management until November 2002 when he was appointed Interim 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.

Leslie J. Parrette, Jr. (A.B., Harvard College; J.D., Harvard Law School)

Les joined our company in July 2000 as Senior Vice President and General Counsel. In September 2001, he was also appointed Corporate Secretary of Aquila. Prior to joining our company, Les was a partner in the law firm of Blackwell Sanders Peper Martin LLP from 1992 through June 2000.

C. E. Payne Jr. (B.S., Portland State University)

Cal joined our company in December 1995 as our first Trading Control Officer. In 2000, he was appointed Vice President and Chief Risk Officer, and in March 2001 he became Senior Vice President and Chief Risk Officer. Prior to joining our company, Cal held executive and management positions for 11 years at Transco Energy Company in Houston, Texas.

Michael G. Jonagan (B.S. Mechanical Engineering and B.S. Petroleum Engineering, University of Missouri—Rolla; M.S. Engineering Management, University of Kansas)

Mike joined our company in 1986 as a staff engineer at our Sibley Generating Station. Between 1986 and 1999 he held various operating positions. In 1999, he was named Vice President, Origination at Aquila Merchant Services and in 2000 he became Vice President, Regulated Power Generation. In October 2000, Mike became Chief Operating Officer of UEL and he presently serves on its board of directors. From July 2002 until October 2002, Mike was the Chief Executive Officer of our domestic regulated utility business and in October 2002 he became Senior Vice President, Capacity Services.

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 “Capacity Services,” “International Networks—Canada” and “Domestic Networks.” Certain of these properties are encumbered by liens securing loans made to us. See Notes 12 and 13 to our Consolidated Financial Statements for a description of the liens.

Item 3. Legal Proceedings

On February 19, 2002, we filed a suit against Chubb Insurance Group, the issuer of surety bonds in support of certain of our long-term gas supply contracts. Previously, Chubb had demanded that it be released from its surety obligation of up to \$540 million or, alternatively, that we post collateral to secure its obligation. We do not believe that Chubb is entitled to be released from its surety obligations or that we are obligated to post collateral to secure its obligations unless it is likely we will default on the contracts. Chubb has not alleged that we are likely to default on the contracts. If Chubb were to prevail, it would have a material adverse impact on our liquidity and financial position. We rely on other sureties in support of long-term gas supply contracts similar to those described above. There can be no assurance that these sureties will not make claims

similar to those raised by Chubb. We have performed under these contracts since their inception and intend to continue to fully perform under these contracts.

A consolidated lawsuit was filed against us in Delaware Chancery Court in connection with our recombination with our Aquila Merchant subsidiary that occurred pursuant to an exchange offer completed in January 2002. The suit raises 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. The plaintiffs' claims for equitable relief were denied by the Delaware Chancery Court in January 2002, and there has been no further activity with the lawsuit. Securities fraud complaints seeking damages based on the same conduct were also filed against us in federal court in Missouri. Persons holding certificates formerly representing approximately 1.8 million shares of Aquila Merchant common stock are also pursuing their appraisal rights in connection with the recombination. We do not believe that any of these actions will have an outcome materially adverse to us.

A number of companies that have engaged in energy trading activities, including us, have received requests from various regulatory agencies to furnish data and answer questions relating to the possible inaccurate reporting of gas trade information to various industry publications in 2000 and 2001. In response to such inquiries, we initiated a review of our reported information relative to recorded data and are fully cooperating with these investigations. Additionally, we have reported to the Federal Energy Regulatory Commission and the Commodity Futures Trading Commission that we have been unable to reconcile all of the gas trade data reported to various trade publications with the gas trade data in our internal records and that our former traders may have reported inaccurate information. A lawsuit was filed against us and numerous other energy trading companies in November 2002 by the Lieutenant Governor of the State of California alleging that we misreported gas trade data that, in turn, affected the market price of electricity in California.

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 2002.

Part 2

Item 5. Market for Registrant's Common Equity and Related Shareholder Matters

Our common stock (par \$1) is listed on the New York Stock Exchange under the symbol ILA. Through March 15, 2002, the symbol was UCU. At March 14, 2003, we had approximately 40,000 common shareholders of record. Information relating to market prices of common stock on the New York Stock Exchange and cash dividends on common stock is set forth below.

Market Price

	High	Low	Cash Dividends
2002 Quarters			
First	\$26.95	\$21.77	\$.300
Second	25.23	7.26	.300
Third	8.23	2.04	.175
Fourth	4.25	1.56	—
2001 Quarters			
First	\$32.40	\$24.81	\$.300
Second	37.85	29.35	.300
Third	33.00	26.60	.300
Fourth	31.80	21.85	.300

Item 6. Selected Financial Data

<i>In millions, except per share amounts</i>	2002	2001	2000	1999	1998
Sales	\$ 2,377.1	\$ 3,711.0	\$ 3,194.5	\$2,821.2	\$1,985.1
Gross profit	833.7	1,688.1	1,313.5	1,061.9	894.1
Earnings (loss) from continuing operations(1)	(1,722.8)(2)	245.3(3)	194.3(4)	148.0	134.7(5)
Basic earnings (loss) per common share—					
Continuing operations	\$ (10.65)	\$ 2.19	\$ 2.09	\$ 1.62	\$ 1.68
Diluted earnings per common share—					
Continuing operations	\$ (10.65)	\$ 2.12	\$ 2.08	\$ 1.61	\$ 1.66
Cash dividends per common share	\$.775	\$ 1.20	\$ 1.20	\$ 1.20	\$ 1.20
Total assets	\$ 9,259.2	\$11,966.5	\$14,026.9	\$7,538.6	\$6,130.9
Short-term debt	301.0	548.6	501.0	248.9	235.6
Long-term debt (including current maturities)	2,928.7	2,327.0	2,397.6	2,245.1	1,625.4
Company-obligated preferred securities (including current maturities)	—	350.0	450.0	350.0	100.0
Common shareholders' equity	1,607.9	2,551.6	1,799.6	1,525.4	1,446.3

The following notes reflect the pre-tax effect of items affecting the comparability of the Selected Financial Data above:

(1) Depreciation and amortization expense included (in millions) \$19.1, \$10.9, \$2.7 and \$1.2 of goodwill amortization for the years ended December 31, 2001, 2000, 1999 and 1998, respectively. Goodwill amortization was not recorded in the year ended December 31, 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, \$10.5, \$6.6 and \$7.3, respectively, of goodwill amortization.

(2) Included in earnings (loss) from continuing operations for the year ended December 31, 2002, is (a) a \$696.1 million impairment charge on our investment in Quanta Services due to a continued drop in its share price, the termination of our proxy contest for control of Quanta Services and the decline of the telecommunications industry; (b) a \$247.5 million impairment charge on our investment in Midlands Electricity due to the indicated fair value being substantially below our carrying value as suggested by recent sale negotiations and analysis, as well as a corresponding impairment charge being taken at the investment level; (c) a \$127.2 million impairment charge on our investment in Multinet and AlintaGas based on the status of negotiations to sell our interest in these businesses, as well as a corresponding impairment charge being taken at the investment level; (d) a \$227.6 million impairment charge related to our 96% owned investment in Everest Connections due to our decision to significantly reduce our funding to this business and lower values for certain technology related investments; (e) a \$178.6 million write-down of Wholesale Services' goodwill in connection with our exit of the energy trading business; (f) other impairment charges and losses on sale of assets of \$106.2 million, primarily as a result of our decision to sell \$1 billion in 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 restructure of our utility business.

(3) 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 (EBIT and net income reflect 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 Networks; (c) recorded charges of \$16.5 million in our communications business related to preliminary system design and leases in markets we do not intend to develop; 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.

(4) 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 communications fiber-optic networks. We also recorded a \$44.0 million gain on the sale of a 34% interest in Uecomm Limited to the public.

(5) In 1998 we recorded (a) asset impairment charges of \$13.2 million reflecting a plan to curtail our retail activities, (b) an \$8.0 million charge relating to our plan to dissolve the EnergyOne, LLC partnership and (c) a \$6.5 million impairment related to our investment in a power plant project.

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

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. Corporate management is responsible for making all financing decisions. 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 generally accepted accounting principles (GAAP), as an indicator of operating performance or as a measure of liquidity, or other performance measures used under GAAP. In addition, the term may not be comparable to similarly titled measures used by other entities.

See page 64 for cautionary statements and risk factors concerning forward looking statements contained in this analysis.

<i>In millions, except per share amounts</i>	Year Ended December 31,		
	2002	2001	2000
Earnings (Loss) Before Interest and Taxes:			
Domestic Networks	\$ (829.6)	\$117.9	\$215.6
International Networks	(70.1)	125.4	159.4
Total Global Networks Group	(899.7)	243.3	375.0
Capacity Services	(105.0)	88.4	21.4
Wholesale Services	(566.0)	224.9	124.5
Minority interest	—	(26.4)	—
Total Merchant Services	(671.0)	286.9	145.9
Corporate and other	(37.7)	112.6	(26.1)
Total EBIT	(1,608.4)	642.8	494.8
Interest expense	249.5	216.4	188.8
Income tax expense (benefit)	(135.1)	181.1	111.7
Earnings (loss) from continuing operations	(1,722.8)	245.3	194.3
Earnings (loss) from discontinued operations, net of tax	(329.6)	34.1	12.5
Cumulative effect of accounting change, net of tax	(22.7)	—	—
Net income (loss)	\$(2,075.1)	\$279.4	\$206.8
Diluted earnings (loss) per share:			
Continuing operations	\$ (10.65)	\$ 2.12	\$ 2.08
Discontinued operations	(2.04)	.30	.13
Cumulative effect of accounting change	(.14)	—	—
Net income (loss)	\$ (12.83)	\$ 2.42	\$ 2.21

Key Factors Impacting EBIT

Our total EBIT decreased significantly in 2002 compared to 2001. Key factors affecting 2002 results were as follows:

- We exited from the wholesale energy trading business during the third quarter of 2002 and incurred trading and contract losses of \$115.8 million during the last half of the year that related to our exit. This business contributed EBIT of approximately \$25.6 million in the third and fourth quarters of 2001, compared to a loss before interest and taxes of \$270.0 million in 2002, before impairments and restructuring charges.
- Less volatile commodity prices in the first half of 2002 compared to a robust commodity environment in the same period of 2001 resulted in a \$139.5 million decrease in EBIT from Wholesale Services, before restructuring and impairment charges.
- In 2002, we incurred \$210.2 million of restructuring charges in connection with the realignment of our Domestic Networks business and the exit from our wholesale energy trading business.
- As a result of asset sales and impairments, we recorded impairment charges and net losses on sale of assets of \$1,583.2 million in 2002.
- Lower power prices and higher natural gas prices in 2002 resulted in narrow “spark spreads” (the difference between the price at which electricity is sold and the cost of the fuel used to generate it) which reduced or eliminated the economic benefits of running certain power plants and exercising power generation rights under our tolling contracts. These conditions also negatively impacted our ability to sell additional generation capacity that came on-line. EBIT for Capacity Services in 2002 was down \$96.9 million when compared to 2001, before impairments and restructuring charges.

Cumulative Effect of Accounting Change

In October 2002, the Emerging Issues Task Force (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 Statement of Financial Accounting Standards 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 restructuring charges for the year ended December 31, 2002 that consisted of the following:

<i>In millions</i>	Year Ended December 31, 2002
Domestic Networks:	
Severance costs	\$ 16.2
Disposition of corporate aircraft	5.1
Total Domestic Networks	21.3
Capacity Services:	
Interest rate swap reductions	6.2
Total Capacity Services	6.2
Wholesale Services:	
Severance costs	30.6
Retention payments	30.5
Lease agreements	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
Total Wholesale Services	173.8
Corporate and Other severance costs	8.9
Total restructuring charges	\$210.2

Impairment Charges and Net Loss on Sale of Assets

As further discussed in Note 5 to the Consolidated Financial Statements, we recorded the following impairment charges and net loss on sale of assets for the years ended December 31, 2002, 2001 and 2000:

<i>In millions</i>	Year Ended December 31,		
	2002	2001	2000
Domestic Networks:			
Quanta Services	\$ 696.1	\$—	\$—
Everest Connections and other communication investments	227.6	16.5	4.0
Enron exposure	—	31.8	—
Gas distribution system	9.0	—	—
Total Domestic Networks	932.7	48.3	4.0
International Networks:			
Midlands	247.5	—	—
Multinet and AlintaGas	127.2	11.5	—
Other	3.4	—	—
Total International Networks	378.1	11.5	—
Capacity Services:			
Turbines	42.1	—	—
Exit from Lodi gas storage investment	21.9	—	—
Termination of Cogentrix acquisition	12.2	—	—
Capacity Services goodwill	7.9	—	—
Other	6.2	—	—
Total Capacity Services	90.3	—	—
Wholesale Services:			
Wholesale Services goodwill	178.6	—	—
Enron exposure	—	35.0	—
Other	3.5	—	3.0
Total Wholesale Services	182.1	35.0	3.0
Corporate and Other:			
Information technology assets	—	—	10.0
Corporate identity intangibles	—	—	2.4
Total Corporate and Other	—	—	12.4
Total impairment charges and net loss on sale of assets	\$1,583.2	\$94.8	\$19.4

During 2002, we also incurred a \$426.6 million loss on an impairment charge and net losses on asset sales that are reflected in discontinued operations and is not included in the table above. See the paragraph below for further discussion of these charges.

Discontinued Operations

As further discussed in Note 6 to the Consolidated Financial Statements, in connection with the sales of our gas storage facility, our gas gathering and pipeline assets, our Merchant loan portfolio

and our coal handling facility, we have reported the results of these businesses in discontinued operations for the years ended December 31, 2002, 2001 and 2000 in the Consolidated Statements of Income.

Operating results of discontinued operations are as follows:

<i>In millions</i>	Year Ended December 31,		
	2002	2001	2000
Sales	\$ 235.3	\$459.5	\$513.6
Cost of sales	164.8	359.6	398.4
Gross profit	70.5	99.9	115.2
Operating expenses:			
Operating expense	60.4	63.9	83.3
Impairment charges and net loss on sale of assets	426.6	—	7.8
Depreciation and amortization expense	23.7	32.0	31.4
Total operating expenses	510.7	95.9	122.5
Other income (expense)			
Equity in (losses) earnings of investments	5.3	3.5	(.3)
Other income (expense)	48.4	54.4	52.8
Earnings (loss) before interest and taxes	(386.5)	61.9	45.2
Interest expense	5.6	6.7	26.2
Earnings (loss) before income taxes	(392.1)	55.2	19.0
Income tax expense (benefit)	(62.5)	21.1	6.5
Earnings (loss) from discontinued operations	\$(329.6)	\$ 34.1	\$ 12.5

2002 versus 2001

Sales, Cost of Sales and Gross Profit

Sales, cost of sales and gross profit decreased \$224.2 million, \$194.8 million and \$29.4 million, respectively, in 2002 compared to 2001. These decreases were primarily due to lower natural gas liquids prices and throughput volumes for the first three quarters of 2002 as compared to the same period in 2001. As a result, sales, cost of sales and gross profit from our gas gathering and pipeline business all decreased by \$165.4 million, \$149.9 million and \$15.5 million, respectively. The sale of these operations on October 1, 2002, as compared to a full fourth quarter of operations in 2001, caused a further reduction in sales, cost of sales and gross profit of \$66.0 million, \$44.9 million and \$21.1 million, respectively.

Impairment Charges and Net Loss on Sale of Assets

In 2002, we incurred 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 handling facility and a \$4.3 million pretax gain on sale of our gas storage assets.

Depreciation and Amortization Expense

Depreciation and amortization expense decreased in 2002 by \$8.3 million primarily as a result of the sale of our gas gathering and pipeline assets in October 2002.

Income Tax Expense (Benefit)

Our current year losses resulted in an income tax benefit in 2002, as compared to income tax expense in 2001 due to earnings. In 2002, \$190.9 million of our losses will be 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 any future capital gains, we recorded a \$75.4 million valuation allowance against our capital loss carryforward. In addition, the above impairment charges and net loss on sale of assets include the effects of \$31.9 million of goodwill and other intangibles that were not deductible for income tax purposes.

2001 versus 2000

Sales, Cost of Sales and Gross Profit

Sales, cost of sales and gross profit decreased \$54.1 million, \$38.8 million and \$15.3 million, respectively, for the year ended December 31, 2001 compared to 2000. These decreases were primarily due to a 15% decline in natural gas throughput volumes from our gas gathering and pipeline assets in 2001 when compared to 2000. In addition, lower natural gas liquids prices caused further decreases to our sales, cost of sales and gross profit in 2001.

Operating Expense

Operating expense decreased \$19.4 million in 2001 from 2000 primarily due to a decrease in provisions for bad debts in the Merchant Services loan portfolio.

Impairments and Net Loss on Sale of Assets

In 2000, we recognized asset impairment charges of \$7.8 million with respect to our assessment of certain under-performing pipeline assets.

Interest Expense

Interest expense decreased \$19.5 million in 2001 compared to 2000. The majority of interest expense represents inter-company interest charges from Corporate that are eliminated in consolidation. Lower interest expense in 2001 resulted from the repayment of inter-company debt and the way interest expense was being allocated to the various business units.

Global Networks Group

Our Global Networks Group consists of our investments in domestic and international regulated electric, gas and communications networks. Domestic Networks is principally made up of our electric and gas regulated utility businesses, which operate as Aquila Networks in Colorado, Iowa, Kansas, Michigan, Minnesota, Missouri and Nebraska. Also included is 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 three years 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 selling down our ownership interest in Quanta in July 2002 and sold our remaining 11.6 million shares in February 2003.

International Networks includes our investments in Canada, Australia and the United Kingdom. Our wholly owned Canadian electric distribution companies have operations in the provinces of Alberta and British Columbia. Our Australian investments include 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% interest, held jointly with UEL, in AlintaGas Limited, a gas distribution company in Western Australia. Our United Kingdom investment consists of a 79.9% interest in Avon Energy Partners Holding Company, the holding company for Midlands Electricity, an electric distribution company in central England. Midlands also owns a combined 884 megawatts of net generation capacity in the United Kingdom, Turkey and Pakistan. Included in our results for the three years ending December 31, 2002, are the earnings from our investment in UnitedNetworks, a New Zealand gas and electric distribution company that was sold in October 2002.

Three-Year Review—Domestic Networks

<i>Dollars in millions</i>	Year Ended December 31,		
	2002	2001	2000
Sales	\$1,815.7	\$2,210.0	\$1,915.0
Cost of sales	1,119.9	1,473.1	1,244.1
Gross profit	695.8	736.9	670.9
Operating expenses:			
Operating expense	444.6	454.1	385.9
Restructuring charges	21.3	—	—
Impairment charges and net loss on sale of assets	932.7	48.3	4.0
Depreciation and amortization expense	140.8	162.1	129.3
Total operating expenses	1,539.4	664.5	519.2
Other income (expense):			
Equity in earnings of investments	1.9	28.5	52.9
Minority interest	7.8	6.4	1.9
Other income (expense)	4.3	10.6	9.1
Earnings (loss) before interest and taxes	\$ (829.6)	\$ 117.9	\$ 215.6
Identifiable assets	\$2,666.5	\$3,512.5	\$3,584.7
Electric sales and transportation volumes (GWh)	12,373	12,286	11,390
Gas sales and transportation volumes (Mcf)	235,127	216,559	241,708
Electric customers	438,000	431,000	408,000
Gas customers	891,000	874,000	863,000

2002 versus 2001

Sales, Cost of Sales and Gross Profit

Sales and cost of sales for the Domestic Networks businesses decreased \$394.3 million and \$353.2 million, respectively, in 2002 compared to 2001. These decreases were primarily the result of lower gas prices and mild winter weather in 2002, both of which impacted sales and cost of sales. Because gas purchase costs for our gas utility networks are passed through to our customers, the change in gas prices did not have a corresponding impact on our gross profit. Gross profit decreased \$41.1 million primarily as the result of \$30.1 million in 2001 off-system power sales that were not repeated in 2002. Gross profit decreased an additional \$11.5 million due to the sale of our Missouri pipeline business in January 2002.

Operating Expense

Operating expense decreased \$9.5 million in 2002 compared to 2001. The decrease in operating expense was primarily due to reduced expenses in Everest Connections resulting from the elimination of costs associated with our telecommunications consulting operation in early 2002, greater operating efficiencies and the suspension of incentive payments under the long-term incentive plan. Although there were significant labor savings in our regulated business due to a reduction in workforce and annual incentives, these amounts were offset by increased pension costs, costs associated with our proxy contest with Quanta Services and expenses related to certain regulatory matters.

Restructuring Charges

As a result of the restructuring of our domestic utility business to more closely align it with our state service areas, we incurred \$21.3 million in restructuring costs, primarily in the form of severance for terminated employees and the disposition of our corporate aircraft operation.

Impairment Charges and Net Loss on Sale of Assets

As further discussed in Note 5 to the Consolidated Financial Statements, Domestic Networks incurred \$932.7 million of losses resulting from impairments and asset sales in 2002. The impairments consisted primarily of \$696.1 million of impairment losses related to our investment in Quanta Services and \$227.6 million of impairment losses related to Everest and other communication technology investments. In addition, we recorded a \$9.0 million asset impairment charge related to a local natural gas distribution system deemed unrecoverable in one of our regulatory jurisdictions.

Depreciation and Amortization Expense

Depreciation and amortization expense decreased \$21.3 million, of which \$11.4 million was due to the elimination of goodwill amortization attributed to our Quanta Services investment and our acquisition of St. Joseph Light & Power Company. Also impacting depreciation and amortization expense was a \$13.5 million decrease in depreciation resulting from our recent Missouri electric rate case. These decreases were offset in part by a \$5.0 million increase in depreciation expense on additional communication networks placed in service during late 2001 and 2002.

Equity in Earnings of Investments

Equity in earnings of investments decreased \$26.6 million in 2002 compared to 2001. The decrease was primarily due to a decrease in equity earnings from our Quanta Services investment resulting from Quanta Services lower earnings in 2002 and a reduction of our ownership percentage in Quanta Services from 38% to 10.2% during 2002. Partially offsetting Quanta Services' lower earnings was the elimination of approximately \$9.5 million of goodwill amortization that was previously in the financial statements of Quanta Services.

Other Income (Expense)

Other income (expense) decreased \$6.3 million in 2002 from 2001. This decrease was primarily due to the loss of interest earned in 2001 on the note receivable from Enron discussed below.

2001 versus 2000

Sales, Cost of Sales and Gross Profit

Sales, cost of sales and gross profit for our Domestic Networks businesses increased (in millions) \$295.0, \$229.0 and \$66.0, respectively, in 2001 compared to 2000. Increased sales and cost of sales were mainly driven by higher natural gas prices in early 2001. Our acquisition of St. Joseph Light & Power Company in December 2000 contributed sales, cost of sales and gross profit of (in millions) \$104.1, \$40.9 and \$63.2, respectively. Gross profit in 2001 also increased \$12.6 million due to stronger off-system power sales.

Operating Expense

Operating expense increased \$68.2 million in 2001 compared to 2000 due to the inclusion of a full year's operations of St. Joseph Light & Power, which had operating expenses of \$21.9 million. Start-up operating expenses in connection with the build-out of Everest Connections contributed an additional \$30.5 million of the increase. Increased bad debt expenses related to higher natural gas costs in late 2000 and early 2001 and certain industrial customer bankruptcies in 2001 also contributed to higher operating expenses.

Impairment Charges and Net Loss on Sale of Assets

In 2001, we recorded an impairment charge of \$31.8 million on an unsecured note receivable from Enron Corporation that was written off following Enron's December 2001 bankruptcy filing. In addition, we wrote off \$16.5 million related to Everest Connections' abandonment of certain communication system assets and related leases in markets it originally intended to develop.

Depreciation and Amortization Expense

Depreciation and amortization expense increased \$32.8 million in 2001 compared to 2000, primarily as the result of \$16.4 million of increased depreciation related to the assets acquired in the St. Joseph Light & Power merger that occurred in December 2000. Also contributing to the increase was \$4.6 million of depreciation on additional capital expenditures in our utility operations and \$10.3 million of additional depreciation resulting from our Everest network build-out.

Equity in Earnings of Investments

Equity in earnings of investments decreased \$24.4 million in 2001 compared to 2000, primarily due to reduced equity earnings from our investment in Quanta Services and the termination of our management fee agreement with Quanta Services in December 2000. Our reduced equity earnings from Quanta Services stemmed from a slowdown in the telecom market and the write-off of certain receivables from its telecom customers.

Current Operating Developments

Quanta Services Ownership. During 2002 we wrote our investment in Quanta Services down to fair value and sold approximately 17.6 million of its shares which reduced our ownership from 38% to 10.2%. As a result, we now account for this asset as a cost method security available for sale in future periods. At December 31, 2002, our carrying value of this investment was \$40.6 million or \$3.50 a share. We sold our remaining 11.6 million shares during the first quarter of 2003 at a net price of \$2.90 a share.

Everest Connections. During the fourth quarter of 2002, we restricted future funding of Everest to levels necessary to complete construction in progress and serve existing customers. We evaluated the strategic alternatives for Everest and chose to restructure the business so that going forward it is self-funded from operations.

Three Year Review—International Networks

<i>Dollars in millions</i>	Year Ended December 31,		
	2002	2001	2000
Sales	\$ 261.7	\$ 253.6	\$ 492.4
Cost of sales	34.0	43.0	311.8
Gross profit	227.7	210.6	180.6
Operating expenses:			
Operating expense	120.2	94.5	63.0
Impairment charges and net loss on sale of assets	378.1	11.5	—
Depreciation and amortization expense	58.1	55.8	45.4
Total operating expenses	556.4	161.8	108.4
Other income (expense):			
Equity in earnings of investments	112.0	61.5	44.2
Minority interest in income of subsidiaries	—	—	(3.3)
Gain on sale of subsidiary stock	130.5	—	44.0
Other income (expense)	16.1	15.1	2.3
Earnings (loss) before interest and taxes	\$ (70.1)	\$ 125.4	\$ 159.4
Identifiable assets	\$1,607.1	\$1,867.2	\$2,172.8
Electric sales volumes (GWh)	16,003	15,373	13,785
Canadian electric customers	483,000	469,000	456,000

2002 versus 2001

Sales, Cost of Sales and Gross Profit

Sales increased \$8.1 million in 2002 compared to 2001, primarily due to a \$4.2 million rate increase in British Columbia and a \$9.6 million interim rate increase in Alberta. Offsetting the rate increases were the reduction in sales and cost of sales stemming from the sale of the Alberta retail operations in January 2001. Cost of sales decreased an additional \$9.0 million in 2002 due to the deferral of additional excess purchased power costs in Alberta that regulatory authorities have now approved for recovery in future periods.

Operating Expense

Operating expense increased \$25.7 million in 2002 compared to 2001. This increase was primarily due to \$6.0 million of business development costs, \$6.0 million of costs associated with the integration of our British Columbia and Alberta operations, \$4.0 million of increased operating costs in our Canadian networks and \$2.8 million of transition costs related to our Midlands Electricity acquisition.

Impairment Charges and Net Loss on Sale of Assets

In 2002, impairment charges mainly consisted of \$247.5 million related to our investment in Midlands Electricity in the U.K. and a \$127.2 million impairment charge related to our investments in Multinet Gas and AlintaGas in Australia. These impairments were determined based on the estimated fair value of these investments considering current market information, which included recent offers to sell our interest in these businesses, as well as corresponding impairment charges being taken in the financial statements of the underlying business.

Equity in Earnings of Investments

Equity in earnings of investments increased \$50.5 million in 2002 compared to 2001. Midlands, acquired in May 2002, contributed \$41.9 million, excluding impairments, of the increase. An additional \$8.1 million of the increase was due to goodwill no longer being amortized in the financial statements of our equity method investments.

Gain on Sale of Subsidiary Stock

In October 2002, through a public tender offer in New Zealand, VECTOR Limited acquired all of the outstanding shares of UnitedNetworks Limited (UNL), in which we had a 70.2% indirect interest. We realized a \$130.5 million pretax gain on the sale of this investment.

2001 versus 2000

Sales, Cost of Sales and Gross Profit

Sales and cost of sales for our International Networks businesses decreased \$238.8 million and \$268.8 million, respectively, in 2001 compared to 2000. Gross profit increased \$30.0 million in 2001. These changes were primarily due to the following:

- The deconsolidation of our New Zealand operations in June 2000 decreased sales, cost of sales and gross profit by \$104.6 million, \$32.7 million and \$71.9 million, respectively, but increased equity earnings as shown below.

- Our acquisition of TransAlta's electric distribution business in Alberta, Canada in August 2000, and subsequent sale of its lower margin retail business in January 2001, resulted in a decrease in sales and cost of sales of \$134.9 million and \$237.1 million, respectively. This increased gross profit by \$102.2 million.

Operating Expense

Operating expense increased \$31.5 million in 2001 compared to 2000. The purchase of our Alberta network increased operating expenses by \$39.7 million, while deconsolidating our New Zealand business decreased operating expenses by \$10.5 million.

Impairment Charges and Net Loss on Sale of Assets

In 2001, we recorded charges of \$11.5 million relating to the realizability of deferred tax assets and interest receivable on shareholder loans in our Australian equity investments.

Equity in Earnings of Investments

Equity in earnings of investments increased \$17.3 million in 2001 compared to 2000. After the sale of a portion of our New Zealand investment in June 2000, we were required to deconsolidate this investment and use the equity method of accounting to record our share of earnings. This increased equity earnings by \$16.5 million.

Other Income (Expense)

Other income (expense) increased \$12.8 million, primarily reflecting the allowed recovery of carrying costs on deferred excess purchased power costs in Alberta. Alberta regulators approved the recovery of carrying costs in December 2001.

Gain on Sale of Subsidiary Stock

We recorded a \$44.0 million gain when UEL completed an initial public offering of 34% of Uecomm Limited, its telecom business.

Current Operating Developments

United Kingdom. Recent downgrades in credit ratings assigned to the public debt in the Midlands ownership chain have 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 (Ofgem), now requires pre-approval of cash payments to the owners in the form of management fees or dividends. Accordingly, we intend to record equity earnings and management fees only to the extent of cash received.

In August 2002, Aquila and FirstEnergy initiated a process for the sale of Midlands with final bids due in December 2002. We received offers in early December and are currently in negotiations with the prospective buyers.

Australia. We are currently exploring the possible sale of our investments in Australia and anticipate a sale being completed in 2003, however, there can be no assurances that this will occur.

Canada. In December 2001, we filed for an annual rate increase in Alberta of about \$30.0 million along with an application for a performance-based rate-setting mechanism. We subsequently modified that request and sought a \$12.7 million increase for 2002 and a \$6.0 million increase for 2003. In July 2002, an interim rate increase of approximately \$9.6 million was approved. Hearings were held in September and October 2002 and a final order was issued in February 2003, resulting in a decrease in rates of \$21.0 million for 2002, and no increase in rates in 2003 (2002 rates carried forward to 2003). Almost all of the reduction in rates related to depreciation on distribution assets (average asset lives were extended) and the related income tax effect. The decision did not adjust the allowed rate of return earned by the Company and therefore, net income is not expected to be materially impacted by this decision. However, the decision is estimated to reduce annual cash flow from operations by approximately \$17.0 million for 2004 and beyond. With regard to 2003, cash flow from operations will be reduced by approximately \$33.0 million, which includes the effect of both the 2002 and 2003 reduction.

As a result of the above action, we are currently reassessing the future recoverability of \$188.6 million of recorded goodwill in Canada.

Merchant Services

We conduct our Merchant Services business through Aquila Merchant Services, Inc. (Aquila Merchant), which operates as two business segments, Capacity Services and Wholesale Services. Capacity Services primarily owns, operates and contractually controls our non-regulated power generation assets. Wholesale Services includes our North American and European commodity, client and capital businesses.

In 2000 and the first four months of 2001, we owned 100% of Aquila Merchant. In April 2001, approximately 20% of Aquila Merchant was sold to the public. For the remainder of 2001, Aquila Merchant was consolidated with a minority interest reflected in the financial statements. In January 2002, we acquired the outstanding public shares of Aquila Merchant in an exchange offer and merger. The following Capacity Services and Wholesale Services financial information includes 100% of Aquila Merchant before minority interest, which totaled \$26.4 million for the year ended December 31, 2001.

Three-Year Review—Capacity Services

<i>In millions</i>	Year Ended December 31,		
	2002	2001	2000
Sales	\$ 399.4	\$ 604.6	\$ 297.6
Cost of sales	389.5	490.6	271.1
Gross profit	9.9	114.0	26.5
Operating expenses:			
Operating expense	64.5	47.9	22.3
Restructuring charges	6.2	—	—
Impairment charges and net loss on sale of assets	90.3	—	—
Depreciation and amortization expense	9.5	7.5	1.5
Total operating expenses	170.5	55.4	23.8
Other income (expense):			
Equity in earnings of investments	52.8	28.9	18.7
Other income (expense)	2.8	.9	—
Earnings (loss) before interest and taxes	\$ (105.0)	\$ 88.4	\$ 21.4
Identifiable assets	\$1,203.2	\$1,593.5	\$1,382.1

2002 versus 2001

Sales, Cost of Sales, and Gross Profit

Sales and cost of sales for our Capacity Services operations decreased \$205.2 million and \$101.1 million, respectively, in 2002 compared to 2001, resulting in a decrease in gross profit of \$104.1 million. These decreases were primarily due to the following factors:

- Decreases in electricity prices resulted in lower sales and cost of sales, and the lack of pricing volatility reduced the opportunities to optimize our assets with forward sales of power, both of which decreased gross profit in our power generation business relative to the mark-to-market gains of approximately \$54.6 million we recorded in 2001.
- In connection with our merchant power plants, we make fixed capacity payments evenly throughout the year. For the year ended December 31, 2002, capacity payments increased by \$32.6 million when compared to 2001 as new plants became operational or were on-line for a full year. Due to lower power prices in 2002, this additional capacity was utilized on a limited basis at prices that were not sufficient to cover the fixed payments.
- Contract terminations due to counterparty creditworthiness generated losses of \$10 million in 2002.
- Reduced demand for electricity driven by reduced liquidity in the market and over-building of generation capacity has resulted in lower electricity prices and “spark spreads” (the difference between the price at which electricity is sold and the cost of the fuel used to

generate it) which have substantially impacted our ability to economically operate our peaking generation plants.

Operating Expense

Operating expense increased \$16.6 million due to increased operating costs from additional power plants and gas storage coming on line. This was partially offset by lower compensation expense resulting from the elimination of incentive compensation in 2002.

Restructuring Charges

In 2002, we recorded restructuring charges of \$6.2 million relating to the termination of certain interest rate swaps associated with the construction financings for our Clay County and Piatt County power plants. As debt related to these facilities was paid down earlier than anticipated, our swaps were in excess of our outstanding debt. We therefore reduced our position and realized the loss associated with the cancelled portion of the unfavorable swap.

Impairment Charges and Net Loss on Sale of Assets

Impairment charges and net loss on sale of assets of \$90.3 million included \$42.1 million relating to the expected loss associated with either the sale or contract termination of four electric turbines that will be 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 the Cogentrix acquisition, \$7.9 million of goodwill that was impaired under SFAS 142 and \$6.2 million of other impairments.

Equity in Earnings of Investments

Equity in earnings of investments increased \$23.9 million due to \$10.4 million of continued strong operating performance from various independent power projects and \$7.1 million of increased earnings resulting from the recovery of accounts receivable that were reserved for in 2001.

2001 versus 2000

Sales, Cost of Sales and Gross Profit

Sales and cost of sales for our Capacity Services operations increased \$307.0 million and \$219.5 million, respectively, in 2001 compared to 2000. Gross profit increased \$87.5 million. These increases were primarily the result of the following factors:

- The GPU International acquisition in December 2000 added approximately \$54.9 million to gross profit in 2001 while adding \$81.6 million and \$26.7 million to sales and cost of sales, respectively.
- In 2001, we sold power generation capacity at prices significantly above our operational cost, thus increasing sales, cost of sales and gross profit.
- The additional sales and cost of sales are also the result of additional capacity brought on line.

Operating Expense

Operating expense increased \$25.6 million in 2001 compared to 2000, primarily as the result of our GPU International acquisition in December 2000.

Depreciation and Amortization Expense

Depreciation and amortization expense increased \$6.0 million in 2001 compared to 2000, primarily as the result of our GPU International acquisition in December 2000.

Equity in Earnings of Investments

Equity earnings of investments increased \$10.2 million in 2001 compared to 2000. Approximately \$11.6 million of this increase relates to the equity investments in four independent power plants that we added as part of our acquisition of GPU International in December 2000.

Merchant Power Capacity Payments

We have cash obligations under long-term fixed capacity contracts that entitle us to generate power at power plants owned by others over the next 18 years. See Note 23 to the Consolidated Financial Statements for a summary of these contracts. Due to reduced spark spreads and an oversupply of generation that are expected to continue in the foreseeable future, it is unlikely that we will be able to recover the \$101.3 million of capacity payments in 2003. Using current forecasted spark spreads for 2003, we expect to generate gross profit of approximately \$3.0 million (before considering hedges and previous forward sales of \$19.8 million) to offset these capacity payments. These losses and cash outflows negatively impact our financial condition and liquidity position. Because resources are limited and these arrangements are inconsistent with our long-term strategy, we are attempting to restructure or terminate certain of these contractual obligations on terms mutually acceptable to us and our counterparties. The expected impact of our power capacity payments for 2003 are summarized below:

In millions

Annual capacity payments	\$101.3
Pretax income statement expected loss	78.5
Amount capacity payments exceed cash inflows	61.9

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 by the continued construction of additional power plants over the next 18-month horizon. This increase in supply has placed downward pressure on power prices and subsequently the value of unsold merchant generation capacity. As a result of the above factors and our change in strategy, we do not expect our Capacity Services unit to be profitable in the next 2 to 3 years.

We attempt to optimize and hedge our power plants with forward contracts which qualify as derivative instruments. When we enter into these positions, they are accounted for 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.

Three-Year Review—Wholesale Services

<i>In millions</i>	Year Ended December 31,		
	2002	2001	2000
Sales	\$ (99.7)	\$ 642.8	\$ 489.5
Cost of sales	—	16.2	54.0
Gross profit (loss)	(99.7)	626.6	435.5
Operating expenses:			
Operating expense	113.6	333.1	276.6
Restructuring charges	173.8	—	—
Impairment charges and net loss on sale of assets	182.1	35.0	3.0
Depreciation and amortization expense	6.4	16.0	15.9
Total operating expenses	475.9	384.1	295.5
Other income (expense):			
Equity in earnings of investments	—	.2	—
Other income (expense)	9.6	(17.8)	(15.5)
Earnings (loss) before interest and taxes	\$ (566.0)	\$ 224.9	\$ 124.5
Identifiable assets	\$3,092.1	\$4,653.9	\$6,504.9

2002 versus 2001

Sales and Gross Profit

Sales and gross profit for our Wholesale Services operations decreased \$742.5 million and \$726.3 million, respectively, in 2002 compared to 2001. These decreases were primarily due to the following factors:

- In the second quarter of 2002, we announced that we were exiting the wholesale energy trading business. Therefore, we were not adding to our trading portfolio in the second half of 2002 and had limited opportunities for earnings. Gross profit in the last half of 2001 was \$170.3 million, compared to a loss of \$231.6 million in 2002.
- Included in the \$231.6 million loss in the third and fourth quarters of 2002, were gross margin losses of approximately \$115.8 million to balance counterparty positions, reduce open positions and terminate existing contracts as a result of our decision to exit the wholesale energy trading business. Our remaining 2002 margin losses that were incurred in the last six months of the year stem from unfavorable movements in credit, liquidity and interest reserves, unfavorable movements in trading positions, and unfavorable adjustments related to final settlements.
- Lack of price trends and lower volatility limited our opportunities to execute our trading strategy in the first half of 2002, which reduced sales and gross profit by approximately

\$324.4 million. During the first six months of 2001, price trends and high price volatility in the market provided the strongest two quarters in Wholesale Services history.

Due to the rescission of EITF 98-10 as previously discussed, our gains and losses from energy trading contracts are now required to be shown on a net basis. To the extent losses exceeded gains, as was our case in 2002, sales are shown as a negative number.

Operating Expense

Operating expense decreased \$219.5 million primarily due to the elimination of incentive compensation expense in 2002 and lower compensation expense due to staff reductions related to our exit of Wholesale Services.

Restructuring Charges

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 excess 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.

Impairment Charges and Net Loss on Sale of Assets

Impairment charges and net loss on sale of assets consisted primarily of an impairment charge of \$178.6 million related to goodwill associated with Wholesale Services that became unrealizable due to our exit from wholesale energy trading.

Depreciation and Amortization Expense

Depreciation and amortization expense decreased \$9.6 million due to the elimination of goodwill amortization, the write-off in 2001 of certain interactive web-based assets and the 2002 restructuring charge on leasehold improvements and equipment that have now been fully expensed and therefore no longer subject to depreciation and amortization.

Other Income (Expense)

Other income (expense) increased by \$27.4 million primarily due to a decrease in accounts receivable sale program fees due to the cancellation of the program in early 2002 and lower interest paid on customer margin deposits in 2002.

2001 versus 2000

Sales and Gross Profit

Sales and cost of sales for our Wholesale Services operations increased \$153.3 million and decreased \$37.8 million, respectively, in 2001 compared to 2000, while gross profit increased \$191.1 million in the same period. These fluctuations were primarily due to the following:

- A volatile pricing environment for gas and electricity, particularly in early 2001, provided opportunities to profitably execute our trading strategies and increase sales of our risk management products and services to our clients.
- Electricity and gas volumes marketed in 2001 increased 84% and 13%, respectively, over 2000, contributing to a combined 34% increase on a total Btu equivalent per day basis. These increases, together with a 27% increase in the number of commodity transactions executed, contributed to the increase in sales and gross profit.
- In 2001, we sold our merchant retail business, which caused sales and cost of sales to drop \$38.6 million and \$37.0 million, respectively, when compared to 2000.
- A 5% increase in average gas prices also increased our sales.
- A 28% increase in the number of client transactions in 2001 compared to 2000 contributed to a 34% increase in gross profit from our origination deals and from the more highly customized products we called Client Services. These products included our GuaranteedWeather® and GuaranteedGenerationSM products as well as our longer-duration gas and electric contracts.

Operating Expense

Operating expense increased \$56.5 million because our merchant business expanded during 2001 and our stronger performance in 2001 resulted in higher incentive compensation expense. Also impacting operating expenses was the allocation of \$10.8 million of expenses from Corporate and Other.

Impairment Charges and Net Loss on Sale of Assets

Impairment charges in 2001 included the write-off of approximately \$35.0 million related to our trading exposures with Enron. While the \$35.0 million write-off represents our best estimate of our exposure based on our contracts with Enron, the ultimate outcome is subject to review by the bankruptcy courts.

Earnings Trend and Impact of Strategy Change

As previously stated, 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 while we continue to deliver gas under our long-term gas contracts. Because our trading book is predominantly hedged, we should experience little in the way of 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. However, there may be earnings volatility associated with the runoff of a portion of our trading book representing

highly customized, actuarial based products. These transactions are typically hedged using an actuarial approach similar to that used by the insurance industry and could have negative outcomes as book obligations settle over time. As of December 31, 2002, we had ten contracts remaining in this portion of the portfolio, with the last contract expiring in 2006. Using a long-term value at risk methodology, with a 95% confidence level, we would estimate \$47 million of total exposure (potential losses) through 2006 related to these contracts.

Corporate Matters

Corporate and Other

The table below summarizes the Corporate and Other EBIT for the three years ended December 31, 2002. Corporate and Other primarily contains the retained costs of the Company that are not allocated to the business units.

<i>In millions</i>	Year Ended December 31,		
	2002	2001	2000
Operating expenses:			
Operating expense	\$ 13.7	\$ 13.0	\$ 13.2
Restructuring charges	8.9	—	—
Impairment charges and net loss on sale of assets	—	—	12.4
Depreciation and amortization expense	(.5)	(.5)	1.5
Total operating expenses	22.1	12.5	27.1
Other income (expense):			
Equity in earnings of investments	.2	.2	—
Gain on sale of subsidiary stock	—	110.8	—
Other income (expense)	(15.8)	14.1	1.0
Earnings (loss) before interest and taxes	\$ (37.7)	\$112.6	\$ (26.1)
Identifiable assets	\$690.3	\$339.4	\$382.3

2002 versus 2001

Restructuring Charges

Restructuring charges in 2002 includes \$8.9 million of executive severance in connection with the separation agreements with our former Chief Executive Officer and Chief Financial Officer.

Other Income (Expense)

Other income (expense) decreased \$29.9 million in 2002 when compared to 2001. Included in 2002 was \$5.9 million of foreign exchange and interest rate losses relating to our original planned financing structure that was not consummated in connection with the Midlands acquisition. Also impacting 2002 were \$3.4 million of foreign currency losses on inter-company loans and \$4.0 million of write-downs on certain technology related investments. We also paid approximately \$2.4 million of fees in the fourth quarter of 2002 in connection with the waiver of a covenant default on several bank financing agreements. In addition, in 2001 we allocated

\$10.8 million of additional expense to our merchant business that had no effect on the consolidated results. However, it was a favorable adjustment in 2001 that did not occur in 2002.

Interest Expense

Interest expense and minority interest in income of partnership and trusts increased \$33.1 million in 2002 compared to 2001. Interest expense was higher primarily as a result of the following:

- The issuance of \$287.5 million of senior notes in February 2002;
- Interest on debt relating to the acquisition of our interest in Midlands in May 2002; and
- The issuance of \$500.0 million of 14.875% senior notes in July 2002.

These increases were offset in part by lower rates on variable rate short-term and long-term debt and the retirement of \$350.0 million of company-obligated preferred securities in 2002. In addition, we retired \$100.0 million of company-obligated preferred securities and \$204.1 million of other long-term notes in June 2001.

Income Tax Expense (Benefit)

Income taxes decreased \$316.2 million in 2002 compared to 2001, primarily as a result of our loss before income taxes in 2002 as compared to record earnings in 2001. However, the 2002 expected income tax benefit was significantly reduced as a result of the following factors.

- The tax benefit from a number of our asset sales or impairments generated substantial capital losses that were limited to available capital gains in the preceding three years and subsequent five years. Because capital gains within the carryback period were less than the loss and significant capital gains could not be assured in the foreseeable future, a \$306.2 million valuation allowance was established to offset our capital loss carryforward.
- The \$178.6 million and \$21.9 million of impairment charges and asset sales related to Wholesale Services and Capacity Services goodwill, respectively, are considered a permanent difference between book and taxable income and does not result in the recognition of a tax benefit.
- Due to our need for capital and our change in business strategy to return the Company back to a domestic regulated utility with some non-regulated generation, we sold our New Zealand investment, and we are in the process of exploring the sale of our Australian, United Kingdom, and Canadian investments. As a result, we can no longer represent that cash from our international investments will be permanently invested. Therefore, additional deferred tax was recorded to account for taxes that will arise when we bring asset sale proceeds back to the United States. As a result, we recorded additional taxes of \$148.3 million in 2002.

2001 versus 2000

Impairment Charges and Net Loss on Sale of Assets

In 2000 we recognized charges of \$10.0 million related to certain information technology assets that are no longer used in the business, and \$2.4 million related to our decision to discontinue use of certain corporate identity intangibles.

Gain on Sale of Subsidiary Stock

In connection with the initial public offering of Aquila Merchant in April 2001, we sold 5.75 million of previously issued shares and realized a pretax gain of approximately \$110.8 million.

Other Income (Expense)

Other income (expense) increased \$13.1 million primarily due to the allocation of \$10.8 million of expenses to our merchant business that had no effect on the consolidated results, but was a favorable corporate adjustment in 2001.

Interest Expense

Interest expense and minority interests in income of partnership and trusts increased \$27.6 million in 2001 compared to 2000. This was primarily due to increased long-term borrowings in late 2000 and early 2001 related to the acquisitions of our Alberta network, AlintaGas, St. Joseph Light & Power and GPU International.

Income Tax Expense

Income taxes increased \$69.4 million in 2001 compared to 2000. This was primarily due to the increased earnings before income taxes in 2001 resulting from the factors previously discussed. Our overall effective tax rate increased from 36.5% in 2000 to 42.5% in 2001. The increase in our effective tax rate was due primarily to the effect of increased minority interest in income of subsidiaries, taxes on the gain recognized on the sale of our shares in Aquila Merchant, and valuation allowances on certain international losses.

Critical Accounting Policies

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:

Sales Recognition. The portion of our sales related to 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 period 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.

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 the customer after the date of the last meter reading and recorded as unbilled revenue. The unbilled revenue is calculated each month based on estimated customer usage, weather factors, line losses and applicable customer rates.

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 Statement of Financial Accounting Standards (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 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, which could be considerably less than the carrying amount of future undiscounted cash flows. 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 generally determined by calculating the discounted future cash flows using a discount rate based upon our weighted average cost of capital. 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.

Investments in Unconsolidated Subsidiaries. We account for our equity investments in accordance with Accounting Principles Board No. 18, "The Equity Method of Accounting for Investments in Common Stock" (APB 18). APB 18 states that a loss in value which is considered other than temporary should be recognized. APB 18 states that if the current fair value of an investment is less than its carrying amount, this may indicate an other than temporary loss in the value of the investment. As discussed above, determining fair market value is highly subjective, requiring significant judgments and assumptions. Changes in estimates could have a material effect on the assessment of our equity investments.

Goodwill and Other Intangible Assets. On January 1, 2002, we adopted Statement of Financial Accounting Standards (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. Other intangibles are to be tested for impairment in accordance with SFAS 144 as discussed above. 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.

Regulatory Accounting Implications. We currently record the economic effects of regulation in accordance with the provisions of Statement of Financial Accounting Standards No. 71 "Accounting for the Effects of Certain Types of Regulation" (SFAS 71). Accordingly, our balance sheet reflects certain costs as 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 net regulatory assets at December 31, 2002 were \$137.4 million, including deferred purchased power costs of \$82.1 million related to our Alberta, Canada electricity business.

Valuation of Deferred Tax Assets. We are required to assess the ultimate realization of deferred tax assets generated from capital losses incurred on the sale of assets. This assessment takes into consideration tax planning strategies within our control, including assumptions regarding the availability and character of future taxable income. At December 31, 2002, we have recorded \$381.6 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. The ultimate amount of deferred tax assets realized could be materially different from those recorded, as impacted by political changes in federal income tax laws and upon the actual realization of the related tax assets.

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, 2002, our average assumed discount rate was 6.71% and our average expected return on plan assets was 9.15%.

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 or decrease 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, 2002, and our estimated annual pension cost (APC) on the income statement for 2003 by a similar amount in the opposite direction. Each sensitivity below reflects an evaluation of the change based solely on a change in that assumption.

<i>Dollars in millions</i>	Change in Assumption Inc(dec)	Impact on PBO Inc(dec)	Impact on APC Inc(dec)
Discount rate	.25%	\$(11.7)	\$(.9)
Rate of return on plan assets	.25%	—	\$(.8)

LIQUIDITY AND CAPITAL RESOURCES

Overall

We are currently operating in a business environment that has substantially limited our ability to raise incremental capital through the bank and capital markets. As of March 14, 2003, we had \$486.4 million of unrestricted cash on hand, no available capacity under our current revolver and the following short-term debt, net of any collateral held:

<i>In millions</i>	Debt Outstanding at December 31, 2002	Debt Outstanding at March 14, 2003	Cash Collateral Held at March 14, 2003	Net Amount Outstanding at March 14, 2003
Short-term debt:				
Revolving credit facility—				
United States(a)(b)	\$244.4	\$189.8	\$ —	\$189.8
Turbine facility(a)	43.4	33.8	(28.0)	5.8
Bank borrowings and other—Canada	13.2	14.1	—	14.1
Subtotal	301.0	237.7	(28.0)	209.7
Current maturities of long-term debt:				
Clay County project notes(a)	98.4	75.3	—	75.3
Piatt County project notes(a)	146.7	126.6	(54.3)	72.3
Canadian denominated credit facilities(a)	78.6	84.2	—	84.2
Australian notes(d)	83.8	22.3	—	22.3
Canadian asset securitization(c)	91.6	99.3	—	99.3
Miscellaneous	31.6	31.9	—	31.9
Subtotal	530.7	439.6	(54.3)	385.3
Total	\$831.7	\$677.3	\$(82.3)	\$595.0

(a) Amount repaid in full concurrent with new financings described below.

(b) We have cash collateral held by our revolving credit banks of \$60.1 million as of March 14, 2003, which collateralizes \$228.0 million of letters of credit issued under the revolving credit facility.

(c) This facility is secured by certain future rate collections and will be repaid monthly through February 2004.

(d) Amount repaid in full in April 2003.

On April 11, 2003, we closed on a three-year senior secured financing of \$430.0 million and a 364-day senior secured financing of \$100.0 million. The 364-day financing also includes an option under which we can, during a 30-day period following closing, at our discretion, increase the size of the financing by up to \$100.0 million. See Notes 12 and 13 to the Consolidated Financial Statements for additional information regarding the terms of the financings. Proceeds from the financings will be used to retire debt and support existing and future letters of credit. The

secured financings will eliminate the covenant violations stated below. With the above financings, we believe we will have sufficient liquidity to cover our operational needs through June 2004. Our next significant need for outside capital relates to our need to retire senior notes maturing in 2004. We anticipate retiring these notes with proceeds from additional asset sales. In the event we are not successful in closing the asset sales, we would need to obtain a bridge loan to meet these obligations. Although no assurance can be given on the above actions, we expect to be successful in their execution.

Financing and Debt Covenants

On April 12, 2002, we entered into a new revolving credit facility totaling \$650 million that replaced a \$400 million credit facility. The new credit facility consisted of two \$325 million agreements, one with a maturity date of 364 days, the other three years. At December 31, 2002, we had \$244.4 million of revolving bank loan borrowings outstanding and \$195.6 million of letters of credit issued against the facility.

As explained in Note 12 of the Consolidated Financial Statements, we received waivers in the third quarter from lenders under our revolving credit facilities and other credit arrangements from the requirement that we maintain a certain interest coverage ratio. In exchange, we agreed to use a portion of the proceeds we received from certain asset sales to reduce our obligations to those lenders. Such prepayments on our revolving credit agreements reduced, on a dollar-for-dollar basis, the lenders' commitment to extend credit to us under those agreements. As of December 31, 2002, we made payments of approximately \$161.1 million against our revolver that in turn reduced our maximum borrowing limits to \$494.4 million and established a cash collateral balance of \$5.5 million against our letters of credit. Between December 31, 2002 and March 14, 2003, we made additional payments from asset sale proceeds of \$109.2 million, further reducing our borrowing capacity to \$439.8 million and increasing our cash collateral balance to \$60.1 million. In April 2003, debt outstanding under the 364-day credit facility was repaid in full and the unutilized portion of the three-year credit facility was terminated. The utilized portion of this facility is only being used as support for our letters of credit currently outstanding. The lenders have agreed to (a) allow the letters of credit that are fully cash collateralized under the three-year credit facility (and, thus, the facility itself) to remain outstanding and (b) waive certain restrictions for an additional three-week period. During the next three weeks, the Company intends to replace the letters of credit issued under the three-year facility with new letters of credit under a different credit facility that will be fully cash collateralized.

Asset Sales Program

Earlier this year we initiated an extensive asset sales program to enhance our liquidity and, in light of our change in business strategy, dispose of non-core assets. Following is a table of asset sales completed during 2002.

<i>In millions</i>	Gross Proceeds
Gas gathering and pipeline assets	\$ 262.9
Lockport Energy	37.5
UnitedNetworks	489.1
U.K. gas storage	36.9
Quanta Services investment	48.5
Gas storage facility	160.4
Merchant loan portfolio	258.5
Other assets	55.7
Total	\$1,349.5

Suspension of Dividend

In November 2002, the Board of Directors suspended the annual dividend on our common stock for an undetermined time. This decision stems from a detailed analysis of our current financial condition, its liquidity forecast and its earnings prospects after completion of the asset sales program discussed above. Based on this analysis, the Board of Directors decided that the most prudent course of action was to suspend the dividend until our financial condition and stability is clarified. At this time we cannot predict when or if the Board of Directors will reinstate the dividend or, if reinstated, what the annualized dividend rate will be in the future. Our three-year senior secured credit facility described in Note 13 to the Consolidated Financial Statements prohibits us from paying dividends if our senior unsecured debt is not rated at least Ba2 by Moody's and BB by S&P.

Current Credit Ratings

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 April 11, 2003, our senior unsecured long-term debt ratings, as assessed by the three major credit rating agencies, were as follows:

Agency	Rating	Commentary
Moody's Investors Service (Moody's)	Caa1	Negative Outlook
Standard & Poor's Corporation (S&P)	B	Negative Outlook
Fitch Ratings (Fitch)	B-	Negative Outlook

During 2002, Moody's lowered our credit rating from investment grade of Baa3 to Ba2 negative outlook, a non-investment grade. Additionally, S&P downgraded us to BB, a non-investment grade rating, from BBB, with a negative outlook and Fitch downgraded us to BB, from BBB -, with a negative outlook. In 2003, Moody's further downgraded us to Caa1 and Fitch and S&P downgraded us to B- and B, respectively. As a result of these downgrades, we were required to post additional collateral to support certain loan and operating contracts discussed below.

Ratings Triggers

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 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. Certain of our subsidiaries have trigger events tied to specified credit ratings. Because of guarantee and cross default provisions between Aquila, Inc. and these subsidiaries, the ratings triggers of our subsidiaries discussed below should be viewed as if they are directly applicable to Aquila, Inc.

In 2002, we retired \$91.7 million of our Australian denominated notes that were put to us after the credit downgrades. Our Australian subsidiaries have three other outstanding series of Australian denominated notes totaling \$78.6 million at December 31, 2002. The holders of \$62.9 million of these notes exercised their put rights and were repaid in January 2003. The remaining notes totaling \$15.7 million were repaid in April 2003.

Aquila Merchant also has three “tolling agreements,” a construction loan and certain margining agreements that have trigger events tied to Aquila’s credit ratings. Under the tolling agreements, our subsidiary uses a third party’s generation assets to convert fuel into electric power for its subsequent resale. As of March 14, 2003, we have posted collateral due to our downgrades by Moody’s and S&P of \$82.3 million related to the tolling agreements, \$27.5 million related to the construction loan, and \$60.0 million related to standard margining agreements.

Other Potential Demands for Collateral Due to Downgrades

Although we have substantially exited the wholesale energy trading business of Aquila Merchant, a number of energy trading agreements remain to be settled or liquidated. These contracts consist of various long-term gas contracts, forward purchases and sales of gas and electricity, weather derivatives, alternative risk contracts, coal and other commodity trading contracts that are difficult to liquidate. These contracts typically include provisions that allow counterparties to request additional collateral to support underlying transactions if events occur that cause counterparties to believe that there has been deterioration in our creditworthiness. As a result of the downgrades, we provided collateral to certain counterparties in the form of cash deposits or letters of credit totaling \$145.0 million through March 14, 2003. While it is difficult to predict how many additional parties may successfully demand some form of collateral, we currently estimate that the amount of additional cash collateral if S&P or Moody’s were to downgrade us further would be minimal.

The following table summarizes the collateral posted or debt repaid due to credit downgrades through March 14, 2003, and additional collateral or debt that may be required to be posted or repaid in the future:

<i>In millions</i>	Potential Amount	Amounts Posted/ Paid to Date
Australian denominated bonds	\$170.3	\$154.6
Tolling agreements	82.3	82.3
Construction loan	27.5	27.5
Standard margining agreements	62.0	60.0
Other collateral demands	145.0	145.0
Total	\$487.1	\$469.4

In addition to collateral calls made due to credit downgrades, fluctuations in commodity prices can also cause both significant inflows and outflows of collateral. This will vary depending on the magnitude of the price movement and the current position of our portfolio.

Contractual Obligations

Long-Term Gas Contracts

Our obligations under our long-term gas delivery contracts that were paid to us in advance, will result in cash outflows and losses as outlined in the table below. We are committed to meeting these obligations.

<i>In millions</i>	Long-Term Gas Contract Settlement(1)	Long-Term Gas Contract Margin Loss(2)	Total Long-Term Gas Contract Cash Payments(3)
2003	\$ 81.5	\$ 45.9	\$ 127.4
2004	84.9	48.1	133.0
2005	87.6	49.8	137.4
2006	90.9	52.2	143.1
2007	91.9	53.0	144.9
Thereafter	315.9	196.5	512.4
Total	\$752.7	\$445.5	\$1,198.2

(1) *This represents the reduction of long-term gas contracts each period.*

(2) *This represents the loss that is reflected as a reduction to gross margin each period.*

(3) *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 recognize the relief of 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 may be asked to pay the issuers of the surety bonds on these arrangements an amount that is greater than the long-term gas contract balance on our Consolidated Balance Sheet. As of December 31, 2002, our best estimate of this additional amount ranges from \$68.0 million to \$101.0 million, depending on the discount rate used. This difference arises due to our use of the units of revenue method of relieving the long-term obligation versus a present value method that would likely be used by the sureties.

Merchant Power Plant Capacity Obligations

Our scheduled capacity payments for power generation in our Capacity Services business during 2003 aggregate approximately \$101.3 million. Because it is generally expected that the fuel and start-up costs of operating merchant power plants will exceed the revenues that would be generated from the power sales, we believe that our capacity to generate power will largely be unutilized. If our tolling agreements that comprise a substantial portion of our capacity payments are not terminated or restructured on terms acceptable to our counterparties and us, our

earnings and liquidity will be severely impacted. We have communicated to certain counterparties the necessity that these agreements be terminated or restructured.

<i>In millions</i>	Capacity Payments
2003	\$ 101.3
2004	101.3
2005	112.4
2006	120.2
2007	120.2
Thereafter	1,508.1
Total	\$2,063.5

Other Obligations

We also have contractual cash obligations including maturities of long-term debt, minimum payments on operating leases and regulated power, gas and coal purchase contracts. See Note 23 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:

<i>In millions</i>	2003	2004	2005	2006	2007	Thereafter	Total
Long-term debt obligations	\$530.7	\$431.8	\$ 69.6	\$103.8	\$ 56.1	\$1,736.7	\$2,928.7
Operating leases obligations	47.4	41.6	22.6	16.9	15.6	55.8	199.9
Merchant gas transportation obligations	8.8	8.8	8.8	8.6	5.8	38.6	79.4
Regulated purchase obligations	292.0	227.5	189.4	156.7	107.4	1,642.1	2,615.1
Total	\$878.9	\$709.7	\$290.4	\$286.0	\$184.9	\$3,473.2	\$5,823.1

Capital Expenditures

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

	Actual	Future Cash Requirements		
<i>In millions</i>	2002	2003	2004	2005
Domestic Utilities	\$154.5	\$137.0	\$185.6	\$187.8
Everest Connections	101.0	—	—	—
Canadian Utilities	112.4	102.3	130.0	125.4
Merchant Services	168.5	36.4	.5	.5
Corporate and Other	8.9	9.3	9.9	7.3
Total capital expenditures	\$545.3	\$285.0	\$326.0	\$321.0

Legal Proceeding

On February 19, 2002, we filed a suit against Chubb Insurance Group, the issuer of surety bonds in support of certain of our long-term gas contracts. Previously, Chubb had demanded that it be released from its surety obligation of up to \$540 million or, alternatively, that we provide collateral to secure its obligation. We do not believe that Chubb is entitled to be released from its surety obligations or that we are obligated to provide collateral to secure its obligations unless it is likely we will default on the contracts. Chubb has not alleged that we are likely to default on the contracts. If Chubb were to prevail, it would have a material adverse impact on our liquidity and financial position. We rely on other sureties in support of long-term gas supply contracts similar to those described above. There can be no assurance that these sureties will not make claims similar to those raised by Chubb. We have performed under these contracts since their inception and intend to continue to fully perform on the contracts.

Cash Flows

Cash Flows from Operating Activities—Cash flows from operating activities were significantly lower in 2002 compared to 2001, primarily due to net losses in 2002 and the termination of our accounts receivable sales programs. Also impacting cash flows from operating activities was the payment of higher annual and long-term incentive compensation based on the record earnings in 2001. In addition, we made payments of \$39.3 million to our defined benefit pension plans to offset declines in plan asset values due to market performance. Partially offsetting decreased cash flows in 2002 were cash collections related to price risk management assets.

Cash Flows from Investing Activities—Cash flows used for investing activities included increased capital expenditures for utility plant additions and merchant power generation construction. In addition, the acquisition of our interest in Midlands Electricity in May 2002 increased cash used for investing activities. Offsetting these cash flows was \$1.1 billion of cash received on the sale of assets and a reduction in Merchant capital expenditures.

Cash Flows from Financing Activities—Cash flows from financing activities came primarily from our issuance of common stock and senior notes. In January 2002, we issued 12.5 million shares of our 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 the accounts receivables sale programs and to retire debt and preferred securities.

Significant Balance Sheet Movements

Total assets decreased \$2.7 billion in 2002 compared to 2001. This decrease is primarily due to the following:

- Cash increased \$178.8 million. See our Consolidated Statements of Cash Flows for analysis of the increase.
- Restricted cash increased \$493.9 million partially due to the escrow of \$239.9 million of proceeds from our sale of our Merchant loan portfolio in December 2002, cash collateral posted in relation to the turbine facility and the Clay County power plant and the segregation of cash deposited with us by one of our counterparties, which was done at the

counterparties' request. See Note 7 to the Consolidated Financial Statements for a more detailed discussion of these transactions.

- Funds on deposit increased \$142.1 million due to increased commodity prices and an increase in margin deposits due to the downgrades of our credit ratings.
- Accounts receivable decreased by \$1.3 billion primarily due to our exit from the wholesale energy trading business, partially offset by increased commodity prices in 2002.
- Inventories and supplies decreased \$145.1 million primarily due to the sell-down of our gas storage inventory in 2002 due to the exit from our Wholesale Services business.
- Price risk management assets, current and non-current, decreased \$222.9 million primarily due to the collection of approximately \$241.5 million of current contracts outstanding at December 31, 2001 and the liquidation of wholesale energy trading contracts stemming from our exit of that business, partially offset by higher forward pricing of natural gas and electricity.
- Prepayments and other increased \$132.6 million, primarily due to an income tax receivables amount of \$191.1 million resulting from current year losses and \$39.3 million of additional funding to our pension plan, partially offset by a decrease in power and coal options premiums due to the exit from our energy trading business as well as cash collateral that has been released.
- A \$278.7 million increase in property, plant and equipment, net, resulted primarily from the accounting consolidation of the Clay County and Piatt County power plants and fixed asset additions in the current year, partially offset by asset sales and impairments.
- A \$1.1 billion decrease in investments in unconsolidated subsidiaries is primarily due to the \$696.1 million impairment of our investment in Quanta Services, the \$127.2 million write-down of our Australia investments and the sale of our \$353.5 million investment in UnitedNetworks Limited.
- Deferred charges and other assets decreased \$106.0 million, primarily due to deferred purchased power costs reclassified to current as the current portion was collected through rates, and cash collateral on the Clay County power plant lease that was reclassified into restricted cash.
- Non-current assets of discontinued operations decreased \$1.0 billion due to asset sales in 2002.

In 2002, total liabilities decreased by \$1.5 billion, while company-obligated preferred securities decreased by \$250.0 million and common shareholders' equity decreased \$943.7 million. These changes were primarily due to the following:

- Short term debt decreased \$247.6 million primarily due to the repayment of short-term borrowings using proceeds from equity offerings, long-term debt offerings and asset sales. See Note 12 to the Consolidated Financial Statements for further discussion.
- Accounts payable decreased by \$1.5 billion primarily due to our exit from the wholesale energy trading business, partially offset by an increase in prices from December 31, 2001.

- Accrued liabilities decreased by \$254.8 million primarily due to the payment of accrued annual and long-term incentives that were based on record earnings in 2001 and lower accrued taxes due to current period losses, partially offset by increased accrued interest due to our non-investment grade credit rating.
- Price risk management liabilities, current and non-current, increased \$83.4 million primarily due to higher forward pricing of natural gas.
- Current and long-term gas contracts decreased \$79.8 million due to current year deliveries on these contracts.
- Customer funds on deposit increased \$124.6 million primarily due to an increase in commodity prices and lower counterparty credit ratings, which resulted in additional margin deposits received.
- Long-term debt, including current maturities, increased by \$501.7 million primarily due to the issuance of \$287.5 million of 7.875% senior notes in February 2002, \$500.0 million of 14.875% senior notes in July 2002, the accounting consolidation of the Clay County and Piatt County debt, partially offset by the pay down of certain New Zealand and Australian notes and \$100.0 million of current maturities of Company obligated preferred securities. See Note 13 to the Consolidated Financial Statements for further discussion.
- Deferred income taxes and credits increased \$75.2 million primarily due to the removal of our permanent investment election relating to our international investments (See Note 18 in our Consolidated Financial Statements), partially offset by deferred taxes recognized in 2002 due to asset sales.
- Minority interest decreased \$144.2 million primarily due to the exchange offer by which we acquired the 20% minority interest in Aquila Merchant Services that was owned by the public.
- Company-obligated preferred securities decreased net \$250.0 million due to these securities being converted to common stock.
- Common shareholders' equity decreased \$943.7 million primarily as a result of the \$2,075.1 million net loss in 2002 and the \$115.7 million of dividends declared, partially offset by the issuance of 12.6 million shares of our stock in the Merchant Services exchange offer and the 12.5 million and 37.5 million shares of our stock issued in January 2002 and July 2002, respectively.

New Accounting Standards

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). In 2002 and 2001, the Financial Accounting Standards Board (FASB) issued four new Statements of Financial Accounting Standards (SFAS) that have potential impacts on our financial results: SFAS No. 142, "Goodwill and Other Intangible Assets;" SFAS No. 143, "Accounting for Asset Retirement Obligations," SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," and SFAS No. 148, "Accounting for Stock-Based Compensation—Transition and Disclosure." The FASB also issued Interpretation No. 45 regarding guarantees and Interpretation No. 46 regarding variable interest entities in 2002. See Note 2 to the Consolidated Financial Statements for a 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, including statements that (i) our hedging activities will minimize losses in our remaining trading portfolio, (ii) significant amounts of cash collateral provided to counterparties will be returned to us, (iii) our long-term liquidity plan calls for sales of international assets, the restructuring of generation capacity obligations and refinancing of maturing debt and (iv) we do not believe that pending litigation or governmental investigations will result in outcome that is materially adverse to us. The words “may,” “will,” “should,” “expect,” “anticipate,” “intend,” “plan,” “believe,” “seek,” “estimate,” or the negative of these terms or similar expressions identify further forward-looking statements.

These forward-looking statements involve risks and uncertainties, and there are certain important factors that can cause actual results to differ materially from those anticipated. Some of the important factors and risks that could cause actual results to differ materially from those anticipated include:

- Counterparties may default on their obligations to return collateral to us or to meet their obligations under commercial contracts, including those designed to hedge against movements in commodity prices.
- Our credit ratings and financial condition will limit our ability to access the capital markets we historically used to refinance our debt. Because we recently pledged a significant portion of our assets as collateral for loans, it will be difficult for us to obtain additional unsecured financing. We must obtain regulatory approvals to use the majority of our remaining unencumbered assets as collateral for additional loans.
- If our financial condition improves in the short-term, the market prices for our long-term debt may increase and limit our ability to repurchase it. Our new credit agreements require us to use a significant portion of the proceeds from the sale of our assets to reduce our obligations to those lenders before retiring more expensive debt.
- Because of the location and significant size of our Australian investment, there are a limited number of potential purchasers of these assets. Because we are a minority owner, other investors must agree to any sale that we support.
- Our commitments under long-term gas delivery contracts and capacity generation contracts will generate significant losses and negative cash flows for an extended period of time. Because these obligations represent favorable contracts to the counterparties, absent a risk of our default, they may be unwilling to restructure or sell the contracts.
- There are numerous ongoing state and federal investigations of the trading activities of companies that participated in the energy trading industry, including us. Companies that have violated laws or rules of the investigating agencies have been required to pay significant fines. Even if no wrongdoing is found, we could incur substantial legal and accounting costs associated with complying with the discovery requests of the investigating body.

Item 7a. Quantitative and Qualitative Disclosures About Market Risk

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 of natural gas, electricity, coal, global liquids, weather derivatives 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, many of these risks have been significantly reduced as the majority of our positions are hedged.

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

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

The average value at risk for all commodities during the first six months of 2002 was \$5.7 million, \$1.8 million during the second half of the year and \$3.8 million for the full year. The \$15.0 million value at risk limit approved by the Board of Directors has been revised downward at various times during 2002 by our Risk Management Committee and is currently limited to \$3.0 million for the remaining trading portfolio and a \$5.0 million target for the aggregate book that includes the first 18 months of Capacity Services’ asset positions. In addition to value at risk, we also apply other risk control measures that incorporate volumetric limits by commodity, loss limits, durational limits and we perform stress testing to our various risk portfolios.

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

The table below shows the expected net cash flows associated with the interest rate financial instruments related to our trading portfolio at December 31, 2002.

<i>Dollars in millions</i>	2003	2004	2005	2006
Variable to fixed rate	\$(13.0)	\$ (8.0)	\$ (4.0)	\$ (1.8)
Average rate paid	5.26%	5.47%	5.97%	6.35%
Average rate received	2.93%	2.93%	3.03%	3.25%

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 2002 are summarized below:

<i>In millions</i>	Wholesale Services	Capacity Services	Total
Fair value at December 31, 2001	\$415.2	\$175.7	\$590.9
Reduction in fair value during the year	(65.6)	(24.4)	(90.0)
Contracts realized or cash settled—entered into in 2002	(4.4)	29.5	25.1
Contracts realized or cash settled—entered into in prior years	(165.0)	(76.5)	(241.5)
Fair value at December 31, 2002	\$180.2	\$104.3	\$284.5

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

<i>In millions</i>	2003	2004	2005	2006	Thereafter(a)	Total
Wholesale Services:						
Prices actively quoted	\$45.9	\$—	\$—	\$—	\$—	\$ 45.9
Prices provided by other external sources	—	30.7	27.3	—	—	58.0
Priced based on models and other valuation methods	1.2	—	—	25.7	49.4	76.3
Fair value of contracts	47.1	30.7	27.3	25.7	49.4	180.2
Capacity Services:						
Prices actively quoted	28.6	—	—	—	—	28.6
Prices provided by other external sources	—	19.0	7.7	—	—	26.7
Priced based on models and other valuation methods	—	—	—	19.4	29.6	49.0
Fair value of contracts	28.6	19.0	7.7	19.4	29.6	104.3
Net price risk management assets	\$75.7	\$49.7	\$35.0	\$45.1	\$79.0	\$284.5

(a) *As these contracts have been significantly hedged, movement in commodity prices will have limited impact on the net value provided.*

Credit Risk

In conducting our network, energy marketing and risk management activities, 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 have deteriorated to certain levels, we will assert any contractual rights that allow us to secure our exposures by requesting collateral against these obligations.

A natural result from 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 aggregate 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, 2002, 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.

<i>In millions</i>	Investment Grade	Non-investment Grade	Total
Utilities and merchants	\$378.9	\$230.6	\$ 609.5
Financial institutions	271.0	—	271.0
Oil and gas producers	40.8	48.6	89.4
Commercial/industrial	12.0	32.2	44.2
Total	\$702.7	\$311.4	\$1,014.1

Our credit exposure will diminish significantly in April 2003 and April 2004 as contracts expire and the winter season concludes.

Currency Rate Exposure

We do not currently hedge our net investment in foreign operations. As a result, our foreign denominated assets and liabilities will fluctuate in value. Historically, our net exposure to changes in foreign currency has been limited as our foreign investments have been financed largely through the local currency. However, as a result of our recent credit downgrades and debt maturities, we have been required to repay certain foreign debt with other than local currency.

We hedge the earnings of our foreign operations through financial “put” transactions. On average, we hedge 75% of our annual expected earnings from foreign operations. To the extent that foreign currency dollars change in value against the U.S. dollar in countries in which we operate, the foreign currency “put” will offset the majority of this change.

The table below summarizes the average value of foreign currencies used to value sales and expenses along with the related sensitivity.

<i>In millions</i>	Net Investment at December 31, 2002	Impact of 10% Currency Change on 2002 EBIT(a)	Average Currency Unit Value in U.S. Dollars			
			2002	2001	2000	
Australia	\$512.7	±	\$2.8	\$.54	\$.52	\$.58
Canada	264.7	±	3.6	.64	.65	.67
United Kingdom	75.5	±	2.7	1.54	1.44	1.52
Total		±	\$9.1			

(a) Represents the impact of a 10% change in local currency value relative to the U.S. dollar as if the change occurred uniformly over the entire year, multiplied by our 2002 EBIT, excluding any impairment charges recorded in 2002.

Interest Rate Exposure

We have about \$833.4 million in unhedged variable rate financial obligations. A 100-basis-point change in the variable rate financial instruments would affect net income by approximately \$5.0 million.

Item 8. Financial Statements and Supplementary Data

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Aquila, Inc.
Consolidated Statements of Income

<i>In millions, except per share amounts</i>	Year Ended December 31,		
	2002	2001	2000
Sales:			
Electricity—regulated	\$ 933.3	\$ 917.1	\$1,065.0
Natural gas—regulated	762.2	964.3	826.5
Electricity—non-regulated	419.6	795.5	415.5
Natural gas—non-regulated	227.2	940.2	796.5
Other—non-regulated	34.8	93.9	91.0
Total sales	2,377.1	3,711.0	3,194.5
Cost of sales:			
Electricity—regulated	332.2	314.8	547.3
Natural gas—regulated	501.4	719.6	558.0
Electricity—non-regulated	389.3	490.6	271.2
Natural gas—non-regulated	290.8	469.0	478.3
Other—non-regulated	29.7	28.9	26.2
Total cost of sales	1,543.4	2,022.9	1,881.0
Gross profit	833.7	1,688.1	1,313.5
Operating expenses:			
Operating expense	756.6	942.6	761.0
Restructuring charges	210.2	—	—
Impairment charges and net loss on sale of assets	1,583.2	94.8	19.4
Depreciation and amortization expense	214.3	240.9	193.6
Total operating expenses	2,764.3	1,278.3	974.0
Other income (expense):			
Equity in earnings of investments	166.9	119.3	115.8
Minority interest in income of subsidiaries	7.8	(20.1)	(1.4)
Gain on sale of subsidiary stock	130.5	110.8	44.0
Other income (expense)	17.0	23.0	(3.1)
Total other income (expense)	322.2	233.0	155.3
Interest expense:			
Interest expense	230.6	187.9	157.9
Minority interest in income of partnership and trust	18.9	28.5	30.9
Total interest expense	249.5	216.4	188.8
Earnings (loss) from continuing operations before income taxes	(1,857.9)	426.4	306.0
Income tax expense (benefit)	(135.1)	181.1	111.7
Earnings (loss) from continuing operations	(1,722.8)	245.3	194.3
Earnings (loss) from discontinued operations, net of tax	(329.6)	34.1	12.5
Cumulative effect of accounting change, net of tax	(22.7)	—	—
Net income (loss)	\$(2,075.1)	\$ 279.4	\$ 206.8
Basic earnings (loss) per common share:			
Continuing operations	\$ (10.65)	\$ 2.19	\$ 2.09
Discontinued operations	(2.04)	.30	.13
Cumulative effect of accounting change	(.14)	—	—
Net income (loss)	\$ (12.83)	\$ 2.49	\$ 2.22
Diluted earnings (loss) per common share:			
Continuing operations	\$ (10.65)	\$ 2.12	\$ 2.08
Discontinued operations	(2.04)	.30	.13
Cumulative effect of accounting change	(.14)	—	—
Net income (loss)	\$ (12.83)	\$ 2.42	\$ 2.21

See accompanying notes to consolidated financial statements.

Aquila, Inc.
Consolidated Balance Sheets

<i>In millions</i>	December 31,	
	2002	2001
Assets		
Current assets:		
Cash and cash equivalents	\$ 441.7	\$ 262.9
Restricted cash	493.9	—
Funds on deposit	310.3	168.2
Accounts receivable, net	1,672.8	2,926.8
Inventories and supplies	144.3	289.4
Price risk management assets	545.2	824.5
Prepayments and other	466.0	333.4
Total current assets	4,074.2	4,805.2
Property, plant and equipment, net	3,180.6	2,901.9
Investments in unconsolidated subsidiaries	914.9	2,045.6
Price risk management assets	491.6	435.2
Goodwill, net	299.6	335.2
Deferred charges and other assets	278.8	384.8
Non-current assets of discontinued operations	19.5	1,058.6
Total Assets	\$9,259.2	\$11,966.5
Liabilities and Shareholders' Equity		
Current liabilities:		
Current maturities of long-term debt	\$ 530.7	\$ 679.1
Short-term debt	301.0	548.6
Accounts payable	1,616.6	3,156.2
Accrued liabilities	351.0	605.8
Price risk management liabilities	469.5	493.5
Current portion of long-term gas contracts	81.5	79.8
Customer funds on deposit	246.6	122.0
Total current liabilities	3,596.9	5,685.0
Long-term liabilities:		
Long-term debt, net	2,398.0	1,747.9
Deferred income taxes and credits	423.0	347.8
Price risk management liabilities	282.8	175.4
Long-term gas contracts	671.2	752.7
Minority interest	13.4	157.6
Deferred credits	266.0	298.5
Total long-term liabilities	4,054.4	3,479.9
Company-obligated preferred securities, net	—	250.0
Common shareholders' equity	1,607.9	2,551.6
Total Liabilities and Shareholders' Equity	\$9,259.2	\$11,966.5

See accompanying notes to consolidated financial statements.

Aquila, Inc.
Consolidated Statements of Common Shareholders' Equity

<i>In millions, except per share amounts</i>	Year Ended December 31,		
	2002	2001	2000
Common Stock: authorized 400,000,000 at December 31, 2002 and 2001, and 200,000,000 shares at December 31, 2000, par value \$1 per share, 193,782,782 shares issued at December 31, 2002 (115,941,120 at December 31, 2001 and 100,350,977 at December 31, 2000); authorized 20,000,000 shares of Class A common stock, par value \$1 per share, none issued			
Balance beginning of year	\$ 115.9	\$ 100.4	\$ 93.6
Issuance of shares in public offerings	50.0	11.5	—
Issuance of shares through Premium Equity Participating Security conversion	11.7	—	—
Issuance of shares through Aquila Merchant exchange offer	12.6	—	—
Issuance of shares to acquire St. Joseph Light & Power	—	—	6.6
Issuance of shares under compensation arrangements	3.6	4.0	.2
Balance end of year	193.8	115.9	100.4
Premium on Capital Stock:			
Balance beginning of year	2,047.0	1,405.7	1,226.5
Issuance of shares in public offerings	498.9	321.1	—
Issuance of shares through Premium Equity Participating Security conversion	238.3	—	—
Issuance of shares through Aquila Merchant exchange offer	314.3	—	—
Issuance of subsidiary common stock	—	211.6	—
Issuance of shares to acquire St. Joseph Light & Power	—	—	183.7
Issuance of shares under compensation arrangements	60.1	108.6	(4.5)
Balance end of year	3,158.6	2,047.0	1,405.7
Retained Earnings (Deficit):			
Balance beginning of year	479.3	334.5	239.3
Net income (loss)	(2,075.1)	279.4	206.8
Dividends on common stock, \$.775 per share in 2002 (\$1.20 per share in 2001 and 2000)	(115.7)	(134.6)	(111.6)
Balance end of year	(1,711.5)	479.3	334.5
Treasury stock , at cost 7,443 shares at December 31, 2002 (447 shares at December 31, 2001 and 40,441 shares at December 31, 2000)			
	—	—	(.8)
Accumulated other comprehensive losses	(33.0)	(90.6)	(40.2)
Total Common Shareholders' Equity	\$ 1,607.9	\$2,551.6	\$1,799.6

See accompanying notes to consolidated financial statements.

Aquila, Inc.
Consolidated Statements of Comprehensive Income

<i>In millions</i>	Year Ended December 31,		
	2002	2001	2000
Net income (loss)	\$(2,075.1)	\$279.4	\$206.8
Unrealized translation adjustments, net	74.0	(51.3)	(42.2)
Unrealized cash flow hedges (net of deferred tax benefit (expense) of \$10.8 million and \$(.6) million for 2002 and 2001, respectively)	(18.9)	.9	—
Unrealized market value gains on securities held for sale	7.3	—	—
Additional minimum pension liability	(4.8)	—	—
Comprehensive income (loss)	\$(2,017.5)	\$229.0	\$164.6

See accompanying notes to consolidated financial statements.

Aquila, Inc.
Consolidated Statements of Cash Flows

<i>In millions</i>	Year Ended December 31,		
	2002	2001	2000
		(Restated— See Note 21)	(Restated— See Note 21)
Cash Flows From Operating Activities:			
Net income (loss)	\$(2,075.1)	\$ 279.4	\$ 206.8
Adjustments to reconcile net income (loss) to net cash provided from (used for) operating activities:			
Depreciation and amortization expense	238.0	272.9	225.0
Gain on sale of subsidiary stock	(130.5)	(110.8)	(44.0)
Restructuring charges	210.2	—	—
Cash paid for restructuring charges	(95.2)	—	—
Impairment charges and net loss on sale of assets	2,009.8	94.8	27.2
Net changes in price risk management assets and liabilities	297.5	(26.8)	(217.2)
Deferred income taxes and investment tax credits	88.2	(29.7)	(111.0)
Equity in earnings of investments	(172.2)	(122.8)	(115.5)
Dividends and fees from investments	91.9	57.0	74.4
Minority interests in income of subsidiaries	(7.8)	20.1	1.4
Changes in certain assets and liabilities, net of effects of acquisitions and divestitures:			
Restricted cash	(171.7)	—	—
Funds on deposit	(132.3)	(13.9)	(107.0)
Accounts receivable/payable, net	38.9	47.8	(61.1)
Accounts receivable sales programs	(297.5)	(107.5)	39.2
Inventories and supplies	126.7	(109.0)	83.4
Prepayments and other	(162.5)	(55.3)	(73.8)
Deferred charges and other assets	81.7	165.8	(224.5)
Accrued liabilities	(352.6)	84.5	348.8
Customer funds on deposit	124.6	(247.4)	362.4
Deferred credits	(45.1)	15.2	43.2
Other	38.0	(19.2)	(63.9)
Cash (used for) provided from operating activities	(297.0)	195.1	393.8
Cash Flows From Investing Activities:			
Additions to utility plant	(266.9)	(252.4)	(138.7)
Merchant capital expenditures	(168.5)	(273.6)	(56.1)
Net increases in merchant notes receivable	(41.5)	(102.4)	(133.9)
Investments in international businesses	(216.7)	(105.6)	(725.2)
Investments in domestic businesses	(101.0)	(106.5)	(640.6)
Cash proceeds on sale of assets and subsidiary stock	1,115.8	129.9	—
Other	23.6	(65.1)	(34.9)
Cash provided from (used for) investing activities	344.8	(775.7)	(1,729.4)

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

<i>In millions</i>	Year Ended December 31,		
	2002	2001	2000
		(Restated— See Note 21)	(Restated— See Note 21)
Cash Flows From Financing Activities:			
Issuance of common stock	548.9	332.6	5.8
Issuance of subsidiary common stock	—	315.4	—
Issuance (retirement) of company-obligated preferred securities	(100.0)	(100.0)	100.0
Issuance of long-term debt	1,146.9	612.4	973.9
Retirement of long-term debt	(989.7)	(624.1)	(309.7)
Short-term borrowings, net	(280.3)	47.6	454.3
Cash received on long-term gas contracts	—	—	443.9
Cash paid on long-term gas contracts	(79.8)	(82.2)	(47.8)
Cash dividends paid	(115.7)	(134.6)	(111.6)
Other	.7	83.8	(5.5)
Cash provided from financing activities	131.0	450.9	1,503.3
Increase (decrease) in cash and cash equivalents	178.8	(129.7)	167.7
Cash and cash equivalents at beginning of year	262.9	392.6	224.9
Cash and Cash Equivalents at End of Year	\$ 441.7	\$ 262.9	\$ 392.6
Supplemental cash flow information:			
Interest paid, net of amount capitalized	\$ 216.8	\$ 236.0	\$ 215.4
Income taxes paid (refunded), net	(65.7)	241.5	60.2
Liabilities assumed in acquisitions:			
Fair value of assets acquired	\$ —	\$ —	\$ 2,229.2
Cash paid for acquisitions	—	—	(1,421.9)
Stock issued for acquisitions	—	—	(190.2)
Liabilities assumed	\$ —	\$ —	\$ 617.1

See accompanying notes to consolidated financial statements.

Aquila, Inc.
Notes to the Consolidated Financial Statements

Note 1: Summary of Significant Accounting Policies

Description of Business

Aquila, Inc. (Aquila), formerly UtiliCorp United Inc., is an international energy provider headquartered in Kansas City, Missouri. We operate in two business groups, the Global Networks Group and Merchant Services, with four financial reporting segments. Global Networks Group is comprised of our Domestic Networks and International Networks segments, while Merchant Services conducts business through two segments, Capacity Services and Wholesale Services.

Domestic Networks operates primarily as Aquila Networks in the distribution and transmission of electricity and natural gas to retail and wholesale customers in seven states. Our electric generation facilities supply electricity to our own distribution systems in three states. We also sell excess power to wholesale customers outside our service areas. During peak periods, we buy energy in the wholesale market for our utility load. Domestic Networks 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 investment in Quanta Services, Inc. (Quanta Services), based in Houston, Texas. Quanta Services provides specialized construction and maintenance services to the utility, telecommunications and cable television industries. International Networks owns or has interests in foreign businesses that distribute and transmit electricity and natural gas to retail and wholesale customers. International Networks operates in two Canadian provinces and has investments in Australia and the United Kingdom. Our Canadian electric generation facilities supply electricity to our own distribution systems in Canada. In October 2002, we sold our investment in New Zealand.

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 through its Wholesale Services business segment, which 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. Through the Capacity Services business segment, Aquila Merchant currently owns, operates or contractually controls non-regulated electric power generation assets. Although we sold these businesses in 2002, we formerly owned natural gas and gas liquids gathering, transportation, storage and processing assets. These operations are also reported as discontinued operations.

In 2000 and through April 2001, we owned 100% of Aquila Merchant. In April 2001, approximately 20% of Aquila Merchant's ownership was sold to the public. In January 2002, we acquired all the outstanding public shares of Aquila Merchant in an exchange offer and merger. Aquila Merchant was consolidated in each year with a minority interest reflected in 2001.

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, 2002 and 2001, and the reported amounts of sales and expenses during the three years ended December 31, 2002. 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 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 use equity accounting for investments in which we have significant influence but do not control. We do not control certain investments in which our partners have substantive participating and protective rights. This does not allow us to consolidate those investments. We eliminate inter-company accounts and transactions.

We evaluate the carrying value of our equity method investments periodically or when there are 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 consider 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 Securities Exchange Commission 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, together with the costs of removal 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 Statement of Financial Accounting Standards 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. See Note 2 for further discussion.

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 the customer after the date of the last meter reading and recorded as unbilled revenue. 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 Emerging Issues Task Force Issue (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 enter into these types of transactions. 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 expected weather in the period (in cooling or heating degree days) multiplied by the contract price.

Funds on Deposit

Funds that we have on deposit with counterparties consist primarily of margin requirements related to 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. 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.

Accounts Receivable Sales Programs

We sold trade accounts receivables to third party issuers of receivable-backed securities on an ongoing basis and without recourse. The sale of the receivables was accounted for under SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities" (SFAS 140). We received a fee for the servicing of the receivables sold. The loss on the sale of the receivables was based on their relative fair value at the date of the transfer and is included in Other Income (Expense) in our Consolidated Statements of Income. We generally estimated fair value based on the present value of future expected cash flows, using our best estimate of the key assumptions, including credit losses, forward yield curves and discount rates commensurate with the risks involved. These programs were terminated in 2002. See Note 8 for further discussion.

Inventories

Our inventories consist primarily of natural gas in storage, coal, materials and supplies that are valued at the lower of weighted average cost or market. See Note 2 for further discussion of certain natural gas trading inventories that were accounted for at fair value during 2002.

Development Activity

We incur project-related development costs including feasibility studies, bid preparation, permitting and licensing that are expensed as incurred until the project is deemed to be probable of development. At that point, we may capitalize costs incurred based on their nature. These costs may be recoverable through partners in the projects or other third parties, or classified as an investment and recovered through future project cash flows.

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 relief 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 in enacted. We amortize deferred investment tax credits over the lives of the related properties. 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.

Stock Based Compensation

We issue stock options to employees from time to time and account for these options under Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" (APB 25). All stock options issued are granted at the common stock's then current market price. This means we record no compensation expense related to stock options. We also offer employees a stock purchase plan that enables them to purchase our common stock at a 15% discount from the market price. See Note 16 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. For the years ended December 31, 2002, 2001 and 2000, our pro forma net income (loss) and diluted earnings (loss) per share would have been as follows:

<i>In millions, except per share amounts</i>	2002	2001	2000
Net income (loss):			
As reported	\$(2,075.1)	\$279.4	\$206.8
Total stock-based employee compensation expense determined under fair value method, net of related tax	(6.2)	(8.4)	(2.4)
Pro forma net income (loss)	\$(2,081.3)	\$271.0	\$204.4
Basic earnings (loss) per share:			
As reported	\$ (12.83)	\$ 2.49	\$ 2.22
Pro forma	(12.87)	2.42	2.20
Diluted earnings (loss) per share:			
As reported	\$ (12.83)	\$ 2.42	\$ 2.21
Pro forma	(12.87)	2.34	2.18

The fair value of stock options granted in 2002, 2001 and 2000 was estimated on the date of grant using the Black-Scholes option-pricing model. The weighted average fair values and assumptions were as follows:

	2002	2001	2000
Weighted average fair value per share	\$ 1.03	\$ 5.08	\$ 2.39
Expected volatility	51.60%	19.75%	17.78%
Risk-free interest rate	3.53%	5.06%	6.71%
Expected lives	7 years	8 years	9 years
Dividend yield	0.00%	3.93%	6.25%

Stock options granted in 2001 by our Merchant Services subsidiary 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.

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, 2002 and 2001, our cash held in foreign countries was (in millions) \$179.5 and \$93.7, 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 2002 presentation. In particular, sales and cost of sales have been reclassified to report energy trading gains and losses on a net basis pursuant to 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) as discussed in Note 2. Also, as discussed in Note 6, certain assets that have been sold 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

Goodwill and Other Intangible Assets

On January 1, 2002, we were required to adopt SFAS No. 142, "Goodwill and Other Intangible Assets" (SFAS 142). SFAS 142 requires that goodwill no longer be amortized to expense. Instead,

goodwill must be tested for impairment at least annually and, if impaired, be 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.

At December 31, 2002 and 2001, we had goodwill of \$318.6 million and \$363.5 million, net of accumulated amortization of \$19.0 million and \$28.3 million, respectively. Amortization expense for the years ended December 31, 2001 and 2000 totaled \$19.1 million and \$10.9 million, respectively. In addition, our earnings from equity method investments included \$17.6 million and \$10.5 million of amortization expense for the years ended December 31, 2001 and 2000, respectively. Approximately \$3.3 million of goodwill amortization expense is included in earnings from discontinued operations for the years ended December 31, 2001 and 2000.

As discussed in Note 16, \$218.7 million of goodwill was recorded on the repurchase of Aquila Merchant in January 2002. We allocated \$175.0 million of that amount to Wholesale Services and \$43.7 million to Capacity Services based upon future expected cash flows. As a result of our second quarter decision to exit the wholesale energy trading business, we determined that all of the goodwill in Wholesale Services was impaired. Therefore, we recorded an impairment charge of \$178.6 million in the second quarter of 2002. In addition, as further discussed in Note 5, we recorded a total impairment charge of \$696.1 million related to our investment in Quanta Services, Inc., including a \$328.0 million goodwill impairment charge related to this investment. When performing our annual assessment of the realizability of our remaining goodwill on November 30, 2002, we concluded that our remaining Capacity Services goodwill was impaired and thus recorded an impairment charge for \$7.9 million. As discussed in Note 5, as a result of changes in our future funding of Everest, we assessed the realizability of its \$21.6 million of goodwill and determined that it was also impaired. This goodwill was written off as an impairment charge in the fourth quarter of 2002.

In connection with the sale of our interest in Lockport Energy, allocated goodwill from the repurchase of Aquila Merchant of \$14.0 million was included in the basis used in determining the loss included in Impairment Charges and Net Loss on Sale of Assets. Also, in connection with the sale of our gas gathering and pipeline assets and our gas storage facility, \$19.0 million and \$26.7 million of goodwill, respectively, was included in the basis used in determining the 2002 loss from discontinued operations. See Note 6 for further discussion.

Our goodwill allocated to each segment at December 31, 2002 and 2001 is as follows:

<i>In millions</i>	December 31,	
	2002	2001
Goodwill, net:		
Domestic Networks	\$111.0	\$130.6
International Networks	188.6	193.1
Wholesale Services	—	3.6
Capacity Services	—	7.9
	299.6	335.2
Goodwill in investments in unconsolidated subsidiaries	—	328.0
Total	\$299.6	\$663.2

Following are disclosures of net income and earnings per share for the years ended December 31, 2001 and 2000, had goodwill not been amortized in those periods:

<i>In millions, except per share amounts</i>	Year Ended December 31, 2001		Year Ended December 31, 2000	
	Continuing Operations	Discontinued Operations	Continuing Operations	Discontinued Operations
Reported net income	\$245.3	\$34.1	\$194.3	\$12.5
Goodwill amortization	19.1	3.3	10.9	3.3
Goodwill amortization in equity in earnings	17.6	—	10.5	—
Adjusted net income	\$282.0	\$37.4	\$215.7	\$15.8
Adjusted earnings per share:				
Basic	\$ 2.51	\$.33	\$ 2.32	\$.17
Diluted	2.43	.33	2.30	.17

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 accrued 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.

The adoption of SFAS 143 required 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, removal and disposal of storage tanks and PCB-containing transformers. 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 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 \$2.2 million and increased property, plant and equipment, net of accumulated depreciation, by less than \$100,000. Because this business is a regulated utility subject to the provisions of SFAS 71, the \$2.2 million cumulative effect of adoption of SFAS 143 was recorded as a regulatory asset and therefore had no impact on net income. The asset retirement obligation related to our non-regulated generation assets was immaterial as of January 2003.

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.

If the provisions of SFAS 143 had been applied to our Consolidated Balance Sheets presented, our liability for asset retirement obligations would have been \$2.2 million and \$1.9 million as of December 31, 2002 and 2001, respectively.

Impairment or Disposal of Long-Lived Assets

In August 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS 144). SFAS 144 addresses how and when to measure impairment on long-lived assets and how to account for long-lived assets that an entity plans to dispose of either through sale, abandonment, exchange or a distribution to owners. Additionally, this statement expands the scope of discontinued operations and requires expected future operating losses from discontinued operations to be recorded in the period in which the losses are incurred rather than when the plan of disposal is approved. SFAS 144 also requires that the respective income statements for current and prior periods for components of an entity that have been disposed of, or that are carried as held for sale, be shown as the results from discontinued operations, less applicable income taxes, as a separate component of income in the consolidated income statement. In addition, assets held for sale shall be presented separately in the consolidated balance sheet. This standard became effective for us on January 1, 2002. See Note 5 for further discussion regarding impairment of assets. See Note 6 for information regarding discontinued operations.

Gas Storage Inventory

Effective January 1, 2002, we changed our method of accounting for our Merchant Services gas storage inventory (inventory used in daily trading activities) from the lower of cost or market method to a fair value method. In connection with the exit of our wholesale trading activities, we sold our entire gas storage inventory used in daily trading activities during the third quarter of 2002.

In October 2002, the EITF reached a consensus in EITF 02-3, that inventories should no longer be marked-to-market through earnings beginning on October 25, 2002. As discussed below, we adopted this standard in the fourth quarter of 2002. This would have resulted in an accounting change from carrying our inventory at current market prices back to carrying our inventory at historical cost. However, as we sold our entire gas storage inventory used in trading activities prior to the effective date, this change had no impact on our results of operations or financial position.

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 requires 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.

The following table reconciles gross sales and cost of sales previously reported to sales and cost of sales reported after the effects of EITF 02-3 and the reclassification of discontinued operations discussed in Note 6 for the years ended December 31, 2001 and 2000:

<i>In millions</i>	Year Ended December 31,	
	2001	2000
Sales:		
Previously reported gross sales	\$ 40,376.8	\$ 28,974.9
Sales netted per EITF 02-3	(36,206.3)	(25,266.8)
Sales reclassified to discontinued operations	(459.5)	(513.6)
Reported net sales	\$ 3,711.0	\$ 3,194.5
Cost of Sales:		
Previously reported gross cost of sales	\$ 38,588.8	\$ 27,546.2
Cost of sales netted per EITF 02-3	(36,206.3)	(25,266.8)
Cost of sales reclassified to discontinued operations	(359.6)	(398.4)
Reported net cost of sales	\$ 2,022.9	\$ 1,881.0

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 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 the Consolidated Statements of Income as an additional loss before income taxes of \$37.5 million, or \$22.7 million after tax.

Stock-Based Compensation

In December 2002, the FASB issued SFAS No. 148, "Accounting for Stock-Based Compensation-Transition and Disclosure." This statement amends SFAS No. 123, "Accounting for Stock-Based Compensation," to provide alternative methods of transition for voluntary changes to the fair-value based method of accounting for stock-based employee compensation. This statement also requires certain disclosures in both annual and interim financial statements regarding the method of accounting for stock-based compensation. We issue stock options to employees and account for these options under the intrinsic value method under APB No. 25. Therefore, we record no compensation expense related to these options. We currently do not expect to change our method of accounting for stock options and therefore, do not expect this standard to affect our financial results.

Guarantees

In November 2002, the FASB issued Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness to Others, an interpretation of FASB Statements No. 5, 57 and 107 and a rescission of FASB Interpretation No. 34." This interpretation elaborates on the disclosures to be made by a guarantor in its interim and annual financial statements about its obligations under guarantees issued. The interpretation also clarifies that a guarantor is required to recognize, at inception of a

guarantee, a liability for the fair value of its obligation undertaken. The initial recognition and measurement provisions are applicable to guarantees issued or modified after December 31, 2002 and are not expected to have a material effect on our financial statements. The disclosure requirements are effective for financial statements for periods ending after December 15, 2002. See Note 23 for further discussion.

Variable Interest Entities

In January 2003, the FASB issued 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 interests in variable interest entities created or obtained after January 31, 2003. The application of this interpretation is not expected to have an impact on our financial statements because no such entities currently exist.

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.

Effective January 1, 2001, we adopted SFAS 133 as amended, which requires us to recognize all derivative instruments on the balance sheet at fair value. It also established new accounting rules for hedging instruments, which depend on the nature of the hedge relationship. The adoption of SFAS 133 resulted in our recording transition adjustments to recognize derivative instruments at fair value and to recognize the ineffective portion of the change in the fair value of the derivatives. The cumulative effect of these transition adjustments at January 1, 2001, was a reduction to accumulated other comprehensive income (OCI) of approximately \$4.5 million (\$2.7 million net of tax). The reduction in OCI was related to cash flow hedges of forecasted foreign currency transactions, future natural gas liquids production and variable interest rate obligations.

Trading Activities

During the second half of 2002, we exited 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. Our remaining energy trading contracts have been significantly hedged against changes in commodity prices. 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 exiting 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. 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 offering fixed price commitments into the future. The contractual amounts and terms of these financial instruments at December 31, 2002 are below:

December 31, 2002			
<i>Dollars in millions</i>	Fixed Price Payor	Fixed Price Receiver	Maximum Term in Years
Energy Commodities:			
Natural gas (<i>trillion Btu's</i>)	3,769	2,709	10
Electricity (<i>megawatt-hours</i>)	16,848,968	18,510,105	6
Crude oil (<i>barrels</i>)	3,697,467	3,668,400	3
Natural gas liquids (<i>barrels</i>)	1,820,000	1,912,354	1
Coal (<i>tons</i>)	—	111,600	1
Financial Products:			
Interest rate instruments	\$ 3,772	\$ 1,744	18

We have attempted to balance our remaining physical and financial contracts in terms of quantities 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, 2002, using market interest rates for the contract term adjusted for our credit rating or the credit rating of the counterparty. 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, 2002, and the average value for the year ended December 31, 2002:

<i>In millions</i>	Price Risk Management Assets		Price Risk Management Liabilities	
	Average Value	December 31, 2002	Average Value	December 31, 2002
Natural gas	\$ 854.9	\$ 829.7	\$583.7	\$637.1
Electricity	244.2	164.2	168.4	82.7
Coal	32.2	22.5	11.2	6.6
Other	25.7	20.4	21.7	25.9
Total	\$1,157.0	\$1,036.8	\$785.0	\$752.3

Our Price Risk Management Assets are concentrated in five contracts representing 37% of the total asset value of the portfolio. We hold collateral from these counterparties representing approximately half of the asset value. This concentration of customers may impact our overall exposure to credit risk, either positively or negatively, since 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). 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, 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 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.

Fair Value Hedges

We use foreign currency hedging to reduce the risk that our eventual inflows or outflows of net U.S. dollar cash (resulting from inter-company financing transactions outside the U.S.) will be adversely affected by changes in exchange rates. These contracts are accounted for as fair value hedges with changes in fair value recorded in Other Income (Expense) and Price Risk Management Assets or Liabilities. The underlying financing transaction is also accounted for at fair value. During the year ended December 31, 2002, these fair value hedges were not 100% effective. The earnings impact due to ineffectiveness was a \$3.4 million loss for 2002.

Cash Flow Hedges

Our long-term debt contains a combination of fixed and variable rate instruments. Our policy is to fix the future cash flows related to this debt within defined parameters. To accomplish this we use floating to fixed rate swaps. These swaps related to debt with a principal amount of \$214.5 million and had maturities ranging from approximately two to five years at December 31, 2002.

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 an \$18.9 million decrease in OCI related to cash flow hedges in 2002, net of both taxes and reclassifications to earnings. This will generally offset future cash flow gains relating to the underlying exposures being hedged. We estimate that we will reclassify into earnings \$14.5 million of losses that are reported in OCI within the next 12 months. As of December 31, 2002, the fair value of cash flow hedges resulted in \$28.2 million of unfavorable OCI (\$18.0 million net of tax).

Regulated Commodity Management

Our domestic regulated businesses produce, purchase and distribute power in three states and purchase and distribute gas in seven states. All of our gas distribution utilities have Purchased Gas Cost Adjustment (PGA) provisions that allow them to pass the 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.

In our regulated electric business, we generate approximately 56% of the power that we sell and purchase the remaining 44% through long-term contracts or in the open market. The regulatory provisions for recovering power costs vary by state. In Kansas, we have an Energy Cost Adjustment (ECA) that serves a similar purpose as the PGAs in place for the gas utility. 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. For Colorado, we have an Incentive Clause Adjustment (ICA) that provides for an equal sharing of the variability of energy costs between us and the customer. In Missouri, there is no provision to pass through changes in costs except through a rate case filing. 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.

Our other wholly owned distribution businesses are located in Canada. Our electric utility business in Alberta is a distribution company only, so fluctuations in power prices have no direct

effect on its earnings. In British Columbia, we generate and distribute power to the consumer and substantially all of the variation between our actual power cost and amounts billed is passed through to the consumer on an annual basis during the following year.

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

During 2002, we restructured Domestic Networks to align it more closely with its regulatory service areas and substantially exited our wholesale energy trading business due to recent events in that industry and the increasing cost of capital required for that business. The reductions in employees that resulted from the restructuring, including employees transferred with the sale of businesses, consisted of approximately 1,205 Merchant Services employees, 75 Corporate employees, and 550 Domestic Networks employees.

Because of these decisions, we recorded severance costs of \$55.7 million during the year. Severance costs were accrued and charged to expense, but will be paid bi-weekly over the term of the severance benefit. The amount of severance costs paid for the year ended December 31, 2002, was \$39.1 million. The remaining liability for severance costs as of December 31, 2002, was \$16.6 million and is included in Accrued Liabilities in the Consolidated Balance Sheets. Certain employees of the wholesale energy trading operations had retention agreements to ensure an orderly exit of the business. During 2002, we paid approximately \$30.5 million of retention payments to these employees.

As a result of these actions, we recorded the following restructuring charges during 2002:

<i>In millions</i>	Year Ended December 31, 2002
Domestic Networks:	
Severance costs	\$ 16.2
Disposition of corporate aircraft	5.1
Total Domestic Networks	21.3
Capacity Services:	
Interest rate swap reductions	6.2
Total Capacity Services	6.2
Wholesale Services:	
Severance costs	30.6
Retention payments	30.5
Lease agreements	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
Total Wholesale Services	173.8
Corporate and Other severance costs	8.9
Total restructuring charges	\$210.2

The disposition of the corporate aircraft primarily included the termination of applicable lease agreements and losses associated with the sale of our corporate aircraft. During 2002, we also expensed certain leasehold improvements and equipment in our wholesale energy trading business that were no longer realizable based on management's best estimate of their fair value. As we began downsizing our operations to match the future direction of the Company, we vacated various office facilities that were used in the wholesale energy trading operations with future lease commitments of \$86.7 million. During the year, we determined that \$38.5 million of these leases would no longer be used and therefore recorded a restructuring charge for the estimated future net lease cost after estimated sublease recoveries. Approximately \$6.3 million of these excess lease costs were paid in 2002. The remaining liability for excess lease costs as of December 31, 2002, was \$32.2 million and is included in Accrued Liabilities in the Consolidated Balance Sheets.

We incurred a \$6.2 million charge to exit portions of interest rate swaps related to the Clay County and Piatt County construction financing arrangements. As debt related to these facilities was paid down earlier than anticipated due to debt covenant violations resulting from the restructure of our business, our interest rate swaps exceeded the outstanding debt. Thus we reduced our position and realized the loss associated with the cancelled portion of the unfavorable swap. In connection with our exit from our wholesale energy trading business, we also incurred a \$9.0 million loss on the negotiated termination of certain aggregator loans to substantially complete our exit from that business.

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

We recorded the following impairment charges and net loss on sale of assets for the years ended December 31, 2002, 2001 and 2000. 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.

<i>In millions</i>	Year Ended December 31,		
	2002	2001	2000
Domestic Networks:			
Quanta Services	\$ 696.1	\$—	\$—
Everest Connections and other communication investments	227.6	16.5	4.0
Enron exposure	—	31.8	—
Gas distribution system	9.0	—	—
Total Domestic Networks	932.7	48.3	4.0
International Networks:			
Midlands	247.5	—	—
Multinet and AlintaGas	127.2	11.5	—
Other	3.4	—	—
Total International Networks	378.1	11.5	—
Capacity Services:			
Turbines	42.1	—	—
Exit from Lodi gas storage investment	21.9	—	—
Termination of Cogentrix acquisition	12.2	—	—
Capacity Services goodwill	7.9	—	—
Other	6.2	—	—
Total Capacity Services	90.3	—	—
Wholesale Services:			
Wholesale Services goodwill	178.6	—	—
Enron exposure	—	35.0	—
Other	3.5	—	3.0
Total Wholesale Services	182.1	35.0	3.0
Corporate and Other:			
Information technology assets	—	—	10.0
Corporate identity intangibles	—	—	2.4
Total Corporate and Other	—	—	12.4
Total impairment charges and net loss on sale of assets	\$1,583.2	\$94.8	\$19.4

During 2002, we also incurred \$426.6 million of impairment charges and net loss on sale of assets 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.

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 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 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's 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 North American utility operations, we made a decision in the fourth quarter of 2002 to reduce the future funding of Everest Connections' (Everest) network build-out to levels necessary to complete construction in progress and serve existing customers. We evaluated the strategic alternatives for Everest 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's 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 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 the long-term prospects of these businesses. Accordingly, we recorded a \$23.1 million pretax impairment charge, or \$13.9 million after-tax, relating to these investments in June 2002.

Certain members of Everest have the option (put right) to sell their membership interests to us if Everest does not meet certain financial and operational performance measures as of December 31, 2004. If the put rights were exercised, we would be obligated to purchase up to 4.0 million and 4.75 million membership interests at a price of \$1.00 and \$1.10, 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. As of December 31, 2002, we have provided for \$7.8 million related to this obligation.

During 2001, we decided to limit our fiber-optic communications business to the Kansas City market. As a result, we wrote off \$16.5 million related to network design, long-term leases and other development costs related to markets outside of Kansas City that we currently do not intend to develop. In 2000, we recorded charges of \$4.0 million related to the construction of our communications networks.

Enron Exposure

In connection with the bankruptcy filing of Enron Corporation in December 2001, we evaluated our overall exposure with Enron and wrote off \$31.8 million related to an unsecured note receivable in Domestic Networks and \$35.0 million related to trading activity in Wholesale Services. While these write-offs represent our best estimate of our exposure based on our contracts with Enron, the ultimate outcome is subject to review by the bankruptcy courts.

Gas Distribution System

In the course of evaluating the need for rate relief in one of our gas jurisdictions, 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. Accordingly, we recorded a pretax charge of \$9.0 million, or \$5.5 million after tax, related to this system.

Midlands

We purchased this investment 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 are currently in negotiations with prospective buyers. Our evaluation of these offers indicated that this investment was impaired. The impairment stems from our inability to hold the investment long-term and thus realize the benefits anticipated in our original analysis. We believe the decrease in value is other than temporary. As a result, we recorded a pretax and after-tax impairment charge of \$247.5 million related to this investment. 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 is consistent with a corresponding impairment charge taken in the financial statements of the underlying business.

Multinet and AlintaGas

In 2002, 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 in Australia. Approximately \$109 million of this pretax charge related to the Multinet Gas business in Melbourne, Australia. We acquired our interest in the Multinet gas distribution business in 1999. We have extracted

significant synergies from this business as its service territory overlaps our existing electric distribution business in Melbourne. However, gas volumes normalized for the mild weather experienced since 1999 have not met the expectations set for this business based on the historical information provided to us during the purchase process. Our liquidity situation and change in strategic direction has caused us to change our intention to hold this investment for the long-term. As a result, we considered the current market value of this business, which included a recent proposal to sell our interest in this business, as well as an impairment charge taken in the financial statements of the underlying business, to assess the realizability of our investment. We believe the decrease in fair value was other than temporary.

The remaining impairment charge was related to our investment in AlintaGas. We acquired this cornerstone stake in AlintaGas in October 2000 from the government of Western Australia at a substantial premium over that paid by the public shareholders for the remaining shares. Our ability to recover this premium was based on our ability to optimize the operating efficiencies in this business with our other Australian investments and to hold this investment for the long-term. While this business has performed very well, our liquidity situation and change in strategic direction has caused us to change our view concerning the long-term nature of this investment. As a result, we considered the current market value of this business, which included a recent proposal to sell this business, to assess the realizability of our investment. Our evaluation of these offers indicated the decrease in fair value was other than temporary.

In 2001, we recorded \$11.5 million of pretax and after-tax charges in International Networks relating to certain Australian equity investments. We recorded charges related to the collectibility of interest on shareholder loans to Multinet and the realizability of Multinet's deferred tax assets. Multinet also wrote off its interest receivable on shareholder loans to Pulse Energy, an equity investment of both United Energy and Multinet. In addition, through our investment in United Energy, which owns approximately 66% of Uecomm, write-downs and provisions were taken during the year related to the realizability of loans and interest due from Uecomm.

Turbines

As discussed in Note 12, we had a contract to acquire four GE 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 first quarter of 2003, we sold two of these turbines for approximately their impaired value.

Exit from Lodi Gas Storage Investment

In August 2001, Aquila Merchant and a partner agreed to acquire 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'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 \$21.9 million pretax, or \$21.6 million after-tax loss on this transaction.

Termination of Cogentrix Acquisition

In August 2002, we agreed to terminate 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 current 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 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.

Capacity Services Goodwill

SFAS 142 requires that we test goodwill at least annually for impairment. We performed our annual SFAS 142 testing as of November 30, 2002. Due to reduced spark spreads and an oversupply of generation, the results of this test indicated a goodwill impairment. Therefore, we recorded an impairment charge of \$7.9 million in the fourth quarter of 2002 to write off Capacity Service's remaining goodwill balance.

Capacity Services—Other

Included in other impairments for Capacity 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.

Wholesale 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 Wholesale 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 \$178.6 million of unamortized goodwill in the second quarter of 2002.

Corporate and Other

In 2000, we recognized charges of \$10.0 million related to certain information technology assets that are no longer used in the business and \$2.4 million related to our decision to discontinue use of certain corporate identity intangibles.

Note 6: Discontinued Operations

Consistent with our announced intention to sell \$1 billion of assets, we have sold the following assets that are considered discontinued operations in accordance with SFAS 144. See Note 2 for further discussion of this new standard. 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.

Gas Storage Facility

In August 2002, we signed an agreement 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 signed an agreement 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 a \$152.0 million after-tax loss.

Merchant Loan Portfolio

Historically, we provided capital to energy-related businesses seeking financing to fund energy projects. We offered this financing as an additional service as we continued to expand as a risk management company. After we made the decision to exit the wholesale energy trading business, it was decided to sell our loan portfolio due to this business no longer being 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. Given the environment of the industry and our liquidity needs, we sold these loans at a substantial discount to their carrying value.

Coal Handling Facility

During the fourth quarter of 2002, we decided to dispose of our coal terminal and handling facility, Aquila Dock, Inc. 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, 2002 in the Consolidated Statements of Income. The related assets to be sold from these businesses have been reclassified as Non-Current Assets of Discontinued Operations on the December 31, 2002 and 2001 Consolidated Balance Sheets.

Non-Current Assets of Discontinued Operations as of December 31, 2002 and 2001 are as follows:

<i>In millions</i>	December 31,	
	2002	2001
Property, plant and equipment, net	\$.3	\$ 490.4
Investments in unconsolidated subsidiaries	—	99.4
Notes receivable, net	19.2	415.6
Goodwill, net	—	18.4
Deferred charges and other assets	—	34.8
Total	\$19.5	\$1,058.6

Operating results of discontinued operations for the years ended December 31, 2002, 2001 and 2000 are as follows:

<i>In millions</i>	Year Ended December 31,		
	2002	2001	2000
Sales	\$ 235.3	\$459.5	\$513.6
Cost of sales	164.8	359.6	398.4
Gross profit	70.5	99.9	115.2
Operating expenses:			
Operating expense	60.4	63.9	83.3
Impairment charges and net loss on sale of assets	426.6	—	7.8
Depreciation and amortization expense	23.7	32.0	31.4
Total operating expense	510.7	95.9	122.5
Other income (expense):			
Equity in earnings (losses) of investments	5.3	3.5	(.3)
Other income (expense)	48.4	54.4	52.8
Earnings (loss) before interest and taxes	(386.5)	61.9	45.2
Interest expense	5.6	6.7	26.2
Earnings (loss) before taxes	(392.1)	55.2	19.0
Income tax expense (benefit)	(62.5)	21.1	6.5
Earnings (loss) from discontinued operations	\$(329.6)	\$ 34.1	\$ 12.5

Note 7: Restricted Cash

Our restricted cash is made up of margin deposits, asset sale proceeds held in escrow and cash collateral. During the year, certain counterparties required us to segregate the customer funds on deposit that they had advanced to us from our daily cash accounts. This amount is considered “restricted cash” and not available for day-to-day operations. The amount of these deposits at December 31, 2002 was \$171.7 million. Also included in restricted cash is \$239.9 million of cash proceeds from the sale of our Merchant loan portfolio. These funds were temporarily placed in an escrow account until final resolution of sale contingencies. In January 2003, these funds were released from escrow. We used 50% of the proceeds to pay down debt in accordance with our

default waiver agreements with our lenders. The remaining 50% was used to provide additional liquidity. See Note 12 for further explanation of the waiver agreements.

Lastly, under the terms of our leases surrounding the turbine facility and the Piatt County power plant as described in Notes 12 and 13, we were required to post cash collateral related to the construction financing. As of December 31, 2002, we had posted cash collateral of \$28.0 million and \$54.3 million related to the turbine facility and Piatt County power plant, respectively. The \$82.3 million of cash collateral was applied against the debt on these projects in connection with the payoff of these loans in April 2003.

Note 8: Accounts Receivable

Our Accounts Receivable on the Consolidated Balance Sheets are comprised as follows:

<i>In millions</i>	December 31,	
	2002	2001
Merchant Services accounts receivable	\$1,485.1	\$3,014.1
Regulated utility accounts receivable	103.2	179.4
Other accounts receivable	7.9	8.3
Allowance for doubtful accounts	(30.6)	(65.9)
Unbilled utility revenue	107.2	88.4
Accounts receivable sale programs	—	(297.5)
Total	\$1,672.8	\$2,926.8

Previously we had two agreements allowing us to periodically transfer undivided ownership interests in a revolving pool of our trade receivables to multi-seller conduits administered by independent financial institutions. One of these agreements was for up to \$275 million of our Merchant Services receivables. The second, totaling up to \$130 million, related to accounts receivable generated from sales of gas and power by our domestic regulated utilities. However, due to the downgrades of our credit rating to non-investment grade, the buyers of these receivables could no longer participate in the programs. As a result, these programs were cancelled in 2002.

Under the terms of the agreements, we would sell trade receivables to bankruptcy-remote special purpose entities (SPEs). The SPEs were related to the financial institutions and were not related to us. The percentage ownership interest in receivables purchased by the SPEs would increase or decrease over time, depending on the characteristics of the trade receivables, including delinquency rates and debtor concentrations. We serviced the receivables transferred to the SPEs and received servicing fees that approximated market rates totaling (in millions) \$.6, \$2.9 and \$3.0 in 2002, 2001 and 2000, respectively. Collections on these receivables were reinvested on behalf of the buyers in newly created receivables. We had gross sales of accounts receivable of (in billions) \$1.4, \$4.1 and \$4.5 during 2002, 2001 and 2000, respectively. Our Consolidated Statements of Income include the loss on the sale of receivables of (in millions) \$2.5, \$15.6 and \$26.6 in 2002, 2001 and 2000, respectively.

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:

<i>In millions</i>	December 31,	
	2002	2001
Electric utility	\$ 3,274.1	\$ 3,070.7
Gas utility	1,192.5	1,237.5
Non-regulated electric power generation	497.1	122.5
Communications	59.2	128.1
Corporate	336.8	396.2
Electric and gas utility plant—construction in process	80.3	102.2
	5,440.0	5,057.2
Less—accumulated depreciation and amortization	(2,259.4)	(2,155.3)
Total property, plant and equipment, net	\$ 3,180.6	\$ 2,901.9

	Composite Depreciation Rates
Electric utility	4.0%
Gas utility	3.4%
Non-regulated electric power generation	2.9%
Communications	10.4%
Other	9.3%

Note 10: Investments in Unconsolidated Subsidiaries

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

<i>Dollars in millions</i>	Effective Ownership at 12/31/02	Country	Investment at December 31,		Equity Earnings—Year Ended December 31,		
			2002	2001	2002	2001	2000
United Energy Limited	33.8%	Australia	\$252.0	\$ 218.8	\$ 29.1	\$ 16.5	\$ 19.8
Multinet Gas *	25.5%	Australia	175.5	222.8	3.0	6.5	10.4
AlintaGas Limited	22.5%	Australia	85.2	87.9	7.1	8.1	.1
UnitedNetworks Limited	Sold	New Zealand	—	386.7	30.9	30.4	13.9
Midlands Electricity plc *	79.9%	United Kingdom	75.5	—	41.9	—	—
Quanta Services, Inc. *	10.2%	United States	40.6	773.6	2.4	30.6	53.7
Independent power project partnerships	20%-50%	U.S. & Jamaica	281.2	312.5	52.8	28.9	18.7
Other	Various		4.9	43.3	(.3)	(1.7)	(.8)
Total			\$914.9	\$2,045.6	\$166.9	\$119.3	\$115.8

- * *These businesses recorded significant impairment charges during 2002. We have reflected our proportionate share in our Impairment Charges and Net Loss on Sale of Assets in our Consolidated Statements of Income as described in Note 5. The impairment charges are netted against our investment balance at December 31, 2002.*

United Energy Limited, Multinet Gas and AlintaGas Limited—We acquired our initial investment in Australia in 1995. Our current ownership interest in United Energy Limited (UEL), a publicly owned electric distribution company in Melbourne, Australia is 33.8%. UEL also owns a 66% interest in Uecomm Limited (UEC), a communications business, and a 22.5% interest in AlintaGas Limited, a gas utility in Western Australia. At December 31, 2002, the market value of our net effective ownership in UEL was \$225.9 million.

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, Australia. 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 June 2000, UEL and Ikon closed a transaction that resulted in the formation of Pulse Energy, a joint venture with Shell Australia Ltd and Woodside Energy Ltd. UEL contributed its electric retail customers in exchange for \$210 million and Ikon contributed its gas retail customers in exchange for \$281 million. UEL and Ikon each loaned Pulse \$70 million, and held a combined 50% ownership of Pulse.

In September 2000, UEC, formerly a wholly owned subsidiary of UEL, sold 34% of its common stock to the public, reducing UEL's ownership share of UEC to 66%. As a result, we recorded a \$44.0 million gain from the public offering in Gain on Sale of Subsidiary Stock.

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 is reflected as an equity investment with the remaining 22.5% reflected as part of our interest in UEL. At December 31, 2002, the market value of our net effective ownership in AlintaGas was \$84.9 million.

In 2001, we also recognized charges totaling \$11.5 million related to our investment in Multinet and Pulse that we classified in Impairment Charges and Net Loss on Sale of Assets. See Note 5 for further discussion.

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 approximate 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 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. We are currently exploring the possible sale of our Australian investments.

Following is the summarized financial information for UEL:

<i>In millions</i>	December 31,	
	2002	2001
Assets:		
Current assets	\$ 68.4	\$ 80.4
Non-current assets	1,072.7	1,072.1
Total Assets	\$1,141.1	\$1,152.5
Liabilities and Equity:		
Current liabilities	167.5	208.1
Non-current liabilities	441.1	458.6
Equity	532.5	485.8
Total Liabilities and Equity	\$1,141.1	\$1,152.5

<i>In millions</i>	Year Ended December 31,		
	2002	2001	2000
Operating Results:			
Sales	\$238.6	\$249.6	\$710.5
Costs and expenses	202.1	229.3	635.3
Net Income	\$ 36.5	\$ 20.3	\$ 75.2

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; super majority 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%. We recognized a \$5.8 million pretax gain on this transaction.

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 were utilized 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 \$38.5 million. We recorded a \$130.5 million pretax gain, or \$28.0 million after-tax gain, in the fourth quarter of 2002 as a result of this sale.

Following is the summarized financial information for UNL. The balance sheet as of December 31, 2002 is not included because we sold our investment in 2002:

<i>In millions</i>	December 31, 2001
Assets:	
Current assets	\$ 39.2
Non-current assets	965.7
Total Assets	\$1,004.9
Liabilities and Equity:	
Current liabilities	\$ 27.6
Non-current liabilities	822.5
Equity	154.8
Total Liabilities and Equity	\$1,004.9

<i>In millions</i>	Nine Months Ended September 30, 2002	Year Ended December 31, 2001	2000
Operating Results:			
Sales	\$164.6	\$189.1	\$207.2
Costs and expenses	119.0	166.3	196.8
Net Income	\$ 45.6	\$ 22.8	\$ 10.4

Midlands Electricity plc—In May 2002, we purchased from FirstEnergy Corporation a 79.9% economic interest in Avon Energy Partners Holding Company, the holding company for Midlands Electricity, a United Kingdom electricity network. FirstEnergy retained the remaining 20.1% of Avon. Although we have since written off substantially all of our investment, at the time of acquisition, the gross purchase price of the acquisition was valued at approximately \$262 million, and was comprised of the following:

<i>In millions</i>	
Initial payment	\$155
Transaction costs	20
Present value of promissory note to be paid in six annual payments of \$19 million beginning on May 8, 2003	87
Total value of purchase price	\$262

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. Midlands also owns a combined 884 megawatts of net generation capacity in the United Kingdom, Turkey and Pakistan. Pursuant to an operating services agreement, we provide 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 have 50% voting power and an equal number of representatives on the Avon board of directors. Although we have the majority economic interest, FirstEnergy's participation in day-to-day business decisions is significant, including approval of executive compensation, additional capital contributions, budgets, and the dissolution of the company. As such, we are required to account for this acquisition using the equity method of accounting. FirstEnergy has the right to sell its interest in Midlands to us at fair market value if, at any time during the 30-day period prior to May 8, 2008, the fair value of FirstEnergy's holdings is less than \$72.8 million.

Recent downgrades in credit ratings assigned to the public debt in the Midlands ownership chain have called into question the ability of Midlands to pay management fees and dividends to us. Additionally, the local regulatory body, the Office of Gas and Electricity Markets (Ofgem), now requires pre-approval of cash payments to the owners in the form of management fees or dividends. Accordingly, in 2003 and beyond, we intend to record equity earnings and management fees only to the extent of cash received.

In August 2002, Aquila and FirstEnergy initiated a bid process for the sale of Midlands. We received offers in early December and are currently in negotiations with prospective buyers. As a result of these 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 less costs to sell. See Note 5 for further discussion.

Following is the summarized financial information for Midlands Electricity plc:

<i>In millions</i>	December 31, 2002
Assets:	
Current assets	\$ 399.2
Non-current assets	2,369.6
Total Assets	\$2,768.8
Liabilities and Equity:	
Current liabilities	\$ 193.2
Non-current liabilities	2,511.4
Equity	64.2
Total Liabilities and Equity	\$2,768.8

In millions

**Year Ended
December 31, 2002**

Operating Results:

Sales	\$ 605.5
Costs and expenses	818.2
Net Loss	\$(212.7)

Quanta Services, Inc.—Between 1999 and 2001, we acquired voting convertible preferred and common stock of Quanta Services, Inc. (Quanta Services) 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.

Quanta Services paid us management advisory fees of \$36.2 million for 2000. The management fee agreement was terminated in December 2000. In addition, 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 (in millions) \$24.8, \$35.9 and \$18.2 in 2002, 2001 and 2000, respectively.

Following is the summarized financial information for Quanta Services. Due to the significance of the income statement impact from our investment in Quanta Services, we have attached their financial statements for the three years ended December 31, 2002, as Exhibit 99.3.

<i>In millions</i>	December 31,	
	2002	2001
Assets:		
Current assets	\$ 529.5	\$ 577.1
Non-current assets	835.3	1,465.8
Total Assets	\$1,364.8	\$2,042.9
Liabilities and Equity:		
Current liabilities	\$ 212.1	\$ 241.5
Non-current liabilities	468.1	594.6
Equity	684.6	1,206.8
Total Liabilities and Equity	\$1,364.8	\$2,042.9

<i>In millions</i>	Year Ended December 31,		
	2002	2001	2000
Operating Results:			
Sales	\$1,750.7	\$2,014.9	\$1,793.3
Costs and expenses	2,370.3	1,929.1	1,687.6
Net Income (Loss)	\$ (619.6)	\$ 85.8	\$ 105.7

Independent Power Project Partnerships—We own interests in 12 independent power projects 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. See Note 5 for further discussion of this sale.

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.

<i>In millions</i>	December 31,	
	2002	2001
Assets:		
Current assets	\$ 367.0	\$ 387.5
Non-current assets	2,344.0	2,553.3
Total Assets	\$2,711.0	\$2,940.8
Liabilities and Equity:		
Current liabilities	\$ 882.6	\$ 317.9
Non-current liabilities	1,183.8	2,106.3
Equity	644.6	516.6
Total Liabilities and Equity	\$2,711.0	\$2,940.8

<i>In millions</i>	Year Ended December 31,		
	2002	2001	2000
Operating Results:			
Sales	\$1,026.8	\$944.0	\$526.7
Costs and expenses	1,050.9	833.8	445.9
Net Income (Loss)	\$ (24.1)	\$110.2	\$ 80.8

Note 11: Regulatory Assets

Federal, state, provincial 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 at December 31, 2002 and 2001. We primarily show these as Deferred Charges and Other Assets and Deferred Credits on our Consolidated Balance Sheets.

<i>In millions</i>	2002	2001
Regulatory Assets:		
Purchased power costs	\$ 82.1	\$177.5
Under-recovered gas costs	19.8	21.5
Income taxes	97.7	82.3
Environmental	15.3	17.2
Regulatory accounting orders	15.0	7.3
Other	16.9	21.4
Total Regulatory Assets	246.8	327.2
Regulatory Liabilities:		
Income taxes	80.9	52.5
Revenue subject to refund	8.8	10.3
Over-recovered gas costs	8.9	10.2
Pensions	10.8	12.1
Total Regulatory Liabilities	109.4	85.1
Net Regulatory Assets	\$137.4	\$242.1

Regulatory assets are either currently being collected in rates or are expected to be collected through rates in a future period.

- In 2000, purchased power costs for Aquila Networks Canada rose to levels above that collected in rates. We deferred these excess costs and filed an application to increase future rates charged to customers in order to recover these costs. In November 2000, the provincial government in Alberta, Canada suspended pending rate increases to recover such purchased power costs. In December 2001, the Alberta Energy and Utility Board issued its decision permitting us to recover such costs during 2002 and 2003, including carrying costs.
- Under-recovered gas costs represent the cost of gas in excess of that allowed in current rates. These costs will be collected from customers in future periods as rates are periodically adjusted.
- Income taxes represent amounts expected to be collected from customers in future periods.
- 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.
- Regulatory accounting orders include costs such as ice storm recovery and others that have been specifically approved for recovery over future periods.

Regulatory liabilities represent items we expect to pay to customers through billing reductions in future periods.

- Income taxes represent amounts that we expect to refund 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 collected from 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 result from different accounting treatment afforded pension costs by regulators versus that required by generally accepted accounting principles.

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

Short-term debt includes the following components:

<i>Dollars in millions</i>	December 31,	
	2002	2001
Bank borrowings and other—United States	\$244.4	\$310.0
Turbine facility	43.4	—
Bank borrowings and other—Canada	13.2	37.0
Commercial paper	—	201.6
Total	\$301.0	\$548.6
Weighted average interest rate at year end	3.04%	3.10%

Revolving Credit Facility

On April 12, 2002, we entered into a new revolving credit facility totaling \$650 million that replaced a \$400 million credit facility. The new credit facility consisted of two \$325 million credit agreements, one with a maturity date of 364 days, the other three years. Our credit agreement contained restrictive covenants and charged annual commitment fees ranging from .65% to .75%.

Debt Covenants

Certain of our finance arrangements, including our \$650 million revolving credit facility, required that, subject to certain exclusions of non-cash gains or losses, our earnings before interest, taxes, depreciation and amortization during the previous four quarters must be at least 2.25 times our interest expense during that same period. We refer to this as our interest coverage ratio. These

agreements also required us to maintain a ratio of total debt to total capitalization of less than 62.5%. We refer to this as our capitalization ratio. As a result of our operating performance, the winding down of our wholesale energy trading business and our asset sales program, we were not in compliance with our interest coverage ratio since September 30, 2002, or our capitalization ratio covenant since December 31, 2002.

We obtained waivers from the affected lenders from the requirement to comply with our interest coverage ratio until April 12, 2003. This waiver required that 50% of any net cash proceeds under \$1 billion and 100% of any net cash proceeds above \$1 billion (that were received prior to April 12, 2003, from any sales of our North American assets) would be used to reduce our obligations to those lenders on a pro rata basis. Any cash proceeds that are used to reduce borrowings under these financing arrangements permanently reduced, on a dollar-for-dollar basis, the amount of credit available to us under those agreements. We also agreed to make reasonable efforts to obtain approvals that would allow us to pledge our regulated assets as security for the benefit of our lenders. We were required to pay fees of approximately \$2.4 million to the lenders in connection with these waivers. We also received additional waivers until April 12, 2003 of a covenant that requires us to maintain a certain capitalization ratio. We paid our lenders fees of approximately \$1.2 million for these additional waivers.

As of December 31, 2002, we made payments of approximately \$161.1 million to those lenders that in turn reduced our borrowings under the revolving credit facility to \$244.4 million and reduced our revolver capacity to \$494.4 million and established a cash collateral balance of \$5.5 million against our letters of credit. In addition to the borrowings as of December 31, 2002, we had \$195.6 million of letters of credit outstanding against our credit facility. Subsequent to December 31, 2002, we made additional payments from asset sale proceeds of \$109.2 million which further reduced our revolver capacity to \$439.8 million and increased our cash collateralization of letters of credit to \$60.1 million. In April 2003, debt outstanding under the 364-day credit facility was repaid in full and the unutilized portion of the three-year credit facility was terminated. The utilized portion of this facility is being used solely as support for our letters of credit currently outstanding. The lenders have agreed to (a) allow the letters of credit that are fully cash collateralized under the three-year credit facility (and, thus, the facility itself) to remain outstanding and (b) waive certain restrictions for an additional three-week period. During the next three weeks, the Company intends to replace the letters of credit issued under the three-year facility with new letters of credit under a different credit facility that will be fully cash collateralized.

At December 31, 2001, \$135.0 million of domestic commercial paper was outstanding. Because our credit has deteriorated, we are no longer able to borrow funds under our commercial paper program. The commercial paper program was supported by our prior credit agreement. We also had \$310.0 million of borrowings outstanding under various uncommitted, unsecured bank facilities at December 31, 2001.

Our debt arrangements include syndicated bank debt, uncommitted bank lines, bonds (secured and unsecured) and financial guarantees that support subsidiary financings. The syndicated bank debt, most bonds outstanding and financial guarantees contain cross-default provisions, which are usual and customary for these types of arrangements.

Turbine Facility

In May 2001, we entered into a five-year operating lease through a special purpose entity for 10 electric power plant turbines plus related equipment. Under this agreement, we could lease up to

\$265 million in turbines and equipment. In June 2002, six of these turbines were transferred to the Piatt County power plant discussed in Note 13 and reduced the above facility to \$120.0 million. In our negotiations at the end of the third quarter to obtain waivers of our interest coverage ratio breach, we agreed to use 50% of the proceeds from asset sales to reduce our obligations to the affected lenders on a pro rata basis. Any cash proceeds that are used to reduce borrowings under these financing arrangements permanently reduced, on a dollar-for-dollar basis, the amount of credit available to us under those agreements. During the fourth quarter of 2002, we repaid \$3.0 million of debt related to the turbine facility. Through March 14, 2003, we paid an additional \$9.7 million on these notes. Because of these debt repayments and the redemption of a portion of the special purpose entity's equity, this special purpose entity no longer qualified for off-balance sheet treatment at December 31, 2002. We therefore consolidated \$47.9 million of these assets and \$46.0 million of related debt in the fourth quarter of 2002. As of December 31, 2002, the total debt outstanding on the turbines was \$43.4 million. As discussed in Note 7, we have posted \$28.0 million of cash collateral in support of these notes. These notes are scheduled to mature in 2005, however, as these notes were repaid in full in April 2003, we have classified the notes as short-term debt.

364-Day Senior Secured Credit Facility

On April 11, 2003, we closed on a 364-day senior secured financing of \$100.0 million. The borrower under the facility is UtiliCorp Australia, Inc., a wholly-owned subsidiary of Aquila. The facility has an option under which we can for a 30-day period following closing, at our discretion, increase the size of the financing by up to \$100.0 million. The interest rate on this financing is the London Inter Bank Offering Rate (LIBOR) (with a 3% floor) plus 4.0% for the first 90 days. After the first 90 days, the interest rate increases an additional 2% and will increase an additional 2% every subsequent 90 days with a maximum rate at maturity of LIBOR (with a 3% floor) plus 10%. In addition, we were required to pay up front commitment and arrangement fees of \$4.1 million. If we increase the size of the financing under the above option, an additional fee of up to \$4.1 million would be required. Proceeds from the financing were used to retire debt.

The 364-day term loan facility is secured by (i) a pledge of the equity of a wholly-owned subsidiary that indirectly holds our interests in independent power projects, (ii) a pledge of the equity of a wholly-owned subsidiary that indirectly holds our Australian utility investments, (iii) a pledge of the equity of our two subsidiaries that own our interests in our power plants in Clay County and Piatt County, Illinois, and (iv) a pledge, junior to that in favor of the lenders under the three-year facility, of the equity of subsidiaries that indirectly hold our Canadian utility business. If we default on this loan, the lenders would be entitled to be fully repaid from the proceeds of this collateral before other creditors could assert their claims against the collateral.

We are required to use certain funds to prepay amounts outstanding under the 364-day facility. These include:

- (1) all distributions and proceeds from our Australian investments and independent power project investments,
- (2) all distributions, proceeds and excess cash from our power plants in Clay County and Piatt County, Illinois,
- (3) all proceeds from any accounts receivable financing or sales program, and,

- (4) all distributions and proceeds from our Canadian utility business to the extent not required to be used to repay outstanding amounts under the Three-Year Senior Secured Credit Facility described in Note 13.

Among other restrictions, the 364-day facility contains the following debt covenants:

- (1) If the sale of our Australian equity investments has not been completed within 180 days from April 11, 2003, a formal public sale process will commence on both our Australian equity investments and our independent power project investments.
- (2) We are restricted from paying dividends, issuing additional debt, entering into any mergers or acquisitions not meeting a specified leverage requirement or the repurchase or redemption of common stock.
- (3) The fair market value of our collateral provided must be at least twice the value of the debt outstanding.

We can voluntarily prepay amounts under the 364-day facility without penalty at any time. However, amounts that are repaid cannot be reborrowed. To the extent we default on any of our loan covenants, our interest rate will increase an additional 2% during the default period.

Canadian Denominated Credit Facilities

As of December 31, 2002, we had three different revolving demand lines totaling C\$60 million with two different banks at our Canadian networks businesses. As of December 31, 2002 and 2001, we had outstanding borrowings of US\$13.2 million and US\$37.0 million, respectively, against these lines. At December 31, 2002, we also had US\$11.2 million in letters of credit issued against these lines.

As of December 31, 2001, we had in place a C\$150 million commercial paper program at our Canadian networks business. This program was supported by a C\$150 million credit facility. At December 31, 2001, US\$66.6 million of commercial paper was outstanding. Effective in June 2002, this agreement was amended to reduce the available commercial paper program and credit facility to C\$112.5 million with annual commitment fees of .185%. As of December 31, 2002, no borrowings or commercial paper were outstanding under this facility.

Note 13: Long-Term Debt

This table summarizes the Company's long-term debt:

<i>In millions</i>	December 31,	
	2002	2001
First Mortgage Bonds:		
Various, 9.44%, due annually through 2021(c)	\$ 21.4	\$ 29.5
Senior Notes:		
2.89% Floating Rate Series, due May 15, 2002	—	230.0
Aquila Southwest Energy 8.29% Series, due September 15, 2002	—	12.5
7.0% Series, due July 15, 2004	250.0	250.0
6.875% Series, due October 1, 2004	150.0	150.0
9.03% Series, due December 1, 2005	20.2	20.2
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	200.0	200.0
9.95% Series, due February 1, 2011	250.0	250.0
14.875% Series, due July 1, 2012	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	—
Medium Term Notes:		
Various, 7.77%*, due 2005-2023	40.0	40.0
Convertible Subordinated Debentures:		
6.625%, due July 1, 2011 (convertible into 224,429 common shares at \$15.79 per share)	3.5	3.7
Other:		
Note Payable to FirstEnergy, 8.15%, due annually through 2008	87.4	—
Clay County Project Notes, 8.47%, due November 3, 2003 and 2007(c)	98.4	—
Piatt County Project Notes, 6.44%, due May 16, 2005(c)	146.7	—
Canadian Asset Securitization, 3.458%, due monthly to February 15, 2004(c)	107.6	—
Canadian Secured Debentures, 8.145%*, due 2003-2023(c)	94.0	62.2
Canadian Senior Notes (U.S. Denominated), 7.75%, due June 2011	200.0	200.0
Australian Senior Notes, 6.72%*, due October 2002	—	76.6
Australian Medium-term Notes, 6.35%*, due January-April 2003	78.6	90.3
New Zealand Floating Rate Notes, 5.67%, due April-October 2002	—	83.5
New Zealand Denominated Credit Facility, due June 2002	—	110.5
Australian Denominated Credit Facilities, due March 2004	5.2	49.7
Canadian Denominated Credit Facilities, due April 2003 and May 2005	91.3	159.7
Other notes and obligations(c)	36.7	48.4
Total Long-Term Debt	2,928.7	2,327.0
Less current maturities(a)	530.7	579.1
Long-term debt, net	\$2,398.0	\$1,747.9
Fair value of long-term debt, including current maturities(b)	\$2,212.4	\$2,416.6

* Weighted average interest rate.

(a) Included in Current Maturities of Long-Term Debt in our 2001 Consolidated Balance Sheet is \$100.0 million of current maturities related to Company-Obligated Preferred Securities as discussed in Note 15.

- (b) *The fair value of long-term debt is based on current rates at which the Company could borrow funds with similar remaining maturities.*
- (c) *Approximately \$486.6 million of our long-term debt, including \$18.6 million in other notes and obligations, are secured by certain assets of the Company as specified in various mortgages, indentures and security agreements.*

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

<i>In millions</i>	Maturing Amounts
2003	\$ 530.7
2004	431.8
2005	69.6
2006	103.8
2007	56.1
Thereafter	1,736.7
Total	\$2,928.7

Senior Notes

In February 2002, we issued \$287.5 million of 7.875% senior notes due in March 2032. These notes are callable by us at par after February 28, 2007. Net proceeds from the sale were used to replace liquidity of \$220.0 million previously provided from receivables sold in connection with one of our accounts receivable sales programs and to retire short-term debt incurred for general corporate purposes.

In July 2002, we issued \$500.0 million of 11.875% senior notes due in July 2012. We used the proceeds from these offerings to repay borrowings under the revolving credit facility, to retire \$100.0 million of current maturities of company-obligated preferred securities and to increase our liquidity. Because Moody's and Standard & Poor's 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. Net proceeds from the sale were used to reduce short-term debt incurred for acquisitions and general corporate purposes. Because Moody's and Standard & Poor's have downgraded our credit ratings, the interest rate on these notes has been adjusted to a maximum rate of 9.95%.

Three-Year Senior Secured Credit Facility

On April 11, 2003, we closed on a three-year senior secured financing of \$430.0 million. The initial interest rate on the facility will be LIBOR (which has a 3% floor) plus 5.75%. In addition, we were required to pay up front commitment and arrangement fees of \$17.8 million. Proceeds from the financing will be used to retire debt and support existing and future letters of credit.

The three-year facility is secured by (i) \$430.0 million first mortgage bonds issued under a new indenture that constitutes a lien on our existing and future Michigan and Nebraska tangible utility network assets, (ii) a pledge of the equity of two wholly-owned subsidiaries that indirectly hold our Canadian utility business, and (iii) a pledge, junior to that in favor of the lenders under

the 364-day senior secured credit facility, of the equity of a wholly-owned subsidiary that indirectly holds our interests in independent power projects. If we default on this loan, the lenders would be entitled to be fully repaid from the proceeds of this collateral before other creditors could assert their claims against the collateral.

We have also committed to use reasonable efforts to obtain approvals that would provide these lenders additional utility assets as collateral for their loans. If, as a result of the addition of any such collateral, the value of the collateral securing the indenture exceeds 167% of the loan secured by the indenture, the pledge of the Canadian equity interest may be released and the interest rate would be reduced to LIBOR (which has a 3% floor) plus 5.00%.

We are required to use certain funds to prepay amounts outstanding under the three-year facility unless the value of the collateral will, absent such payment, remain equal to at least 200% of the outstanding loan amount under this facility (subject to certain reductions following certain events). These funds include:

- (1) all proceeds from the disposition of any collateral subject to the lien of the first mortgage indenture and,
- (2) all distributions and proceeds from our Canadian utility business and independent power project investments so long as the applicable pledge agreements continue to secure this facility.

In addition, the \$430.0 million senior secured debt would become immediately due and payable if we do not complete an exchange offer, tender offer, refinancing or other retirement transaction with regard to 80% of the outstanding principal of our 7% senior note series due July 15, 2004 and our 6.875% senior note series due October 1, 2004, at least two weeks prior to their respective maturity dates.

Among other restrictions, the senior secured facility contains the following debt covenants:

- (1) Beginning July 1, 2003, we must maintain a ratio of total debt to total capital of not more than .75 to 1.00 as of September 30, 2003 and December 31, 2003, decreasing to .70 to 1.00 for quarters ending after December 31, 2003.
- (2) Beginning July 1, 2003, we must maintain a trailing twelve-month ratio of earnings before interest, taxes, depreciation and amortization (EBITDA) from pledged assets to interest expense related to these assets of no less than 1.05 to 1.00, increasing up to 2.0 to 1.0 for quarters ending after December 31, 2004.
- (3) Beginning July 1, 2003, we must maintain a trailing twelve-month ratio of debt outstanding on our pledged assets to EBITDA from our pledged assets of no more than 10.5 to 1.0, decreasing to 5.5 to 1.0 for quarters ending after June 30, 2004.

The three-year facility also contains covenants that restrict certain activities including, among others, limitations on additional indebtedness, restrictions on acquisition and sale transactions, and restrictions on the amount that we can fund our unregulated merchant businesses and our Everest telecommunications business. 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 three-year facility.

Amounts under the three-year facility cannot be voluntarily prepaid except with payment of a make-whole amount. Amounts that are repaid cannot be reborrowed. To the extent we default on any of our loan covenants, our interest rate will increase an additional 2% during the default period.

Debt Refinancing Exchange Offer

In June 2001, we exchanged \$189.5 million of senior notes with interest rates ranging from 8.0% to 9.0% for \$200.0 million of new Canadian senior notes with interest rates at 7.75%, maturing in June 2011. Additionally, during 2001, we retired \$204.1 million of senior notes, mortgage bonds and company-obligated preferred securities.

Note Payable to FirstEnergy

In connection with the acquisition of our interest in Midlands Electricity from FirstEnergy Corporation, described in Note 10, we issued a note payable to the seller, FirstEnergy, for a portion of the purchase price. This note requires 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%. If we sell our interest in Midlands prior to the maturity of the note we would be required to pay the remaining unpaid installments to FirstEnergy on an undiscounted basis.

Clay County and Piatt County Construction Financing

In November 2000, we entered into a \$145.0 million lease through a special purpose entity to finance the 340-megawatt Clay County power plant, then under construction. This plant was completed in 2002. In February 2002, we entered into an agreement to lease from a special purpose entity a \$235 million, 510-megawatt power plant that is being constructed in Piatt County, Illinois. We expect construction to be completed in June 2003. As discussed in Note 12, in our negotiations to obtain waivers regarding our interest coverage ratio breach and consents with respect to asset dispositions, we agreed to use 50% of the proceeds from asset sales to reduce our obligations to the affected lenders on a pro rata basis. Any cash proceeds that are used to reduce borrowings under these financing arrangements permanently reduced, on a dollar for dollar basis, the amount of credit available to us under those agreements. During the fourth quarter of 2002, we repaid \$34.5 million and \$30.0 million of debt related to Clay County and Piatt County, respectively. Because of these debt repayments and the redemption of a portion of the SPEs' equity, these SPEs no longer qualified for off-balance sheet treatment. Therefore we consolidated these assets and the related debt in the fourth quarter of 2002, as summarized below:

<i>In millions</i>	Clay County	Piatt County
Cash and cash equivalents	\$ —	\$ 8.1
Funds on deposit	—	9.9
Property, plant and equipment, net	138.5	169.4
Total Assets	\$138.5	\$187.4
Long-term debt	\$132.9	\$175.0
Minority interest	5.6	12.4
Total Liabilities	\$138.5	\$187.4

The debt outstanding on the Clay County power plant was \$98.4 million as of December 31, 2002, \$84.1 million which was scheduled to mature on November 3, 2003 and \$14.3 million which was scheduled to mature on November 3, 2007. However, as a result of cash proceeds received on asset sales through March 14, 2003, an additional \$23.2 million of debt was repaid prior to April 2003.

The debt outstanding on the Piatt County power plant was \$146.7 million as of December 31, 2002. The debt was scheduled to mature on May 16, 2005. However, as a result of cash proceeds received on asset sales through March 14, 2003, an additional \$21.0 million of debt has been repaid. As discussed in Note 7, we provided \$54.3 million of cash collateral in support of this debt. The collateral was applied against the loan in connection with the retirement of this debt in April 2003.

As the remaining balance under both the Clay County and Piatt County facilities were repaid in April 2003, we have classified both facilities as current maturities of long-term debt.

Canadian Asset Securitization

In 2002, our Canadian network in Alberta entered into a securitization agreement under which certain deferred purchase power costs that are being recovered from customers through a rate increase were sold to an unrelated financial institution. This securitization has been recorded as a financing and is secured by future rate collections. The amount securitized as of December 31, 2002 was US\$107.6 million, which bears interest at a fixed rate of 3.458%.

Canadian Denominated Credit Facilities

Our Canadian networks business maintained a credit facility with five banks, which matured in April 2003. The interest rate on this facility fluctuated with changes in the Bankers Acceptance Discount Rate. At December 31, 2002, US\$78.6 million was outstanding at a rate of 4.96%. In April 2003, this debt was fully repaid.

Our Canadian networks business also maintains a C\$20 million credit facility that matures in May 2005. The interest rate on this facility fluctuates with changes in the Bankers Acceptance Discount Rate. At December 31, 2002, US\$12.7 million was outstanding at a rate of 3.70%.

In June 2001, our wholly owned Canadian finance subsidiary, Aquila Networks Canada Finance Corporation, issued \$200.0 million of 7.75% senior notes in the U.S. public debt market. Aquila has fully and unconditionally guaranteed these notes.

Credit Rating Triggers

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. Because of guarantee and cross default provisions between Aquila, Inc. and its subsidiaries, the ratings triggers of our subsidiaries discussed below should be viewed as if they are directly applicable to Aquila, Inc.

As of April 11, 2003, our senior unsecured long-term debt ratings, as assessed by the three major credit rating agencies, were as follows:

Agency	Rating	Outlook
Moody's Investors Service (Moody's)	Caa1	Negative Outlook
Standard & Poor's Corporation (S&P)	B	Negative Outlook
Fitch Ratings (Fitch)	B–	Negative Outlook

During 2002, Moody's lowered our credit rating from investment grade of Baa3 to Ba2 negative outlook, a non-investment grade. Additionally, S&P downgraded us to BB, a non-investment grade rating, from BBB, with a negative outlook and Fitch downgraded us to BB, from BBB-, with a negative outlook. In 2003, Moody's downgraded us to Caa1 and Fitch and S&P downgraded us to B– and B, respectively. As a result of these downgrades, our interest costs have increased and we were required to repay certain notes.

In 2002, we retired \$91.7 million of our Australian denominated notes that were put to us after the credit downgrades. Our Australian subsidiaries have three other outstanding series of Australian denominated notes totaling \$78.6 million at December 31, 2002. The holders of \$62.9 million of these notes exercised their put rights and were repaid in January 2003. The remaining notes totaling \$15.7 million were repaid in April 2003.

Secured Financing

Each state in which we have utility operations that have not been pledged as collateral, requires us to obtain the approval of their public service commission before pledging utility assets located in their state. We currently do not have any approval from any of these public service commissions to pledge those utility operations as collateral.

In addition, we are required to obtain the prior approval from FERC before we can issue long-term or short-term debt. We currently have authority from the FERC to have outstanding up to \$1.5 billion of short-term, unsecured debt, but do not have authority to issue any additional long-term debt. 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.

Repayment of Debt

With the April 11, 2003 financings previously described, we believe we will have sufficient liquidity to cover our operational needs through June 2004. Our next significant need for outside capital relates to our need to retire senior notes maturing in 2004. We anticipate retiring these notes with proceeds from additional asset sales. In the event we are not successful in closing the asset sales, we would need to obtain a bridge loan to meet these obligations. Although no assurance can be given on the above actions, we expect to be successful in their execution.

Note 14: Long-Term Gas Contracts

In 1997 through 2000, we were paid in advance on certain contracts to deliver gas to municipal utilities over the subsequent 10 to 12 years. These contracts are settled monthly through the physical delivery of gas. We have hedged our exposure to changes in gas prices related to these contracts. See Note 21 for further discussion of the cash flow presentation of these contracts.

Our obligations under our long-term gas delivery contracts that were paid in advance will result in cash outflows and losses as outlined in the table below.

<i>In millions</i>	Long-Term Gas Contract Settlement(1)	Long-Term Gas Contract Margin Loss(2)	Total Long-Term Gas Contract Cash Payments(3)
2003	\$ 81.5	\$ 45.9	\$ 127.4
2004	84.9	48.1	133.0
2005	87.6	49.8	137.4
2006	90.9	52.2	143.1
2007	91.9	53.0	144.9
Thereafter	315.9	196.5	512.4
Total	\$752.7	\$445.5	\$1,198.2

- (1) *This represents the reduction of the long-term gas contract liability each period.*
- (2) *This represents the loss that is reflected as a reduction to gross profit each period.*
- (3) *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 recognize relief of 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 these obligations, or were unable to perform on them, we may be asked to pay the issuers of the surety bonds on these arrangements an amount that is greater than the long-term gas contract balance on our Consolidated Balance Sheet. As of December 31, 2002, our best estimate of this additional amount ranges from \$68.0 million to \$101.0 million, depending on the discount rate used. This difference arises due to our use of the units of revenue method of relieving the long-term obligation versus a present value method that would likely be used by the sureties.

Note 15: Company-Obligated Preferred Securities

Summarized information regarding our Company-Obligated Preferred Securities is as follows:

<i>In millions</i>	December 31,	
	2002	2001
UtiliCorp Capital Trust I (UCT I) 9.75% Premium Equity Participating Security Units (PEPS Units) 465 shares at December 31, 2002 (10,000,000 shares at December 31, 2001)(a)	\$—	\$ 250.0
UtiliCorp Capital Trust II (UCT II) 3.68% Trust Preferred Securities (100,000 shares at December 31, 2001)(b)	—	100.0
Total company-obligated preferred securities	\$—	\$ 350.0
Fair value of company-obligated preferred securities(c)	\$—	\$ 351.5

- (a) *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 UCT I. Each purchase contract yielded 2.40% per year, paid quarterly, on the \$25 stated amount of the PEPS Unit. Each trust preferred security yields 7.35% per year, paid quarterly on the \$25 stated amount of the PEPS Unit, until November 16, 2002. Substantially all of the purchase contracts were settled in November 2002 by issuing approximately 11.7 million shares of our common stock and canceling the trust preferred securities.*
- (b) *These securities, which were included in Current Maturities of Long-Term Debt at December 31, 2001, and were redeemed in July 2002.*
- (c) *The fair value of the company-obligated preferred securities at December 31, 2001, was based on the most recent quoted market price of the PEPS units plus the cost of the floating rate 3.68% trust preferred securities which approximated fair value.*

Note 16: 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 raised approximately \$446 million in net proceeds. Of the 19,975,000 shares, Aquila Merchant sold 14,225,000 new shares and Aquila sold 5,750,000 previously issued shares. A pretax gain of \$110.8 million, or \$.51 per share, was recognized in the second quarter of 2001 on the shares sold by Aquila. Upon completion of the offering, Aquila 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 1.8 million shares of Aquila Merchant Class A shares exercised dissenters' rights with respect to the merger.

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 was in excess of our proportionate interest in the fair value of the net assets of Aquila Merchant acquired by approximately \$218.7 million. This excess was classified as goodwill and allocated as \$175.0 million to our Wholesale Services segment and \$43.7 million to our Capacity Services segment based on future expected cash flows. We wrote off all of this goodwill in 2002. See Note 2 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 which 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 that raised 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.

Suspension of Dividend

In November 2002, the Board of Directors suspended the annual dividend on common stock for an undetermined time period. This decision stems from 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. Based on this analysis, the Board decided that the most prudent course of action was to suspend the dividend as part of our strategy to strengthen the credit profile of the Company.

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 Stock Purchase Plan

We offer current and potential shareholders the option to participate in a Dividend Reinvestment and Common Stock Purchase Plan (the Stock Plan). The Stock Plan allows 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 allows members to reinvest dividends into additional common shares at a 5% discount. For the years ended December 31, 2002, 2001 and 2000, 2,168,892, 843,201 and 1,286,515 shares were issued, respectively, under the Stock Plan. As of December 31, 2002, there were 609,248 shares still available to be issued under this plan.

Employee Stock Purchase Plan

Participants in our Employee Stock Purchase Plan have 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. Contributions are credited to the participant's account throughout an option period. At the end of the option period, the participant's total account balance is applied to the purchase of common stock. The shares are purchased at 85% of the lower of the market price on the first day or the last day of the option period. Participants must be 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, 2002, 2001 and 2000, 281,534, 260,046 and 297,772 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 company-matching contributions were in Aquila stock. Effective in 2003, company-matching contributions will be made in cash and invested as directed by the employee. Company contributions were \$11.5 million, \$11.2 million and \$9.9 million during the years ended December 31, 2002, 2001 and 2000, 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 will be 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 2002, 2001 and 2000, compensation expense (in millions) of \$5.9, \$5.0 and \$4.7, 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 the company common stock and their elections. Total compensation expense for the years ended December 31, 2001 and 2000, was \$19.6 million and \$8.5 million, respectively. Due to the company's 2002 performance, no awards were earned for the year ended December 31, 2002, no new awards were granted in 2002, and potential awards for the year ended December 31, 2003 were suspended.

Stock Incentive Plan

Through 2001 our Stock Incentive Plan enabled the company to grant common shares to certain employees as restricted stock awards, restricted stock unit awards and as stock options. We hold

shares issued as restricted stock or restricted stock unit awards until certain restrictions lapse, generally on the first or third award anniversary depending on the specific terms of the award. Stock options granted under the Plan allow the purchase of common shares at a price not less than fair market value at the date of grant. Options granted under this Plan vest 25% after two years, 50% after three years and 100% after four years. They expire 10 years after the date of grant. The Omnibus Incentive Compensation Plan discussed below has replaced this plan.

Employee Stock Option Plan

The Board approved the establishment of an Employee Stock Option Plan in 1991 and readopted the plan in 2001. Through 2001 this Plan provided for the granting of up to 3.0 million stock options to eligible employees other than those eligible to receive options under the Stock Incentive Plan. Stock options granted under the Employee Stock Option Plan carry the same provisions as those issued under the Stock Incentive Plan. Broad-based option grants have been made under this plan in only two years. During 1998 and 1992, respectively, options for 1,278,713 and 1,114,350 shares were granted to employees. The exercise prices of these options are \$24.02 and \$18.21, respectively. The options granted in 1992 have been exercised or expired in 2002. As of December 31, 2002, 411,118 shares granted in 1998 remained outstanding. The Omnibus Incentive Compensation Plan discussed below has replaced this plan.

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. This plan was created to replace the Stock Incentive Plan and Employee Stock Option Plan. All new awards will be issued under this plan. However, options and awards existing under the previous plans will remain issued under those plans. Stock options under the Plan will generally vest evenly over three years and expire after seven years. However, in December 2002, options for 1,789,152 shares were granted to employees other than company officers under this plan. These options vest in one year and are exercisable for seven years.

Summary of Stock Options

This table summarizes all stock options as of December 31, 2002, 2001 and 2000:

	2002	2001	2000
	Shares		
Beginning balance	6,118,123	7,156,600	7,347,961
Granted	1,789,152	825,069	1,153,487
Converted from Merchant plan	2,641,369	—	—
Exercised	(270,028)	(1,779,548)	(610,345)
Cancelled	(1,370,108)	(83,998)	(734,503)
Ending balance	8,908,508	6,118,123	7,156,600
Weighted average prices:			
Beginning balance	\$22.37	\$21.39	\$21.80
Granted price	1.83	28.75	18.84
Converted price	34.82	—	—
Exercised price	24.14	21.42	20.73
Cancelled price	29.49	21.69	21.91
Ending balance	\$20.75	\$22.37	\$21.39

This table summarizes all outstanding and exercisable stock options as of December 31, 2002:

Outstanding Options				Exercisable Options	
Exercise Price Range	Number	Weighted Average Remaining Contractual Life in Years	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
\$1.83-16.30	1,782,352	6.96	\$ 1.83	—	—
\$16.31-23.99	4,245,603	5.02	\$21.20	3,326,227	\$21.18
\$24.00-29.99	1,043,208	6.59	\$26.51	526,603	\$24.47
\$30.00-42.34	1,837,345	7.55	\$34.83	1,112,947	\$34.83
Total	8,908,508			4,965,777	

In connection with the recombination of Aquila Merchant with Aquila, Aquila Merchant stock options were converted into 2,641,369 options to purchase Aquila common stock at prices ranging from \$24.80 to \$42.34.

Total restricted stock awards granted during the year were 923,937 shares at a weighted average fair value of \$24.08 at grant date.

Note 17: Earnings Per Share

The table below shows how we calculated diluted earnings per share and diluted shares outstanding. Basic earnings per share and basic weighted average shares are the starting point in calculating the dilutive measures. To calculate basic earnings per share, divide earnings available for common shares by weighted average shares outstanding without adjusting for dilutive items. Diluted earnings per share are calculated by dividing earnings 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 loss in 2002, the potential issuances of common stock were anti-dilutive and therefore not included in the calculation of diluted earnings per share.

<i>In millions, except per share amounts</i>	2002	2001	2000
Earnings (loss) available for common shares from continuing operations	\$(1,722.8)	\$245.3	\$194.3
Interest on convertible bonds	—	.2	.2
Earnings (loss) available for common shares from continuing operations after assumed conversion of dilutive securities	(1,722.8)	245.5	194.5
Earnings (loss) from discontinued operations	(329.6)	34.1	12.5
Cumulative effect of accounting change	(22.7)	—	—
Earnings (loss) available for common shares after assumed conversion of dilutive securities	\$(2,075.1)	\$279.6	\$207.0
Basic earnings (loss) per share:			
Earnings (loss) from continuing operations	\$ (10.65)	\$ 2.19	\$ 2.09
Earnings (loss) from discontinued operations	(2.04)	.30	.13
Cumulative effect of change in accounting	(.14)	—	—
Net income (loss)	\$ (12.83)	\$ 2.49	\$ 2.22
Diluted earnings (loss) per share:			
Earnings (loss) from continuing operations	\$ (10.65)	\$ 2.12	\$ 2.08
Earnings (loss) from discontinued operations	(2.04)	.30	.13
Cumulative effect of change in accounting	(.14)	—	—
Net income (loss)	\$ (12.83)	2.42	2.21
Weighted average number of common shares used in basic earnings per share	161.72	112.10	93.05
Effect of dilutive securities:			
Stock options and restricted stock	—	1.46	.42
Convertible bonds	—	.24	.28
Company-obligated preferred securities	—	1.91	—
Weighted average number of common shares and dilutive common stock used in diluted earnings per share	161.72	115.71	93.75

Note 18: Income Taxes

Earnings (loss) from continuing operations before income taxes consisted of:

<i>In millions</i>	Year Ended December 31,		
	2002	2001	2000
Domestic	\$(1,841.6)	\$348.4	\$176.7
Foreign	(16.3)	78.0	129.3
Total	\$(1,857.9)	\$426.4	\$306.0

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

<i>In millions</i>	Year Ended December 31,		
	2002	2001	2000
Current:			
Federal	\$(359.5)	\$156.3	\$146.0
Foreign	96.6	51.7	60.4
State	(63.8)	18.0	15.0
Deferred:			
Federal	(189.8)	(9.9)	(84.1)
Foreign	110.6	(31.5)	(17.0)
State	(33.7)	(2.0)	(7.5)
Change in valuation allowance	306.2	—	—
Investment tax credit amortization	(1.7)	(1.5)	(1.1)
Income tax expense (benefit) from continuing operations	(135.1)	181.1	111.7
Income tax expense (benefit) from discontinued operations:			
Current	40.9	5.9	7.8
Deferred (net of valuation allowance of \$75.4 million in 2002)	(103.4)	15.2	(1.3)
Income tax expense (benefit) from discontinued operations	(62.5)	21.1	6.5
Income tax benefit on cumulative effect of accounting change	(14.8)	—	—
Total	\$(212.4)	\$202.2	\$118.2

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

<i>In millions</i>	December 31,	
	2002	2001
Deferred Tax Assets:		
Alternative minimum tax credit carryforward	\$ 56.9	\$ —
Mark-to-market losses	18.9	30.2
Accrued bonuses and deferred compensation	16.6	45.2
Allowance for uncollectible accounts	12.3	29.5
Realized capital loss carry forward for income tax purposes	174.4	—
Unrealized capital losses	207.2	—
Less: valuation allowance	(381.6)	—
Total deferred tax assets	104.7	104.9
Deferred Tax Liabilities and Credits:		
Accelerated depreciation and other plant differences:		
Regulated	309.7	220.1
Non-regulated	33.5	176.6
Basis difference in international investments	133.8	13.2
Regulatory asset	16.8	29.7
Other, net	33.9	13.1
Total deferred tax liabilities and credits	527.7	452.7
Deferred income taxes and credits, net	\$ 423.0	\$347.8

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

	December 31,		
	2002	2001	2000
Statutory Federal Income Tax Rate	(35.0)%	35.0%	35.0%
Tax effect of:			
State income taxes, net of federal benefit	(3.4)	2.4	1.6
Revocation of permanent foreign reinvestments	8.0	—	—
Change in valuation allowance	16.5	—	—
Minority interest	—	2.2	—
Goodwill	3.8	1.2	1.0
Other	2.8	1.7	(1.1)
Effective Income Tax Rate	(7.3)%	42.5%	36.5%

At December 31, 2002, we have alternative minimum tax credit carryforwards of \$56.9 million. These credits do not expire and can be used to decrease future cash tax payments.

Change in Valuation Allowance. In 2002, we realized \$618.2 million of capital losses (for income tax purposes) on the sale of assets and recognized impairment charges of \$539.1 million that we expect to realize (for income tax purposes) as capital losses when the assets are sold. We carried back \$170.9 million of the realized capital losses to offset capital gains in 1999 through 2001. At

December 31, 2002, we had approximately \$447.3 million of net realized capital loss carryforwards that were available for federal income tax purposes and expire in 2007. 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 recorded a total valuation allowance of \$381.6 million in our 2002 deferred income tax provision.

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 investment and are in the process of exploring the sale of our other foreign investments. As a result, we can no longer represent that cash from our international investments will be permanently invested. Therefore, additional deferred tax was recorded to account for taxes that will arise when we bring asset sale proceeds back to the United States. As a result, we recorded additional taxes of \$148.3 million in 2002.

Goodwill. Included in impairment charges and net loss on sales of assets was \$178.6 million and \$21.9 million of Wholesale Services and Capacity Services goodwill, respectively, which is not deductible for income tax purposes and therefore does not result in the recognition of a tax benefit.

In addition to the capital losses carried back to prior years discussed above, we generated a net operating loss of \$528.9 million in 2002. This net operating loss was carried back in our federal income tax return for 2002 to offset taxable income in 1997 through 2000. As a result of these capital and operating loss carrybacks, we had a federal income tax receivable of \$191.1 million at December 31, 2002, which was included in Prepayments and Other in our Consolidated Balance Sheet. This receivable was collected in March 2003.

Note 19: Employee Benefits

We provide defined benefit pension plans for our employees in the United States and Canada. Benefits under these plans reflect the employees' compensation, years of service and age at retirement. We satisfy the minimum funding requirements under the Employee Retirement Income Security Act of 1974, as amended. In addition to pension benefits, we provide certain post-retirement health care and life insurance benefits for substantially all retired employees. We accrue the cost of post-retirement benefits during an employee's service. We fund the portion of the net periodic post-retirement benefit costs that are tax deductible. For measurement purposes, projected benefit obligations and the fair value of plan assets were determined as of September 30, 2002 and 2001.

Effective September 30, 2002, we changed our actuarial assumptions for the average expected rate of return on plan assets from 9.58% to 9.15% to reflect recent market performance and expected long-term returns for the types of assets generally held in our plans. We also changed the average assumed discount rates from 7.42% to 6.71%.

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:

<i>Dollars in millions</i>	Pension Benefits		Other Post-retirement Benefits	
	2002	2001	2002	2001
Change in Projected Benefit Obligation:				
Benefit obligation at start of year	\$316.8	\$276.0	\$ 86.3	\$ 69.6
Service cost	11.9	9.7	.6	1.1
Interest cost	23.0	20.3	6.1	6.5
Plan participants' contribution	.8	.9	1.6	1.4
Amendments	(2.7)	12.6	—	(9.8)
Actuarial (gain) loss	32.9	19.3	(4.4)	23.9
Curtailment (gain) loss	(6.5)	(1.4)	(2.5)	.7
Benefits paid	(18.4)	(17.6)	(6.5)	(6.9)
Foreign currency exchange changes	.4	(3.0)	—	(.2)
Projected benefit obligation at end of year	\$358.2	\$316.8	\$ 81.2	\$ 86.3
Change in Plan Assets:				
Fair value of plan assets at start of year	\$319.4	\$387.6	\$ 12.1	\$ 13.4
Actual return on plan assets	(38.8)	(49.9)	(.9)	.1
Employer contribution	39.3	1.7	7.4	4.1
Plan participants' contribution	1.1	1.0	1.6	1.4
Transfers	(2.8)	—	—	—
Benefits paid	(18.4)	(17.6)	(6.5)	(6.9)
Foreign currency exchange changes	.5	(3.4)	—	—
Fair value of plan assets at end of year	\$300.3	\$319.4	\$ 13.7	\$ 12.1
Funded status:				
Funded status	\$ (57.9)	\$ 2.6	\$(67.5)	\$(74.2)
Unrecognized transition amount	(3.6)	(5.1)	17.4	21.6
Unrecognized net actuarial (gain) loss	153.5	61.4	23.0	25.9
Unrecognized prior service cost	27.7	27.7	3.2	4.2
Employer contribution	.3	.7	—	3.6
Net amount recognized	\$120.0	\$ 87.3	\$(23.9)	\$(18.9)
Amounts Recognized in the Consolidated Balance Sheets:				
Prepaid benefit cost	\$123.0	\$ 95.3	\$ —	\$ —
Accrued benefit liability	(18.7)	(14.9)	(23.9)	(18.9)
Intangible asset	10.9	6.9	—	—
Accumulated other comprehensive income	4.8	—	—	—
Net amount recognized	\$120.0	\$ 87.3	\$(23.9)	\$(18.9)
Reconciliation of Net Amount Recognized:				
Net amount recognized at start of year	\$ 87.3	\$ 72.4	\$(18.9)	\$(14.4)
Net periodic benefit cost	(8.2)	8.9	(9.8)	(10.4)
Curtailment (gain) loss	—	.8	(2.5)	(1.5)
Contributions	38.9	2.0	7.3	7.8
Expense adjustment	2.0	3.2	—	(.4)
Net amount recognized at end of year	\$120.0	\$ 87.3	\$(23.9)	\$(18.9)
Weighted Average Assumptions as of September 30:				
Discount rate for expense	7.42%	7.75%	7.47%	7.85%
Discount rate for disclosure	6.71%	7.42%	6.73%	7.47%
Expected return on plan assets for expense	9.58%	9.51%	7.00%	7.87%
Rate of compensation increase	5.10%	5.21%	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 starting at 11% in 2003 and decreasing 1% annually until the rate levels out at 5% for years 2009 and thereafter.

<i>In millions</i>	Pension Benefits			Other Post-retirement Benefits		
	2002	2001	2000	2002	2001	2000
Components of Net Periodic Benefit Cost:						
Service cost	\$ 11.9	\$ 9.7	\$ 8.3	\$.6	\$ 1.1	\$.9
Interest cost	23.0	20.3	16.3	6.1	6.5	3.7
Expected return on plan assets	(29.9)	(36.8)	(27.7)	(1.0)	(1.0)	(.5)
Amortization of transition amount	(1.5)	(1.9)	(1.2)	1.9	2.2	1.9
Amortization of prior service cost	1.8	.8	.6	.5	1.3	.1
Recognized net actuarial (gain) loss	2.9	(1.0)	(1.9)	1.7	.3	—
Curtailment (gain) loss	—	(.8)	(1.0)	2.5	1.5	(.3)
Regulatory adjustment	(1.8)	(4.9)	(1.3)	—	—	—
Net Periodic Benefit Cost	\$ 6.4	\$ (14.6)	\$ (7.9)	\$ 12.3	\$ 11.9	\$ 5.8

The Supplemental Executive Retirement Plan was amended in 2001 to include certain participants' annual incentive compensation in the calculation of plan benefits.

We maintain defined benefit pension plans in the United States and Canada. The actuarial assumptions used to calculate the benefit obligation and periodic pension costs for those plans are essentially the same. 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 United States and Canada plans are summarized below:

<i>In millions</i>	United States		Canada	
	2002	2001	2002	2001
Projected Benefit Obligations in Excess of Plan Assets:				
Fair value of plan assets at end of year	\$248.4	\$ —	\$ 38.8	\$ 17.5
Projected benefit obligation at end of year	301.7	18.3	49.7	23.7
Funded status	\$ (53.3)	\$ (18.3)	\$ (10.9)	\$ (6.2)
Accumulated Benefit Obligations in Excess of Plan Assets:				
Fair value of plan assets at end of year	\$ —	\$ —	\$ 38.8	\$ 17.5
Accumulated benefit obligation at end of year	13.8	12.2	44.1	20.2
Funded status	\$ (13.8)	\$ (12.2)	\$ (5.3)	\$ (2.7)

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 or decrease 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, 2002, and our estimated annual pension cost (APC) on the income statement for 2003 by a similar amount in the opposite direction. Each sensitivity below reflects an evaluation of the change based solely on a change in that assumption.

<i>Dollars in millions</i>	Change in Assumption Inc(dec)	Impact on PBO Inc(dec)	Impact on APC Inc(dec)
Discount rate	.25%	\$(11.7)	\$(.9)
Rate of return on plan assets	.25%	—	(.8)

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 2002.

<i>In millions</i>	1 Percentage-Point	
	Increase	Decrease
Effect on total of service and interest cost components	\$.6	\$ (.6)
Effect on post-retirement benefit obligation	7.8	(6.9)

Note 20: Mergers, Acquisitions and Divestitures

In addition to the acquisitions and divestitures discussed in Notes 5, 6 and 10, we completed the following transactions.

Pipeline Operations

In January 2002, we completed the sale of an intrastate pipeline for our net book value of \$65.9 million, including a \$5.0 million deposit received in 2001.

St. Joseph Light & Power Company

Effective December 31, 2000, St. Joseph Light & Power Company (SJL&P) merged with us. Under the merger agreement, SJL&P shareholders received \$23.00 in Aquila common shares for

each SJL&P common share held. We issued approximately 6.6 million shares of Aquila common stock with a total value of \$190.2 million in connection with this merger. We also assumed short-term debt of \$23.6 million and long-term debt of \$68.1 million. We accounted for the transaction as a purchase. We paid a premium for the purchase of SJL&P as we anticipated the realization of certain synergies with our existing network in Missouri, including reduced general and administrative costs, joint dispatching of power in the region and off-system sales of power. In addition, SJL&P possessed a strong balance sheet that we believed would strengthen our credit position. These factors supported a purchase price for the business in excess of the underlying fair value of the assets and liabilities acquired.

GPU International

In December 2000, Aquila Merchant purchased GPU International for \$225 million, a company holding interests in six independent U.S.-based generation plants. We accounted for the transaction as a purchase.

TransAlta Assets

In August 2000, we completed our acquisition of TransAlta Corporation's Alberta-based electricity distribution and retail assets for approximately \$480 million. We operate this business as Aquila Networks Canada (Alberta) Ltd. In November 2000, we sold the retail assets to Epcor, an Edmonton-based utility, for approximately \$75 million. A premium was paid for the company as we anticipated the realization of certain synergies with our existing network in Canada, a reduction in executive and corporate services, as well as workforce efficiencies. These factors supported a purchase price for the business in excess of the underlying fair value of the assets and liabilities acquired.

Pro Forma Operating Results

The following reflects our results for the year ended December 31, 2000, assuming the above transactions occurred as of the beginning of 2000:

<i>In millions, except per share amounts</i>	Year Ended December 31, 2000 (Unaudited)
Sales	\$3,637.8
Net income	243.1
Diluted earnings per common share	\$ 2.42

The pro forma results of operations are not necessarily indicative of the actual results that would have been obtained had we made the acquisitions at the beginning of the period, or of results that may occur in the future. The 2000 pro forma operating results include certain unusually large mark-to-market gains. The pro forma operating results do not include adjustments for synergies or other adjustments to the business operations.

Note 21: Restatement of Consolidated Statements of Cash Flows

As disclosed in our 2001 Annual Report, we reported a \$110.8 million gain on the sale of Aquila Merchant shares in connection with their initial public offering in April 2001. Cash proceeds from

the sale were included in Cash Flows From Operating Activities, but should have been reported as Cash Flows From Investing Activities. Accordingly, we decreased Cash Flows From Operating Activities by \$110.8 million and increased the Cash Flows From Investing Activities by the same amount. This reclassification was included in our Form 10-K/A that was filed in August 2002.

As more fully discussed in Note 14, as part of our wholesale energy trading business, we entered into long-term gas contracts that require us to deliver natural gas to municipal utility customers over a period of 10 to 12 years. In exchange for our commitment to deliver the natural gas, we were paid in advance. We consider these contracts part of our energy trading operations. As such, both the receipt of the advance cash payments and the monthly cash outflows to purchase the gas to be delivered to the customers in satisfaction of our commitments were included in our Consolidated Statements of Cash Flows under the caption Net Changes in Price Risk Management Assets and Liabilities and included in Cash Flows From Operating Activities. These contracts were also included under the caption Price Risk Management Liabilities in our Consolidated Balance Sheets.

In 2002, the EITF in its deliberations regarding EITF 02-3 discussed a number of items related to energy trading and risk management activities. In order to more fully address certain of the items discussed, the EITF formed a working group. One of the items discussed by the working group was “prepaid gas contracts.” These discussions included the cash flow presentation of contracts similar to our long-term gas contracts. Based on this discussion, and other accounting and industry discussions and guidance occurring in 2002, we believe that the current industry and accounting consensus is to report these contracts as financing activities in the statement of cash flows. As a result, we have reported these cash flows in accordance with the current accounting interpretations and guidance for all years presented in our Consolidated Statements of Cash Flows. This resulted in an \$82.2 million increase in Cash Flows From Operating Activities for the year ended December 31, 2001, and a \$396.1 million decrease in Cash Flows From Operating Activities for the year ended December 31, 2000, as compared to the amounts previously reported. Cash Flows From Financing Activities in each year changed by the corresponding amounts, resulting in no change in total cash flows. This change had no impact on earnings or losses.

The net effect of the changes discussed above are shown in the following table:

<i>In millions</i>	For the Year Ended December 31,			
	2001		2000	
	As Previously Reported	As Restated	As Previously Reported	As Restated
Cash provided from operating activities	\$ 223.7	\$ 195.1	\$ 789.9	\$ 393.8
Cash used for investing activities	(886.5)	(775.7)	(1,729.4)	(1,729.4)
Cash provided from financing activities	533.1	450.9	1,107.2	1,503.3
Net increase (decrease) in cash and cash equivalents	\$(129.7)	\$(129.7)	\$ 167.7	\$ 167.7

Note 22: Segment Information

We manage our business in two distinct groups, Global Networks Group and Merchant Services. Global Networks is managed as two segments, Domestic Networks and International Networks. Merchant Services is also managed in two segments, Capacity Services and Wholesale Services. 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.

A. Business Lines

<i>In millions</i>	Year Ended December 31,		
	2002	2001	2000
Sales:*			
Global Networks Group—			
Domestic Networks	\$1,815.7	\$2,210.0	\$1,915.0
International Networks	261.7	253.6	492.4
Total Global Networks Group	2,077.4	2,463.6	2,407.4
Merchant Services—			
Capacity Services	399.4	604.6	297.6
Wholesale Services	(99.7)	642.8	489.5
Total Merchant Services	299.7	1,247.4	787.1
Total	\$2,377.1	\$3,711.0	\$3,194.5

* For the years ended December 31, 2002, 2001 and 2000, Capacity Services sales of (in millions) \$233.0, \$455.8 and \$506.3, respectively, and Wholesale Services sales of (in millions) \$2.3, \$3.7 and \$7.3, respectively, have been reclassified to discontinued operations and are not included in the above amounts.

<i>In millions</i>	Year Ended December 31,		
	2002	2001	2000
Earnings Before Interest and Taxes:*			
Global Networks Group—			
Domestic Networks	\$ (829.6)	\$117.9	\$215.6
International Networks	(70.1)	125.4	159.4
Total Global Networks Group	(899.7)	243.3	375.0
Merchant Services— **			
Capacity Services	(105.0)	88.4	21.4
Wholesale Services	(566.0)	224.9	124.5
Minority Interest	—	(26.4)	—
Total Merchant Services	(671.0)	286.9	145.9
Corporate and other	(37.7)	112.6	(26.1)
Total EBIT	(1,608.4)	642.8	494.8
Interest expense	249.5	216.4	188.8
Earnings (loss) from continuing operations before income taxes	\$(1,857.9)	\$426.4	\$306.0

* Included in EBIT for each segment for the years ended December 31, 2002, 2001 and 2000, respectively, is equity in earnings of investments as follows (in millions): Domestic Networks, \$1.9, \$28.5 and \$52.9; International Networks, \$112.0, \$61.5 and \$44.2; Capacity Services, \$52.8, \$28.9 and \$18.7; Wholesale Services, \$.2 in 2001; and Corporate and Other, \$.2, \$.2 and \$—, respectively.

** For the years ended December 31, 2002, 2001 and 2000, Capacity Services EBIT of (in millions) \$(223.4), \$25.3 and \$24.5, respectively, and Wholesale Services EBIT of (in millions) \$(163.1), \$36.6 and \$20.7, respectively, have been reclassified as discontinued operations and are not included in the above amounts.

<i>In millions</i>	Year Ended December 31,		
	2002	2001	2000
Depreciation and Amortization Expense:			
Global Networks Group—			
Domestic Networks	\$140.8	\$162.1	\$129.3
International Networks	58.1	55.8	45.4
Total Global Networks Group	198.9	217.9	174.7
Merchant Services— *			
Capacity Services	9.5	7.5	1.5
Wholesale Services	6.4	16.0	15.9
Total Merchant Services	15.9	23.5	17.4
Corporate and other	(.5)	(.5)	1.5
Total	\$214.3	\$240.9	\$193.6

* For the years ended December 31, 2002, 2001 and 2000, Capacity Services depreciation and amortization expense of (in millions) \$23.3, \$31.8 and \$30.8, respectively, and Wholesale Services depreciation and amortization expense of (in millions) \$.4, \$.2 and \$.6, respectively, have been reclassified as discontinued operations and are not included in the above amounts.

<i>In millions</i>	December 31,	
	2002	2001
Identifiable Assets: *		
Global Networks Group—		
Domestic Networks	\$2,666.5	\$ 3,512.5
International Networks	1,607.1	1,867.2
Total Global Networks Group	4,273.6	5,379.7
Merchant Services— **		
Capacity Services	1,203.2	1,593.5
Wholesale Services	3,092.1	4,653.9
Total Merchant Services	4,295.3	6,247.4
Corporate and other	690.3	339.4
Total	\$9,259.2	\$11,966.5

* Included in Identifiable Assets for each segment as of December 31, 2002 and 2001, is investments in unconsolidated subsidiaries as follows (in millions): Domestic Networks, \$40.6 and \$773.6; and International Networks, \$588.2 and \$916.2; and Capacity Services, \$281.2 and \$312.5; and Wholesale Services, \$— and \$6.7, and Corporate, \$4.9 and \$36.6, respectively.

** Included in Identifiable Assets as of December 31, 2002 and 2001, is Non-Current Assets of Discontinued Operations as follows (in millions): Capacity Services, \$.3 and \$626.7; and Wholesale Services, \$19.2 and \$431.9, respectively.

<i>In millions</i>	Year Ended December 31,		
	2002	2001	2000
Capital Expenditures:			
Global Networks Group—			
Domestic Networks	\$255.5	\$223.3	\$249.9
International Networks	112.4	95.7	24.2
Total Global Networks Group	367.9	319.0	274.1
Merchant Services—			
Capacity Services	147.5	237.5	23.9
Wholesale Services	21.0	36.1	32.2
Total Merchant Services	168.5	273.6	56.1
Corporate and other	8.9	33.5	24.8
Total	\$545.3	\$626.1	\$355.0

B. Geographical Information

<i>In millions</i>	Year Ended December 31,		
	2002	2001	2000
Sales:			
United States	\$2,151.3	\$3,355.4	\$2,611.8
Canada	228.6	292.2	456.0
Other international	(2.8)	63.4	126.7
Total	\$2,377.1	\$3,711.0	\$3,194.5

<i>In millions</i>	December 31,	
	2002	2001
Long-Lived Assets:*		
United States	\$2,988.3	\$3,520.2
Canada	518.8	468.9
Other international	588.4	958.4
Total	\$4,095.5	\$4,947.5

* Includes Property, Plant and Equipment, net and Investments in Unconsolidated Subsidiaries.

Note 23: Commitments and Contingencies

Commitments

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

<i>In millions</i>	2003	2004	2005	2006	2007	Thereafter	Total
Future minimum lease payments—facilities and equipment	\$ 47.4	\$ 41.6	\$ 22.6	\$ 16.9	\$ 15.6	\$ 55.8	\$ 199.9
Merchant power plant obligations	101.3	101.3	112.4	120.2	120.2	1,508.1	2,063.5
Merchant gas transportation obligations	8.8	8.8	8.8	8.6	5.8	38.6	79.4
Regulated business purchase obligations:							
Purchased power obligations	119.8	117.5	95.5	83.9	49.6	1,227.3	1,693.6
Purchased gas obligations	81.8	40.4	29.6	21.5	11.3	19.2	203.8
Coal contracts	90.4	69.6	64.3	51.3	46.5	395.6	717.7

Future minimum lease payments. Future minimum lease 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 2002, 2001 and 2000 was (in millions) \$41.9, \$35.6 and \$23.9, respectively.

Merchant power plant obligations. In connection with our Merchant power generation business, we have entered into long-term power purchase agreements for a portion of the total output of certain merchant power plants owned by others. These agreements are treated as operating leases for accounting purposes.

Merchant gas transportation obligations. We have long-term commitments 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. Our integrated electric utility operations in the U.S. and British Columbia, Canada, generate 56% and 54% of the power delivered to their customers, respectively. Our domestic utility operations purchase coal and natural gas as fuel for its generating power plants under long-term contracts. Our British Columbia electric utility owns hydroelectric dams to generate power for its customers. Both of these operations also purchase power and gas to meet customer needs under short-term and long-term power purchase contracts.

Contingent Obligations

Midlands Electricity—In connection with our purchase of a 79.9% interest in Midlands Electricity from FirstEnergy Corporation, we entered into certain agreements that expose us to contingent payment obligations. FirstEnergy has the right to sell its interest in Midlands to us at fair market value if, at any time during the 30-day period prior to May 8, 2008, the fair value of FirstEnergy's holdings is less than \$72.8 million. In addition, as part of the purchase price, we executed a note payable to FirstEnergy that requires us to make six annual payments of \$19.0 million. We recorded this obligation at its fair value of \$87.4 million. If at any time prior to the repayment of this obligation we transfer 33% or more of our interest in Midlands to an

unrelated third party, we would be required to make all remaining payments to FirstEnergy on an undiscounted basis.

Merchant Loan Portfolio—In connection with our former portfolio of Merchant loans to energy-related businesses, we also 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 under certain conditions 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. At December 31, 2002, the value of these swaps was \$33.8 million.

Aquila, Inc has 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.

Standby Letters of Credit—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, 2002, we had \$195.6 million of letters of credit outstanding with expiration dates ranging from one month to 13 months.

Guarantee of Subsidiary Obligations—In the normal course of business, we guarantee certain payment obligations of our wholly owned subsidiaries including certain operating leases as discussed above and short and long-term debt as discussed in Notes 12 and 13.

Aggregator Loans—We have guaranteed the performance of certain gas aggregators in connection with our aggregator loans that were made in connection with our wholesale energy trading business. We terminated all but two of these agreements upon our exit from the wholesale energy trading business. In connection with these agreements, we guarantee to pay the aggregators' counterparties if the aggregators are unable to make their payments for the gas they have purchased. Our exposure is limited to the outstanding payable balances of the aggregators as of the termination dates for those agreements that have been terminated. Our total guarantees for these agreements at December 31, 2002 was \$126.5 million. As of March 31, 2003, our guarantees have been reduced to \$43.3 million. We currently estimate \$2.8 million of potential exposure related to these guarantees.

Independent Power Projects—We assumed certain guarantees for two of our IPPs upon purchase of these investments. These guarantees require that we make payment of certain obligations of the IPPs under various circumstances. Our total exposure from these assumed guarantees totals \$11.5 million, of which we have reserved for \$6.6 million on our Consolidated Balance Sheet at December 31, 2002.

Legal

In February 2002, we filed a suit against Chubb Insurance Group, the issuer of surety bonds in support of certain of our long-term gas supply contracts. Previously, Chubb had demanded that it be released from its surety obligation of up to \$540 million or, alternatively, that we post collateral to secure its obligation. We do not believe that Chubb is entitled to be released from its surety obligations or that we are obligated to post collateral to secure its obligations unless it is likely we will default on the contracts. Chubb has not alleged that we are likely to default on the contracts. If Chubb were to prevail, it would have a material adverse impact on our liquidity and

financial position. We rely on other sureties in support of long-term gas supply contracts similar to those described above. There can be no assurance that these sureties will not make claims similar to those raised by Chubb. We have performed under these contracts since their inception and intend to continue to fully perform on the contracts.

A consolidated lawsuit was filed against us in Delaware Chancery Court in connection with the recombination of Aquila with our Aquila Merchant subsidiary that occurred pursuant to an exchange offer completed in January 2002, raising 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. The Delaware Chancery Court denied the plaintiffs' claims for equitable relief in January 2002, and there has been no further activity with the lawsuit. Securities fraud complaints seeking damages based on the same conduct were also filed against us in federal court in Missouri. Persons holding certificates formerly representing approximately 1.8 million shares of Aquila Merchant common stock are also pursuing their appraisal rights in connection with the recombination. We do not believe that any of these actions will have an outcome materially adverse to us.

A number of companies that engaged in energy trading activities, including Aquila, have received requests from various regulatory agencies to furnish data and answer questions relating to the possible inaccurate reporting of gas trade information to various industry publications in 2000 and 2001. In response to such inquiries, we have initiated a review of our reported information relative to recorded data and are cooperating fully with these investigations. Additionally, we have reported to the Federal Energy Regulatory Commission and Commodity Futures Trading Commission that we have been unable to reconcile all of the gas trade data reported to various trade publications with the gas trade data in our internal records and that our former traders may have reported inaccurate information. A lawsuit was filed against us and numerous other energy trading companies in November 2002 by the Lieutenant Governor of the State of California alleging that we misreported gas trade data that, in turn, affected the market price of electricity in California.

The Company is subject to various other legal proceedings and claims that arise in the ordinary course of business operations. We do not expect the amount of liability, if any, from these actions to materially affect our consolidated financial position or results of operations.

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.

We own or previously operated former manufactured gas plant (MGP) sites which may, or may not, require some form of environmental remediation. We have contacted appropriate federal and state agencies and are working to determine what, if any, specific cleanup activities these sites may require. As of December 31, 2002, we estimate probable undiscounted cleanup costs on our identified MGP sites to be \$7.3 million. This amount is our best estimate of the costs of investigation and remediation of our identified MGP sites, and is the amount we consider to be probable for future investigation and remediation of these sites. This estimate is based upon a comprehensive review of the potential costs associated with conducting investigative and remedial actions at our identified MGP 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 action options, it is reasonably possible that these additional costs could exceed our best estimate by approximately \$13.8 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.

In connection with the sale of our gas gathering, processing and pipeline operations in 2002, we retained certain environmental liabilities associated with the past operation of these businesses. We are also named as a potentially responsible party at two disposal sites for PolyChlorinated Biphenyls (PCBs). We estimate our share of the probable cleanup costs to be approximately \$1.4 million.

In May 2000, the state of Missouri adopted a revised regulation that requires reduction of nitrous oxide (NOx) from our power plants. At that time, we estimated the cost of compliance to be \$21.9 million in capital costs and \$2.2 million in annual operation and maintenance expense. However, in July 2002, the state adopted a law enabling changes in the regulation. There is a proposed amendment to the regulation that, if approved, would allow us to comply with the NOx reductions without incurring significant capital or operating expenses. In 2003, several of our power plants will come under a NOx budget requirement. However, this will not significantly impact the business.

In December 2000, the U.S. Environmental Protection Agency (EPA) announced that it would regulate mercury emissions from coal- and oil-fired power plants. The EPA is expected to propose regulations by December 2003 and issue final regulations by December 2004. The impact of this action on our power plants cannot be determined until final regulations are issued.

Regulatory Matters

Canada. In December 2001, we filed for an annual rate increase in Alberta of approximately \$30.0 million along with an application for a performance-based rate-setting mechanism. We subsequently modified that request and sought a \$12.7 million increase for 2002 and a \$6.0 million increase for 2003. In July 2002, an interim rate increase of approximately \$9.6 million was approved. Hearings were held in September and October 2002 and a final order was issued in February 2003, resulting in a decrease in rates of \$21.0 million for 2002, and no increase in rates in 2003 (2002 rates carry forward to 2003). Almost all of the reduction in rates related to depreciation on distribution assets (average asset lives were extended) and the related income tax effect. The decision did not adjust the allowed rate of return earned and therefore, net income is not expected to be materially impacted by this decision. However, the decision is estimated to reduce annual cash flow from operations by approximately \$17 million for 2004 and beyond. With regard to 2003, cash flow from operations will be reduced by approximately \$33.0 million, which includes the effect of both the 2002 and 2003 reduction.

As a result of the above action, we are currently reassessing the future recoverability of \$188.6 million of recorded goodwill in Canada.

Ratings Triggers

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 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. Certain of our subsidiaries have trigger events tied to specified credit ratings. Because of guarantee and cross default provisions between Aquila, Inc. and its subsidiaries, the ratings triggers of our subsidiaries discussed below should be viewed as if they are directly applicable to Aquila, Inc.

In 2002, we retired \$91.7 million of our Australian denominated notes that were put to us after the credit downgrades. Our Australian subsidiaries have three other outstanding series of Australian denominated notes totaling \$78.6 million at December 31, 2002. The holders of \$62.9 million of these notes exercised their put rights and were repaid in January 2003. The remaining notes totaling \$15.7 million were repaid in April 2003.

Aquila Merchant also has three “tolling agreements,” a construction loan and certain margining agreements that have trigger events tied to Aquila’s credit ratings. Under the tolling agreements, our subsidiary uses a third party’s generation assets to convert fuel into electric power for its subsequent resale. As of March 14, 2003, we have posted collateral due to our downgrades by Moody’s and S&P of \$82.3 million related to the tolling agreements, \$27.5 million related to the construction loan, and \$60.0 million related to standard margining agreements.

Other Potential Demands for Collateral

Although we have substantially exited the wholesale energy trading business of Aquila Merchant, a number of energy trading agreements remain to be settled or liquidated. These contracts consist of various long-term gas contracts, forward purchases and sales of gas and electricity, weather derivatives, alternative risk contracts, coal and other commodity trading contracts that are difficult to liquidate. These contracts typically include provisions that allow counterparties to request additional collateral to support underlying transactions if events occur that cause counterparties to believe that there has been deterioration in our creditworthiness. As a result of the downgrades, we provided collateral to certain counterparties in the form of cash deposits or letters of credit totaling \$145.0 million through March 14, 2003. While it is difficult to predict how many additional parties may successfully demand some form of collateral, we currently estimate that the amount of additional cash collateral if S&P or Moody’s were to downgrade us further would be minimal.

The following table summarizes the collateral posted and debt repaid due to credit downgrades through March 14, 2003, and additional collateral or debt that may be required to be posted or repaid in the future:

<i>In millions</i>	Potential Collateral	Amounts Posted/ Paid to Date
Australian denominated bonds	\$170.3	\$154.6
Tolling agreements	82.3	82.3
Construction loan	27.5	27.5
Standard margining agreements	62.0	60.0
Other collateral demands	145.0	145.0
Total	\$487.1	\$469.4

In addition to collateral calls made due to credit downgrades, fluctuations in commodity prices can also cause both significant inflows and outflows of collateral. This will vary depending on the magnitude of the price movement and the current position of our portfolio.

Note 24: Quarterly Financial Data (Unaudited)

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

<i>In millions, except per share amounts</i>	2002 Quarters				2001 Quarters			
	First	Second	Third	Fourth(3)	First	Second	Third	Fourth
Sales(1)	\$767.4	\$ 656.0	\$ 542.4	\$ 411.3	\$1,315.2	\$895.8	\$767.4	\$732.6
Gross profit	329.3	314.9	125.8	63.7	481.9	534.0	320.3	351.9
Earnings (loss) from continuing operations	\$ 40.0	\$(818.6)	\$(176.7)	\$(767.5)	\$ 67.7	\$139.2	\$ 59.5	\$(21.1)
Earnings (loss) from discontinued operations	4.4	8.6	(154.9)	(187.7)	5.8	4.0	9.4	14.9
Cumulative effect of change in accounting	—	—	—	(22.7)	—	—	—	—
Net income (loss)	\$ 44.4	\$(810.0)	\$(331.6)	\$(977.9)	\$ 73.5	\$143.2	\$ 68.9	\$(6.2)
Basic earnings per common share:(2)								
From continuing operations	\$.29	\$ (5.75)	\$ (.99)	\$ (4.10)	\$.65	\$ 1.22	\$.52	\$ (.18)
From discontinued operations	.03	.06	(.86)	(1.00)	.06	.04	.08	.13
Cumulative effect of change in accounting	—	—	—	(.12)	—	—	—	—
Net income (loss)	\$.32	\$ (5.69)	\$ (1.85)	\$ (5.22)	\$.71	\$ 1.26	\$.60	\$(.05)
Diluted earnings per common share:(2)								
From continuing operations	\$.29	\$ (5.75)	\$ (.99)	\$ (4.10)	\$.63	\$ 1.18	\$.50	\$ (.18)
From discontinued operations	.03	.06	(.86)	(1.00)	.06	.03	.08	.13
Cumulative effect of change in accounting	—	—	—	(.12)	—	—	—	—
Net income (loss)	\$.32	\$ (5.69)	\$ (1.85)	\$ (5.22)	\$.69	\$ 1.21	\$.58	\$(.05)

- (1) Sales for all periods presented above have been adjusted to reflect the adoption of EITF 02-3, as it relates to the netting of sales for energy trading contracts. This standard requires that gains and losses on energy trading contracts be shown net on the income statement. See Note 2 for further discussion.
- (2) 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.
- (3) Included in earnings (loss) from continuing operations for the fourth quarter ended December 31, 2002, is (a) a \$247.5 million impairment charge on our investment in Midlands Electricity due to the indicated fair value being substantially below our carrying value as indicated in recent sale negotiations and analysis; (b) a \$127.2 million impairment charge on our investment in Multinet and AlintaGas based on the status of negotiations to sell our interest in these businesses; (c) a \$204.5 million impairment charge related to our 96% owned investment in Everest Connections due to our decision to significantly reduce our funding to this business; (d) a \$130.5 million gain on the sale of our investment in UnitedNetworks; (e) other impairment charges and losses on sale of assets of \$70.4 million primarily as a result of our decision to sell \$1 billion in assets to improve our liquidity position; and (f) \$22.4 million of restructuring charges for our exit from the wholesale energy trading business and restructure of our utility business. Included in earnings (loss) from discontinued operations is a \$184.0 million loss on the sale of our Merchant loan portfolio.

Report of Management

The management of Aquila, Inc. is responsible for the information that appears in this annual report, including its accuracy. We prepared the accompanying consolidated financial statements in accordance with accounting principles generally accepted in the United States. In addition to selecting appropriate accounting principles, we are responsible for the way information is presented and for its reliability. To report financial results we must often make estimates based on currently available information and judgments of current conditions and circumstances.

We have set up well-developed systems of internal control to ensure the integrity and objectivity of the consolidated financial information in this report. These systems are designed to provide reasonable assurance that Aquila's assets are safeguarded and that the transactions are properly authorized and recorded in accordance with the appropriate accounting principles.

Through its Audit Committee, the Board of Directors participates in the process of reporting financial information. The Audit Committee selects our independent accountants. It also reviews, along with management, our financial reporting and internal accounting controls, policies and practices.

/s/ Gerald L. Shaheen

Gerald L. Shaheen
Audit Committee Chairman

/s/ Rick J. Dobson

Rick J. Dobson
Interim Chief Financial Officer

Independent Auditors' Report

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, 2002 and 2001 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, 2002. In connection with our audits of the consolidated financial statements, we also have audited the consolidated financial statement schedule, "Schedule II—Valuation and Qualifying Accounts," for each of the years in the three-year period ended December 31, 2002. These consolidated financial statements and the financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We did not audit the financial statements of Quanta Services, Inc., a 38%, and 36% owned investee company at December 31, 2001, and 2000, respectively. The Company's investment in Quanta Services, Inc. at December 31, 2001 was \$773.6 million and its equity earnings of Quanta Services, Inc. was \$30.6 and \$53.7 million, respectively for the years ended December 31, 2001, and 2000. The financial statements of Quanta Services, Inc. as of December 31, 2001 and for the two years ended December 31, 2001 were audited by other auditors whose report has been furnished to us, and our opinion, insofar as it relates to the amounts included for Quanta Services, Inc., is based solely on the report of the other auditors who have ceased operations.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. 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 and the report of other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audits and the report of other auditors, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Aquila, Inc. and subsidiaries as of December 31, 2002 and 2001 and the consolidated results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2002 in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the related financial statement schedules when considered in relation to the basic consolidated financial statements taken as a whole, present fairly in all material respects, the information set forth there in.

As discussed in Note 21, the Company restated its Statement of Cash Flows for the years ended December 31, 2001 and 2000. The 2001 and 2000 consolidated financial statements were previously audited by other independent auditors who have ceased operations.

As discussed in Note 2, the Company changed its method of accounting for goodwill and for reporting certain energy trading activities.

/s/ KPMG, LLP
KPMG, LLP
Kansas City, Missouri
April 11, 2003

Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

On May 21, 2002, our Board of Directors, upon the recommendation of its Audit Committee, approved the dismissal of Arthur Andersen LLP (“Arthur Andersen”) as the Company’s independent auditors and the appointment of KPMG LLP to serve as the Company’s independent auditors for the year ending December 31, 2002. The change was effective May 21, 2002.

Arthur Andersen’s reports on the Company’s consolidated financial statements for each of the years ended December 31, 2001 and 2000 did not contain an adverse opinion or disclaimer of opinion, nor were such reports qualified or modified as to uncertainty, audit scope or accounting principles.

During the years ended December 31, 2001 and 2000 and through the date hereof, there were no disagreements with Arthur Andersen on any matter of accounting principle or practice, financial statement disclosure, or auditing scope or procedure which, if not resolved to Arthur Andersen’s satisfaction would have caused them to make reference to the subject matter of the disagreement in connection with the audit reports on the Company’s consolidated financial statements for such years; and there were no reportable events as defined in Item 304(a)(1)(v) of Regulation S-K.

We provided Arthur Andersen with a copy of the foregoing disclosures. A copy of Arthur Andersen’s letter dated May 21, 2002, stating its agreement with such statements was filed as Exhibit 16 to our Current Report on Form 8-K dated May 21, 2002.

During the years ended December 31, 2001 and 2000 and through May 21, 2002, we did not consult KPMG LLP with respect to the application of accounting principles to a specified transaction, either completed or proposed, or the type of audit opinion that might be rendered on the Company’s consolidated financial statements, or any other matters or reportable events as set forth in Items 304(a)(2)(i) and (ii) of Regulation S-K.

Part 3

Items 10, 11, 12 and 13. Directors and Executive Officers of the Company, Executive Compensation, Security Ownership of Certain Beneficial Owners and Management and Related Shareholder Matters, 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 “Executive Officers of the Registrant” in Item 1, Part 1 of this Form 10-K.

Equity Compensation Plan Information

The following table provides information as of December 31, 2002 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	8,497,390(1)	\$20.59	7,117,657(2)
Equity compensation plans not approved by security holders	411,118(3)	\$24.02	—
Total	8,908,508		7,117,657

(1) Includes 1,840,104 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 \$34.82 per share.

(2) These share 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.

(3) Options issued under a broad-based employee stock option plan that has since been terminated.

Item 14. 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 within the last 90 days 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 SEC reports. There have been no significant changes in our internal controls and procedures or in other factors that could significantly affect these controls and procedures subsequent to the date of this evaluation.

Part 4

Item 15. Exhibits, Financial Statement Schedules, and Reports on Form 8-K

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 2002, 2001 and 2000 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)(5) Amended and Restated 1986 Stock Incentive Plan.
- 10(a)(6) First Amendment and Second Amendment to Amended and Restated 1986 Stock Incentive Plan.
- 10(a)(7) Third Amendment to Amended and Restated 1986 Stock Incentive Plan.
- 10(a)(8) Annual and Long-Term Incentive Plan.
- 10(a)(9) First Amendment to Annual and Long-Term Incentive Plan.
- 10(a)(10) 1990 Non-Employee Director Stock Plan, including all amendments.
- 10(a)(11) Form of Severance Compensation Agreement of Certain Executives.
- 10(a)(12) Life Insurance Program for Officers.
- 10(a)(13) Supplemental Executive Retirement Plan, Amended and Restated, effective January 1, 2001.
- 10(a)(14) Employment Agreement for Richard C. Green, Jr.
- 10(a)(15) Employment Agreement for Robert K. Green.
- 10(a)(16) Amended and Restated Capital Accumulation Plan.
- 10(a)(17) First Amendment to the Amended and Restated Capital Accumulation Plan.
- 10(a)(18) Severance Compensation Agreement dated as of March 16, 2001, by and between Aquila Merchant Services, Inc. (formerly Aquila, Inc.) and Keith Stamm.
- 10(a)(19) Severance Compensation Agreement dated as of March 16, 2001, by and between Aquila Merchant Services, Inc. (formerly Aquila, Inc.) and Dan J. Streek.
- 10(a)(20) Severance Compensation Agreement dated as of March 16, 2001, by and between Aquila Merchant Services, Inc. (formerly Aquila, Inc.) and Edward K. Mills.
- 10(a)(21) Aquila, Inc. 2002 Omnibus Incentive Compensation Plan.
- 10(a)(22) Second Amendment to the Amended and Restated Capital Accumulation Plan.
- 10(a)(23) UtiliCorp United Inc. Executive Security Trust Amended and Restated as of April 4, 2002.
- 10(a)(24) Agreement dated October 1, 2002 by and between the Company and Robert K. Green.
- 10(a)(25) Retention Agreement dated as of July 1, 2002 by and between Aquila Merchant Services, Inc. and Edward K. Mills.
- 10(a)(26) Retention Agreement dated as of August 13, 2002 by and between the Company and Leslie J. Parrette, Jr.
- 10(a)(27) Severance Payment Agreement Release and Waiver of Claims dated October 17, 2002 by and between the Company and Dan J. Streek.
- 10(a)(28) Severance Payment Agreement Release and Waiver of Claims dated October 11, 2002 by and between the Company and Edward K. Mills.

* *Incorporated by reference to the Index to Exhibits.*

(b) Reports on Form 8-K

Reports on Form 8-K for the quarter ended December 31, 2002, were as follows:

A Current Report on Form 8-K with respect to Item 5, dated October 1, 2002, was filed with the Securities and Exchange Commission by the Registrant.

(c) Exhibits

The Index to Exhibits follows on page 152.

(d) Financial Statements of Subsidiaries Not Consolidated and Fifty Percent or Less Owned Persons

The financial statements of Quanta Services, Inc. for the three years ended December 31, 2002, are filed as Exhibit 99.3. These financial statements are included as filed by Quanta Services, Inc. We take no responsibility for these financial statements.

AQUILA, INC.
SCHEDULE II—VALUATION AND QUALIFYING ACCOUNTS

For the Three Years Ended December 31, 2002
(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 (a)—				
2002	\$75.8	\$38.4	\$(79.6)	\$34.6
2001	62.8	83.5	(70.5)	75.8
2000	35.1	63.1	(35.4)	62.8
Maintenance Reserves (b)—				
2002	\$ 3.2	\$ 2.6	\$ (2.7)	\$ 3.1
2001	13.5	.7	(11.0)	3.2
2000	6.6	7.5	(.6)	13.5
Other Reserves (c)—				
2002	\$17.8	\$37.4	\$(36.6)	\$18.6
2001	21.9	30.3	(34.4)	17.8
2000	22.7	25.2	(26.0)	21.9
Restructuring Reserves (d)—				
2002	\$—	\$96.0	\$(46.8)	\$49.2

(a) Includes allowance for doubtful accounts receivable and merchant notes receivable.

(b) 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.

(c) Includes reserves for self-insurance and environmental claims.

(d) Includes restructuring reserves for severance, lease and other costs.

AQUILA, INC.
INDEX TO EXHIBITS

<u>Exhibit Number</u>	<u>Description</u>
*3(a)(1)	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)	By-laws of the Company, as amended. (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 percent of the total assets of the Company and its subsidiaries on a consolidated basis will be furnished to the Commission upon request.
10(a)(1)	Indenture of Mortgage and Deed of Trust between the Company and Bank One Trust Company, N.A. dated April 1, 2003.
10(a)(2)	First Supplemental Indenture to the Indenture of Mortgage and Deed of Trust.
10(a)(3)	\$430 million Credit Agreement among the Company, the lenders and Credit Suisse First Boston dated April 9, 2003.
10(a)(4)	\$200 million Credit Agreement among the Company, the lenders and Credit Suisse First Boston dated April 9, 2003.
*10(a)(5)	Amended and Restated 1986 Stock Incentive Plan. (Exhibit 10(a)(2) to the Company's Annual Report on Form 10-K for the year ended December 31, 1999.)
*10(a)(6)	First Amendment and Second Amendment to Amended and Restated 1986 Stock Incentive Plan. (Exhibit 10(a)(2) to the Company's Annual Report on Form 10-K for the year ended December 31, 2000.)
*10(a)(7)	Third Amendment to Amended and Restated 1986 Stock Incentive Plan. (Exhibit 10(a)(3) to the Company's Annual Report on Form 10-K for the year ended December 31, 2001.)
*10(a)(8)	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)(9)	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)(10)	1990 Non-Employee Director Stock Plan, including all amendments. (Exhibit 10(a)(4) to the Company's Annual Report on Form 10-K for the year ended December 31, 1999.)
*10(a)(11)	Form of Severance Compensation 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)(12)	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)(13)	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)(14)	Employment Agreement for Richard C. Green, Jr. (Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2002.)
*10(a)(15)	Employment Agreement for Robert K. Green. (Exhibit 10.5 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 1998.)

*10(a)(16)	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)(17)	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)(18)	Severance Compensation 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)(19)	Severance Compensation Agreement dated as of March 16, 2001, by and between Aquila Merchant Services, Inc. (formerly Aquila, Inc.) and Dan J. Streek. (Exhibit 10.8 to Registration Statement No. 333-51718, filed April 18, 2001 by Aquila Merchant Services, Inc. (formerly Aquila, Inc.))
*10(a)(20)	Severance Compensation Agreement dated as of March 16, 2001, by and between Aquila Merchant Services, Inc. (formerly Aquila, Inc.) and Edward K. Mills. (Exhibit 10.9 to Registration Statement No. 333-51718, filed April 18, 2001 by Aquila Merchant Services, Inc. (formerly Aquila, Inc.))
*10(a)(21)	Aquila, Inc. 2002 Omnibus Incentive Compensation Plan. (Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2002)
*10(a)(22)	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)(23)	UtiliCorp United Inc. 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)(24)	Agreement dated October 1, 2002 by and between the Company and Robert K. Green. (Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2002.)
*10(a)(25)	Retention Agreement dated as of July 1, 2002 by and between Aquila Merchant Services, Inc. and Edward K. Mills. (Exhibit 10(a)(2) to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2002.)
10(a)(26)	Retention Agreement dated as of August 13, 2002 by and between the Company and Leslie J. Parrette, Jr.
10(a)(27)	Severance Payment Agreement Release and Waiver of Claims dated October 17, 2002 by and between the Company and Dan J. Streek.
10(a)(28)	Severance Payment Agreement Release and Waiver of Claims dated October 11, 2002 by and between the Company and Edward K. Mills.
21	Subsidiaries of the Company.
23.1	Consent of KPMG, LLP.
23.2	Consent of PricewaterhouseCoopers LLP
99.1	Certification of Chief Executive Officer.
99.2	Certification of Chief Financial Officer.
99.3	Financial Statements of Quanta Services, Inc. for the years ended December 31, 2002, 2001 and 2000.

* 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 April 11, 2003.

Aquila, Inc.

/s/ Richard C. Green, Jr.

By: Richard C. Green, Jr.
*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 April 11, 2003.

By: <u>/s/ Richard C. Green, Jr.</u> Richard C. Green, Jr.	President, Chief Executive Officer and Chairman of the Board of Directors (Principal Executive Officer)
By: <u>/s/ Rick J. Dobson</u> Rick J. Dobson	Interim Chief Financial Officer (Principal Financial and Accounting Officer)
By: <u>/s/ John R. Baker</u> John R. Baker	Director
By: <u>/s/ Herman Cain</u> Herman Cain	Director
By: <u>s/ Irvine O. Hockaday, Jr.</u> Irvine O. Hockaday, Jr.	Director
By: <u>/s/ Heidi E. Hutter</u> Heidi E. Hutter	Director
By: <u>/s/ Dr. Stanley O. Ikenberry</u> Dr. Stanley O. Ikenberry	Director
By: <u>/s/ Gerald L. Shaheen</u> Gerald L. Shaheen	Director

Aquila, Inc.
Chief Executive Officer
Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

I, Richard C. Green, Jr., certify that:

1. I have reviewed the annual report on Form 10-K of Aquila, Inc. for the year ending December 31, 2002;
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 officers and I are responsible for establishing and maintaining disclosure controls and procedures for the registrant and we have:
 - a) designed such disclosure controls and procedures 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) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this report ("Evaluation Date"); and
 - c) presented in this report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;
5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of the board of directors:
 - a) all significant deficiencies in the design or operation of internal controls which could materially affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and
 - b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and
6. The registrant's other certifying officers and I have indicated in this report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

April 11, 2003

/s/ RICHARD C. GREEN, JR.

Richard C. Green, Jr.
Chairman, President and
Chief Executive Officer, Aquila, Inc.

Aquila, Inc.
Chief Financial Officer
Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

I, Rick J. Dobson, certify that:

1. I have reviewed the annual report on Form 10-K of Aquila, Inc. for the year ending December 31, 2002;
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 officers and I are responsible for establishing and maintaining disclosure controls and procedures for the registrant and we have:
 - a) designed such disclosure controls and procedures 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) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this report ("Evaluation Date"); and
 - c) presented in this report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;
5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of the board of directors:
 - a) all significant deficiencies in the design or operation of internal controls which could materially affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and
 - b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and
6. The registrant's other certifying officers and I have indicated in this report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

April 11, 2003

/s/ RICK J. DOBSON

Rick J. Dobson
Interim Chief Financial Officer,
Aquila, Inc.

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