FORM 10−K

AQUILA INC − ILA

Filed: March 07, 2006 (period: December 31, 2005)

Annual report which provides a comprehensive overview of the company for the past year

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

FORM 10−K

(Mark One)

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

For the fiscal year ended December 31, 2005
or

☐ **Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
For the transition period from ____________ to ____________

Commission file number: 1−03562

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

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

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

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

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

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

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

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

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non−accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12B−2 of the Exchange Act. (Check one):

Large accelerated filer ☒ Accelerated Filer ☐ Accelerated Filer ☐

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

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

Title	Outstanding at March 1, 2006
Common Stock, par value $1.00 per share	**373,671,736**

Documents Incorporated by Reference:	Where Incorporated:
Proxy Statement for 2006 Annual Shareholders Meeting	Part III

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Glossary of Terms and Abbreviations

APB—Accounting Principles Board.

AFUDC—Allowance for Funds Used During Construction.

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

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

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

CFTC—Commodity Futures Trading Commission.

CO_2—Carbon Dioxide.

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

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

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

Energy Act—Energy Policy Act of 2005.

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

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

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

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

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

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

Fitch—Fitch Ratings, a leading global rating agency.

FPA—Federal Power Act.

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

GWh—Gigawatt−hour.

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

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

KCPL—Kansas City Power & Light Company.

kWh—Kilowatt−hour.

LIBOR—London Inter−Bank Offering Rate.

Mcf—One thousand cubic feet.

MGP—Manufactured Gas Plant.

MMBtu—One Million Btus.

Mmcf—One million cubic feet.

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

MW—Megawatt, one thousand kilowatts.

MWh—Megawatt−hour.

NOx—Nitrogen oxide.

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

NYMEX—New York Mercantile Exchange.

NYSE—New York Stock Exchange.

NYSEG—New York State Electric and Gas Corp.

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

PCB—Polychlorinated Biphenyl.

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

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

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

RTO—Regional Transmission Organization.

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

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

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

SO_2—Sulfur dioxide.

Part I

Item 1. Business

History and Organization

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

We have entered into agreements to sell our Electric Utilities in Kansas and our Gas Utilities in Michigan, Minnesota, and Missouri, which results in these operations being considered "held for sale" and reported as discontinued operations. Excluding discontinued operations, our Electric Utilities include 1,827 MW of generation and 14,723 pole miles of electric transmission and distribution lines, and our Gas Utilities include 516 miles of intrastate gas transmission pipelines and 11,104 miles of gas distribution mains and service lines. Our Electric and Gas Utilities generated revenues from continuing and discontinued operations of $1,315.8 million and $816.8 million, respectively, in the year ended December 31, 2005. The continuing and discontinued operations of our Electric and Gas Utilities had total assets of $2.6 billion and $.9 billion, respectively, at December 31, 2005.

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

Access to Company Information and Officer Certifications

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

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

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

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

Business Group Summary

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

I. Electric and Gas Utilities

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

Electric Utilities

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

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

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

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

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

Line Type—In Miles

	Continuing	Discontinued
Electric transmission	2,141	2,500
Electric distribution	12,582	3,835

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

	2005	2004	2003
Sales (in millions)			
Residential	$ 303.8	$ 263.3	$ 250.6
Commercial	190.0	173.0	158.1
Industrial	91.6	84.2	75.7
Other	98.7	73.6	59.7
Total continuing electric operations	684.1	594.1	544.1
Total discontinued electric operations	190.9	165.2	153.4
Total	$ 875.0	$ 759.3	$ 697.5
Volumes Generated and Purchased (GWh)			
Coal	5,248	5,275	5,580
Gas	91	2	38
Coal/Gas	611	686	641
Gas/Oil	61	21	99
Total generated	6,011	5,984	6,358
Purchased	5,860	4,630	3,828
Total generated and purchased	11,871	10,614	10,186
Company use	(15)	(14)	(13)
Line loss	(691)	(668)	(697)
Total continuing electric operations	11,165	9,932	9,476
Total discontinued electric operations	2,311	2,431	2,357
Total	13,476	12,363	11,833
Volumes (GWh)			
Residential	3,961	3,603	3,637
Commercial	3,050	2,893	2,840
Industrial	1,870	1,838	1,775
Other	2,284	1,598	1,224
Total continuing electric operations	11,165	9,932	9,476
Total discontinued electric operations	2,311	2,431	2,357
Total	13,476	12,363	11,833

	2005	2004	2003
Customers at Year End			
Residential	341,589	335,003	328,837
Commercial	46,029	45,084	44,900
Industrial	372	383	383
Other	3,416	3,359	3,397
Total continuing electric operations	391,406	383,829	377,517
Total discontinued electric operations	68,920	68,817	68,373
Total	460,326	452,646	445,890
Continuing Operations Statistics—			
Average annual volume per residential customer (kWh)	11,597	10,755	11,060
Average annual sales per residential customer	$ 889	$ 786	$ 762
Average residential sales per kWh (cents)	7.67	7.31	6.89
Units of Fuel Used in Generation			
Coal—thousand tons	3,569	3,582	3,677
Natural gas—Mmcf	2,120	782	1,903
Average Cost of Fuel			
Coal—per ton	$ 24.97	$ 23.34	$ 21.17
Natural gas—per Mcf	9.85	6.97	4.82

Gas Utilities

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

Line Type—In Miles

	Continuing	Discontinued
Intrastate gas transmission pipelines	516	300
Gas distribution mains and service lines	11,104	8,550

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

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

	2005	2004	2003
Volumes (Mcf)			
Residential	34,922	34,331	37,919
Commercial	14,886	14,230	14,850
Industrial	3,399	3,789	3,248
Transportation	42,465	41,200	44,493
Other	115	141	169
Total continuing gas operations	95,787	93,691	100,679
Total discontinued gas operations	123,136	121,285	127,316
Total	218,923	214,976	227,995
Customers at Year End			
Residential	456,592	448,889	441,263
Commercial	43,213	42,921	42,012
Industrial	1,699	1,691	1,556
Other	7,039	7,306	8,166
Total continuing gas operations	508,543	500,807	492,997
Total discontinued gas operations	414,556	409,309	407,780
Total	923,099	910,116	900,777

Seasonal Variations of Business

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

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

Competition

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

Regulation and Rates

State Regulation

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

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

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

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

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

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

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

The following summarizes our recent rate case activity:

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

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

(2) The Missouri electric settlement included a two−year interim energy charge that allowed the company to recover variable generation and purchased power costs up to a specified amount per Mwh specific to each Missouri regulatory jurisdiction. The interim energy charge rate per unit sold is $13.98/Mwh for our St. Joseph Light & Power operations and $19.71/Mwh for our Missouri Public Service operations. If the amounts collected under the interim energy charge exceeded our average cost incurred for the two−year period, we would refund the excess to the customers, with interest. This fuel and purchased power cost recovery mechanism represents $18.5 million of the $36.2 million 2004 rate increase.

(3) The Missouri gas settlement became effective for our Missouri Public Service operations in May 2004 and for our St. Joseph Light & Power operations in August 2004.

(4) The Colorado electric settlement included the modification of the ECA to provide for the recovery from customers of 100% of the variability of energy costs, an increase from 75%.

(5) In connection with the settlement, the ECA was modified to allow the pass through of SO_2 allowance costs to customers.

(6) The Kansas gas settlement also included $244,000 per year for three years for a pipe replacement program.

(7) Under Iowa regulations, we instituted interim rates, subject to refund, totaling approximately $1.7 million in May 2005. On March 1, 2006, the Iowa Utilities Board issued an order approving a $2.9 million rate increase, inlcuding recovery of rate case costs. The order denied a settlement provision that would have established a recovery mechanism for investments in distribution system integrity. Final rates are expected to be effective in April 2006.

(8) The Missouri electric settlement terminated the interim energy charge established in our 2003 rate case filing and required a $1.0 million refund to our St. Joseph Light & Power customers as part of the termination. The settlement also established the value of our South Harper peaking capacity at approximately $140 million, resulting in an additional $4.4 million impairment of the plant's turbines. See Note 5 to the Consolidated Financial Statements for further discussion. The settlement was approved by the Missouri Commission on February 23, 2006, and the new rates became effective on March 1, 2006. In addition, in February 2006, we settled the Missouri steam rate case for a $4.5 million rate increase. This settlement includes a provision for sharing 80% of fuel cost variability from the established base fuel rates. It was approved by the Missouri Commission in February 2006 and the new rates became effective on March 6, 2006.

Federal Regulation

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

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

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

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

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

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

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

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

Environmental Matters

General

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

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

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

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

Water Issues

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

316(b) Fish Impingement Requirements

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

Missouri River Levels

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

Air Emissions

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

Clean Air Act

Title IV of the Clean Air Act (CAA) created an SO_2 allowance trading program as part of the federal acid rain program. Each allowance gives the owner the right to emit one ton of SO_2. At the end of each year, each emitting unit must have enough allowances to cover its emissions for that year. Allowances may be traded so that affected units that expect to emit more SO_2 than their allowances may purchase allowances from other affected units that expect to emit less than their allocated allowances. The allowance allocation is based on historical operating data. Our facilities emit SO_2 in excess of their allocated allowances. Currently, we purchase additional allowances to stay in compliance. Allowance prices have more than doubled in price during 2005 and we are continuing to evaluate the cost of purchasing allowances versus adding pollution control equipment.

Multi−pollutant regulations

Approximately 53% of our continuing operations generating capacity is coal−fired. The EPA has issued the Clean Air Interstate Rule (CIAR) and the Clean Air Mercury Rule (CAMR) regulations with respect to SO_2, NOx and mercury emissions from coal−fired power plants. These new rules would require significant reductions in these emissions from our power plants in phases, beginning as early as 2009. The rules are being challenged in the courts. We are completing a study to determine the best options for compliance with CAIR and CAMR and participating in state work groups that will adopt the final Federal regulations. Federal multi−pollutant legislation is also being considered that would require reductions similar to the EPA rules and some that could add greenhouse gas emission requirements. We anticipate additional capital costs to comply with the CAIR and CAMR rules.

New Source Review

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

In January 2004, Westar Energy, Inc. received a notification from the EPA that it had violated the EPA's NSR requirements and Kansas environmental regulations by making modifications to the Jeffrey Energy Center without obtaining the proper permits. The Jeffrey Energy Center is a large coal−fired power plant located in Kansas that is 84% owned by Westar and operated exclusively by Westar. We have a 16% interest in the Jeffrey Energy Center and are generally responsible for this portion of its operating costs and capital expenditures. The electric generation plants we own or lease are described in the table at Item 1, page 7. At this time, no settlement has been reached with the EPA, however, it is possible that Westar could be subject to an enforcement action by the EPA and be required to make significant capital expenditures to install additional pollution controls at the Jeffrey Energy Center. Irrespective of the NSR case, the recent high cost of SO_2 allowances may make it economical to install SO_2 technology. In either case, we could potentially be responsible for up to 16% of those costs, including the 8% lease interest held by our Kansas electric utility which is included in discontinued operations.

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

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

Global Climate Change

We utilize a diversified energy portfolio that includes a fuel mix of coal, natural gas, biomass, wind, and nuclear sources. Of these fuel mixes, coal−fired power plants are the most significant sources of CO_2 emissions. We believe that it is possible that greenhouse gases may be regulated within the next five years. There are no specifics on how greenhouse gases will be regulated but, any mandated federal greenhouse gas reductions or caps on CO_2 emissions could have a material impact.

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

Solid Waste

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

Past Operations

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

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

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

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

II. Merchant Services

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

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

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

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

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

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

Competition

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

Regulation

Natural Gas Marketing Regulation

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

Power Generation and Marketing Regulation

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

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

Our Executive Team

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Item 1A. Risk Factors

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

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

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

We must substantially reduce our overhead costs.

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

We expect to continue to incur net losses.

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

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

Our fuel and purchased power costs for our Missouri electric utilities are expected to significantly exceed the costs we are able to pass through to customers during 2006. We expect to file a rate case in July 2006 to implement a mechanism that will allow us to fully recover these costs; however, even if we are successful, we will not realize any rate relief until mid 2007 at the earliest. Until the Missouri Commission establishes rules to implement the legislation adopted in July 2005 that provides a means for the recovery of prudently incurred fuel and purchased power costs without going through a general rate case, our ability to recover fuel and purchased power costs for our Missouri electric operations will continue to be limited due to the time lag associated with filing rate cases. Our inability to pass through fuel and purchased power costs to our Missouri electric customers may also adversely affect our ability to satisfy the financial covenants in our credit agreements, which if breached could cross default our other debt instruments.

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

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

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

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

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

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

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

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

In addition, the Kansas Commission staff recently proposed rules that would require utilities (including us) to "ring fence" their Kansas utility operations. As currently written, the proposal would require us to, among other things, transfer our Kansas utility assets to one or more separate wholly−owned subsidiaries, create a money pool that may only be used by our utility operations, create a separate subsidiary that would provide operating and administrative services to the ring−fencing utility subsidiary, and finance our Kansas utility operations with capital raised by the ring−fenced Kansas utility subsidiary or a finance subsidiary that issues debt on behalf of our Kansas utility subsidiary. Because numerous of our contracts, indentures and loan agreements restrict or prohibit the transfer of utility assets from our company to one or more subsidiaries, compliance with any such proposal adopted by the Kansas Commission could have a material adverse effect on us.

Stockholder approval is required to issue additional common stock.

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

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

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

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

We are experiencing a 15−20% rail curtailment in our contracted coal deliveries from the Southern Powder River Basin, due in part to weather and other track problems that have caused Union Pacific and Burlington Northern to curtail rail shipments. This curtailment affects coal deliveries to our owned coal−fired power plants, and our jointly−owned investments, Iatan and Jeffrey Energy Center. Because substitute coal supplies are typically of higher sulfur content, we are required to purchase additional SO_2 emission allowances at a time when the cost of such allowances is substantially higher than historical levels. The continuation of either or both of these events for any extended period of time could have a material effect on our operations and cash flows if we are not allowed to pass these costs through to our customers.

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

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

Our operating results can be adversely affected by milder weather.

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

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

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

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

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

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

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

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

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

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

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

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

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

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

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

Item 3. Legal Proceedings

See Note 20 to the Consolidated Financial Statements.

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

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

Part II

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

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

Market Price Per Share

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

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

Item 6. Selected Financial Data

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

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

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

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

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

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

(e) Included in loss from continuing operations for the year ended December 31, 2002, are (a) a $696.1 million impairment charge on our investment in Quanta Services; (b) a $247.5 million impairment charge on our investment in Midlands Electricity; (c) a $127.2 million impairment charge on our investment in Multinet Gas and AlintaGas; (d) a $29.8 million impairment charge related to our investments in Everest Connections and various communications projects; (e) a $181.2 million write−down of Merchant Services' goodwill; (f) other impairment charges and losses on sale of assets of $91.9 million; and (g) $210.2 million of restructuring charges from our exit from the wholesale energy trading business and the restructuring of our utility business. We also recorded a $130.5 million gain on the sale of our shares of UnitedNetworks.

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

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

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

Strategic and Financial Repositioning Overview

Overview

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

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

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

Asset Divestures and Strengthen Credit Profile

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

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

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

Historical Review of Repositioning Efforts

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

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

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

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

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

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

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

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

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

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

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

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

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

LIQUIDITY AND CAPITAL RESOURCES

Working Capital Requirements

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

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

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

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

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

Cash Flows

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

Cash Flows from Operating Activities

Our positive 2005 operating cash flows were driven primarily by the return of $88.2 million of funds on deposit as a result of the replacement of cash deposits with letters of credit. The increase in natural gas prices required our merchant and utilities counterparties to post an additional $54.6 million of collateral with us. Offsetting these increases were the use of $33.3 million of cash to inject higher cost natural gas into storage for the winter heating season, a 2005 income tax payment of $30.9 million related to the sale of our Canadian utilities business in 2004, and the $28.0 million settlement with Enron in connection with the netting of amounts owed under various contracts at the time of Enron's bankruptcy filing in 2001.

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

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

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

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

Cash Flows from Investing Activities

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

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

Cash Flows from Financing Activities

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

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

Current Credit Ratings

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

Agency	Rating	Commentary
Moody's	B2	Positive Outlook
S&P	B−	Positive Outlook
Fitch	B−	Positive Outlook

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

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

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

Collateral Positions

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

In millions

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

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

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

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

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

Contractual Obligations

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

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

In millions

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

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

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

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

Regulated business purchase obligations

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

Long−Term Gas Contracts

We accounted for the advance cash payments we received under these contracts as liabilities. We reduce our obligation for these long−term gas contracts as the gas is delivered to the customer under the units of revenue method. If we were to default on these obligations, or were unable to perform on them, we would be required to pay the issuers of the surety bonds or the counterparties on these arrangements approximately $49.2 million. This amount is greater than the long−term gas contract balance on our Consolidated Balance Sheet due to our use of the units of revenue method versus a present value method applied under the default provisions of the contractual agreements. We do not intend to terminate these remaining contracts.

Elwood Tolling Contracts

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

Off−Balance Sheet Arrangements

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

Equity Put Rights

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

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

Capital Expenditures

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

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

Iatan 2

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

Regulatory Approvals Required for Financing

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

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

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

Restriction on Ability to Issue Common Stock

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

FINANCIAL REVIEW

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

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

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

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

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

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

Key Factors Impacting Continuing Operating Results

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

- Total Utilities EBITDA increased $16.1 million primarily due to favorable weather for our electric utilities, and rate increases in Missouri, Colorado and Kansas and customer growth, offset in part by higher costs for natural gas used for fuel and increased labor and compensation costs.

- The continued wind−down of our energy trading businesses in 2005, including $31.3 million of net gains related to the sale of our investment in ICE and the Red Lake gas storage development project and the termination of our Batesville tolling agreement and associated forward sale contract, resulted in a $394.1 million increase in EBITDA compared to 2004. Merchant Services' EBITDA in 2004 included $185.5 million of net losses on sale of assets and other charges, and $166.1 million of margin losses primarily associated with our former long−term gas contracts, alternative risk contracts, and other trading activities.

- Corporate and other loss before EBITDA decreased $79.4 million in 2005 compared to 2004, primarily due to the non−cash loss on the early conversion of the PIES.

Restructuring Charges

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

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

Net Loss on Sale of Assets and Other Charges

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

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

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

Three−Year Review—Electric Utilities

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

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

2005 versus 2004

Sales, Cost of Sales and Gross Profit

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

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

Operating Expense

Operating expenses consisted of the following:

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

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

Other Income

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

Depreciation and Amortization Expense

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

2004 versus 2003

Sales, Cost of Sales and Gross Profit

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

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

Operating Expense

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

Other Income

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

Depreciation and Amortization Expense

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

Earnings Trend

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

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

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

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

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

Three−Year Review—Gas Utilities

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

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

2005 versus 2004

Sales, Cost of Sales and Gross Profit

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

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

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

Operating Expense

Operating expenses consisted of the following:

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

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

2004 versus 2003

Sales, Cost of Sales and Gross Profit

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

- Regulated gas sales and cost of sales increased $32.6 million and $35.4 million, respectively, in 2004 compared to 2003, for a net decrease in gross profit of $2.8 million. Sales and cost of sales increased due to an 18% increase in natural gas prices. However, because gas purchase costs for our gas utility operations are passed through to our customers, the change in gas prices did not have a corresponding impact on gross profit. Regulated gas margins decreased $7.0 million due to unfavorable weather and lower usage per customer in 2004 compared to 2003. Regulated gas margins in 2003 included a $2.5 million favorable change in reserved funds released upon conclusion of multi−year gas cost recovery filings that did not recur in 2004. The overall decline in gas margins due to volume and weather was partially offset by $5.0 million in rate increases in Nebraska and Iowa and $1.1 million of increased margins from customer growth.

- Non−regulated gas sales, cost of sales and gross profit decreased $8.3 million, $6.8 million and $1.5 million, respectively, in 2004 compared to 2003, primarily as the result of the sale of certain non−regulated gas pipeline and gathering operations in August 2003.

- Non−regulated other sales decreased $1.5 million and cost of sales increased $.7 million for a net decrease in gross profit of $2.2 million, primarily as a result of a decrease in appliance service contracts and increased costs of servicing existing contracts.

Operating Expense

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

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

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

Merchant Services

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

Three−Year Review—Merchant Services

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

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

2005 versus 2004

Sales, Cost of Sales and Gross Loss

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

- In 2005, we recorded a net margin loss of $32.4 million associated with our Elwood tolling agreement. We make fixed capacity payments evenly throughout the year that entitle us to generate power at the Elwood plant. The cost to purchase natural gas to fuel this power plant generally exceeded the value of the power that could be generated. Accordingly, we did not generate material revenues.

- As part of the continued wind−down of our wholesale energy trading operations, we assigned the final year of our obligation under a stream flow contract to a third party in the second quarter of 2005. Included in our gross loss for 2005 were mark−to−market losses and settlements of approximately $7.4 million, related to our stream flow transaction.

- We recorded a margin loss of $4.5 million on the 2005 write−off of certain balances retained in our previous sale of gas pipeline investments.

- We also incurred margin losses of $7.1 million resulting from the difference between revenue recognized on our two remaining long−term gas delivery contracts compared to the net cost of gas delivered under these contracts.

- Partially offsetting the gross loss for 2005 was the termination of certain commodity and interest rate hedges. The termination of the hedges and the release of our contingent obligation to the buyer of our former merchant loan portfolio resulted in the reversal of the related liability of $7.1 million associated with these contracts.

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

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

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

- During 2004, we made fixed capacity payments evenly throughout the year that entitled us to generate power at merchant power plants owned by others. For 2004, we recorded net margin loss associated with these agreements of $36.9 million. The cost to purchase natural gas to fuel these power plants generally exceeded the value of the power that could be generated. Accordingly, we did not generate material revenues.

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

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

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

Operating Expense

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

Restructuring Charges

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

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

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

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

2004 versus 2003

Sales, Cost of Sales and Gross Loss

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

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

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

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

Operating Expense

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

Restructuring Charges

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

Net Loss on Sale of Assets and Other Charges

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

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

Depreciation and Amortization Expense

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

Equity in Earnings of Investments

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

Other Income

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

Earnings Trend and Impact of Changing Business Environment

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

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

Corporate Matters

Three−Year Review—Corporate and Other

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

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

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

2005 versus 2004

Operating Expense

Operating expense decreased $10.5 million in 2005 compared to 2004, due to the 2004 settlement of the appraisal rights shareholder lawsuit for $8.8 million, a $8.5 million decrease in costs associated with our former international networks investments in Canada and Australia compared to 2004 and a $3.3 million decrease in insurance costs in 2005. These decreases were offset in part by $7.9 million of increased legal fees related to our ERISA litigation and $4.0 million of increased consulting fees and other costs associated with the process of selling certain of our Gas and Electric Utilities in 2005.

Net Loss on Sale of Assets and Other Charges

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

Other Income

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

2004 versus 2003

Operating Expense

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

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

The 2004 net loss on sale of assets and other charges of $2.8 million is mainly due to the $10.6 million impairment on three natural gas combustion turbines that were held by one of our non−regulated subsidiaries and have now been transferred to our Missouri electric operations at their current fair value. The impairment was partially offset by the reversal of our Everest Connections target−based put rights liability of $4.5 million due to the meeting of certain financial and operational performance measures, and the $3.3 million gain we recorded in connection with the sale of our interest in Midlands Electricity in January 2004. The Midlands Electricity investment was written down to its estimated fair value in 2002 and again in September 2003. However, due to strengthening of the British pound exchange rate in the fourth quarter of 2003 and in early 2004, we realized a gain on the closing of the sale. The 2003 loss on sale of assets of $5.8 million was related to the impairment charge taken on our investment in Midlands Electricity in September 2003 and the net loss on the sale of our interests in AlintaGas, UEL and Multinet Gas in Australia in May and July 2003.

Equity in Earnings of Investments

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

Other Income

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

Interest Expense and Income Tax Benefit

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

In millions	**Year Ended December 31,**		
	2005	**2004**	**2003**
Interest expense	$ 150.2	$ 184.5	$ 198.8
Income tax benefit	$ (43.1)	$ (214.3)	$ (147.0)

2005 versus 2004

Interest Expense

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

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

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

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

Income Tax Benefit

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

2004 versus 2003

Interest Expense

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

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

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

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

Income Tax Benefit

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

Discontinued Operations

Operating results of discontinued operations are as follows:

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

2005 versus 2004

Sales, Cost of Sales and Gross Profit

Electric Utilities

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

Gas Utilities

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

Other

Other sales, cost of sales and gross profit decreased $106.3 million, $14.0 million, and $92.3 million, respectively, in 2005 compared to 2004. Our Canadian utilities and independent power plants, which had 2004 gross profit of $105.7 million, were sold in the first half of 2004. Slightly offsetting this lost profit was a $5.8 million increase in Everest Connections 2005 gross profit as compared to 2004 due to an increase in customers served and a $7.7 million increase in gross profit earned by the Illinois peaking power plants related to increased demand for peaking power and short−term capacity contracts in 2005.

Operating Expense

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

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

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

Other Income (Expense)

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

Depreciation and Amortization Expense

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

Interest Expense

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

Income Tax Expense (Benefit)

Income tax expense decreased $96.4 million in 2005 compared to 2004, primarily due to the pretax loss in 2005 related to the impairment of our investments in Illinois peaking power plants in 2005. The 2005 income tax benefit on a pretax loss from discontinued operations was primarily the result of the impairment of our Illinois peaking facilities, while the 2004 income tax expense on pretax income from discontinued operations resulted from the pretax gain on the sale of our Canadian utility businesses. The tax expense on that 2004 gain was substantially higher than the statutory federal tax rate due to the following factors. The U.S. taxes reflect the partial deduction of Canadian taxes, including withholding taxes, from the U.S. taxable income instead of the full utilization of foreign tax credits. Taxes on the sale also reflect our inability to fully utilize the tax loss on the sale of the Alberta business against the tax gain on the sale of the British Columbia business.

2004 versus 2003

Sales, Cost of Sales and Gross Profit

Electric Utilities

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

Gas Utilities

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

Other

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

Operating Expense

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

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

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

Other Income (Expense)

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

Depreciation and Amortization Expense

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

Interest Expense

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

Income Tax Expense

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

OTHER ITEMS

Critical Accounting Policies and Estimates

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

Energy Trading and Derivative Accounting

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

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

We also have other activities in our utility operations that are accounted for under SFAS 133. The majority of these activities consist of the purchasing of gas, power and coal for our utility operations, which fall under the normal purchases and sales exception. These activities require that management make certain judgments regarding the election of the normal purchases and sales exceptions. In addition, as allowed by state regulatory commissions, we have entered into certain financial instruments to reduce our customers' underlying exposure to fluctuations in gas prices. These financial instruments are considered derivatives under SFAS 133 and are marked−to−market and recorded in our PGA accounts as they are collectible under the provisions of the PGA upon settlement. We also have entered into a program for our electric utility operations in Missouri to mitigate our exposure to natural gas price volatility in the market. This program extends multiple years and the mark−to−market value of the portfolio of $20.7 million related to contracts that will settle against actual purchases of natural gas and purchased power in 2006 through 2008. In connection with the recently settled Missouri electric rate case, we agreed that these contracts would be recognized into cost of sales when they settle. A regulatory liability has been recorded under SFAS 71 in the amount of $20.7 million to reflect the change in the timing of recognition authorized by the Missouri Commission.

Unbilled Utility Revenues

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

Impairment of Long−Lived Assets

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

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

Goodwill and Other Intangible Assets

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

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

Regulatory Accounting Implications

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

Valuation of Deferred Tax Assets

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

As of December 31, 2005, we had approximately $454.5 million of federal net operating loss carryforwards originating in 2003, $579.0 million of estimated federal net operating losses originating in 2004 and an estimated $85.9 million of federal net operating losses originating in 2005. The 2003 federal net operating loss carryforward expires in 2023 and can be carried back to 2001 to offset potential IRS audit adjustments. The 2004 and 2005 federal net operating loss carryforwards expire in 2024 and 2025, respectively, and cannot be carried back due to losses in the carryback years. We did not record valuation allowances against the deferred tax assets related to federal net operating losses. This determination was based on our assessment that it is more likely than not that we will realize these deferred assets during the carryforward period. This assessment considered the forecasted reversal of existing temporary differences and taxable income expected to be generated in the carryforward period and potential IRS audit adjustments in 2001.

Reserve for Contingent Tax Liabilities

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

Pension Plans

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

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

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

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

Legal Contingencies

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

Significant Balance Sheet Movements

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

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

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

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

New Accounting Standards

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

Effects of Inflation

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

Forward−Looking Information

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

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

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

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

  - If the rules implementing the adopted fuel clause adjustment legislation are delayed, we may incur significant losses if we are not otherwise permitted to pass through to ratepayers costs associated with fuel purchases for our Missouri electric operations.
  - Even if the Missouri Commission implements the fuel clause adjustment rules prior to our next electric rate case in Missouri, the Missouri Commission may subsequently determine that certain fuel costs were not prudently incurred and, therefore, refuse to allow such costs to be recovered in rates.

- We anticipate that our current revolving credit capacity and available cash will be sufficient to fund our winter needs and working capital requirements. Some important factors that could cause actual results to differ materially from those anticipated include:
  - Our access to revolving credit capacity depends on maintaining compliance with loan covenants. If we violate these covenants, we may lose revolving credit capacity and not have sufficient cash available for our winter needs and working capital requirements.
  - Unanticipated increases in the price of natural gas that we purchase for our utility customers could exhaust our liquidity in the winter months.
  - Counterparties may default on their obligations to supply commodities or return collateral to us or to meet their obligations under commercial contracts, including those designed to hedge against movements in commodity prices.

- We believe that we have strong defenses to litigation pending against us. Some important factors that could cause actual results to differ materially from those anticipated include:
  - Judges and juries can be difficult to predict and may, in fact, rule against us.
  - Our positions may be weakened by adverse developments in the law or the discovery of facts that hurt our cases.

- We do not expect that the annual limitations on net operating losses would cause any of our net operating losses to expire unutilized for purposes of reducing our taxes. Some important factors that could cause actual results to differ materially from those anticipated include:
  - Changes in the tax law could result in our tax net operating losses going unutilized.
  - The failure to generate sufficient income (including income from asset sales) could result in our tax net operating losses going unutilized.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Market Risk—Utility Operations

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

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

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

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

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

Market Risk—Trading

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

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

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

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

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

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

Certain Trading Activities

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

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

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

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

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

Credit Risk

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

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

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

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

In millions	**Investment Grade**	**Non−investment Grade**	**Total**
Utilities and merchants	$ 52.9	$ 90.2	$ 143.1
Financial institutions	187.7	—	187.7
Oil and gas producers	.2	—	.2
Commercial and industrial	—	.1	.1
Total	$ 240.8	$ 90.3	$ 331.1

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

Currency Rate Exposure

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

Interest Rate Exposure

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

Item 8. Financial Statements and Supplementary Data

Aquila, Inc.
Consolidated Statements of Income

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

See accompanying notes to consolidated financial statements.

Aquila, Inc.
Consolidated Balance Sheets

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

See accompanying notes to consolidated financial statements.

Aquila, Inc.
Consolidated Statements of Common Shareholders' Equity

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

See accompanying notes to consolidated financial statements.

Aquila, Inc.
Consolidated Statements of Comprehensive Income

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

See accompanying notes to consolidated financial statements.

Aquila, Inc.
Consolidated Statements of Cash Flows

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

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

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

See accompanying notes to consolidated financial statements.

Note 1: Summary of Significant Accounting Policies

Description of Business

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

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

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

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

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

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

Use of Estimates

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

Principles of Consolidation

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

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

Property, Plant and Equipment

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

Impairment of Long−Lived Assets

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

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

Goodwill

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

Our goodwill was allocated to each segment as follows:

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

Sales Recognition

Utility Activities

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

Trading Activities

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

Weather Derivatives

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

Funds on Deposit

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

Inventories

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

Pension and Other Postretirement Plans

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

Regulatory Matters

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

Long−Term Gas Contracts

We were paid in advance on certain long−term gas contracts for the future delivery of gas to municipal utilities over the subsequent 10 to 12 years. We accounted for these contracts as long−term obligations. We recognize the reduction of our obligations on these long−term gas contracts as gas is delivered to the customer under the units of revenue method, which matches the revenue recognized with the forecasted volumes of gas to be delivered. See Note 13 for further discussion.

Income Taxes

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

Environmental Matters

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

Stock Based Compensation

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

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

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

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

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

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

Cash and Cash Equivalents

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

Currency Adjustments

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

Reclassifications

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

Note 2: New Accounting Standards

Conditional Asset Retirement Obligations

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

Share−Based Payments

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

Exchanges of Nonmonetary Assets

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

Accounting Changes and Error Corrections

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

Note 3: Risk Management

Overview

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

Merchant Trading Activities

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

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

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

Market Risk

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

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

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

Market Valuation

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

We consider a number of risks and costs associated with the future contractual commitments included in our energy portfolio, including credit risks associated with the financial condition of counterparties and the time value of money. The values of all forward and future contracts are discounted to December 31, 2005, using market interest rates for the contract term adjusted for our credit rating for liabilities or the credit rating of the counterparty for assets. We continuously monitor the portfolio and value it daily based on present market conditions. The following table displays the fair values of Merchant and Utilities price risk management assets and liabilities at December 31, 2005, and the average value for the year ended December 31, 2005:

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

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

Hedging Activities

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

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

Cash Flow Hedges

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

Normal Purchases and Sales Exception

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

Regulated Commodity Management

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

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

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

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

Note 4: Restructuring Charges

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

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

Lease Agreements

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

Interest Rate Swap Reductions

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

Severance Costs and Retention Payments

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

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

Restructuring Reserve Activity

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

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

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

Pretax net loss (gain) on sale of assets and other charges we recorded for the years ended December 31, 2005, 2004 and 2003 are shown below. After−tax losses in the following paragraphs are reported after giving consideration to the effects of capital loss carryback and carryforward limitations. As a result, the net tax effect may differ substantially from our expected statutory tax rates. The after−tax losses (gains) discussed below are based on current estimates of the tax treatment of these transactions and may be adjusted after detailed allocation of the purchase price for tax purposes and the filing of tax returns including these sales.

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

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

Batesville Tolling Contract

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

ICE Sale

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

Aries Power Project and Tolling Agreement

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

Termination of Long−Term Gas Contracts

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

Red Lake Storage Development Project

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

Acadia Tolling Agreement

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

Turbine Contracts

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

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

Independent Power Plants

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

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

Investment in BAF Energy

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

Enron Bankruptcy

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

Marchwood Development Project

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

Early Conversion of the PIES

As discussed in more detail in Note 12, we completed an exchange offer that resulted in the early conversion of approximately 98.9% of our PIES in July 2005. We recorded a pretax and after−tax early conversion loss of $82.3 million in connection with this transaction. We did not record a tax benefit from this transaction as the premium paid to complete the conversion is not deductible for tax purposes.

Everest Connections Target−Based Put Rights

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

Midlands

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

Australia

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

Turbines Impairment

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

Note 6: Discontinued Operations

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

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

Electric and Gas Utilities

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

Utility	Buyer		Base Price (in millions)
Kansas Electric	Mid−Kansas Electric Company	$	255.2
Michigan Gas	WPS Resources Corporation		269.5
Minnesota Gas	WPS Resources Corporation		288.0
Missouri Gas	The Empire District Electric Company		84.0

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

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

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

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

Merchant Peaking Power Plants

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

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

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

In connection with the sale of these facilities, we determined that the Goose Creek Energy Facility and the Raccoon Creek Energy Facility should be classified as "held for sale" and included in discontinued operations, rather than "held and used" as they had previously been classified. As a result, we reassessed the realizability of the carrying value of our investments in these facilities and concluded that they were impaired. We based this conclusion on the anticipated net sale proceeds of the sale transactions described above. Based on the expected net sale proceeds and transaction−related costs, we recorded a pre−tax non−cash impairment charge of approximately $93.6 million and $65.9 million for the Goose Creek Energy Facility and the Raccoon Creek Energy Facility, respectively, or an after−tax loss of approximately $58.5 million and $41.2 million on the Goose Creek Energy Facility and the Raccoon Creek Energy Facility, respectively. We expect to receive an aggregate book tax benefit on the asset sales of approximately $59.8 million (tax calculation on the pre−tax loss of approximately $159.5 million), although there will be no immediate cash tax receivable on the asset sales due to our loss carryovers.

Everest Connections

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

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

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

Interest Allocation to Discontinued Operations

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

Canada

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

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

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

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

Independent Power Plants

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

Summary

We have reported the results of operations from these assets in discontinued operations for the three years ended December 31, 2005 in the Consolidated Statements of Income. The related assets and liabilities included in the sale of these businesses, as detailed below, have been reclassified as current and non−current assets and liabilities of discontinued operations on the December 31, 2005 and 2004 Consolidated Balance Sheets as follows:

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

Operating results of discontinued operations are as follows:

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

Note 7: Accounts Receivable

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

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

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

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

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

Note 8: Property, Plant and Equipment

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

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

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

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

Jointly Owned Electric Utility Plant

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

Allowance for Funds Used During Construction

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

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

Asset Retirement Obligations

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

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

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

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

We identified asbestos abatement costs associated with the closure of certain owned power plants and other structures as conditional asset retirement obligations. The ability to reasonable estimate when the obligation would occur was a matter of judgment, based upon our ability to estimate the dates and methods of asbestos abatement. We considered historical practices, industry practices, our management's intent and the estimated useful lives of our assets in determining settlement dates and methods. Based on our estimates, we measured the fair value of our obligations using the present value of future abatement costs discounted at our credit adjusted risk free borrowing rates.

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

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

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

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

Note 9: Investments in Unconsolidated Subsidiaries

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

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

Independent Power Plant Partnerships

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

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

Midlands Electricity plc

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

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

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

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

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

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

In millions		**Year Ended December 31, 2003**
Operating Results:		
Sales	$	623.3
Costs and expenses		543.2
Net income	$	80.1

United Energy Limited, Multinet Gas and AlintaGas Limited

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

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

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

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

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

In millions		**Seven Months Ended July 31, 2003**
Operating Results:		
Sales	$	157.3
Costs and expenses		126.4
Net income	$	30.9

Aries Power Project and Tolling Agreement

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

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

In millions	**Year Ended December 31, 2003**	
Operating Results:		
Sales	$	912.6
Costs and expenses		750.2
Net income	$	162.4

Note 10: Regulatory Assets

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

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

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

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

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

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

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

- Cost of removal represents the estimated cumulative net provision for future removal costs included in depreciation expense for which there is no legal removal obligation. See Note 8 for further discussion.

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

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

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

- Gas price derivatives represents the mark−to−market value of the portfolio of natural gas financial contracts that will settle against actual purchases of natural gas and purchased power in 2006 through 2008. In connection with the recently settled Missouri electric rate case, we agreed that these contracts would be recognized into cost of sales when they settle. A regulatory liability has been recorded under SFAS 71 to reflect the change in the timing of recognition authorized by the Missouri Commission.

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

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

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

Note 11: Short−Term Debt

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

364−Day Letter of Credit Facility

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

$180 Million Unsecured Revolving Credit and Letter of Credit Facility

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

Six−Month Secured Revolving Credit Facility

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

Four−Year Secured Revolving Credit Facility

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

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

$100 Million Secured Revolving Credit Facility

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

$50 Million Revolving Credit and Letter of Credit Facility

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

Note 12: Long−Term Debt

This table summarizes our long−term debt:

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

* *Weighted average interest rate.*

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

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

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

In millions		Maturing Amounts
2006	$	88.3
2007 *(a)*		42.0
2008		2.5
2009		421.5
2010		1.9
Thereafter		1,423.3
Total	$	1,979.5

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

Mandatorily Convertible Senior Notes

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

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

Senior Notes Rating Triggers

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

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

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

Three−Year Secured Term Loan

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

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

Five−Year Unsecured Term Loan and Revolving Credit Facility

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

(1) We are required to maintain a ratio of total debt to total capital (expressed as a percentage) of not more than 90% from December 31, 2005 through September 30, 2007; 75% from December 31, 2007 through September 30, 2008; 70% from December 31, 2008 through June 30, 2009; and 65% thereafter.

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

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

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

Iatan 2 Construction Financing

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

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

(2)
We must maintain a trailing 12−month ratio of EBITDA, as defined in the agreement, to interest expense of no less than 1.2 to 1.0 through September 30, 2006; 1.3 to 1.0 from October 1, 2006 through September 30, 2007; 1.4 to 1.0 from October 1, 2007 through September 30, 2008; 1.6 to 1.0 from October 1, 2008 through September 30, 2009; and 1.8 to 1.0 thereafter.

(3)
We must maintain a trailing 12−month ratio of debt outstanding to EBITDA of no more than 7.75 to 1.0 through September 30, 2006; 7.5 to 1.0 from October 1, 2006 through September 30, 2007; 6.0 to 1.0 from October 1, 2007 through September 30, 2008; 5.5 to 1.0 from October 1, 2008 through September 30, 2009; and 5.0 to 1.0 thereafter.

(4)
We must maintain a ratio of mortgaged property to extensions of credit (borrowings plus outstanding letters of credit) of no less than 2.0 to 1.0 as of the last day of each fiscal quarter.

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

Credit Ratings

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

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

Agency	Rating	Outlook
Moody's	B2	Positive Outlook
S&P	B−	Positive Outlook
Fitch	B−	Positive Outlook

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

Secured Financing

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

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

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

Note 13: Long−Term Gas Contracts

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

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

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

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

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

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

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

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

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

Note 14: Capital Stock and Stock Compensation

Capital Stock

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

Equity Offerings

In August 2004, we sold 46.0 million shares of our common stock to the public, including an over−allotment option of 6.0 million shares, which raised $112.3 million in net proceeds. We used the proceeds of this offering to retire long−term debt and reduce other long−term liabilities.

Suspension of Dividend

In November 2002, the Board of Directors suspended the annual dividend on common stock for an indefinite period. This decision followed a detailed analysis of the company's then current financial condition, its liquidity forecast and its earnings prospects after completion of certain asset sales. Currently four of our loan agreements and a regulatory order prohibit us from paying any dividends. We can make no determination as to whether or when we will pay dividends in the future.

Aquila Merchant Dissenters' Rights

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

Stockholder Rights Plan

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

Dividend Reinvestment and Common Stock Purchase Plan

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

Employee Stock Purchase Plan

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

Retirement Investment Plan

A defined contribution plan, the Retirement Investment Plan (Savings Plan), covers all of our full−time and eligible part−time employees. Participants may generally elect to contribute up to 50% of their annual pay on a before− or after−tax basis subject to certain limitations. The company generally matches contributions up to 6% of pay. Participants may direct their contributions into various investment options. Matching contributions are made in cash and invested as directed by the employee. Company contributions for continuing operations were

$6.6 million, $6.7 million and $6.5 million and for discontinued operations were $1.6 million, $1.7 million and $1.6 million during the years ended December 31, 2005, 2004, and 2003, respectively. The Savings Plan also includes a discretionary contribution fund to which the company historically contributed an additional 3% of base wages for eligible full−time employees. These contributions are made in cash and invested as directed by the employee. Vesting occurs ratably over five years of employment with distribution upon termination of employment. For 2005, 2004 and 2003, compensation expense for continuing operations of $3.7 million, $3.4 million and $4.1 million, respectively, and for discontinued operations of $1.0 million, $.9 million and $.8 million, respectively, was recognized. Any Aquila common shares that have been elected by the employee related to this program are classified as outstanding when calculating earnings per share.

Long−Term Incentive Plan

Our Long−Term Incentive Plan (LTIP) enables the company to reward key executives who have an ongoing company−wide impact. Eligible executives are awarded performance units based on experience and responsibilities in the company. Incentives earned are based on a comparison of our total shareholder return over three years to a specific group of companies with operations similar to ours. Incentives have been paid in cash, restricted stock, restricted stock units or deferred compensation agreements funding stock option grants based on the executives' total shareholdings of company common stock and their elections. No new grants have been provided to senior executive officers since the performance cycle beginning in 2002. We currently have only one outstanding grant to junior executives for the 2003 through 2005 performance cycle. Certain recipients of that outstanding grant have since become senior executive officers of our company, and those grants are reported in our 2006 proxy statement. Total compensation expense for the years ended December 31, 2005, 2004 and 2003, was $(.1) million, $.3 million and $.4 million, respectively.

Omnibus Incentive Compensation Plan

In 2002, the Board and our shareholders approved the Omnibus Incentive Compensation Plan. This plan authorizes the issuance of 9,000,000 shares of Aquila common stock as stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance units, stock awards, cash−based awards and annual incentive awards to all eligible employees and directors of the company. All equity−based awards are issued under this plan. Stock options under this plan and preceding plans have generally been granted at market prices with one to three year vesting terms and have been exercisable for seven to 10 years from the date of grant. In December 2004, we granted fully vested stock options for approximately 1.9 million shares to all employees other than senior executive officers of the company. These options are exercisable for seven years from the date of grant. As of December 31, 2005, we have approximately 5.0 million shares of common stock available for grant under this plan and preceding plans.

Summary of Stock Options

This table summarizes all stock option activity:

	Year Ended December 31,		
	2005	2004	2003
Shares:			
Beginning balance	9,638,099	8,558,048	8,908,508
Granted	30,000	1,900,760	408,300
Exercised	(308,763)	(472,591)	(85,577)
Cancelled	(2,813,729)	(348,118)	(673,183)
Ending balance	6,545,607	9,638,099	8,558,048
Weighted average prices:			
Beginning balance	$17.73	$20.22	$20.75
Granted price	3.44	3.75	1.44
Exercised price	2.28	4.06	3.04
Cancelled price	25.76	21.57	17.15
Ending balance	$14.92	$17.73	$20.22

This table summarizes all outstanding and exercisable stock options as of December 31, 2005:

	Outstanding Options			Exercisable Options	
Exercise Price Range	Number	Weighted Average Remaining Contractual Life in Years	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
$1.44−1.83	1,165,878	3.98	$ 1.78	1,091,178	$ 1.81
$3.44−3.75	1,797,410	6.00	3.74	1,797,410	3.74
$18.50−24.90	2,549,402	2.62	21.69	2,549,402	21.69
$28.42−39.52	1,032,917	5.23	32.51	1,032,917	32.51
Total	6,545,607			6,470,907	

In 2005, 183,823 shares of restricted stock were awarded to certain managers and executives as an incentive to retain their services through this transition time. These awards will vest two years after the award date. No restricted stock awards were granted during 2004 or 2003. As of December 31, 2005, we had 632,210 restricted stock awards outstanding.

Note 15: Accumulated Other Comprehensive Income (Loss)

The table below reflects the activity for accumulated other comprehensive income (loss) for 2003, 2004 and 2005:

In millions	Foreign Currency Adjustments	Cash Flow Hedges	Held for Sale Securities	Minimum Pension Liability	Accumulated Other Comprehensive Income (Loss)
Balance December 31, 2002	$ (17.5)	$ (18.0)	$ 7.3	$ (4.8)	$ (33.0)
2003 change	81.3	9.2	(7.3)	.4	83.6
Balance December 31, 2003	63.8	(8.8)	—	(4.4)	50.6
2004 change	(63.0)	8.8	—	4.4	(49.8)
Balance December 31, 2004	.8	—	—	—	.8
2005 Change	(.9)	—	—	—	(.9)
Balance December 31, 2005	$ (.1)	$ —	$ —	$ —	$ (.1)

Note 16: Earnings (Loss) Per Share

The table below shows how we calculated diluted earnings (loss) per share and diluted shares outstanding. Basic earnings (loss) per share and basic weighted average shares are the starting point in calculating the dilutive measures. To calculate basic earnings (loss) per share, divide earnings (loss) available for common shares by weighted average shares outstanding, without adjusting for dilutive items. Weighted average shares used in basic earnings per share includes 110.9 million shares issuable on the conversion of our PIES from August 24, 2004, the date of issuance of the PIES. On July 7, 2005, approximately 98.9% of the PIES units were converted to 131.4 million shares of common stock pursuant to an exchange offer. See Note 12 for further discussion. Diluted earnings (loss) per share is calculated by dividing earnings (loss) available for common shares, after assumed conversion of dilutive securities, by weighted average shares outstanding, adjusted for the effect of dilutive securities. As a result of the net losses in 2005, 2004 and 2003, the potential issuances of common stock were anti−dilutive and therefore not included in the calculation of diluted earnings (loss) per share.

In millions, except per share amounts	Year Ended December 31, 2005	2004	2003
Loss from continuing operations	$ (158.0)	$ (348.3)	$ (356.5)
Interest and debt amortization costs associated with the PIES	12.6	9.4	—
Loss available for common shares from continuing operations	(145.4)	(338.9)	(356.5)
Earnings (loss) from discontinued operations	(72.0)	55.8	20.1
Loss available for common shares	$ (217.4)	$ (283.1)	$ (336.4)

Basic and diluted earnings (loss) per share:			
Loss available for common shares from continuing operations	$ (.40)	$ (1.35)	$ (1.83)
Earnings (loss) from discontinued operations	(.20)	.22	.10
Net loss available for common shares	$ (.60)	$ (1.13)	$ (1.73)
Weighted average number of common shares used in basic and diluted earnings (loss) per share	363.30	251.35	194.75

Note 17. Income Taxes

Loss from continuing operations before income taxes consisted of:

In millions	Year Ended December 31,		
	2005	**2004**	**2003**
Domestic	$ (183.2)	$ (560.9)	$ (494.3)
Foreign	(17.9)	(1.7)	(9.2)
Total	$ (201.1)	$ (562.6)	$ (503.5)

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

In millions	Year Ended December 31,		
	2005	**2004**	**2003**
Current:			
Federal	$ —	$ —	$ (36.1)
Foreign	(2.6)	(.5)	2.5
State	—	—	(6.4)
Deferred:			
Federal	(20.7)	(168.9)	(116.0)
Foreign	(5.1)	—	(.6)
State	(3.7)	(29.9)	(20.6)
Change in valuation allowance	(53.2)	(8.1)	(51.0)
Change in reserve for contingent tax liabilities	43.5	(5.4)	82.9
Investment tax credit amortization	(1.3)	(1.5)	(1.7)
Income tax benefit from continuing operations	(43.1)	(214.3)	(147.0)
Income tax expense (benefit) from discontinued operations:			
Current	—	36.3	22.5
Deferred (net of valuation allowance of $(11.1) million and $11.1 million in 2004 and 2003, respectively)	(41.0)	19.1	(19.7)
Income tax expense (benefit) from discontinued operations	(41.0)	55.4	2.8
Total	$ (84.1)	$ (158.9)	$ (144.2)

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

In millions	December 31, 2005	December 31, 2004
Deferred Tax Assets:		
Alternative minimum tax credit carryforward	$ 103.6	$ 103.6
U.S. net operating loss carryforward	449.9	359.7
Mark−to−market losses	14.9	8.1
Accrued bonuses and deferred compensation	8.4	14.9
Allowance for doubtful accounts	8.0	11.6
Asset impairments	73.4	25.4
Realized capital loss carryforward for income tax purposes	225.7	275.4
Unrealized capital losses	11.3	17.4
Other	2.1	12.4
Less: reserve for contingent tax liabilities	(287.6)	(244.0)
Less: valuation allowance	(248.9)	(304.7)
Total deferred tax assets	360.8	279.8
Deferred Tax Liabilities and Credits:		
Accelerated depreciation and other plant differences:		
Regulated	306.2	301.0
Non−regulated	42.4	35.9
Currency translation adjustment	—	.5
Pension costs	29.7	38.2
Regulatory asset	54.0	52.2
Total deferred tax liabilities and credits	432.3	427.8
Deferred income taxes and credits, net	$ 71.5	$ 148.0

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

	Year Ended December 31, 2005	2004	2003
Statutory Federal Income Tax Rate	(35.0)%	(35.0)%	(35.0)%
Tax effect of:			
State income taxes, net of federal benefit	(1.7)	(3.8)	(3.4)
Change in valuation allowance	(26.4)	(1.5)	(10.1)
Reserve for contingent tax liabilities	21.6	(.8)	17.1
Non−deductible loss on PIES exchange	14.3	—	—
Non−deductible interest and amortization of PIES	2.2	.6	—
Other	3.6	2.4	2.2
Effective Income Tax Rate	(21.4)%	(38.1)%	(29.2)%

Tax Credits

At December 31, 2005 and 2004, we had alternative minimum tax credit carryforwards of $103.6 million. These credits do not expire and can be used to decrease future cash tax payments. In addition, at December 31, 2005 and 2004, we had general business tax credit carryforwards of

$6.7 million. The substantial majority of the general business credits expire in 2018, after which time they become a deduction against taxable income instead of a credit against tax. We did not record valuation allowances against the deferred tax asset related to the general business credits as we believe that more likely than not they will be utilized.

Capital Loss Carryforwards

As of December 31, 2005 and 2004, respectively, we had approximately $588.1 million and $716.3 million, respectively, of net realized capital loss carryforwards available for federal income tax purposes that expire in 2007 through 2010 and recognized impairment charges of $29.4 million and $45.1 million, respectively, that we expect to realize (for income tax purposes) as capital losses when the assets are sold. The tax benefit of these carryforwards and impairments is reflected on our balance sheets as of December 31, 2005 and 2004, as deferred tax assets of $237.0 million and $292.8 million, respectively. The decrease in capital loss carryforwards from 2004 to 2005 is primarily due to capital gains recognized on our 2004 tax return.

We have assessed the likelihood that all or a portion of the deferred tax assets relating to the remaining capital losses would not be realized. This assessment included consideration of positive and negative factors, including our current financial position and results of operations, projected future taxable income, including projected capital gains, and available tax planning strategies. As a result of such assessment, we determined that it was more likely than not that deferred tax assets relating to capital losses would not be realized. Therefore, we have established full valuation allowances of $237.0 million and $292.8 million, respectively, against these tax benefits as of December 31, 2005 and 2004, respectively. The decrease in tax expense in 2005 related to the reduction in the valuation allowances was substantially offset by an increase in 2005 in the reserve for contingent tax liabilities.

Net Operating Loss Carryforwards

As of December 31, 2005, we had approximately $454.5 million of federal net operating loss carryforwards originating in 2003, $579.0 million originating in 2004 and an estimated $85.9 million of originating in 2005. The 2003 federal net operating loss carryforward expires in 2023 and can be carried back to 2001 to offset potential IRS audit adjustments. The 2004 and 2005 federal net operating loss carryforwards expire in 2024 and 2025, respectively, and cannot be carried back due to losses in the carryback years. At December 2005 and 2004, we had recorded deferred tax benefits of $449.9 million and $359.7 million, respectively, related to our cumulative net operating loss carryforwards. Included in these amounts are deferred tax benefits of $58.1 million and $52.0 million, respectively, related to state net operating losses as of December 31, 2005 and 2004, respectively. The state net operating loss carryforwards expire in various years.

We did not record valuation allowances against the deferred tax assets related to the federal net operating losses as we believe it is more likely than not that sufficient taxable income to utilize these losses during the carryforward period will be generated from continuing operations, including the reversal of deferred tax liabilities on our regulated business plus income from the sale of assets. However, as of December 31, 2005 and 2004 we have recorded a valuation allowance related to state net operating losses of $11.9 million. During 2005, we recorded additional valuation allowance of $2.6 million related to state tax benefits from net operating losses and an adjustment for 2004 state income tax returns filed in 2005. We also wrote off $2.6 million of deferred tax assets and related valuation allowance because we no longer operate in certain states. This valuation allowance is necessary because we believe that it is more likely than not that we will not realize the deferred tax assets related to these state net operating losses during the applicable carryforward periods. This assessment considered the decline in future business activity in certain states and the taxable income we expect to generate in the applicable state carryforward periods.

Reserve for Contingent Tax Liabilities

As of December 31, 2005 and 2004, we have recorded liabilities of $287.6 million and $244.0 million, respectively, of cumulative tax provisions for tax deduction or income positions taken in prior tax returns that we believe were properly treated on such tax returns but for which it is reasonably likely that these deductions or income positions will be challenged when the returns are audited. The tax returns containing these tax deductions or income positions are currently under audit or will likely be audited. The reserve is included in deferred taxes because the timing of the resolution of these audits is uncertain and if the positions taken on the tax returns are not ultimately sustained, we may be required to make cash payments plus interest and/or utilize our net operating loss carryforwards, alternative minimum tax credit carryforwards, and/or general business credit carryforwards.

Loss on PIES Exchange

As discussed in Note 12, we recorded a pretax loss of $82.3 million in 2005 on the early conversion of the PIES. In addition, in 2005 and 2004 we recorded interest and amortization of debt issue costs on our PIES of $12.6 million and $9.4 million, respectively. No tax benefits were recorded as these costs were not deductible for income tax purposes.

Note 18: Employee Benefits

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

In February 2005, we amended our pension and other post−retirement benefit plans to bring our benefits into line with our regulated utility peers. The effect of these amendments on our projected (pension) benefit obligation and accumulated post−retirement benefit obligation was an increase of $40.9 million and $24.8 million, respectively, as of our most recent measurement date, September 30, 2005. This unrecognized prior service cost is recognized prospectively as a component of net periodic benefit cost, amortized on a straight−line basis over the average future service of active plan participants.

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

The following table shows the funded status of our pension and post−retirement benefit plans and the amounts included in the Consolidated Balance Sheets and Consolidated Statements of Income. For measurement purposes, projected benefit obligations and the fair value of plan assets were determined as of September 30, 2005 and 2004.

	Pension Benefits		**Other Post−retirement Benefits**	
Dollars in millions	**2005**	**2004**	**2005**	**2004**
Change in Projected Benefit Obligation:				
Benefit obligation at start of year	$ 337.6	$ 330.4	$ 68.2	$ 81.1
Service cost	8.9	7.8	.6	.2
Interest cost	22.0	19.4	5.0	4.7
Plan participants' contribution	—	—	2.2	2.3
Amendments	40.9	—	24.8	—
Actuarial (gain) loss	15.1	(4.7)	(7.8)	(12.3)
Benefits paid	(15.6)	(15.3)	(7.6)	(7.8)
Projected benefit obligation at end of year	$ 408.9	$ 337.6	$ 85.4	$ 68.2
Change in Plan Assets:				
Fair value of plan assets at start of year	$ 313.6	$ 288.4	$ 13.9	$ 14.3
Actual return on plan assets	46.6	39.7	.6	.2
Employer contribution	8.8	.8	4.0	4.9
Plan participants' contribution	—	—	2.2	2.3
Benefits paid	(15.6)	(15.3)	(7.6)	(7.8)
Fair value of plan assets at end of year	$ 353.4	$ 313.6	$ 13.1	$ 13.9
Funded status:				
Funded status	$ (55.5)	$ (24.0)	$ (72.3)	$ (54.3)
4th quarter employer contribution	.2	—	7.0	—
Unrecognized transition amount	(.6)	(1.5)	10.8	12.4
Unrecognized net actuarial loss	82.7	90.9	6.9	14.8
Unrecognized prior service cost	48.7	12.0	26.0	3.3
Accumulated regulatory gain/loss adjustment	7.3	10.6	(2.0)	(1.0)
Net amount recognized before SFAS 71 regulatory liability	82.8	88.0	(23.6)	(24.8)
SFAS 71 regulatory liability	(10.5)	(6.6)	—	—
Net amount recognized	$ 72.3	$ 81.4	$ (23.6)	$ (24.8)
Amounts Recognized in the Consolidated Balance Sheets:				
Prepaid benefit cost	$ 94.8	$ 98.7	$ —	$ —
Accrued benefit liability	(19.5)	(18.1)	(23.6)	(24.8)
SFAS 71 regulatory liability	(10.5)	(6.6)	—	—
Intangible asset	7.5	7.4	—	—
Net amount recognized	$ 72.3	$ 81.4	$ (23.6)	$ (24.8)
Reconciliation of Net Amount Recognized:				
Net amount recognized at start of year	$ 81.4	$ 96.4	$ (24.8)	$ (21.0)
Net periodic benefit cost before curtailments and regulatory expense adjustments	(10.8)	(11.3)	(8.8)	(7.8)
Contributions	9.0	.8	11.0	4.9
Regulatory gain/loss adjustment	(3.4)	(.2)	(1.0)	(.9)
SFAS 71 regulatory adjustment	(3.9)	(4.3)	—	—
Net amount recognized at end of year	$ 72.3	$ 81.4	$ (23.6)	$ (24.8)
Weighted Average Assumptions as of September 30:				
Discount rate for expense	6.00%	6.00%	6.00%	6.00%
Discount rate for disclosure	5.80%	6.00%	5.53%	6.00%
Expected return on plan assets for expense	8.50%	8.50%	7.00%	7.00%
Expected return on plan assets for disclosure	8.50%	8.50%	7.00%	7.00%
Rate of compensation increase	4.40%	4.40%	n/a	n/a

For measurement purposes, to calculate the annual rate of increase in the per capita cost of covered health benefits for each future fiscal year, we used a graded rate for non−prescription drug medical costs starting at 11% in 2006 and decreasing 1% annually until the rate levels out at 5% for years 2012 and thereafter. For prescription drug costs, we used a graded rate starting at 13% in 2006 and decreasing 1% annually until the rate levels out at 5% for years 2014 and thereafter.

	Pension Benefits			**Other Post−retirement Benefits**		
In millions	**2005**	**2004**	**2003**	**2005**	**2004**	**2003**
Components of Net Periodic Benefit Cost:						
Service cost	$ 8.9	$ 7.8	$ 8.0	$ .6	$ .2	$ .3
Interest cost	22.0	19.4	19.2	5.0	4.7	4.8
Expected return on plan assets	(27.6)	(23.9)	(22.9)	(1.0)	(1.0)	(1.2)
Amortization of transition amount	(.8)	(1.2)	(1.2)	1.5	1.5	1.6
Amortization of prior service cost	4.2	1.1	1.1	2.2	.7	.7
Recognized net actuarial (gain) loss	4.1	8.1	10.3	.5	1.7	1.2
Net periodic benefit cost before curtailments and regulatory expense adjustments	10.8	11.3	14.5	8.8	7.8	7.4
Curtailment (gain) loss	—	—	.3	—	—	(.2)
Regulatory gain/loss adjustment	3.4	.2	(3.5)	1.0	.9	.1
SFAS 71 regulatory adjustment	3.9	4.3	2.3	—	—	—
Net periodic benefit cost after curtailments and regulatory expense adjustments	$ 18.1	$ 15.8	$ 13.6	$ 9.8	$ 8.7	$ 7.3

In a 2004 settlement with the Missouri Commission, we agreed to recover our Missouri−related pension funding at an agreed−upon annual amount for ratemaking purposes. As ordered by the Missouri Commission, the difference between the agreed−upon expense for ratemaking purposes and the amount determined under SFAS 87, "Employers' Accounting for Pensions," will be recognized as a regulatory asset or liability in accordance with SFAS 71.

Previously, the Missouri Commission ordered the recognition of actuarial gains/losses for our Missouri−related pension and post−retirement benefit plans to follow an alternative method to the prescribed "corridor" method outlined in SFAS 87 and SFAS 106, "Employers' Accounting for Postretirement Benefits Other Than Pension." The difference between the "Missouri" method and the "corridor" method is noted as regulatory gain/loss adjustment or accumulated regulatory gain/loss adjustment in the preceding tables.

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

In millions	2005	2004
Projected Benefit Obligations in Excess of Plan Assets:		
Fair value of plan assets at end of year	$ 353.4	$ 313.6
Projected benefit obligation at end of year	408.9	337.6
Funded status	$ (55.5)	$ (24.0)
Accumulated Benefit Obligations in Excess of Plan Assets:		
Fair value of plan assets at end of year	$ —	$ —
Accumulated benefit obligation at end of year	19.5	18.1
Funded status *(a)*	$ (19.5)	$ (18.1)

(a) *The SERP is reflected as an unfunded accumulated benefit obligation as plan assets are not netted against the obligations for non−qualified plans. We have segregated approximately $4.2 million of assets for the SERP as of December 31, 2005. We expect to fund estimated future benefit payments from these assets and company contributions as needed.*

The accumulated benefit obligation for all our defined benefit pension plans was $361.7 million and $311.2 million at September 30, 2005, and 2004, respectively.

We engaged benefit plan consultants to assist in the development of a statement of pension plan investment objectives and to perform a study modeling expectations of future returns of numerous portfolios using historic rates of return. The rate of return assumption we used was a result of selecting the model portfolio from the study that best fit our pension plan long−term investment objectives.

Pension Plan Investment Objectives

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

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

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

Our qualified pension plan weighted−average asset allocations by asset category at September 30, 2005 and 2004, along with the long−term targets and target ranges, are as follows:

	Plan Assets at September 30,		Plan Asset Allocation Targets	
	2005	**2004**	**Long−Term**	**Range**
Asset Category:				
Core fixed income	19.8%	14.6%	21.0%	5.0−25.0%
High yield bonds	9.5	8.2	10.0	6.0−10.0
Large cap equities	28.0	32.2	28.5	27.0−37.0
Mid cap equities	10.2	9.9	10.0	8.0−12.0
Small cap equities	3.4	10.2	3.5	0.0−12.0
International equities	14.3	13.0	14.5	10.0−15.0
Emerging markets equities	2.6	2.7	2.5	0.0−5.0
Real estate	8.5	7.8	7.5	5.0−10.0
Private equity	.7	1.3	2.5	0.0−5.0
Cash	3.0	.1	—	—
Total	100.0%	100.0%	100.0%	100.0%

Our other post−retirement benefit plan assets at December 31, 2005 and 2004 were 100% invested in short−term debt instruments and cash equivalents.

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

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

Dollars in millions	**Change in Assumption Incr.(decr.)**	**Impact on PBO Incr.(decr.)**	**Impact on APC Incr.(decr.)**
Discount rate	.25%	$ (13.7)	$ (1.4)
Rate of return on plan assets	.25%	−	(.9)

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

Our health care plans are contributory, with participants' contributions adjusted annually. The life insurance plans are generally non−contributory. In estimating future health care costs, we have assumed future cost−sharing changes. The assumed health care cost trends significantly affect the amounts reported for the health care plans. A one−percentage−point change in assumed health care cost trend rates would have the following effects for 2006.

	1 Percentage−Point	
In millions	**Increase**	**Decrease**
Effect on total of service and interest cost components	$ .3	$ (.3)
Effect on post−retirement benefit obligation	5.1	(4.5)

Based on actuarial projections, we expect to contribute $.8 million and $9.4 million to our defined benefit pension plans and other post−retirement benefit plans, respectively, in 2006. No discretionary contributions are planned in 2006.

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

In millions	**Pension Benefits**	**Other Post−retirement Benefits**	**Medicare Drug Subsidy**
Estimated Future Benefit Payments:			
2006	$ 17.0	$ 7.0	$ (.9)
2007	18.1	7.7	(.9)
2008	19.2	8.1	(1.0)
2009	20.6	8.4	(1.1)
2010	22.2	8.6	(1.1)
2011−2015	134.9	42.8	(5.6)

As disclosed in Note 6, the four utility operations being held for sale have been reclassified as discontinued operations. The preceding employee benefits footnote information, including the various tables, has been presented for these plans in total. As of and for the year ended

December 31, 2005, select pension and other post−retirement benefit plan information related to discontinued operations is summarized below.

In millions	Pension Benefits	Other Post−retirement Benefits
Discontinued Operations		
Accumulated benefit obligation at end of year	$ 85.4	$ 31.9
Projected benefit obligation at end of year	96.6	31.9
Net asset (liability) amount recognized in the balance sheet at end of year	25.9	(5.5)
Net periodic benefit cost	3.7	3.3
Estimated future benefit payments for 2006	4.6	2.2

Note 19: Segment Information

We have restated our financial reporting segments to reflect the significant changes in our business over the last three years, including the continuing wind−down of our wholesale energy trading operations and the sale of our merchant loan portfolio, our natural gas pipeline, gathering and storage assets, our investments in international utility networks and our investment in Quanta Services, Inc. We now manage our business in three business segments: Electric Utilities, Gas Utilities and Merchant Services. Our Electric and Gas Utilities consist of our regulated electric utility operations in three states and our natural gas utility operations in seven states. We manage our electric and gas utility divisions by state. However, as each of our electric utility divisions and each of our gas utility divisions have similar economic characteristics, we aggregate our three electric utility divisions into the Electric Utilities reporting segment and our seven gas utility divisions into the Gas Utilities reporting segment. The operating results of our Kansas electric division and our Michigan, Minnesota, and Missouri gas divisions, which are in the process of being sold, have been reclassified to discontinued operations. Merchant Services includes our remaining investments in merchant power plants, our commitments under merchant capacity tolling obligations and long−term gas contracts and the remaining contracts from our wholesale energy trading operations. The operating results of our two Illinois merchant power plants, which are in the process of being sold, and two consolidated independent power plants, which were sold in 2004, have been reclassified to discontinued operations. All other operations are included in Corporate and Other, including the costs not allocated to our operating businesses and costs of our investment in Everest Connections and our former investments in Canada, Australia and the United Kingdom. The operating results of Everest Connections, which is currently held for sale, and our former Canadian utility businesses, which were sold in 2004, have been reclassified to discontinued operations.

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

Business Lines

In millions	Year Ended December 31,		
	2005	**2004**	**2003**
Sales: *(a)*			
Utilities:			
Electric Utilities	$ 684.7	$ 594.9	$ 545.1
Gas Utilities	631.1	529.0	506.2
Total Utilities	1,315.8	1,123.9	1,051.3
Merchant Services	(1.6)	(152.9)	(70.1)
Corporate and Other	—	—	1.9
Total	$ 1,314.2	$ 971.0	$ 983.1

(a) *For the years ended December 31, 2005, 2004 and 2003, respectively, the following (in millions) have been reclassified to discontinued operations and are not included in the above amounts: Electric Utilities sales of $191.0, $165.4 and $153.6; Gas Utilities sales of $625.8, $536.3 and $506.9; Merchant Services sales of $17.0, $8.0 and $73.7; and Corporate and Other sales related to our former Canadian utility businesses and Everest Connections of $46.0, $161.2 and $279.1.*

In millions	Year Ended December 31,		
	2005	**2004**	**2003**
Earnings (Loss) Before Interest, Taxes, Depreciation and Amortization (EBITDA): *(a)(b)*			
Utilities:			
Electric Utilities	$ 147.7	$ 130.3	$ 128.0
Gas Utilities	33.6	34.9	46.8
Total Utilities	181.3	165.2	174.8
Merchant Services	(22.6)	(416.7)	(378.4)
Corporate and Other	(103.2)	(23.8)	19.0
Total EBITDA	55.5	(275.3)	(184.6)
Depreciation and amortization	106.4	102.8	120.1
Interest expense	150.2	184.5	198.8
Loss from continuing operations before income taxes	$ (201.1)	$ (562.6)	$ (503.5)

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

(b) *For the years ended December 31, 2005, 2004 and 2003, respectively, the following (in millions) have been reclassified to discontinued operations and are not included in the above amounts: Electric Utilities EBITDA of $47.9, $31.4 and $32.6; Gas Utilities EBITDA of $96.9, $88.9 and $96.9; Merchant Services EBITDA of $(156.1), $2.4 and $(34.9); and Corporate and Other EBITDA relating to our former Canadian utility businesses and Everest Connections of $12.0, $124.6 and $79.8.*

In millions	Year Ended December 31, 2005	2004	2003
Depreciation and Amortization Expense: *(a)*			
Utilities:			
Electric Utilities	$ 64.0	$ 60.1	$ 62.0
Gas Utilities	35.8	35.0	35.0
Total Utilities	99.8	95.1	97.0
Merchant Services	6.3	7.3	24.3
Corporate and Other	.3	.4	(1.2)
Total	$ 106.4	$ 102.8	$ 120.1

(a) *For the years ended December 31, 2005, 2004 and 2003, respectively, the following depreciation and amortization expense (in millions) have been reclassified to discontinued operations and are not included in the above amounts: Electric Utilities $9.7, $11.4 and $11.1; Gas Utilities $16.1, $19.9 and $21.1; Merchant Services $9.2, $10.1 and $8.0; and Corporate and Other relating to our former Canadian utility businesses and Everest Connections $7.5, $6.1 and $13.0.*

In millions	December 31, 2005	2004
Identifiable Assets: *(a)(b)*		
Utilities:		
Electric Utilities	$ 2,073.8	$ 1,862.3
Gas Utilities	1,421.9	1,353.4
Total Utilities	3,495.7	3,215.7
Merchant Services	918.6	1,080.6
Corporate and other	216.4	481.0
Total	$ 4,630.7	$ 4,777.3

(a) *Included in identifiable assets for each segment as of December 31, 2005 and 2004, respectively, are investments in unconsolidated subsidiaries as follows (in millions): Gas Utilities, $.1 and $.1; and Corporate and Other, $.6 and $1.4.*

(b) *Included in identifiable assets as of December 31, 2005 and 2004, are current and non−current assets of discontinued operations as follows (in millions): Electric Utilities, $273.6 and $250.5; Gas Utilities, $657.3 and $598.8; Merchant Services, $175.0 and $341.3; and Corporate and Other related to Everest Connections, $61.0 and $58.6.*

In millions	Year Ended December 31, 2005	2004	2003
Capital Expenditures: *(a)*			
Utilities:			
Electric Utilities	$ 175.5	$ 96.3	$ 79.2
Gas Utilities	53.4	50.3	46.3
Total Utilities	228.9	146.6	125.5
Merchant Services	—	—	20.5
Corporate and other	18.9	95.3	140.5
Total	$ 247.8	$ 241.9	$ 286.5

(a) *Included in the years ended December 31, 2005, 2004 and 2003, respectively, are capital expenditures of discontinued operations as follows (in millions): Electric Utilities, $24.3, $15.5 and $11.6; Gas Utilities, $22.6, $22.2 and $20.4; Merchant Services, $−, $− and $26.9 and Corporate and Other relating to our former Canadian utility businesses and Everest Connections, $11.4, $86.8 and $133.9.*

Geographical Information

In millions	Year Ended December 31, 2005	2004	2003
Sales: *(a)*			
United States	$ 1,304.4	$ 971.0	$ 1,005.1
Canada	.3	1.3	7.0
Other international	9.5	(1.3)	(29.0)
Total	$ 1,314.2	$ 971.0	$ 983.1

(a) *For the years ended December 31, 2005, 2004 and 2003, respectively, the following (in millions) sales have been reclassified to discontinued operations and are not included in the above amounts: United States sales of $879.8, $748.0, and $764.5; Canadian sales of $−, $122.9, and $248.8.*

We had no material long−lived assets, including property, plant and equipment, net, or investments in unconsolidated subsidiaries outside of the United States as of December 31, 2005 or 2004.

Note 20: Commitments and Contingencies

Capital Expenditures

We have made certain construction commitments in connection with our 2006 capital expenditure plan. During 2006, we estimate that our total capital expenditures will be approximately $217.7 million, plus approximately $22.0 million for discontinued operations.

Commitments

We have various commitments of our continuing and discontinued operations relating to power, gas and coal supply commitments and lease commitments as summarized below.

In millions	2006	2007	2008	2009	2010	Thereafter	Total
Future minimum payments Continuing Operations—							
Facilities and equipment	$ 11.4	$ 9.6	$ 8.9	$ 6.7	$ 5.2	$ 15.1	$ 56.9
Other services	1.2	1.1	.9	—	—	—	3.2
Elwood tolling contracts	37.3	37.3	37.3	37.4	37.4	230.3	417.0
Merchant gas transportation obligations	8.5	5.5	5.4	5.4	5.4	18.1	48.3
Regulated business purchase obligations:							
Purchased power obligations	101.8	101.7	104.1	106.7	109.3	150.5	674.1
Purchased gas obligations	56.2	31.0	23.9	21.0	20.0	63.3	215.4
Coal and rail contracts	93.2	82.0	50.7	25.4	26.3	141.2	418.8
Future minimum payments Discontinued Operations—							
Facilities and equipment	3.0	2.3	1.6	1.3	.9	4.9	14.0
Jeffrey Energy Center lease	10.6	10.6	12.1	12.9	12.9	58.0	117.1
Regulated business purchase obligations:							
Purchased power obligations	17.7	19.8	19.7	11.7	3.5	7.0	79.4
Purchased gas obligations	37.9	30.0	25.6	16.8	14.0	91.1	215.4
Coal and rail contracts	17.9	18.6	19.2	19.9	20.6	140.4	236.6

Operating Lease Obligations

Future minimum payments include operating leases of coal rail cars, vehicles and office space over terms of up to 20 years. Rent expense for continuing operations for the years 2005, 2004 and 2003 was (in millions), $10.9, $13.1 and $18.9, respectively, and for discontinued operations was $3.4, $6.5 and $20.1, respectively.

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

Elwood tolling contracts

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

Merchant gas transportation obligations

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

Regulated business purchase obligations

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

Contingent Obligations

Guarantees

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

We have entered into various agreements that require letters of credit for financial assurance purposes. These letters of credit are available to fund the payment of such obligations. At December 31, 2005, we had $196.6 million of letters of credit outstanding with expiration dates generally ranging from one month to 24 months.

In the normal course of business, we guarantee certain payment obligations of our wholly−owned subsidiaries.

Equity Put Rights

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

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

Legal

Price Reporting Litigation

On August 18, 2003, Cornerstone Propane Partners filed suit in the Southern District of New York against 35 companies, including Aquila, alleging that the companies manipulated natural gas prices and futures prices on NYMEX through misreporting of natural gas trade data in the physical market. The suit does not specify alleged damages and was filed on behalf of all parties who bought and sold natural gas futures and options on NYMEX from 2000 to 2002. On September 24, 2004, the court denied Aquila Merchant's motion to dismiss along with similar motions filed by most of the other defendants. Fact discovery closed on December 23, 2005, and the parties have now begun the expert discovery phase of the action. We will defend this case vigorously as we believe we have strong defenses to the plaintiff's claims. We cannot predict with certainty whether we will incur any liability, nor can we estimate the damages, if any, that might be incurred in connection with this lawsuit. However, given the nature of the claims, an adverse outcome could have a material adverse effect on our financial condition, results of operations and cash flows.

On June 7, 2004, the City of Tacoma, Washington, filed suit against 56 companies, including Aquila Merchant, for allegedly conspiring to manipulate the California power market in 2000 and 2001 in violation of the Sherman Act. This case was dismissed in February 2005. The City of Tacoma has appealed to the Ninth Circuit Court of Appeals.

On July 8, 2004, the County of Santa Clara and the City and County of San Francisco each filed suit against seven energy trading companies and their subsidiaries and affiliates, including Aquila and Aquila Merchant, in the Superior Court of California for San Diego County alleging manipulation of the California natural gas market in 1999 through 2002. Since that date, 14 other complaints making nearly identical allegations have been filed against Aquila and Aquila Merchant in California state courts. These lawsuits allege violations of the Cartwright Act and in some cases California's Unfair Competition Law, and also assert an unjust enrichment claim. The lawsuits have been coordinated before a single Motion Coordination Judge in the Superior Court of California for the County of San Diego, in the proceeding entitled *In re Natural Gas Antitrust Cases I, II, III & IV*. We believe we have strong defenses and will defend these cases vigorously. We cannot predict with certainty whether we will incur any liability, nor can we estimate the damages, if any, that might be incurred in connection with these lawsuits. However, given the nature of the claims, an adverse outcome could have a material adverse effect on our financial condition, results of operations and cash flows.

Aquila Merchant is also a defendant in two federal actions that were filed on November 30, 2004 and October 31, 2005 in the United States District Court for the Eastern District of California. These cases were transferred by the Judicial Panel on Multidistrict Litigation to the United States District Court for the District of Nevada on January 21, 2005 and September 1, 2005, respectively. The action originally filed on November 30, 2004 was subsequently consolidated with two other actions. All of these lawsuits are now part of the proceeding known as *In re Western States Wholesale Natural Gas Antitrust Litigation*, MDL Docket No. 1566, and make allegations similar to those made in the *In re Natural Gas Antitrust Cases I, II, III & IV*. The plaintiffs in the November 2004 action allege violations of the Sherman Act, the Cartwright Act, California's Unfair Competition Law, unjust enrichment, and constructive trust, whereas the plaintiffs in the October 2005 action allege only violations of the Sherman Act. The action originally filed on November 30, 2004 has been dismissed, and the plaintiffs have appealed the dismissal to the Ninth Circuit Court of Appeals. We believe we have strong defenses and will defend these cases vigorously. We cannot predict with certainty whether we will incur any liability, nor can we estimate the damages, if any, that might be incurred in connection with these lawsuits. However, given the nature of the claims, an adverse outcome could have a material adverse effect on our financial condition, results of operations and cash flows.

In connection with our continuing evaluation of the above claims, we determined that the ultimate resolution of such claims would likely result in an obligation of at least $9.0 million. In December 2005, we provided a liability at that amount. The timing and amount of the ultimate resolution of these claims remains uncertain and could exceed that reserve by a material amount.

On February 22, 2005, Utility Choice and Cirro Group filed suit against three major Texas utilities and retail electricity providers, including Aquila Merchant, for allegedly conspiring to manipulate the Texas power market in 2000 and 2001 in violation of the Sherman Act. The parties reached an out−of−court settlement on November 16, 2005 for $175,000, and the case was dismissed with prejudice on November 18, 2005.

Lender Litigation

On October 5, 2004 and October 15, 2004, lawsuits were filed against us by our lenders alleging that we were obligated to pay a "make whole" amount when we prepaid the $430 million three−year secured term loan in September 2004. We believe that our termination of the term loan required us to pay a prepayment penalty of $8.7 million. The plaintiff lenders sued us for breach of contract for their proportionate share of the difference between their prepayment calculation and the $8.7 million. In May 2005, our motions for summary judgment in these lawsuits were granted and $20.6 million of restricted cash that we had deposited into an escrow account, which equaled the amount in dispute, was returned to us. Certain of the plaintiffs representing a claim of approximately $6.0 million have appealed the dismissal of these cases. On February 22, 2006, the Second Circuit Court of Appeals affirmed an order by the District Court for the Southern District of New York, dismissing the claims of plaintiffs representing a claim of approximately $2.3 million. We believe we have strong defenses and will defend these cases vigorously. We cannot predict with certainty whether we will incur any liability in connection with this lawsuit.

ERISA Litigation

On September 24, 2004, a lawsuit was filed in the U.S. District Court for the Western District of Missouri against us and certain members of our Board of Directors and management, alleging they violated the Employee Retirement Income Security Act of 1974, as amended (ERISA) and are responsible for losses that participants in the our 401(k) plan experienced as a result of the decline in the value of their Aquila common stock held in the 401(k) plan. A number of similar lawsuits alleging that the defendants breached their fiduciary duties to the plan participants in violation of ERISA by concealing information and/or misleading employees who held our common stock through our 401(k) plan were subsequently filed against us. The suits also seek damages for the plan's losses resulting from the alleged breaches of fiduciary duties. On January 26, 2005, the court ordered that all of these lawsuits be consolidated into a single case captioned *In re Aquila ERISA Litigation.* The plaintiffs filed an amended consolidated complaint in March 2005, which largely repeats each of the allegations in the first complaint. This case has been set for trial in July 2007. We believe we have strong defenses and will defend this case vigorously. We cannot predict with certainty whether we will incur any liability, nor can we estimate the damages, if any, that might be incurred in connection with this lawsuit. However, given the nature of the claims, an adverse outcome could have a material adverse effect on our financial condition, results of operations and cash flows.

South Harper Peaking Facility

We have constructed a 315 MW natural gas "peaking" power plant and related substation in an unincorporated area of Cass County, Missouri. Cass County and local residents filed suit claiming that county zoning approval was required to construct the project. In January 2005, a trial court judge granted the County's request for an injunction; however, we were permitted to continue construction while the order was appealed. We appealed the trial court decision to the Missouri Court of Appeals for the Western District of Missouri and, on June 21, 2005, the appellate court affirmed the circuit court ruling. In July 2005, we requested that the Court of

Appeals either rehear the case or transfer the case to the Missouri Supreme Court and, in October 2005, the Court of Appeals granted our request for rehearing.

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

Environmental

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

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

The EPA finalized CAIR and CAMR regulations in 2005 that would affect our coal−fired power plants by requiring reductions in emissions of sulfur dioxide, nitrogen oxide and mercury. We initiated engineering studies to evaluate the costs and likely controls for compliance with CAIR and CAMR in 2005. For continuing operations, we estimate that probable capital expenditures will be approximately $159 million and reasonably possible expenditures could be $293 million to comply with the regulations. We estimate the capital expenditures for 2006 to be approximately $7 million. If our Kansas electric utility is not sold, our estimated probable capital expenditures would be approximately $187 million and reasonably possible expenditures could be $322 million. We believe these costs would likely be allowed for recovery in future rate cases.

Note 21: Quarterly Financial Data (Unaudited)

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

In millions, except per share amounts	**2005 Quarters**				**2004 Quarters**			
	First	**Second**	**Third**	**Fourth**	**First**	**Second**	**Third**	**Fourth**
Sales	$ 352.9	$ 262.7	$ 300.9	$ 397.7	$ 282.7	$ 207.1	$ 209.2	$ 272.0
Gross profit	97.7	105.6	149.7	97.5	44.0	62.1	77.4	66.3
Loss from continuing operations	(13.2)	(23.6)	(80.0)	(41.2)	(94.3)	(60.8)	(110.4)	(82.8)
Earnings (loss) from discontinued operations	13.9	(3.6)	4.3	(86.6)	42.5	17.5	(6.0)	1.8
Net income (loss)	$ .7	$ (27.2)	$ (75.7)	$ (127.8)	$ (51.8)	$ (43.3)	$ (116.4)	$ (81.0)
Basic and diluted earnings (loss) per common share: *(a)*								
From continuing operations	$ (.02)	$ (.05)	$ (.21)	$ (.11)	$ (.48)	$ (.31)	$ (.42)	$ (.22)
From discontinued operations	.04	(.01)	.01	(.23)	.22	.09	(.02)	.01
Net income (loss)	$ .02	$ (.06)	$ (.20)	$ (.34)	$ (.26)	$ (.22)	$ (.44)	$ (.21)

(a) *The sum of the quarterly earnings per share amounts may differ from that reflected in Note 16 due to the weighting of common shares outstanding during each of the respective periods.*

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Aquila, Inc.:

We have audited the accompanying consolidated balance sheets of Aquila, Inc. and subsidiaries as of December 31, 2005 and 2004, and the related consolidated statements of income, common shareholders' equity, comprehensive income, and cash flows for each of the years in the three−year period ended December 31, 2005. In connection with our audits of the consolidated financial statements, we also have audited the financial statement schedule, "Schedule II—Valuation and Qualifying Accounts," for each of the years in the three−year period ended December 31, 2005. These consolidated financial statements and the financial statement schedule are the responsibility of the company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Aquila, Inc. and subsidiaries as of December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the years in the three−year period ended December 31, 2005 in conformity with United States generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Aquila, Inc.'s internal control over financial reporting as of December 31, 2005 based on criteria established in *Internal Control—Integrated Framework,* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 3, 2006 expressed an unqualified opinion on management's assessment of, and the effective operation of, internal control over financial reporting.

/s/ KPMG LLP
Kansas City, Missouri

March 3, 2006

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Aquila, Inc.:

We have audited management's assessment, included in the Management's Report on Internal Control Over Financial Reporting appearing under Item 9A, that Aquila, Inc. (the Company) maintained effective internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control—Integrated Framework,* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Aquila, Inc.'s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that Aquila, Inc. maintained effective internal control over financial reporting as of December 31, 2005 is fairly stated, in all material respects, based on criteria established in *Internal Control—Integrated Framework,* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Also, in our opinion, Aquila, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005 based on criteria established in *Internal Control—Integrated Framework,* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Aquila, Inc. and subsidiaries as of December 31, 2005 and 2004, and the related consolidated statements of income, common shareholders' equity, comprehensive income, and cash flows for each of the years in the three−year period ended December 31, 2005, and our report dated March 3, 2006 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP
Kansas City, Missouri

March 3, 2006

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

Not Applicable.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

Our Chief Executive Officer (CEO) and Chief Financial Officer (CFO) are responsible for establishing and maintaining the company's disclosure controls and procedures. These controls and procedures were designed to ensure that material information relating to the company and its subsidiaries are communicated to the CEO and the CFO. We evaluated these disclosure controls and procedures as of the end of the period covered by this report under the supervision of our CEO and CFO. Based on this evaluation, our CEO and CFO concluded that our disclosure controls and procedures are effective in timely alerting them to material information required to be included in our periodic reports filed with the SEC. There has been no change in our internal controls over financial reporting during the period covered by this report that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a−15(f). Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under the framework in *Internal Control—Integrated Framework*, our management concluded that our internal control over financial reporting was effective as of December 31, 2005.

Our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2005, has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their report which is included herein.

Item 9B. Other Information

Not Applicable.

Part III

Items 10, 11, 12 and 13. Directors and Executive Officers of the Company, Executive Compensation, Security Ownership of Certain Beneficial Owners and Management, and Certain Relationships and Related Transactions

Information regarding these items appears in our proxy statement and is hereby incorporated by reference in this Annual Report on Form 10−K. For information regarding our executive officers, see "Our Executive Team" in Part I, Item 1 of this Form 10−K.

Equity Compensation Plan Information

The following table provides information as of December 31, 2005 about our compensation plans under which shares of stock have been authorized.

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights *(a)*	Weighted−average exercise price of outstanding options, warrants and rights *(b)*	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column *(a)*) *(c)*
Equity compensation plans approved by security holders *	6,333,518	$ 14.62	4,988,400 **
Equity compensation plans not approved by security holders	212,089 ***	$ 24.02	—
Total	6,545,607		4,988,400

* *Includes 661,292 options issued upon conversion of Merchant Services options in connection with our acquisition of the minority interest in Merchant Services. These options have a weighted average price of $34.81 per share.*

** *These shares are available for issuance under our 2002 Omnibus Incentive Compensation Plan. Awards may be in the form of stock options, restricted stock awards, stock appreciation rights, stock awards or other forms of equity based compensation.*

*** *Options issued under a broad−based employee stock option plan that has since been terminated.*

Item 14. Principal Accountant Fees and Services

Information regarding this item appears in our proxy statement and is hereby incorporated by reference in this Annual Report on Form 10−K.

Part IV

Item 15. Exhibits and Financial Statement Schedules

The following documents are filed as part of this report:

(a)(1) Financial Statements:

The consolidated financial statements required under this item are included under Item 8.

(a)(2) Financial Statement Schedules

Schedule II—Valuation and Qualifying Accounts for the years 2005, 2004 and 2003 on page 148.

All other schedules are omitted because they are not applicable or the required information is shown in the financial statements or notes thereto.

(a)(3) List of Exhibits*

The following exhibits relate to a management contract or compensatory plan or arrangement:

10(a)(12)	Annual and Long−Term Incentive Plan.
10(a)(13)	First Amendment to Annual and Long−Term Incentive Plan.
10(a)(14)	Form of Severance Compensation Agreement (change in control agreement) of Certain Executives.
10(a)(15)	Life Insurance Program for Officers.
10(a)(16)	Supplemental Executive Retirement Plan, Amended and Restated, effective January 1, 2001.
10(a)(17)	Employment Agreement for Richard C. Green
10(a)(18)	Aquila, Inc. Capital Accumulation Plan, as amended and restated, effective January 1, 2005
10(a)(19)	Form of Performance Bonus Agreement
10(a)(20)	Severance Compensation Agreement (change in control agreement) dated as of March 16, 2001, by and between Aquila Merchant Services, Inc. (formerly Aquila, Inc.) and Keith Stamm.
10(a)(21)	Aquila, Inc. 2002 Omnibus Incentive Compensation Plan.
10(a)(22)	Executive Security Trust Amended and Restated as of April 4, 2002.
10(a)(23)	Supplemental Executive Retirement Agreement, by and between Aquila, Inc. (formerly UtiliCorp United Inc.) and John R. Baker, dated as of May 7, 1990.

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

(b) Exhibits

The Index to Exhibits follows on page 149.

AQUILA, INC.
SCHEDULE II—VALUATION AND QUALIFYING ACCOUNTS

For the Three Years Ended December 31, 2005
(in millions)

Column A	Column B	Column C	Column D	Column E
Description	**Beginning Balance at January 1**	**Additions Charged to Expense**	**Deductions from Reserves for Purposes for Which Created**	**Ending Balance at December 31**
Allowance for Doubtful Accounts				
2005	$ 27.7	$ 1.2	$ (19.6)	$ 9.3
2004	34.4	6.7	(13.4)	27.7
2003	26.0	14.0	(5.6)	34.4
Maintenance Reserves *(a)*				
2005	$ 2.9	$ 2.9	$ (2.3)	$ 3.5
2004	3.8	2.9	(3.8)	2.9
2003	2.5	2.2	(0.9)	3.8
Other Reserves *(b)*				
2005	$ 17.6	$ 36.1	$ (32.7)	$ 21.0
2004	21.8	32.2	(36.4)	17.6
2003	13.2	45.8	(37.2)	21.8
Restructuring Reserves *(c)*				
2005	$ 7.8	$ 6.6	$ (14.3)	$ .1
2004	16.9	.9	(10.0)	7.8
2003	49.2	28.2	(60.5)	16.9
Deferred Tax Valuation Allowance				
2005	$ 304.7	$ (53.2)	$ (2.6)	$ 248.9
2004	341.7	(19.2)	(17.8)	304.7
2003	381.6	(39.9)	—	341.7
Reserve for Contingent Tax Liabilities *(d)*				
2005	$ 244.0	$ 43.6	—	$ 287.6
2004	208.7	35.3	—	244.0
2003	93.2	115.5	—	208.7

(a) *Costs to be incurred related to scheduled maintenance outages on regulated generating facilities are accrued in advance of the scheduled outage consistent with current regulatory treatment.*

(b) *Includes reserves for self−insurance, environmental claims and other.*

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

(d) *The additions to this reserve include amounts originally charged to current or deferred tax expense, and reclassified to the reserve for tax contingencies after the tax returns were filed.*

Exhibit Number	Description
*3(a)	Restated Certificate of Incorporation of the company (Exhibit 3(a) to the company's Quarterly Report on Form 10−Q for the quarter ended June 30, 2002).
*3(b)	Amended and Restated By−Laws of the company (Exhibit 3.1 to the company's Current Report on Form 8−K filed May 6, 2005).
*4(a)	Long−term debt instruments of the company in amounts not exceeding 10% of the total assets of the company and its subsidiaries on a consolidated basis will be furnished to the Commission upon request.
*4(b)	Form of Rights Agreement between the company and UMB Bank, N.A. (as successor to First Chicago Trust Company of New York), as Rights Agent (Exhibit 4 to the company's Form 10−Q for the period ended September 30, 1996).
*4(c)	Amendment to Rights Agreement (Exhibit 4(d) to the company's Post Effective Amendment No. 1 to Registration Statement on Form S−3 No. 333−29657 filed March 15, 2002).
*10(a)(1)	Indenture, dated as of August 24, 2001, between the company and BankOne Trust Company, N.A., as Trustee (Exhibit 4(d) to the company's Registration Statement on Form S−3 (File No. 333−68400) filed August 27, 2001).
*10(a)(2)	First Supplemental Indenture to the August 24, 2001 Indenture, dated February 28, 2002, between the company and BankOne Trust Company, N.A., as Trustee (Exhibit 4 to the company's Current Report on Form 8−K filed February 27, 2002).
*10(a)(3)	Third Supplemental Indenture to the August 24, 2001 Indenture, between the company and J.P. Morgan Trust Company (Exhibit 4 to the company's Current Report on Form 8−K filed August 20, 2004).
*10(a)(4)	Bond Indenture, Mortgage, Deed of Trust, Security Agreement and Fixture Filing, dated as of August 31, 2005, between the company and Union Bank of California, N.A., as trustee and securities intermediary (Exhibit 10.2 to the company's Current Report on Form 8−K filed September 6, 2005 (the "September 6 Form 8−K")).
*10(a)(5)	First Supplemental Bond Indenture, Mortgage, Deed of Trust, Security Agreement and Fixture Filing, dated as of August 31, 2005, between the company and Union Bank of California, N.A., as trustee and securities intermediary (Exhibit 10.3 to the September 6 Form 8−K).
*10(a)(6)	$110 million Revolving Credit Agreement among the company, the lenders and Credit Suisse First Boston dated September 20, 2004 (Exhibit 10.1 to the company's Current Report on Form 8−K filed September 21, 2004).
*10(a)(7)	$220 million Credit Agreement among the company, the lenders and Credit Suisse First Boston dated September 20, 2004 (Exhibit 10.2 to the company's Current Report on Form 8−K filed September 21, 2004).
*10(a)(8)	$180 Million Credit Agreement dated as of April 13, 2005, among the company, the lenders, Citicorp USA, Inc., as issuing bank and administrative agent, and Union Bank of California, N.A., as paying agent (Exhibit 10.1 to the company's Current Report on Form 8−K filed April 18, 2005).

*10(a)(9)	Financing Agreement dated as of April 22, 2005, among the company, the lenders from time to time party thereto, and Union Bank of California, N.A., as agent (Exhibit 10.1 to the company's Current Report on Form 8−K filed April 26, 2005).
*10(a)(10)	$300 Million Credit Agreement, dated as of August 31, 2005, among the company, the banks and other lenders party thereto, and Union Bank of California, N.A., as issuing bank, administrative agent, and sole lead arranger (Exhibit 10.1 to the September 6 Form 8−K).
*10(a)(11)	$100,000,000 Credit Agreement, dated as of January 19, 2006, among the company, the banks named therein, and Union Bank of California, N.A., as administrative agent and collateral agent (Exhibit 10.1 to the company's Current Report on Form 8−K filed January 23, 2006).
*10(a)(12)	Annual and Long−Term Incentive Plan (Exhibit 10(a)(3) to the company's Annual Report on Form 10−K for the year ended December 31, 1999).
*10(a)(13)	First Amendment to Annual and Long−Term Incentive Plan. (Exhibit 10(a)(5) to the company's Annual Report on Form 10−K for the year ended December 31, 2001).
*10(a)(14)	Form of Severance Compensation Agreement (change in control agreement) between the company and certain Executives of the company (Exhibit 10(a)(7) to the company's Annual Report on Form 10−K for the year ended December 31, 2001).
*10(a)(15)	Life Insurance Program for Officers (Exhibit 10 (a)(13) to the company's Annual Report on Form 10−K for the year ended December 31, 1995).
*10(a)(16)	Supplemental Executive Retirement Plan, Amended and Restated, effective January 1, 2001 (Exhibit 10(a)(1) to the company's Quarterly Report on Form 10−Q for the quarter ended June 30, 2001).
*10(a)(17)	Employment Agreement for Richard C. Green (Exhibit 10.1 to the company's Quarterly Report on Form 10−Q for the quarter ended September 30, 2002).
*10(a)(18)	Aquila, Inc. Capital Accumulation Plan, as amended and restated, effective January 1, 2005 (Exhibit 10.1 to the company's Current Report on Form 8−K filed January 6, 2006).
*10(a)(19)	Form of Performance Bonus Agreement (Exhibit 10.5 to the company's Current Report on Form 8−K filed September 27, 2005 (the "September 27 Form 8−K")).
*10(a)(20)	Severance Compensation Agreement (change in control agreement) dated as of March 16, 2001, by and between Aquila Merchant Services, Inc. (formerly Aquila, Inc.) and Keith Stamm (Exhibit 10.7 to Registration Statement No. 333−51718, filed April 18, 2001 by Aquila Merchant Services, Inc. (formerly Aquila, Inc.)).
*10(a)(21)	Aquila, Inc. 2002 Omnibus Incentive Compensation Plan (Exhibit 10.3 to the company's Quarterly Report on Form 10−Q for the quarter ended September 30, 2002).
*10(a)(22)	Executive Security Trust Amended and Restated as of April 4, 2002 (Exhibit 10.5 to the company's Quarterly Report on Form 10−Q for the quarter ended September 30, 2002).
*10(a)(23)	Supplemental Executive Retirement Agreement, by and between Aquila, Inc. (formerly UtiliCorp United Inc.) and John R. Baker, dated as of May 7, 1990.

*10(a)(24)	Asset Purchase Agreement by and between the company and The Empire District Electric Company, dated September 21, 2005 (Exhibit 10.1 to the September 27 Form 8−K).
*10(a)(25)	Asset Purchase Agreement by and between the company and WPS Michigan Utilities, dated September 21, 2005 (Exhibit 10.2 to the September 27 Form 8−K).
*10(a)(26)	Asset Purchase Agreement by and between the company and WPS Minnesota Utilities, dated September 21, 2005 (Exhibit 10.3 to the September 27 Form 8−K).
*10(a)(27)	Asset Purchase Agreement by and between the company and Mid−Kansas Electric Company, dated September 21, 2005 (Exhibit 10.4 to the September 27 Form 8−K).
*10(a)(28)	Asset Purchase and Sale Agreement by and between Aquila Piatt County Power, L.L.C. and Union Electric Company d/b/a AmerenUE, dated as of December 16, 2005 (Exhibit 10.1 to the company's Current Report on Form 8−K filed December 16, 2005 (the "December 16 Form 8−K")).
*10(a)(29)	Asset Purchase and Sale Agreement by and between MEP Flora Power, LLC and Union Electric Company d/b/a AmerenUE, dated as of December 16, 2005 (Exhibit 10.2 to the December 16 Form 8−K).
10(a)(30)	Amended and Restated Power Sales Agreement, dated as of June 30, 2000 between Aquila Energy Marketing Corporation, the company and Elwood Energy II, LLC.
10(a)(31)	Power Sales Agreement, dated as of June 30, 2000 between Aquila Energy Marketing Corporation, the company and Elwood Energy III, LLC.
*10(a)(32)	Unit Purchase Agreement by and between Everest Global Technologies Group, LLC and Everest Connections Holdings, Inc. (Exhibit 10.1 to the company's Current Report on Form 8−K filed March 6, 2006).
12	Ratio of Earnings to Fixed Charges.
*14	Code of Ethics (Exhibit 14 to the company's Annual Report on Form 10−K for the year ended December 31, 2004).
*17	Gerald L. Shaheen resignation letter (Exhibit 99.1 to the company's Current Report on Form 8−K filed January 6, 2006).
21	Subsidiaries of the company.
23	Consent of KPMG LLP.
31.1	Certification of Chief Executive Officer under Section 302.
31.2	Certification of Chief Financial Officer under Section 302.
32.1	Certification of Chief Executive Officer under Section 906.
32.2	Certification of Chief Financial Officer under Section 906.
*99.1	Order of the State Corporation Commission of the State of Kansas on Docket No. 02−UTCG−701−GIG, dated May 7, 2003 (Exhibit 99.1 to the company's Annual Report on Form 10−K for the year ended December 31, 2003).
*99.2	Order of the State Corporation Commission of the State of Kansas on Docket No. 02−UTCG−701−GIG, dated June 26, 2003 (Exhibit 99.2 to the company's Annual Report on Form 10−K for the year ended December 31, 2003).

* *Exhibits marked with an asterisk are incorporated by reference herein. Parenthetical references describe the SEC filing that included the document incorporated by reference.*

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized as of March 6, 2006.

Aquila, Inc.

By: /s/ RICHARD C. GREEN

Richard C. Green
President, Chief Executive Officer and Chairman of the Board of Directors

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated, as of March 6, 2006.

By:	/s/ RICHARD C. GREEN Richard C. Green	President, Chief Executive Officer and Chairman of the Board of Directors (Principal Executive Officer)
By:	/s/ RICK J. DOBSON Rick J. Dobson	Senior Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)
By:	/s/ HERMAN CAIN Herman Cain	Director
By:	/s/ DR. MICHAEL M. CROW Dr. Michael M. Crow	Director
By:	/s/ IRVINE O. HOCKADAY, JR. Irvine O. Hockaday, Jr.	Director
By:	/s/ HEIDI E. HUTTER Heidi E. Hutter	Director
By:	/s/ DR. STANLEY O. IKENBERRY Dr. Stanley O. Ikenberry	Director
By:	/s/ PATRICK J. LYNCH Patrick J. Lynch	Director
By:	/s/ NICHOLAS J. SINGER Nicholas J. Singer	Director

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EXHIBIT 10(a)(30)
Execution Copy

AMENDED AND RESTATED

POWER SALES AGREEMENT

Dated as of June 30, 2000

Between

Aquila Energy Marketing Corporation,

UtiliCorp United Inc.
(Buyer)
and

Elwood Energy II, LLC
(Seller)

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APPENDICES

AMENDED AND RESTATED
POWER SALES AGREEMENT

THIS AMENDED AND RESTATED POWER SALES AGREEMENT (including Appendices, this "Agreement") dated as of June 30, 2000, is entered into between Aquila Energy Marketing Corporation ("Aquila"), and UtiliCorp United Inc. ("UCU") (Aquila and UCU referred to herein collectively as "Buyer"), and Elwood Energy II, LLC, a Delaware limited liability company ("Seller"); Buyer and Seller are sometimes referred to herein individually as a "Party" and collectively as the "Parties");

W I T N E S S E T H:

WHEREAS, Seller owns and operates an electric generating facility in Elwood, Illinois and is engaged in the generation and sale of Electric Energy, Capacity and associated Ancillary Services; and

WHEREAS, Seller is building the Facility which will be located at the Elwood Station; and

WHEREAS, Seller anticipates the Commercial Operations Date of Units 5 and 6 of the Facility will occur on or prior to June 1, 2001; and

WHEREAS, Seller and Buyer previously executed a Power Sales Agreement (the "Original Agreement") dated as of June 30, 2000 whereby Buyer shall receive and purchase, and Seller shall deliver and sell the Electric Energy, Capacity and associated Ancillary Services from Units 5 and 6 of the Facility and Replacement Power, pursuant to this Agreement; and

WHEREAS, the Parties now desire to revise the Original Agreement such that this Amended and Restated Agreement supersede the Original Agreement.

NOW, THEREFORE, in consideration of the mutual covenants and agreements herein set forth, the Parties hereto agree as follows:

1. *Definitions and Interpretation.*

1.1 *Definitions.* As used in this Agreement, the terms set forth below in this Section 1 shall have the respective meanings so set forth.

"ASME" means the American Society of Mechanical Engineers.

"Actual Heat Rate" for any period shall be the Heat Rate which is determined based upon actual performance of the Facility and the Elwood III Units during such period and calculated by the quotient of the aggregate gas energy consumption in Btus for Units 5 and 6 (not including gas consumed to generate Test Energy, incremental gas consumed (at a Heat Rate above the Net Heat Rate) to generate Incremental Energy to the extent used to offset what would otherwise be a Forced Derating, or gas consumed during Failed Starts), and the Elwood III Units as measured by the Station Fuel Meter divided by the Electric Energy output (in kWh) produced by the same Units and the Elwood III Units during the identical period as measured by the Revenue Meter.

"Affected Party" has the meaning set forth in Section 19.1.

"Affiliate" means, when used with respect to any Person, any Person controlling, controlled by or under common control with such Person. For the purposes of this definition, the term "controlling" (and, with correlative meanings, the terms "controlled by" and "under common control with") shall mean the possession of the power to direct or cause the direction of the management and policies of such Person, whether through the ownership of voting securities or by contract or agency or otherwise.

"Aggregate Delay LD Cap" means $24,567,500, less any Delay Book Out Charges paid by Seller.

"Ancillary Services" has the meaning set forth in Section 9.

"Availability Adjustment" has the meaning set forth in Section 7.1.3.

"Available" means a state in which the Facility is capable of providing full service, whether or not it is actually in operation or in service.

"Average Summer Partial Peak Availability" means the Equivalent Availability during Partial Peak Hours averaged over all months of a given Summer Period, calculated as:

1 − [(sum total of FOH + EFDH)/(sum total of Partial Peak period hours)].

"Average Summer Super Peak Availability" means the Equivalent Availability during Super Peak Hours averaged over all months of a given Summer Period, calculated as:

1 − [(sum total of FOH + EFDH)/(sum total of Super Peak period hours)].

"Bankruptcy" means any case, action or proceeding under any bankruptcy, reorganization, debt arrangement, insolvency or receivership law or any dissolution or liquidation proceeding commenced by or against a Person and, if such case, action or proceeding is not commenced by such Person, such case or proceeding shall be consented to or acquiesced in by such Person or shall result in an order for relief or shall remain undismissed for 90 days.

"Bankruptcy Event" means with respect to a Party, an assignment by such Party for the benefit of creditors or the filing of a case in Bankruptcy or any proceeding under any other insolvency law under which such Party is debtor in bankruptcy.

"Base Fuel Charge" means the Fuel Index plus either 10 cents/MMBTU or 15 cents/MMBTU, as applicable under Section 7.2.5.1 or Section 7.2.5.2.

"Btu" means British thermal unit.

"Business Day" means each weekday (Monday through Friday) excluding NERC Holidays.

"Buyer Event of Default" has the meaning specified in Section 13.2.

"Cap Date" has the meaning specified in Section 3.3.5.

"Capacity" means the capability measured in kW of Seller to produce Electric Energy at the Facility or deliver Replacement Power to the Point of Delivery or the Replacement Power Delivery Point, as applicable.

"Capacity Bonus" has the meaning set forth in Section 7.1.4.

"Capacity Charge" has the meaning set forth in Section 7.1.

"Capacity Rate" has the meaning set forth in Section 7.1.2

"Capacity Rate Reduction Amount" has the meaning set forth in Section 3.3.6.

"Cap Date" has the meaning set forth in Section 3.3.5.

"Change in Law" means, after the Effective Date, the enactment, adoption, promulgation, modification or repeal or a material modification or change in the administrative or judicial application by any Governmental Agency of any applicable Requirement of Law.

"ComEd" means Commonwealth Edison Company or its successors and assigns.

"ComEd/Elwood Switchyard" means that switchyard that provides interconnection services to the Facility as identified Appendix J.

"Commercial Operations" means that a Unit or the Facility shall have achieved all of the conditions specified in Section 3.2.

"Commercial Operations Date" means the day on which a Unit or the Facility achieves Commercial Operations.

"Commercial Operations Delay Period" is the period of time, if any, between the Target COD and the Commercial Operations Date.

"Commission" or "Commissioning" as applicable, means the test and start up process leading up to Commercial Operations.

"Compressor Wash" has the meaning set forth in Section 6.5.

"Confidential Information" has the meaning specified in Section 17.

"Contract Year" means (i) for the first Contract Year, the period commencing on June 1, 2001 and ending on the December 31 occurring immediately thereafter, and (ii) for all other Contract Years (other than the final Contract Year), the calendar year, except that the final Contract Year shall be the period from the first day of the calendar year (during which the Term will expire) through the expiration of the Term.

"Cover Period" means a period during which the Seller is permitted pursuant to this Agreement to deliver or cause to be delivered Replacement Power or Substitute Power to Buyer. Such periods shall include only the following: (i) any time during Commercial Operations Delay Period; (ii) a Forced Outage or a Forced Derating; (iii) a period that could reasonably be likely to result in a Forced Outage or Forced Derating, as a result of which Seller determines, in accordance with Prudent Industry Practices, that safety concerns, potential equipment breakdowns or Unit vibration alarms require the Units to be made unavailable for a period of time necessary to diagnose and remedy such operational problems; or (iv) a Force Majeure Period.

"Day Ahead Schedule" means Buyer's hour by hour Dispatch schedule for the next calendar day or days, as applicable, as provided to Seller pursuant to Section 4.3.2.1.

"Default Rate" means (a) the one−month "LIBOR" as published from time to time in the "Money Rates" section of The Wall Street Journal, plus (b) 4.5% (450 basis points) per annum.

"Degradation Curves" means the combustion turbine degradation curve(s) as represented by General Electric Bulletin No. 519HA772, Rev. A, dated February 9, 1995.

"Delay Book Out Charge" has the meaning specified in Section 3.3.2

"Delay Election" has the meaning specified in Section 3.3.1

"Delay LDs" has the meaning specified in Section 3.3.3.

"Design Limits" means the operating specifications listed in *Appendix A*.

"Diagnostic Period" has the meaning specified in Section 4.5.3.

"Differential Transmission Adjustment" means the difference between the cost to Buyer to have Replacement Power delivered from the Replacement Power Delivery Point to Buyer's ultimate customer and the cost Buyer would have incurred to transmit such power from the Point of Delivery to such customer. Such amount may be a negative or positive number and shall be determined in accordance with Section 7.2.4.3.

"Dispatch" means Buyer's rights to schedule the designated Electric Energy output of the Facility pursuant to Section 4.3 or to schedule the delivery of Replacement Power pursuant to Section 4.7.

"Dispatch Notification" means that Buyer has notified Seller by telephone conversation of Buyer's Dispatch order in accordance with Appendix C.

"Dispatcher" means Buyer's authorized representative for Dispatch under this Agreement.

"DLD Escrow" has the meaning set forth in Section 3.3.5.

"Dominion" means Dominion Energy, Inc., a Virginia corporation.

"Downgrade Event" means (i) with respect to a Buyer or Seller Guarantor whose long term unsecured indebtedness is rated by one or both of Standard & Poor's or Moody's, a downgrade in such ratings such that both fall below Investment Grade, and (ii) with respect to a Seller Guarantor that is not rated, a value below $600,000,000 in owner's equity or a ratio of total liabilities to total assets for Dominion that exceeds 72%.

"EPC Contractor" means the party under contract to Seller to design, engineer, procure, and construct the Facility.

"Effective Date" means the date of this Agreement.

"Electric Energy" means all electric energy output from the Facility (net of Facility station service and auxiliaries for the Units and the Elwood III Units) delivered to Buyer by Seller from and after the Commercial Operations Date in accordance with the terms of this Agreement.

"Elwood Station" means the multi−unit power generation station that includes the Facility and other units, located in Elwood, Illinois owned by Seller and its Affiliates.

"Elwood III Units" means Units 7 and 8 at Elwood Station.

"Emergency Condition" means a condition or situation which (i) in the sole judgment of the Interconnected Utility presents an imminent physical threat of danger to life, or significant threat to health or property (including in the ComEd/Elwood Switchyard), (ii) in the sole judgment of the Interconnected Utility could cause a significant disruption on or significant damage to the Interconnected Utility's System (or any material portion thereof) or the transmission system of a third party (or any material portion thereof), (iii) in the reasonable judgment of Seller presents an imminent physical threat of danger to life, or significant threat to health or property (including in the ComEd/Elwood Switchyard) or (iv) in the reasonable judgment of Seller could cause significant damage to the Facility (or any material portion thereof).

"Energy Charge" has the meaning set forth in Section 7.2.

"Energy Rate" means, individually or collectively, as the context requires, the Replacement Power Energy Rate, the Incremental Energy Rate, the Facility Electric Energy Rate, or the Test Energy Rate.

"Equivalent Availability" has the meaning set forth in Appendix E.

"Equivalent Forced Derated Hours" or "EFDH" has the meaning set forth in Appendix E.

"Escrow Agreement" has the meaning specified in Section 3.3.5.

"Extension Term" has the meaning set forth in Section 2.1.

"Facility" means the natural gas fueled electric generation plant consisting of two GE Frame 7 FA combustion turbines designated as Units 5 and 6, together with appurtenant facilities, and having a total net output estimated to be approximately 303,560 kWs located at the Elwood Station.

"Facility Electric Energy Rate" has the meaning set forth in Section 7.2.

"Failed Start" means an attempted start up of a Unit whereby Seller initiates the Start Up Sequence but does not achieve a Start Up.

"FERC" means the Federal Energy Regulatory Commission.

"Final Commercial Operations Date" means June 1, 2002, as such date may be extended pursuant to Section 19, in which case such date shall be extended by the period during which a Force Majeure Event impairs or precludes the performance by a Party of its obligations hereunder, but in no event beyond June 1, 2003.

"First Outage Notice" has the meaning set forth in Section 4.5.1.

"Force Majeure Event" has the meaning set forth in Section 19.1.

"Force Majeure Period" means any period during which a Force Majeure Event affecting Seller occurs that precludes wholly or in part the capability of the Facility to deliver Electric Energy and Capacity as required hereunder.

"Forced Derating" has the meaning set forth in *Appendix E*.

"Forced Outage" has the meaning set forth in *Appendix E*.

"Forced Outage Hours" or "FOH" has the meaning set forth in *Appendix E*.

"Four Month Date" has the meaning set forth in Section 3.3.6.

"Fuel Charge" means the Base Fuel Charge plus the applicable surcharge, if any, imposed pursuant to Section 7.2.5.3.

"Fuel Index" means the index as published in *Gas Daily*—"Midpoint, Chicago−LDCs, Large e−us"—for the day of Energy delivery to Buyer. If this index ceases to be published the Parties shall select a mutually agreeable substitute index designed to track the market price of gas in the Chicago area for large end users for next day service.

"Fuel Metering Point "means the Station Fuel Meter identified in Appendix J.

"GDP−IPD" means the Gross Domestic Product—Implicit Price Deflator as published in the National Income and Product Account by the U.S. Department of Commerce.

"Government Agency" means any federal, state, local, territorial or municipal government, governmental department, commission, board, bureau, agency, instrumentality, judicial or administrative body (or any agency, instrumentality or political subdivision thereof) having jurisdiction over the Buyer, Seller, the Facility, or the Interconnected Utility.

"Governmental Approval" means any authorization, consent, approval, license, ruling, permit, exemption, filing, variance, order, judgment, decree, publication, notice to, declarations of or with or regulation by or with any Government Agency relating to the acquisition, ownership, occupation, construction, Commissioning, operation or maintenance of the Units and the Facility or to the execution, delivery or performance of this Agreement.

"Gross Margin" shall mean the reasonable documented actual sales proceeds at Prevailing Market Prices for energy and/or capacity, less Transaction Costs, less (i) the Facility Electric Energy Rate or (ii) in the case of Incremental Energy, $100/MWh.

"Guaranteed Availability" means the Guaranteed Non−Summer On Peak Availability, the Guaranteed Summer Partial Peak Availability or the Guaranteed Summer Super Peak Availability for the applicable period.

"Guaranteed Heat Rate" means 10,787 Btu/kWh (HHV), new and clean at Reference Conditions.

"Guaranteed Non−Summer On Peak Availability" shall be equal to 97%.

"Guaranteed Ramp Rate" has the meaning set forth in *Appendix A*.

"Guaranteed Start−Up Time" has the meaning set forth in *Appendix A*.

"Guaranteed Summer Partial Peak Availability" shall be equal to 97%.

"Guaranteed Summer Super Peak Availability" shall be equal to 97%.

"Heat Rate" means the efficiency expressed as the amount of Btus of natural gas consumed to generate a kwh of electric energy.

"Heat Rate Credits" has the meaning set forth in Section 7.3.2.

"ISO" or "Independent System Operator" means any Person, other than ComEd, that becomes responsible as system operator for the Interconnected Utility System.

"Imbalance Charge" means a charge for oversupply or undersupply of Electric Energy incurred pursuant to Schedule 4 of ComEd's Open Access Transmission Tariff or the Interconnection Agreement.

"Incremental Energy" has the meaning set forth in Section 4.4.

"Incremental Energy Rate" has the meaning set forth in Section 7.2.

"Individual Fuel Meter" means the meter located as indicated in Appendix J, measuring gas consumption of an individual Unit or similar meters on the Elwood III Units.

"Initial Net Heat Rate" means the Net Heat Rate as tested in the final performance testing for each Unit under the contract with the EPC Contractor averaged over the Units and the Elwood III Units with evaporative coolers in service as corrected to Reference Conditions in accordance with Appendix B.

"Initial Term" has the meaning set forth in Section 2.1.

"Interconnection Facilities" means the interconnection facilities that will connect the Facility with the Interconnected Utility System, as more fully described in the Interconnection Agreement.

"Interconnected Utility" means ComEd or its successors and assigns; such assigns may include an ISO or any other entity operating a control area that includes the Interconnected Utility System.

"Interconnected Utility System" means the electric transmission and distribution system owned by ComEd and its Affiliates, or their successors and assigns; such assigns may include assignment of operations to an ISO which shall then mean that Interconnected Utility System operated by such ISO.

"Interconnection Agreement" means the Interconnection Agreement to be agreed to and executed between the Interconnected Utility and Seller with respect to the Facility.

"Interconnection Facilities" means the interconnection facilities that will connect the Facility with the Interconnected Utility System, as more fully described in the Interconnection Agreement.

"Investment Grade" means a rating on the long term unsecured indebtedness of an entity of at least Baa3 from Moody's or at least BBB− from Standard & Poor's.

"kW" means kiloWatt

"KWh" means kiloWatthour.

"Lenders" means with respect to the Seller (i) any person or entity that, from time to time, has made loans to the Seller, its permitted successors or permitted assigns for the financing or refinancing of the Facility or the marketing of the Electric Energy, Capacity or Ancillary Services of the Facility or which are secured by the Facility, (ii) any holder of indebtedness of the Seller, (iii) any person or entity acting on behalf of such holder(s) to which any holders' rights under financing documents have been transferred, any trustee or agent on behalf of any such holders, or (iv) any Person who purchases the Facility in connection with a sale−leaseback or other lease arrangement in which the Seller is the lessee of the Facility pursuant to a net lease.

"Liabilities" has the meaning set forth in Section 15.

"MMBtu" means million Btus.

"MW" means megaWatt.

"MWh" means megaWatthour.

"MAIN" means the Mid−America Interconnected Network, or its successors.

"Monthly Adjustment Factor" means, with respect to the calculation of the Availability Adjustment, 18% for the month of June, 32% for the month of July and 32% for the month of August.

"Moody's" means Moody's Investors Service, or its successor.

"NERC" means the North American Electric Reliability Council, or its successor.

"NERC Holidays" means New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day, and other holidays observed by NERC.

"Net Dependable Capacity" means the net aggregate generating capacity measured in kWs of both Units of the Facility, based upon demonstrated output (net of station service and auxiliaries for the Units and the Elwood III Units) achieved during capacity testing of the Facility pursuant to Section 8.1 and *Appendix B*, adjusted by the Degradation Curves and to Reference Conditions; provided, however, that prior to the Commercial Operations Date, the Net Dependable Capacity of the Facility shall be deemed to be 303,560 kW, at Reference Conditions.

If one Unit achieves Commercial Operations prior to the other Unit, then for the period when only one Unit is in Commercial Operations, Net Dependable Capacity for all purposes other than calculation of Capacity Charges shall mean the net dependable capacity of such Unit.

"Net Heat Rate" means the Heat Rate established by periodic testing of the Units and the Elwood III units as corrected with the Degradation Curve to Reference Conditions pursuant to Appendix B.

"Nicor" means Northern Illinois Gas Company, or its successors.

"Non−Billable Generation" has the meaning specified in Section 5.1 and shall be calculated in accordance with Appendix O.

"Non−Summer On Peak Hours" means during the Non−Summer Period, the hour ending 0700 Central Time through the hour ending 2200 Central Time, Monday through Friday, excluding NERC holidays.

"Non−Summer Period" means September 1 through May 31.

"OEM" means the original equipment supplier.

"On Peak Hours" means (i) during the Summer Period, the hour ending 0700 Central Time through the hour ending 2200 Central Time, Monday through Saturday, excluding NERC Holidays and (ii) during the Non−Summer Period, the hour ending 0700 Central Time through the hour ending 2200 Central Time, Monday through Friday, excluding NERC Holidays.

"Outage Book Out Charge" has the meaning set forth in Section 4.5.1.

"Outage Election" means Seller's election during any Cover Period either to provide Replacement Power or cause to be provided Substitute Power in accordance with Section 4.7.3.

"Partial Peak Hours" means, during the Summer Period, the hour ending 0700 through the hour ending 1100 and the hour ending 2000 through the hour ending 2200, Central Time, Monday through Saturday, excluding NERC holidays.

"Pecorp" means Peoples Energy Corporation, an Illinois corporation.

"Period Hours" or "PH" has the meaning set forth in Appendix E.

"Permitted Assignee" means a Person having at least five (5) years experience in the operations and maintenance of electrical generation facilities similar to the Facility and having a level of creditworthiness equivalent to Seller and Seller Guarantors, which Person shall be reasonably acceptable to Buyer.

"Person" means any individual, corporation, partnership, joint venture, limited liability company, association, joint stock company, trust, unincorporated organization, entity, government or other political subdivision.

"Per Unit Delay LD Cap" means $12,283,750, less any Delay Book Out Charges paid by Seller in respect of the applicable Unit.

"Point of Delivery" means, for Electric Energy delivered from a Unit, the point of interconnection between the Facility and the Interconnected Utility System in the ComEd/Elwood Switchyard, as identified in Appendix J.

"Post COD Test Energy" means Test Energy generated on and after the Commercial Operations Date.

"Pre COD Test Energy" means Test Energy generated before the Commercial Operations Date.

"Prevailing Market Price" means the best price available to Buyer (i.e., highest price when Buyer markets Test Energy and Incremental Energy and lowest price when Buyer procures Substitute Power) actually obtained for energy or capacity (taking into account the type, reliability, and duration and other relevant attributes of such energy or capacity), which shall be obtained through commercially reasonable efforts, as evidenced, upon request of Seller, by documentation of such price, unless and until an index or other mechanism mutually acceptable to the Parties is created and agreed upon by the Parties to serve as the Prevailing Market Price.

"Prudent Industry Practice" means any of the practices, methods, standards and acts required or approved by any ISO or engaged in or approved by a significant portion of the electric generation industry in the geographic region covered by MAIN during the relevant time period, or any of the practices, methods, standards and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. "Prudent Industry Practice" is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be acceptable practices, methods or acts generally accepted in the geographic region covered by MAIN and which generally conform to operation and maintenance standards recommended by the OEM, the Design Limits, and Government Approvals.

"Rating Category" means a letter category rating for long term unsecured indebtedness of an entity (e.g. Aaa, Aa, A, Baa, Ba, and so on in the case of Moody's and AAA, AA, A, BBB and so on in the case of Standard & Poor's), disregarding in each case any numerals or other modifiers appended to such rating.

"Reference Conditions" means ambient atmospheric temperature of 95 degrees Fahrenheit (dry−bulb), 60% relative humidity, adjusted for elevation above mean sea level.

"Reference Heat Rate" shall be determined for each hour using the turbine OEM's heat rate performance curves adjusted to site elevation, ambient conditions, load factor and Degradation Curves and as provided in Appendix F.

"Replacement Power" (i) prior to the Commercial Operations Date, means electric Capacity and electric energy provided by Seller from time to time to Buyer from sources (including from other units at the Elwood Station) other than the Facility and (ii) after the Commercial Operations Date, means electric energy provided by Seller from time to time to Buyer from sources (including other units at the Elwood Station) other than the Facility.

"Replacement Power Delivery Point" means the point where Replacement Power is delivered to Buyer, at a point or points that are acceptable to Buyer, such acceptance not to be unreasonably withheld or delayed, unless the Replacement Power Delivery Point shall be the same as the Point of Delivery, in which case it shall be deemed to be acceptable to Buyer.

"Replacement Power Energy Rate" has the meaning set forth in Section 7.2.2

"Requested Load Delivery Time" means the designated time in Buyer's Dispatch schedule for a Unit to be generating at a specified level.

"Requirement of Law" means any applicable federal, state and local laws, statutes, regulations, rules, codes or ordinances enacted, adopted, issued or promulgated by any federal, state, local or other Governmental Agency (including those pertaining to electrical, building, zoning, environmental and occupational safety and health requirements).

"Revenue Meter" means the meter which measures power flow into the main step up transformer of each Unit and similar meters on the Elwood III Units at a point after auxiliary loads are withdrawn from the bus.

"Scheduled Maintenance Outage" means the time period during which a Unit or any portion of the Facility is removed from service to perform work on specific components based upon manufacturer's recommended schedules in accordance with Section 6.4.

"Scheduling Fees" means the charge of Buyer to Seller for scheduling Test Energy and Incremental Energy, which shall equal $1.00 per MWh.

"Second Outage Notice" has the meaning set forth in Section 4.5.3.

"Seller Event of Default" has the meaning specified in Section 13.1.

"Seller Guarantees" has the meaning specified in Section 18.1.

"Seller Guarantor" means Dominion or Pecorp.

"Site" means the real property on which the Units are located.

"Size of Reduction" has the meaning set forth in Appendix E.

"Standard & Poor's" means Standard & Poor's Rating Group a division of McGraw−Hill, Inc. or its successor.

"Start Up" means the initiation of the Start Up Sequence followed by the applicable Unit's generating at least 60% of the Net Dependable Capacity.

"Start Up Charge" has the meaning set forth in Section 7.4.

"Start Up Sequence" means the normal sequence of events, beginning with the cranking process, in order to achieve Start Up.

"Station Fuel Meter" means the Nicor fuel meter common to Units 5 and 6 and to the Elwood III Units.

"Substitute Power" (i) prior to the Commercial Operations Date means electric energy and capacity (ii) after the Commercial Operations Date, electric energy, in each case obtained by Buyer at the direction of Seller in accordance with Section 4.7.3.

"Substitute Power Cost Credit" is a credit adjustment to Buyer for its reasonable costs to acquire Substitute Power at the direction of Seller and as calculated in accordance with Section 7.2.4.3.

"Summer Average Availability" means the Equivalent Availability for all Summer On Peak Hours in each month during the Summer Period of any given Contract Year, averaged over such three months.

"Summer Period" means the period from June 1 through August 31 of each Contract Year.

"Summer Off Peak Hours" means all hours in the Summer Period other than On Peak Hours.

"Summer On Peak Hours" means all Super Peak Hours and Partial Peak Hours.

"Super Peak Hours" means, during the Summer Period, the hour ending at 1200 Central Time and through the hour ending 1900 Central Time, Monday through Saturday, excluding NERC holidays.

"Target COD" means June 1, 2001, as such date may be extended day−for−day due to Force Majeure Events as and to the extent permitted by Section 19 or for days covered by a Delay Book Out Charge pursuant to Section 3.3.3.

"Term" has the meaning specified in Section 2.1.

"Test Energy" means electricity generated during a test at a time when the tested Unit would not be Dispatched by Buyer to generate but for the running of the test.

"Third Party Damages" has the meaning set forth in Section 4.7.4.

"Threshold Heat Rate" is 10,759 Btu/KWh, new and clean at Reference Conditions.

"Transaction Costs" means reasonable documented transaction costs associated with the sale and marketing of Electric Energy or Test Energy, as applicable, including and limited to transmission costs (or fees or charges imposed by a third party in lieu of or in addition to such transmission costs in accordance with common industry practice), transmission line losses, Scheduling Fees and ancillary service charges.

"Unit" means either of the GE frame 7FA gas−fired turbine generator units of the Facility subject to Dispatch by Buyer under this Agreement, i.e., numbers five (5) and six (6).

"Variable O&M Rate" means $1.00/MWh (as of June 1, 1999), and as adjusted on the anniversary of the first and each subsequent Contract Year by the annual change in the GDP−IPD.

1.2 *Interpretation.* In this Agreement, unless a clear contrary intention appears:

1.2.1 the singular number includes the plural number and vice versa;

1.2.2 reference to any Person includes such Person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this Agreement, and reference to a Person in a particular capacity excludes such Person in any other capacity or individually;

1.2.3 reference to any gender includes each other gender;

1.2.4 reference to any agreement (including this Agreement), document, instrument or tariff means such agreement, document, instrument or tariff as amended or modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof;

1.2.5 reference to any Requirement of Law means such Requirement of Law as amended, modified, codified or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder;

1.2.6 reference to any Section or Appendix means such Section of this Agreement or such Appendix to this Agreement, as the case may be, and references in any Section or definition to any clause means such clause of such Section or definition;

1.2.7 "hereunder", "hereof", "hereto" and words of similar import shall be deemed references to this Agreement as a whole and not to any particular Section or other provision hereof or thereof;

1.2.8 "including" (and with correlative meaning "include") means including without limiting the generality of any description preceding such term;

1.2.9 relative to the determination of any period of time, "from" means "from and including", "to" means "to but excluding" and "through" means "through and including"; and

1.2.10 reference to time shall always refer to prevailing Central Time, i.e., standard time or daylight time as applicable in Elwood, Illinois.

1.2.11 wherever this Agreement speaks in terms of both Units (or the Facility), and the context of a provision requires application to only one Unit, then such provision and operative terms or amounts relating thereto shall be appropriately construed or prorated, as appropriate.

1.3 *Legal Representation of Parties.* This Agreement was negotiated by the Parties with the benefit of legal representation and any rule of construction or interpretation otherwise requiring this Agreement to be construed or interpreted against any Party shall not apply to any construction or interpretation hereof or thereof.

1.4 *Titles and Headings.* Section and Appendix titles and headings inthis Agreement are inserted for convenience of reference only and are not intended to be a part of, or to affect the meaning or interpretation of, this Agreement.

1.5 *Order of Precedence.* In the event of a conflict between any of the terms of this Agreement, the conflict shall be resolved by giving priority to the terms in the following order of precedence: (1) Sections 1−23, (2) Appendix E, (3) Appendix A, and (4) the remaining Appendices in the order in which they appear in this Agreement.

2. *Term and Survival*

2.1 *Term.* This Agreement shall have a term (the "Term") commencing on the Effective Date and ending on August 31, 2016 (the "Initial Term") unless otherwise extended or terminated in accordance with the provisions of this Agreement. The Buyer shall have the unilateral right to extend the Initial Term for a five (5) year period (or such other period as the Parties mutually agree) (the "Extension Term") provided the Buyer notifies Seller in writing by September 1, 2014 of its desire to so extend.

2.2 *Survival.* The provisions of Section 1 (Definitions and Interpretation), Section 6.7 (Records), Section 10 (Limitation of Liability and Exclusivity of Remedies), Section 11 (Disagreements), Section 13 (Default, Termination and Remedies), Section 15 (Indemnification), Section 17 (Confidentiality), Section 18 (Security), Section 22 (Miscellaneous), and Section 24 (Entire Agreement and Amendments) shall survive the termination of this Agreement.

2. *Project Implementation and Achievement of Commercial Operations.*

3.1 *Development and Construction (w) Development.* Seller shall (i) use all commercially reasonable efforts to develop, engineer, procure, construct, and Commission the Facility, (ii) achieve the Commercial Operations Date on or prior to the Target COD, and (iii) apply for and obtain all Governmental Approvals and all renewals thereof as are required for Seller to perform its obligations under this Agreement, including air emissions permits.

3.1.2 *Construction.* Seller shall complete, or cause the completion of, the design, construction, installation, and Commissioning of the Facility in a manner consistent with Prudent Industry Practices.

3.1.3 *Status Report.* Starting thirty (30) days after the Effective Date, Seller shall report to Buyer, each month, on the construction status, fuel supply and transportation status, and shall provide a report on Seller's progress toward achieving the milestone schedule included in

Appendix M. Such report shall, at a minimum, provide a schedule showing Facility permit status, items completed and to be completed, the expected Commercial Operations Date, and the estimated percentage of completion for the Facility.

3.2 *Conditions to Commercial Operations.* The occurrence of Commercial Operations of a single Unit or the Facility is contingent upon Seller providing evidence reasonably acceptable to Buyer of the satisfaction or occurrence of all of the following conditions:

3.2.1 *Communications.* The Facility (or single Unit as applicable) has demonstrated the reliability of any communications systems and equipment for communications with the Interconnected Utility's system control center required to be provided by Seller pursuant to this Agreement prior to the Commercial Operations Date.

3.2.2 *Tests.* Seller shall perform a heat rate and capacity testin accordance with Appendix B of a Unit or Units. In conjunction with such test each tested Unit shall operate continuously for a minimum of four (4) consecutive hours synchronized to the Interconnected Utility System at a level equal to at least 288 MW if for both Units and 144 MW if for one Unit, and each Unit has successfully completed five (5) consecutive Start Ups and shutdowns.

3.2.3 *Security.* Seller security arrangements meeting the requirements of Section 18.1 shall have been established.

3.2.4 *Fuel Supply and Transportation.* Seller shall have entered into fuel supply and transportation arrangements of a sufficient level of firmness so as to permit Buyer to Dispatch the Unit or Units in accordance with the terms of this Agreement.

Seller shall be deemed to satisfy this condition if Seller has in place an agreement for balancing services similar in all material respects to the NICOR Transportation and Balancing Agreement for units 1−4 at the Elwood Station. Construction of pipeline facilities and improvements necessary for operation of the Facility has been completed.

3.2.5 *Seller Certification.* Seller has delivered a certificate stating that (1) the Unit has been completed in all material respects (excepting, e.g., punch list items that do not materially adversely affect the ability of the Unit or Units to operate in accordance with Prudent Industry Practice), (2) the Unit or Units has been designed and constructed and all conditions have been satisfied so as to permit Buyer to Dispatch the Unit or Units pursuant to the terms of the Agreement, and (3) that adequate levels of insurance coverage of the types and with the limits for electrical generation facilities similar to the Facility have been purchased by Seller that are usual and customary in accordance with Prudent Industry Practice.

3.2.6 *Opinion of Counsel.* An opinion of Seller's counsel has been rendered that all permits, licenses, approvals, and other Governmental Approvals required for the construction and operation of the Facility in accordance with this Agreement have been obtained.

3.2.7 *Interconnection.* The electrical interconnection of the Facility to the Interconnected Utility System has been completed in accordance with Prudent Industry Practice sufficient to permit Buyer to Dispatch the Unit or Units in accordance with this Agreement.

3.3 *Late Commercial Operations Date.* Seller anticipates that the Commercial Operations Date for each Unit will occur no later than the Target COD.

3.3.1 *COD Delays.* If the Commercial Operations Date for a Unit does not occur prior to 1000 Central Time on the Target COD and if Seller fails to deliver or cause to be delivered Replacement Power or Substitute Power in accordance with Section 4.7.3 or to agree to

Buyer's Delay Book Out Charge as described in Section 3.3.2, Seller shall be liable to Buyer for Delay LDs per Unit per day for the period of the delay.

3.3.2 *Delay Book Out Charge.* Seller may request that Buyer provide Seller a Delay Book Out Charge, which request shall be made by Seller no later than noon sixteen (16) Business Days prior to the Target COD, and by noon every seventh (7/th/) day thereafter, if necessary. Within twenty four (24) hours of Seller's request, Buyer shall provide Seller a quote in dollars at a mutually agreeable time for the first seven (7) days of the Commercial Operations Delay Period (a "Delay Book Out Charge"). Immediately upon Seller's receipt of the quoted Delay Book Out Charge, Seller shall notify Buyer as to whether Seller elects to pay Delay LDs, provide Replacement Power, request Buyer to procure Substitute Power or accept the Delay Book Out Charge (the "Delay Election"). Upon acceptance and payment of the Delay Book Out Charge by Seller, Seller shall be released from any liability for Delay LDs for the first seven (7) days of the Commercial Operations Delay Period and the Target COD shall be delayed by seven (7) days for all purposes other than initiation of Capacity Charges. Seller shall pay Buyer the Delay Book Out Charge within ten (10) days thereafter and may offset such amount against the Capacity Charges due for the period to which the Delay Book Out Charge applies, with such offset discharging Buyer's obligation to pay Capacity Charges to the extent so offset. Subsequent to the Delay Election, if Seller anticipates that the Commercial Operations Date will not occur by the Target COD, Seller may repeat the process for the Delay Election set forth above. If Seller rejects the Delay Book Out Charge, then Seller shall be liable for Delay LDs until the earlier to occur of (a) the time at which Seller begins to deliver or causes to be delivered Replacement Power, (b) the Commercial Operations Date, or (c) the first day of the seven (7) day period to which a subsequent Delay Book Out Charge applies. Any amounts paid by Seller for Delay Book Out Charges shall be deducted from both the Aggregate LD Cap and pro rata from the Per Unit LD Cap for the applicable Unit(s). To the extent that a Unit is capable of delivering and delivers any Electric Energy during a period covered by a Delay Book Out Charge, such Electric Energy shall be purchased by Buyer at a price equal to the Facility Electric Energy Rate plus 80% of the Gross Margin, if the Prevailing Market Price less Transaction Costs exceeds the Facility Electric Energy Rate.

3.3.3 *Amounts of Delay LDs.* Liquidated damages ("Delay LDs") shall accrue at the rate of $100,000 per Unit per day during June, $225,000 per Unit per day during July, $200,000 per Unit per day during August; and for all other months, the prorated daily portion of the applicable month's Capacity Charges per Unit per day, provided however, in no event shall Delay LDs (x) be assessed for the day on which the Commercial Operations Date occurs if it occurs prior to 10:00 a.m. on such day or (y) exceed Per Unit LD Cap, or the Aggregate LD Cap as applicable. Delay LDs shall be offset against Capacity Charges as they come due.

3.3.4 *Interest on Deferred Amounts and Offsets.* To the extent that accrued Delay LDs exceed the Capacity Charges that would have been paid currently if the Facility or a Unit had achieved Commercial Operations on the Target COD, such amounts shall accrue interest at the Default Rate until recovered by Buyer through offsets against Capacity Charges as they come due.

3.3.5 *DLD Escrow.* Notwithstanding the foregoing, if the Commercial Operations Date for one or both Units has not occurred on or before the date (the "Cap Date") that Seller has incurred an aggregate amount of Delay LDs equal to the Per Unit Delay LD Cap (in the case of one Unit) or the Aggregate Delay LD Cap (in the case of both Units), then Seller shall, within seven (7) Business Days after the Cap Date, establish and fund (in cash) an escrow with an A−rated bank (the "DLD Escrow") in an initial amount equal to the gross amount of accrued Delay LDs, plus interest accrued at the Default Rate less offsets of Capacity Charges accrued as of the date the DLD Escrow is funded. If and to the extent Seller fails to establish and/or fully fund the DLD Escrow, the Buyer may draw on the Seller Guarantees for the amount of Delay LDs (plus interest accrued thereon at the Default Rate) not paid or placed in escrow as required by this Section 3.3.5. Upon the Commercial Operations Date, Seller shall be entitled to withdraw from the DLD Escrow an amount equal to the Capacity Charges that accrued from and after the date the DLD Escrow was funded up to and including the Commercial Operations Date. Seller may make subsequent withdrawals each month in an amount equal to such month's Capacity Charges that would be due from Buyer but for offsets pursuant to Section 3.3 until the principal balance in the DLD Escrow is zero. Upon the closing of the account by Seller, Seller shall pay to Buyer an amount equal to the interest that would have been earned on such account at the Default Rate of interest and any funds remaining in the account shall exclusively belong to Seller. At no time shall Buyer be entitled to receive the funds in the account.

3.3.6 *Extended COD Delays.* If the Commercial Operations Date for a Unit has not occurred on or before the date that is 120 days after the Target COD (as extended day−for−day for a Force Majeure Event) (the "Four Month Date"), then the applicable Capacity Rate shall be reduced (the "Capacity Rate Reduction") by an amount equal to $.01 KW−month multiplied by a fraction, the numerator of which is the number of days from the Four Month Date to the Commercial Operations Date and the denominator of which is thirty (30) days. The Capacity Rate Reduction shall take effect beginning with the later to occur of (i) June 1 of the second Contract Year and (ii) the Commercial Operations Date, and continue for the remainder of the Term.

3.3.7 *Termination for Extended Delay.* Buyer may terminate this Agreement with regard to a Unit if the Commercial Operations Date for such Unit is not achieved by June 1, 2002, except to the extent such delay is caused by a Force Majeure Event, in which case such termination date shall be extended by the Force Majeure Period, but in no event beyond June 1, 2003 (provided, however, that Buyer may terminate this Agreement following a Force Majeure Period lasting twelve months or more, unless Seller closes on financing for the Facility by May 31, 2002). If this Agreement is terminated with regard to a Unit(s) pursuant to this Section 3.3.7 for failure to achieve the Commercial Operations Date by June 1, 2002, (i) Buyer's sole remedy for damages and Seller's sole liability for damages shall be for Buyer to offset Delay LDs against Capacity Charges accrued and not paid to Seller prior to termination and to receive the Default Rate of interest on Delay LDs accrued in excess of Capacity Charges due at any given time until such Delay LDs are received by Buyer through offsets against Capacity Charges and (ii) Seller shall have no obligation to pay Delay LDs accrued during any Commercial Operations Delay Period except as an offset against Capacity Charges due from Buyer. If this Agreement is terminated pursuant to this Section 3.3.7, neither Party shall have any liability to the other Party whatsoever (including liability for previously accrued Delay LDs or Capacity Charges, but excluding liability in respect of Delay Book Out Charges and interest accrued on the DLD Escrow at the Default Rate).

3.4 *Commissioning and Test Power.* Seller anticipates that prior to its Commercial Operations Date each Unit will require between 50−100 hours for Commissioning purposes during which Seller will generate Pre COD Test Energy. Buyer shall purchase all Pre COD Test Energy at Pre COD Test Energy Rates as provided in Section 7.2.4. Seller will provide a test schedule prior to each test, and Buyer will advise Seller its estimate of Prevailing Market Prices for Pre COD Test Energy prior to the scheduled start of the testing. Seller shall have no right to sell the Pre COD Test Energy to third parties.

4. *Electric Energy Delivery, Dispatch and Forced Outages Delivery of Electric Energy.* Subject to the terms and conditions of this Agreement, Seller shall sell, make available and deliver at the Point of Delivery and Buyer shall receive and purchase from Seller at the Point of Delivery, Electric Energy as Dispatched by Buyer. Consistent with the terms of this Agreement, Electric Energy shall be generated and delivered from the Facility and may include Incremental Energy.

4.1.1 *Operation in Accordance with Buyer Dispatch.* Buyer shall not be obligated to receive or purchase any Electric Energy from Seller except (a) such Electric Energy as is Dispatched by Buyer and (b) Test Energy. Seller shall not operate either Unit except in response to a Dispatch order from Buyer other than (i) for testing purposes prior to the Commercial Operations Date pursuant to Section 3.4, (ii) for testing purposes after the Commercial Operations Date scheduled in accordance with Section 8.1, or in connection with a Scheduled Maintenance Outage, Forced Derating or Forced Outage or to analyze performance of a Unit or its components; (iii) for Seller's rights to sell to third parties pursuant to Section 13.3.2 or (iv) pursuant to instructions from the Interconnected Utility in accordance with Section 6.6.2 and the Interconnection Agreement. Notwithstanding the above, when a Unit is operating, Seller or its Affiliates may consume electric energy from that Unit for Start−Up of the other Unit of the Facility or other units at the Elwood Station, subject to a credit for the value of such electric energy as set forth in Section 5.1. Seller shall not sell Electric Energy or Capacity to any Person other than (a) Buyer, (b) Interconnected Utility pursuant to the requirements of the Interconnection Agreement, or (c) third parties as permitted under Section 13.3.2.

4.1.2 *Quality of Electric Energy.* All Electric Energy shall be measured by the Revenue Meter and shall meet the specifications of the Interconnected Utility. In the event that electricity delivered by Seller hereunder fails to conform to the specifications of the Interconnected Utility, Seller shall (as soon as reasonably practicable after becoming aware thereof) notify Buyer of the same and of its best good faith estimate of the duration and extent of such failure to conform, and Seller shall attempt to cure such failure as soon as reasonably practicable thereafter. If Seller is unable to deliver electricity to Buyer in accordance with the terms of this Agreement due to such failure to conform to such specifications, such inability to deliver shall be considered a Forced Outage.

4.2 *Point of Sale.* The point where sale of Electric Energy and Replacement Power will take place and title to and risk of loss with respect to, such Electric Energy and Replacement Power shall transfer is at the Point of Delivery for Electric Energy and the Replacement Power Delivery Point for Replacement Power. Buyer shall be responsible for any transmission beyond the Point of Delivery or the Replacement Power Delivery Point, as applicable.

4.3 *Dispatch Rights of Buyer.*

4.3.1 *Buyer Dispatch.* Beginning on the earlier of the Commercial Operations Date and the Target COD and provided that Buyer complies with the mandatory notification obligations in Section 4.3.2, Buyer may Dispatch the delivery of Electric Energy and Replacement Power (if applicable) in accordance with the provisions set forth in this Agreement up to the total Net Dependable Capacity of the Units and may Dispatch Incremental Energy as provided in Section 4.4; *provided, however*, Buyer agrees that Seller may, at its sole discretion but also subject to Prudent Industry Practices, operate any combination of Units 5 and 6 (including overfiring of a Unit to compensate for what would otherwise be a Forced Derating on another Unit), or, during a Cover Period may deliver Replacement Power through other sources (including the Elwood III Units as permitted by the agreement between the owner of the Elwood III Units and the Buyer thereunder) or cause to be delivered Substitute Power to meet Buyer's Dispatch under this Agreement. Notwithstanding the above, except to the extent

Seller has notified Buyer that Seller has arranged for delivery of Replacement Power consistent with the terms of this Agreement, Seller shall be obligated to comply with any Dispatch order issued by Buyer except: (1) during any Scheduled Maintenance Outage or Compressor Wash or (2) to the extent that a Force Majeure Event causes a reduction in the level of the Facility's Available Capacity. Failures by Seller to comply with Buyer's Dispatch orders shall be subject to the provisions of Appendix E for calculation of the Equivalent Availability.

4.3.2 *Dispatch Notifications*

4.3.2.1 *Day Ahead Schedule Notification.* Buyer shall provide to Seller, by no later than 0900 Central Time each day, Buyer's schedule for Dispatch for each hour of the following day (such schedule, the "Day Ahead Schedule"). Buyer may subsequently alter its Dispatch schedule set forth in the Day Ahead Schedule in accordance with Section 4.3.2.3 during Summer Period On−Peak Hours and Section 4.3.2.4 for all other hours.

4.3.2.1 *Facility Availability Notification.* Seller shall, by noon Central Time each day, inform Buyer of the estimated Capacity (taking into account the effect of any expected deratings) that will be available to Buyer for the following three (3) days. These estimates shall not be binding upon Seller and Seller may subsequently alter its estimates. Seller shall advise Buyer of any changes in its estimated Capacity as soon as practicable.

4.3.2.3 *Mandatory Notification Obligation—Summer On Peak Hours.* Buyer must provide Seller its Dispatch request and such request must be confirmed by Seller's operator, for any Summer On Peak Hours a minimum of one hour and twenty five (25) minutes prior to the Requested Load Delivery Time of one or both Units, and if Buyer is also dispatching one or both of the Elwood III Units, one hour and thirty five (35) minutes prior to the Requested Load Delivery Time for all Units Dispatched (including Elwood III Units). Units will be started in accordance with the procedure described in Appendix A. Units will ramp to the requested Dispatch level in accordance with the provisions of Appendix A. Seller shall use reasonable commercial efforts to change Dispatch levels at the request of Buyer while a Unit is running. Buyer must provide one hour's notice, confirmed by Seller's operator, to stop Dispatch (reduce Electric Energy to zero) or to change a Dispatch order during the Summer On Peak Hours. Seller shall not be obligated to comply with any Dispatch order issued for generation during Summer On Peak Hours unless issued with the minimum notice required by this Section, but shall use commercially reasonable efforts to do so. Notwithstanding the above, however, any failure to comply with a noncomplying Dispatch order between the time of issuance of Buyer's Dispatch order and the expiration of the applicable mandatory notification period for such Dispatch order shall not be taken into account for calculation of the Availability Adjustment. For example, if Buyer's Dispatch order for one Unit was given 75 minutes prior to the Requested Load Delivery Time of 1200 and Seller delivers Electric Energy at the requested load by 1210 such delay beyond the Requested Load Delivery Time shall not be taken into account in calculation of an Availability Adjustment; however, deliveries after 1210 shall be taken into account for calculation of the Availability Adjustment.

4.3.2.4 *Mandatory Notification Obligation—Non−Summer Period and Summer Off Peak Hours.* Buyer must provide Seller its Day Ahead Schedule request for Dispatch for any Non−Summer Period and for all Summer Off Peak Hours in accordance with Section 4.3.2.1 above; provided, however, that (a) during the month of September, such Day Ahead Schedule shall not become binding until five (5) hours prior to the scheduled time for a Dispatched Start Up. If Buyer requests to change the Day Ahead Schedule after 0900 on the day covered by such schedule (i.e. the day after the day of its issuance), and if the Unit is on turning gear, Buyer may provide as little as three hours notice prior to its changed Requested Load Delivery Time, with details of the changes to the schedule. Within thirty minutes of Seller's receipt of such notice, Seller shall quote the fee pursuant to Section 7.2.5 in which Seller shall provide Buyer with an expected time at which Seller can achieve the generation level requested by Buyer in its Dispatch order. For the Electric Energy to be delivered between the time of issuance of Buyer's Dispatch order and the expiration of the applicable mandatory notification period for such Dispatch order, Seller shall not be obligated to comply with any Dispatch order issued for generation during the Non−Summer Period or during Summer Off Peak Hours unless either (a) such notice was issued with the minimum notice required by this Section, or (b) Buyer accepts the surcharge above the Base Fuel Charge or a fixed change fee as applicable quoted by Seller pursuant to Section 7.2.5. Immediately upon receipt of Seller's quoted surcharge, Buyer shall either accept such surcharge or the Day Ahead Schedule will remain unchanged. If Buyer accepts such surcharge, Seller shall comply with the revised Dispatch schedule. Notwithstanding the above, however, Buyer must provide one hour's notice to stop Dispatch (reduce Electric Energy to zero).

4.3.2.5 *Cancellation of Start Up.* If Buyer requests Seller to cancel a scheduled Start Up with less than the applicable mandatory notification period (required pursuant to Section 4.3.2 remaining prior to the scheduled Start Up, Seller shall use reasonable commercial efforts to stop or modify its Start Up of the applicable Units and Buyer shall be obligated to pay all of Seller "s reasonable documented out of pocket costs incurred, if any (other than fuel related costs covered in Section 7.2.5) as a result of such cancellation. In addition, if Seller has begun the Start Up Sequence during Summer On Peak Hours or has put the Unit on turning gear during any other hours prior to receipt of Buyer's cancellation request, Buyer shall pay to Seller the Start Up Charge for such Unit.

4.3.2.6 *Communications.* The Parties have developed mutually acceptable procedures for communications between Seller's control room and Buyer's Dispatcher included herewith as Appendix C−Dispatch Communications Guidelines to this Agreement and the Parties shall develop mutually acceptable associated reporting forms for such communications to be appended to this Agreement as Appendix DReporting Forms.

4.3.2.7 *Remote Monitoring.* Seller shall furnish data communication ports on its control system(s), the Revenue Meters, and the Station Fuel Meter such that Buyer may remotely monitor (read only) selected meter and operating data for the Facility and the Elwood III Units. Buyer shall be responsible for all data communication equipment from the data communications port interface to the point of remote monitoring, including the cost of equipment purchase, installation, operations, maintenance and upkeep. Seller shall furnish or shall cause to be furnished in a timely fashion the necessary interface protocol requirements and specifications of its control system and metering equipment such that Buyer may specify its compatible equipment. Seller shall have the right and opportunity to review and approve the specification of the first interface and protective devices of the Buyer to assure that such devices are compatible with and shall not interfere with Seller's control system(s) and metering equipment, and such approval shall not be unreasonably withheld. The data to be sampled, transmitted, and monitored shall include everything that is essential to Buyer's Dispatch. Such data shall include, but may not be necessarily limited to, the meter outputs and process control system data points set forth in Appendix K, which Seller shall use commercially reasonable efforts to make available to

Buyer at Seller's data communications ports on its control system(s), the Revenue Meters, and the Station Fuel Meter.

4.4 *Incremental Energy.* The Facility may through limited over−firing of the Units, have a generation capability that is higher than Net Dependable Capacity of up to approximately five (5) MW per Unit higher than its Net Dependable Capacity. "Incremental Energy" means Electric Energy generated through limited over−firing of the Units (as installed as of the Commercial Operations Date). Buyer may Dispatch Incremental Energy if and to the extent available in an amount of up to 250 hours per Contract Year in accordance with this Section 4.4, if and to the extent that Seller is not generating Incremental Energy to offset a Forced Derating. Buyer shall not be obligated to purchase Incremental Energy at the Incremental Energy Rate to the extent generated by Seller to offset a Forced Derating.

4.5 *Forced Outages*

4.5.1 *First Outage Notice.* Seller must notify Buyer within fifteen (15) minutes (the "First Outage Notice") after discovering that a Unit(s) is (a) unable to deliver all or part of the Electric Energy required during a Dispatch schedule or (b) unavailable for future Dispatch schedules. In such notice Seller shall provide its best estimate of the duration of the Forced Outage or Forced Derating. Within fifteen (15) minutes (but not less than ten (10) minutes) of receipt of such notice, Buyer shall provide to Seller a quote, (such price, the "Outage Book Out Charge") for the remainder of the day of such notice.

4.5.2 *Seller Election.* Immediately upon receipt of Buyer's Outage Book Out Charge, Seller must elect at its sole option, to either:

4.5.2.1 provide Replacement Power on its own behalf as soon as commercially practicable but not later than beginning at the top of the next hour (unless commercial practices permit earlier delivery); or

4.5.2.2 accept Buyer's quoted Outage Book Out Charge; if Seller elects this option then Seller shall pay the quoted and accepted Outage Book Out Charge and upon such payment, Seller shall be released from any further obligation or liability (including Availability Adjustment) associated with the applicable Dispatch order for the remainder of the day covered by such Outage Book Out Charge.

4.5.2.3 Seller's election pursuant to Section 4.5.2 will remain in effect until the earliest to occur of (a) the expiration of Buyer's anticipated Dispatch schedule in effect for that day, (b) the end of the Forced Outage or Forced Derating, or (c) the end of the day of such notice.

4.5.3 *Second Outage Notice.* As soon as practicable, but by no later than two (2) hours after the start of the Forced Outage or Forced Derating (the "Second Outage Notice"), Seller must notify Buyer of (a) the cause of the Forced Outage or Forced Derating, if known, (b) the proposed corrective action, and (c) Seller's best estimate of the expected duration of the Forced Outage or Forced Derating period. Seller shall in such Second Outage Notice elect to either:

4.5.3.1 provide Replacement Power on its own behalf; or

4.5.3.2 request Buyer to procure Substitute Power in accordance with Section 4.7.3.

4.5.3.3 Seller's election under this Section 4.5.3 shall become effective beginning at 0001 on the next day, and will remain in effect until the earlier to occur of: (a) the end of the Forced Outage or Forced Derating or (b) 2300 on the third Business Day after the day on which the Forced Outage or Forced Derating began (the "Diagnostic Period").

4.5.4 *Consequences for Availability Adjustment.* If Seller fails to timely notify Buyer if its election under Section 4.5.2, or its Outage Election or fails to deliver or cause to be delivered either Replacement Power or Substitute Power, such incident shall be included as a Forced Outage or Forced Derating (as applicable) for purposes of the calculation of the Availability Adjustment.

4.5.5 *Incidents Longer than Diagnostic Period.* If Seller determines that the incident is expected to extend beyond the Diagnostic Period, then, Seller shall (as soon as practicable but no later than the expiration of the Diagnostic Period) make an Outage Election applicable to the remainder of the incident.

4.5.6 *Resumption of Delivery.*

4.5.6.1 *From the Facility.* Seller may resume delivery of Electric Energy from the Unit(s) as soon as the Units can produce Electric Energy (if it can be scheduled by Buyer on such short notice). Otherwise, Seller's election under Sections 4.5.2, as applicable above shall take effect no sooner than the top of the next hour provided Seller notifies Buyer 45 minutes in advance of such delivery (for example, if the incident occurs at 0810, Seller's provision of Replacement Power may begin at 0900, avoiding Availability Adjustments as of 0900 but subject to an Availability Adjustment for the period between 0810 and 0900). Seller shall incur an Availability Adjustment only in the event that the incident meets the definition of Forced Outage or Forced Derating and Seller fails to deliver or cause to be delivered Replacement Power or Substitute Power. If Seller is able to resume delivery of Electric Energy before any Outage Election is made, Seller may do so immediately without waiting until the top of the next hour (if it can be scheduled by Buyer on such short notice).

4.5.6.2 *When Substitute Power is Procured.* If Seller is able to resume delivery of Electric Energy from the Unit(s) prior to the expiration of any arrangements (entered into based on Seller's instructions) where Buyer is procuring Substitute Power at Seller's direction in accordance with Section 4.7.3 then, at Seller's direction, Buyer shall use commercially reasonable efforts to liquidate or unwind the Substitute Power arrangements at Prevailing Market Prices and any gain or loss realized by Buyer will be for the Seller's own account.

4.5.6.3 *During an Outage Book Out.* If Seller is able to resume delivery of Electric Energy during a period for which Seller has paid or agreed to pay an Outage Book Out Charge, Seller may resume operation of the applicable Unit(s) or portions thereof and Buyer will market the Electric Energy and pay to Seller 50% of the Gross Margin associated with such transaction plus the Facility Electric Energy Rate, if the Prevailing Market Price less Transaction Costs exceeds the Facility Electric Energy Rate.

4.5.7 *Minimization of Outages.* Consistent with Prudent Industry Practices, Seller shall use reasonable efforts to avoid Forced Outages and Forced Deratings and to minimize the length of any Forced Outages and Forced Deratings.

4.5.8 *Information Related to Outages.* In addition to the foregoing, Seller shall provide to Buyer information relating to outages of Capacity at the Units which could affect Seller's ability to deliver Electric Energy from such Units.

4.6 *Access to Facility.* Seller authorizes Buyer and its authorized agents, employees and inspectors to have access to the Facility, upon reasonable prior notice (in light of the circumstances) and subject to the safety rules and regulations of Seller, solely for the purpose of reading, testing, and maintaining metering equipment, or examining, repairing or removing any of Buyer's property.

4.7 *Delivery of Replacement Power and Substitute Power*

4.7.1 *Replacement Power.* All Replacement Power must be delivered in accordance with the following:

4.7.1.1 Buyer shall issue Dispatch instructions to schedule Replacement Power not in excess of the Net Dependable Capacity for delivery at each hour, and Seller shall, at its expense, deliver or cause to be delivered, all scheduled Replacement Power to the Replacement Power Delivery Point.

4.7.1.1 Buyer shall pay Capacity Charges for all such scheduled and delivered Replacement Power in accordance with Section 7.

4.7.2 *Pre−Commercial Operations Failure to Deliver.* If Seller fails to deliver or fails to cause to be delivered all or any part of any Replacement Power or Substitute Power scheduled for delivery prior to the Commercial Operations Date, Seller shall pay to Buyer within ten (10) days of receipt of an invoice therefor an amount equal to Buyer's actual, reasonable documented direct damages incurred for the cost of cover as a result of such failure to deliver Replacement Power or Substitute Power. At the end of each month during the Commercial Operations Delay Period, Buyer shall invoice Seller for such cost of cover if any incurred during such month, and Seller shall pay such amount within ten (10) days of Buyer's invoice therefor, and if Seller fails to timely pay such amount, Buyer may draw on the Seller Guarantees for such amount.

4.7.3 *Substitute Power.* Any request by Seller that Buyer procure Substitute Power shall be in accordance with the following:

4.7.3.1 Seller shall request Buyer to obtain quotes for Substitute Power on Seller's behalf at Prevailing Market Prices, which instructions shall include information as to whether such Substitute Power shall be obtained on a block or hourly basis.

4.7.3.2 Buyer shall use commercially reasonable efforts to obtain such Substitute Power at Prevailing Market Prices.

4.7.3.3 Subject to Section 4.7.4 at the end of each month, in conjunction with regular billings, if Substitute Power arranged by Buyer is not delivered, Buyer shall pay or credit to Seller any cost of cover damages Buyer receives from the entity that is the source of such Substitute Power.

4.7.4 *Post Commercial Operations Failure to Deliver.* If there is a failure to deliver energy to Buyer under any Substitute Power or Replacement Power arrangement by the entity that is the source of such Replacement Power or Substitute Power, then for the period of the failure until the applicable Unit(s) are able to resume operation in accordance with Buyer's Dispatch Seller shall pay to Buyer the greater of (i) the cost of cover damages ("or market LDs") Seller actually receives from such entity under the Replacement Power arrangement (or the amounts received by Buyer for Substitute Power pursuant to Section 4.7.3.3, (in either case "Third Party Damages") or (ii) the amount of any Availability Adjustment due as a result of such failure, if any.

4.7.5 *Characteristics of Replacement and Substitute Power.* When Seller is delivering Replacement Power to Buyer, Seller shall be obligated to deliver the amount of energy (at no cost to Seller, except to the extent required to deliver Replacement Power to the Replacement Power Delivery Point) scheduled by Buyer, up to the level necessary to comply with Buyer's Dispatch order (taking into account Electric Energy still being delivered by Seller during a Forced Derating) along with associated Ancillary Services in accordance with Section 9. Seller shall make appropriate power purchase and transmission arrangements to the Replacement Power Delivery Point to provide energy to Buyer which is of the same level of firmness (e.g. if unit contingent, an availability comparable to that of the Facility) or higher level of firmness (e.g., system firm, firm with liquidated damages, or as firm as utility native load) as the Net Dependable Capacity hereunder. Substitute Power procured by Buyer may be of a lower level of firmness.

4.8 *Emergency Conditions.* During an Emergency condition, Seller may increase, reduce, curtail or interrupt electrical generation at the Facility in accordance with Prudent Industry Practice or take other appropriate action in accordance with the applicable provisions of the Interconnection Agreement which in the reasonable judgment of the Interconnected Utility may be necessary to operate, maintain and protect the Interconnected Utility System or the transmission system of another Person during an Emergency Condition or in the reasonable judgment of Seller may be necessary to operate, maintain and protect the Facility during an Emergency Condition.

5. *Metering; Billing; Payment*

5.1 *Metering Electricity.* All Electric Energy delivered by Seller to Buyer from the Facility under this Agreement shall be metered by the Revenue Meters and the readings therefrom, including calculated transformer and transmission line losses between the Revenue Meters and the Point of Delivery, shall be made in accordance with Prudent Industry Practice consistently applied. All Replacement Power and Substitute Power delivered to Buyer from facilities inside the Interconnected Utility System, shall be metered by the Interconnected Utility. For all Replacement Power and Substitute Power from sources outside the Interconnected Utility System, the delivered amount shall be the amount scheduled as delivered to the Interconnected Utility System by the system delivering such Replacement Power or Substitute Power into the Interconnected Utility System. The Energy Charge for which Buyer will be billed for Electric Energy also will be net of an adjustment for the value of the amount of electricity consumed by other non−operating Units at the Facility (or the Elwood III Units) during the billing period ("Non−Billable Generation") to yield the "billable generation" for the billing period. To establish the value of kilowatt hours of electricity provided by the Facility and consumed by the Elwood III Units for a billing period, the total for each billing period of electricity consumed by each Unit or unit will be determined from the individual Unit or unit meter readings using the Facility's Revenue Meter(s) (for the Units) and similar meters for the Elwood III Units which will then be summed for (both) Units and the Elwood III Units. Samples of such calculations are set forth in Appendix G.

5.1.1 *Fuel.* Billings for the fuel component of the Energy Rate shall be based on the Actual Heat Rate and the total consumption of gas as measured by the total Station Fuel Meter as prorated to Units 5 and 6 and the Elwood III Units based upon the Individual Fuel Meters, except where Replacement Power and Substitute Power is applicable, in which case the fuel component of the Energy Rate shall be derived in accordance with Section 7.2. Billings for the Variable O&M Rate component of the Energy Charge shall be derived from Revenue Meter information or, in the event Section 5.1.4 below is applicable, the best available data.

5.1.2 *Meter Testing.* The Revenue Meters shall be tested by the Parties at least once each year at Seller's expense and at any other reasonable time upon request by either Party, at the requesting Party's expense; provided, however, Buyer shall have no obligation to pay for any such test if such test results in a recalibration of meters. Seller shall give Buyer at least fourteen (14) days notice of any testing of the Revenue Meters, Station Fuel Meters, and Individual Fuel Meters and Buyer shall have the right to be present during all testing and shall be furnished all testing results on a timely basis.

5.1.3 *Inaccurate Meters.* If testing of the Revenue Meters indicates that an inaccuracy of more than +/−.5% in measurement of Electric Energy has occurred, the affected Revenue Meter shall be recalibrated promptly to register accurately within the Revenue Meter manufacturer stated tolerances. Each Party shall comply with any reasonable request of the other concerning the sealing of meters, the presence of a representative of the other Party when the seals are broken and the tests are made, and other matters affecting the accuracy of the measurement of Electric Energy. If either Party believes that there has been a meter failure or stoppage, it shall immediately notify the other Party.

5.1.4 *Failed Meters.* If, for any reason, any Revenue Meter is out of service or out of repair so that the amount of Electric Energy delivered cannot be ascertained or computed from the readings thereof, the Electric Energy delivered during the period of such outage shall be estimated and agreed upon by the Parties hereto upon the basis of the best data available, and any failure to agree shall be subject to resolution in accordance with Section 11.

5.1.5 *Examination of Records.* Each Party (and its representative(s)) has the right, at its sole expense, upon reasonable notice and during normal working hours, to have an independent third party examine the records of the other Party to the extent reasonably necessary to verify the accuracy of any statement, charge or computation relating to the output of Electric Energy. If requested, a Party shall provide to the other Party statements evidencing the amounts of Electric Energy delivered at the Point of Delivery.

5.2 *Adjustment for Inaccurate Meters.* If a Revenue Meter fails to register, or if the measurement made by a Revenue Meter is found upon testing to be inaccurate by more than or less than one half of one percent (.5%), an adjustment shall be made correcting all measurements by the inaccurate or defective Revenue Meter for both the amount of the inaccuracy and the period of inaccuracy, in the following manner:

5.2.1 As may be agreed upon by the Parties, or

5.2.2 In the event that the Parties cannot agree on the amount of the adjustment necessary to correct the measurements made by any inaccurate or defective Revenue Meter, the Parties shall use Seller's backup metering, if installed, to determine the amount of such inaccuracy; *provided, however*, that Seller's backup metering has been tested and maintained in accordance with the provisions of this Section 5.2.2. In the event that Seller's backup metering also is found to be inaccurate by more than the allowable limits set forth in this Section 5.2.2, the Parties shall mutually agree to estimate the amount of the necessary adjustment on the basis of deliveries of Capacity and Electric Energy during periods of similar operating conditions when the Revenue Meter was registering accurately.

5.2.3 In the event that the Parties cannot agree on the actual period during which the Revenue Meter(s) made inaccurate measurements, the period during which the measurements are to be adjusted shall be the shorter of (i) the last one−half of the period from the last previous test of the Revenue Meter to the test that found the Revenue Meter to be defective or inaccurate, or (ii) the one hundred eighty (180) days immediately preceding the test that found the Revenue Meter to be defective or inaccurate.

5.2.4 To the extent that the adjustment period covers a period of deliveries for which payment has already been made by Buyer, Seller shall use the corrected measurements as determined in accordance with Sections 5.2.1, 5.2.2, or 5.2.3 hereof to recompute the amount due for the period of inaccuracy and shall subtract the previous payments by Buyer for this period from such recomputed amount. If the difference is a positive number, the difference shall be paid by Buyer to Seller; if the difference is a negative number, that difference shall be paid by Seller to Buyer in the form of an offset to payments due Seller by Buyer hereunder. Adjustment of such difference by the owing Party shall be made not later than thirty (30) days after the owing Party receives notice of the amount due, unless Buyer elects payment via an offset.

5.3 *Billing.* Within ten (10) days after the last day of each month during the Term, Seller shall render a statement to Buyer for the amounts due in respect of such month under Section 7, which statement shall contain reasonable detail showing the manner in which the applicable charges were determined.

5.4 *Payments.* The amount due to Seller as shown on any monthly statement rendered by Seller pursuant to Section 5.3 shall be paid by Buyer by electronic wire transfer to an account specified by Seller within ten (10) days after the date such statement is received by Buyer. Any amount not paid by Buyer when due shall bear interest at the Default Rate from the date that the payment was due until the date payment by Buyer is made.

5.5 *Offsets.* Amounts due to Buyer as a result of late Commercial operations Date pursuant to Section 3.3 or amounts due to Buyer pursuant to Section 7 shall be offset against current and future payments due from Buyer with interest accrued daily at the Default Rate until fully offset or paid.

5.6 *Billing Disputes.*

5.6.1 If a Party questions or contests any amount claimed by the other Party to be due under Section 7, the Party obligated to pay shall pay the entire invoiced amount including the disputed portion (except obvious typographical or administrative errors).

5.6.2 In the event that either Party, by timely notice to the invoicing Party, questions or contests the correctness of any charge or payment claimed to be due by the invoicing Party, the invoicing Party shall promptly review the questioned charge or payment and shall notify the invoiced Party, within fifteen (15) Business Days following receipt by the invoicing Party of such notice, of the amount of any error and the amount of any reimbursement that the invoiced Party is entitled to receive in respect of such alleged error. Any disputes not resolved within fifteen (15) Business Days after the invoicing Party's receipt of notice from the invoiced Party shall be resolved in accordance with Section 11. Upon determination of the correct amount of any reimbursement, such amount shall be promptly paid by the invoicing Party to the invoiced Party.

5.6.3 Reimbursements made under this Section 5.6 shall include interest at the Default Rate from the date the original payment was made until the date of such reimbursement.

6. *Operation and Maintenance of the Facility*

6.1 *Standard of Operation*

6.1.1 *Operation and Maintenance.* Seller shall manage, control, operate and maintain the Facility in a manner consistent with Prudent Industry Practice, in accordance with (a) the practices, methods, acts, guidelines, standards and criteria of MAIN, NERC, the ISO and any successors to the functions thereof; (b) the requirements of the Interconnection Agreement; and (c) all applicable Requirements of Law and (d) permits taking into account Buyer's Dispatch rights under this Agreement.

6.1.2 *Fuel Arrangements.* Seller shall obtain and maintain fuel supply and transportation arrangements in a manner consistent with Prudent Industry Practice, taking into account Buyer's Dispatch rights under this Agreement.

6.1.3 *Insurance.* Seller shall obtain and maintain appropriate insurance coverages typical for plants similar to the Facility, in accordance with Prudent Industry Practice.

6.2 *Permits and Licenses.* Seller will obtain and maintain all certifications, permits, licenses and approvals necessary to operate and maintain the Facility and to perform its obligations under this Agreement during the Term.

6.3 *Sole Remedy.* Buyer's sole and exclusive remedy (other than specific performance) and Seller's sole and exclusive liability for breach of Section 6.1 shall be the Availability Adjustment and the termination rights provided in Section 13.4.

6.4 *Scheduled Maintenance.* No later than March 1, 2001, Seller shall submit to Buyer a proposed schedule of Scheduled Maintenance Outages scheduled by Seller for the following Contract Year for the Units, which schedule shall be updated by Seller by each March 31 and September 30 thereafter to cover the twelve month period following each such update; provided, however, that no Scheduled Maintenance Outage may be scheduled to cover the period from May 15 to September 15. Parameters within which Scheduled Maintenance Outages must be planned are included as Appendix I. If the OEM issues recommendations for changes to the parameters in Appendix I, the parties shall negotiate in good faith to revise Appendix I accordingly. Such schedule, and each supplement thereto, shall indicate the planned start and completion dates for each Scheduled Maintenance Outage during the period covered thereby and the amount of the Net Dependable Capacity of a Unit that will be affected. Within thirty (30) days of receipt of such schedule or any supplement thereto, Buyer may request reasonable modifications in the Scheduled Maintenance Outage schedule contained therein. Both parties agree to use reasonable efforts to develop a mutually acceptable final schedule for such Scheduled Maintenance Outages. If within six months prior to the scheduled start of a Scheduled Maintenance Outage, Buyer desires to change the scheduled start or duration of such Scheduled Maintenance Outage, Buyer shall notify Seller of Buyer's requested change and Seller shall use reasonable efforts to accommodate Buyer's requested change. Seller may propose compensation from Buyer to Seller for such change. Buyer shall then have the right to either direct such change and pay Seller such compensation, or withdraw the request for such change. At least one week prior to any Scheduled Maintenance Outage, Seller shall orally notify Buyer of the expected start date of such Scheduled Maintenance Outage, the amount of Capacity at the Units that will not be available to Buyer during such Scheduled Maintenance Outage, and the expected completion date of such Scheduled Maintenance Outage. Seller shall orally notify Buyer of any subsequent changes in such Capacity not available or any subsequent changes in the Scheduled Maintenance Outage completion date. As soon as practicable, all such oral notifications shall be confirmed in writing. Scheduled Maintenance Outages may be taken in any number of non−contiguous periods, subject to Buyer's approval, which shall not be unreasonably withheld or delayed. Subject to the foregoing, the duration, frequency and timing of Scheduled Maintenance Outages shall be based on OEM recommendations and the age and operation of the Units generally plus up to five (5) days per Unit on a semi−annual basis for Non−Summer Period balance of plant maintenance.

6.5 *Compressor Wash.* Buyer shall permit Seller to shut down each Unit (either at the same time or at different times) for a compressor wash, (the "Compressor Wash") at a mutually agreeable time that is not during On−Peak Hours, approximately once per month in the Summer Period. Such Compressor Wash requires that the Unit be off−line for an eighteen (18) hour cool down period prior to the start of such Compressor Wash. Seller agrees that at any time during such cool down period, Buyer may interrupt such cool down, Dispatch the Unit on−line and cause

Seller to reschedule the cool down and Compressor Wash for the next mutually agreeable time. Buyer agrees that once the actual Compressor Wash begins, the Compressor Wash must be completed without interruption and that Buyer cannot Dispatch the Unit on−line until such Compressor Wash is completed.

6.6 *Operating Characteristics*

6.6.1 *Design Limits.* The operating characteristics of the Facility shall be consistent with the Design Limits set forth in Appendix A unless otherwise mutually agreed by the Parties. Any such agreed upon change must be in writing, signed by both Parties. If the OEM provides written direction for operations that requires a change to the Design Limits, the Parties will negotiate in good faith to modify the Design Limits accordingly.

6.6.1 *Interaction with Interconnected Utility System.* Buyer understands that Seller may be required to increase, reduce, curtail or interrupt electrical generation at the Facility in accordance with Prudent Industry Practice or to take other appropriate action in accordance with the applicable provisions of the Interconnection Agreement which in the reasonable judgment of the Interconnected Utility may be necessary to operate, maintain and protect the Interconnected Utility System or the transmission system of another Person during an Emergency Condition or in the reasonable judgment of Seller may be necessary to operate, maintain and protect the Facility during an Emergency Condition. Any such curtailment shall be applied by Seller prorata across all units at the Elwood Station to the extent allowed by existing contracts (for electrical output from the Elwood Station) which terminate December 31, 2004 and in all cases shall be prorata for future power contracts. For purposes of calculating the Availability Adjustment, the Facility shall be considered Available during any such increase, reduction, curtailment, interruption or action, unless the order to increase, reduce, curtail, interrupt, or take other action with respect to generation at the Facility or the Emergency Condition is caused by a condition on Seller's side of the interconnection point between the Facility and the Interconnected Utility System. Buyer acknowledges that other conditions on the Interconnected Utility System (for example, transmission outages or interruptions) may impact Seller's ability to deliver Electric Energy into the Interconnected Utility System at the Point of Delivery. For purposes of calculating the Availability Adjustment, the Facility shall be considered Available during any time that the Facility would have been actually Available but for conditions (including, for example, transmission outages or interruptions) on the Interconnected Utility System.

6.7 *Records.* Each Party shall keep and maintain all records as may be necessary or useful in performing or verifying any calculations made pursuant to this Agreement, or in verifying such Party's performance hereunder. All such records shall be retained by each Party for at least six (6) calendar years following the calendar year in which such records were created. Each Party shall make such records available to the other Party for inspection and copying at the other Party's expense, upon reasonable notice during such Party's regular business hours. Each Party shall have the right, upon thirty days written notice prior to the end of an applicable six (6) calendar year period to request copies of such records. Each Party shall provide such copies, at the other Party's expense, within thirty (30) days of receipt of such notice or shall make such records available to the other Party in accordance with the foregoing provisions of this Section 6.7.

7. *Compensation*

7.1 *Capacity Charge.* For each month, commencing June 1, 2001 (as such date is extended for Force Majeure Events pursuant to Section 19) and each month thereafter during the Term, Buyer shall owe Capacity Charges calculated pursuant to Section 7.1.1 (subject to offsets pursuant to Section 5.5).

7.1.1 *Computation.* The Capacity Charge for each month shall be equal to the product of (a) the applicable Capacity Rate for such month times (b) the Net Dependable Capacity for such month, minus the Availability Adjustment, when applicable.

7.1.2 *Capacity Rates.* The Capacity Rate during the Term shall be: (a) $7.90 per kW per month from June 1, 2001 to December 31, 2001, and (b) $5.11 per kW per month for the remainder of the Initial Term subject in each case to a Capacity Rate Reduction. The Capacity Rate for the Extension Term shall be $4.90 per kW per month, subject to a Capacity Rate Reduction.

7.1.2 *Availability Adjustment to Capacity Charge.* From and after the Commercial Operations Date, if the Facility does not achieve the Guaranteed Summer Super Peak Availability, Guaranteed Summer Partial Peak Availability or the Guaranteed Non−Summer On Peak Availability, as measured by Equivalent Availability in accordance with *Appendix E*, Seller shall be subject to the application of an Availability Adjustment as liquidated damages as provided in this Section 7.1.3.

7.1.3.1 *Summer Period.* For each month in the Summer Period, the Availability Adjustment shall equal the sum of (a) the Availability Adjustment for the Super Peak Hours plus (b) the greater of zero and the Availability Adjustment for the Partial Peak Hours where:

(i) the Availability Adjustment for Super Peak Hours is the product of (a) the sum of the monthly Capacity Charges (before application of the Availability Adjustment) for the applicable Contract Year and (b) the applicable Monthly Adjustment Factor and (c) 75% and (d) the Guaranteed Summer Super Peak Availability less the actual Equivalent Availability for Super Peak Hours during such month; and

(ii) the Availability Adjustment for Partial Peak Hours is the product of (a) the sum of the monthly Capacity Charges (before application of the Availability Adjustment) for the applicable Contract Year and (b) the applicable Monthly Adjustment Factor and (c) 25% and (d) the Guaranteed Summer Partial Peak Availability less the actual Equivalent Availability for Partial Peak Hours during such month.

(iii) for purposes of the calculations in subsections (i) and (ii) above and Section 7.1.3.4 only, in the first Contract Year, the first Contract Year shall be deemed to be from June 1, 2001 through May 31, 2002.

7.1.3.2 *Non−Summer Period.* For the Non−Summer Period the Availability Adjustment shall equal the Availability Adjustment for Non−Summer On Peak Hours, where:

The Availability Adjustment for Non−Summer On Peak Hours is the product of (a) the sum of the monthly Capacity Charges (before application of the Availability Adjustment) for the applicable Contract Year and (b) 18% and (c) the Guaranteed Non−Summer On Peak Availability less the actual Non−Summer On Peak Availability for such Non−Summer Period. This will be calculated once per Contract Year.

7.1.3.3 *Super Peak 80% or below.* If the Equivalent Availability during Super Peak Hours in any month is less than or equal to 80%, then for purposes of calculating the Availability Adjustment during the Partial Peak Hours in the same month, the Equivalent

Availability during Partial Peak Hours shall be deemed to be equal to the Equivalent Availability during Super Peak Hours for such month.

7.1.3.4 *Availability Adjustment Limit.* In no event shall the cumulative Availability Adjustment exceed (i) in the first Contract Year, $24,000,000, (ii) in all other Contract Years, other than the final Contract Year, $18,000,000 per year and (iii) in the final Contract Year $12,000,000.

7.1.4 *Capacity Bonus.*

7.1.4.1 *Applicability of Bonus.* Buyer shall pay Seller a Capacity Bonus if both (a) the Average Summer Super Peak Availability exceeds the Guaranteed Summer Super Peak Availability and (b) the Average Summer Partial Peak Availability exceeds the Guaranteed Partial Peak Availability; provided, however, if the Summer Super Peak Availability during any Summer Period month is less than or equal to 80%, then Seller shall not be entitled to a Capacity Bonus.

7.1.4.2 *Calculation of Bonus.* The Capacity Bonus for each Unit shall be equal to: [(Average Summer Super Peak Availability minus Guaranteed Summer Super Peak Availability)/.03 * maximum Capacity Bonus * .75] + [(Average Summer Partial Peak Availability minus Guaranteed Summer Partial Peak Availability)/.03 * maximum Capacity Bonus * .25]. For the first year of Commercial Operations, the maximum Capacity Bonus per Unit shall be equal to the sum of (a) (number of days of Commercial Operations in June / 30 days) * $27,500 and (b) (number of days of Commercial Operations in July / 31 days) * $48,750 and (c) (number of days of Commercial Operations in August / 31 days) * $48,750. For all other Contract Years, the maximum Capacity Bonus shall be equal to $125,000 per Unit.

7.1.4.3 *Payable Monthly.* The Capacity Bonus shall be divided by 12 and shall be paid over a 12 month term beginning with September of each Contract Year.

7.2 *Energy Charge.* Each month beginning on the earlier of the Commercial Operations Date or the Target COD and continuing for the Term, Buyer shall pay Seller an Energy Charge to the extent Seller delivers Electric Energy, Incremental Energy, Replacement Power or Test Energy. The Energy Charge for a billing month shall equal to the difference between (A) the sum of (a) the product of the total Electric Energy (in MWh) delivered to Buyer at the Point of Delivery from the Facility pursuant to Buyer's Dispatch orders, multiplied by the Facility Electric Energy Rate for each hour of such month plus (b) the product of the total Replacement Power (in MWh) provided by Seller to Buyer at the Replacement Power Delivery Point pursuant to Buyer's Dispatch orders, multiplied by the Replacement Power Energy Rate for each hour of such month adjusted for any Differential Transmission Adjustments incurred by Buyer plus (c) the product of the total Incremental Energy delivered to Buyer at the Point of Delivery pursuant to Section 4.3 multiplied by the Incremental Energy Rate for each hour of such month, plus (d) the product of the Test Energy (either Pre COD Test Energy or Post COD Test Energy, as applicable) multiplied by the applicable Test Energy Rate, minus (B) any Substitute Power Cost Credit.

7.2.1 *Facility Electric Energy Rate.* The Facility Electric Energy Rate is calculated as (the Actual Heat Rate × Fuel Charge)/1000+Variable O&M Rate.

7.2.2 *Replacement Power Energy Rate.* The Replacement Power Energy Rate is calculated as (Reference Heat Rate × Fuel Charge)/1000+Variable O&M Rate.

7.2.3 *Incremental Energy Rate.* The Incremental Energy Rate is the sum of $100/MWh of Incremental Energy delivered to the Point of Delivery plus (a) with respect to the first 100 hours per Unit of Incremental Energy Dispatched by Buyer during any Contract Year, twenty percent (20%) of the Gross Margin resulting from such transaction, and (b) with respect to the next 150 hours per Unit of Incremental Energy Dispatched by Buyer in any Contract Year, thirty five (35%) of the Gross Margin resulting from such transaction.

7.2.4 *Test Energy Rates*

7.2.4.1 *Pre COD Test Energy.* The Pre COD Test Energy Rate shall be one of the following. If the Prevailing Market Price (less Transaction Costs) (expressed as $/MWh) is greater than the Facility Electric Energy Rate, the Pre COD Test Energy Rate shall be the sum of the Facility Electric Energy Rate, plus 95% of the difference between the Facility Electric Energy Rate and the Prevailing Market Price (less Transaction Costs). If the Prevailing Market Price (less Transaction Costs) is less than the Facility Electric Energy Rate, the Pre COD Test Energy Rate shall be 100% of such Prevailing Market Price less Transaction Costs, (but not including Scheduling Fees).

7.2.4.2 *Post COD Test Energy.* The Test Energy Rate for Post COD Test Energy shall be equal to either (a) the Facility Electric Energy Rate with respect to a test requested by Buyer the results of which do not require any corrections or adjustments, or (b) the lesser of the Facility Electric Energy Rate or the Prevailing Market Price (less Transaction Costs) in all other circumstances.

7.2.4.3 *Substitute Power Cost Credit.* Substitute Power Cost Credit shall be the Buyer's documented cost per MWh of Substitute Power (adjusted for any documented Differential Transmission Adjustments incurred by Buyer, if incrementally higher, or less any amounts of Differential Transmission Adjustments saved by Buyer if incrementally lower, less the Replacement Power Energy Rate multiplied by the Substitute Power (expressed in MWh) purchased by Buyer for each hour of such month.

7.2.5 *Fuel Charge*

7.2.5.1 *Base Fuel Charge.* If Buyer does not alter its Day Ahead Schedule, the Fuel Charge for all Electric Energy delivered in accordance with such schedule shall be the Fuel Index value plus 10 cents/MMBtu.

7.2.5.2 *Changes to Day Ahead Schedule for the Summer On Peak Hours and in September for On Peak Hours.* If Buyer makes a change(s) to the Day Ahead Schedule for operation in Summer On Peak Hours or in the On Peak Hours in September as provided in Section 4.3.2.4, the Fuel Charge for such Electric Energy generated pursuant to such Dispatch order shall be the Fuel Index value plus 15 cents/MMBtu.

7.2.5.3 *Changes to Day Ahead Schedule for Non−Summer Period and Summer Off Peak Hours.* If Buyer makes changes to the Day Ahead Schedule for operation in the Non−Summer Period or Summer Off Peak Hours and such change requires Seller to purchase more gas than would have been purchased but for such change in the schedule, then Seller shall provide Buyer with a quoted surcharge to be added to the Base Fuel Charge, the sum of which shall be the Fuel Charge for all Electric Energy generated pursuant to such changed schedule. If such change requires Seller to liquidate any excess gas, then Seller shall provide Buyer with a quoted fixed change fee pursuant to such changed schedule. If Buyer does not accept the quoted fixed change fee, Seller will proceed with operation of the Facility in accordance with the Dispatch schedule in effect prior to the requested change.

7.2.6 *Early Commercial Operations Date.* If the Commercial Operations Date occurs prior to June 1, 2001 for one or both Units, Buyer shall market and sell such Electric Energy delivered to Buyer from such Unit(s) at the Prevailing Market Price therefor, if the Prevailing

Market Price less Transaction Costs exceeds the Facility Electric Energy Rate and Buyer shall remit to Seller 90% of the Gross Margin on any such transaction.

7.3 *Adjustment to Actual Heat Rate for Failure to Meet Guaranteed −Heat Rate.*

7.3.1 *Established by Testing.* For purposes of calculating the Facility Electric Energy Rate, the Actual Heat Rate shall be reduced if the results of periodic tests indicate the combined Net Heat Rate of Units 5 and 6 and the Elwood III Units is greater than the Guaranteed Heat Rate under test conditions as set forth in Appendix B. The adjustment to the Actual Heat Rate shall be equal to the ratio of the Guaranteed Heat Rate divided by the Net Heat Rate, times the Actual Heat Rate. If any adjustment is necessary, the Actual Heat Rate Adjustment shall be effective retroactive to the date on which it was mutually determined that the Actual Heat Rate exceeded the Guaranteed Heat Rate and shall remain in effect until it is demonstrated by testing that the Net Heat Rate is less than the Guaranteed Heat Rate. In the event that Seller makes repairs to reduce the Net Heat Rate, the improvement shall be demonstrated by testing conducted at the expense of the Seller and the resulting adjustment to the Actual Heat Rate shall be retroactive to the date that repairs were effected.

7.3.2 *Accrual of Heat Rate Credits.* To the extent Net Heat Rate (including the Initial Net Heat Rate) is below the Threshold Heat Rate, Seller shall accrue half of such difference as credits to be applied in the future when the Net Heat Rate exceeds the Guaranteed Heat Rate ("Heat Rate Credits"). To the extent that the Net Heat Rate (beginning with the first test of the Net Heat Rate after the determination of the Initial Net Heat Rate) is less than the Initial Net Heat Rate (after application of the Degradation Curve) all of the difference will be accrued as Heat Rate Credits. For the purposes of tracking and accrual tabulation, the Heat Rate Credits that are established by testing shall be multiplied by the Electric Energy (kWh) delivered over the same period as the test results application period, and shall effectively be accrued in units of heat energy (Btus). If there is retroactive adjustment as provided for in Section 7.3.1, then the accrual tabulation of heat energy units shall be adjusted for the same period.

7.3.3 *Application of Heat Rate Credits.* If the Net Heat Rate (including the Initial Heat Rate) exceeds the Guaranteed Heat Rate, Seller may reduce the Net Heat Rate for purposes of calculating the Actual Heat Rate Adjustment (for the period during which such Net Heat Rate is in effect) by up to 50 Btus/kWh so long as Heat Rate Credits exist. The Seller's accumulated quantity of Heat Rate Credits shall be reduced to the extent utilized to reduce the Net Heat Rate. For the purposes of tracking and application tabulation, the negative Heat Rate Credits that are established by testing shall be multiplied by the Electric Energy (kWh) delivered over the same period as the test results application period, and shall effectively become a withdrawal of heat energy units (Btus) from the accumulated units of energy per Section 7.3.2. If there is retroactive adjustment as provided for in Section 7.3.1, then the withdrawal tabulation of heat energy units shall be adjusted for the same period.

7.3.4 *Cost of Heat Rate Tests.* The costs (and allocation of the costs) of any test pursuant to this Section 7.3 are set forth in Section 8.2.

7.4 *Start Up Charge.* For each Start Up of a Unit pursuant to the Dispatch of such Unit by Buyer, Seller shall be entitled to a payment of $2500.00 (the "Start Up Charge") in June 1, 1999 dollars. At the beginning of each Contract Year (i.e., January 1), thereafter, the Start Up Charge shall be adjusted by the change in the GDP−IPD from the GDP−IPD value on the previous January 1 (or June 1 in the case of the first Contract Year). Seller shall pay for the gas consumed during any Failed Starts.

7.5 *Imbalance Charges.* Buyer shall hold Seller harmless from any Imbalance Charges (i) that result from Buyer's Dispatch orders or other scheduling of generation under this Agreement, (ii) that are assessed against Buyer or Seller at any time when the Facility is generating Electric Energy within 1.5% of the Dispatch level directed by Buyer after achieving Start Up and has achieved the desired Dispatched load level for a period of ten (10) minutes, (iii) that are assessed for deliveries of Electric Energy during startup and shutdown, so long as Seller operates, Starts Up and shuts down the Units in accordance with this Agreement or (iv) that result from Unit trips. Buyer and Seller recognize that the Units may produce more or less energy than scheduled by Buyer.

7.6 *Rates Not Subject to Review.* The rates for service specified herein (i.e., delivery of Electric Energy, Replacement Power and Capacity) shall remain in effect for the Term, and shall not be subject to change through application to the FERC pursuant to provisions of Section 205 et seq. of the Federal Power Act, absent agreement of the Parties.

8. *Performance Tests.*

8.1 *Test Procedures.* Seller must conduct a test to determine the Initial Net Heat Rate in conjunction with the final performance testing for each Unit under the contract with the EPC Contractor. Seller must conduct a test on or prior to the Commercial Operations Date to determine Net Dependable Capacity. Thereafter at least once per Contract Year, Seller must conduct a test to determine the Net Dependable Capacity and Net Heat Rate. After the Commercial Operations Date, such annual testing shall be conducted on or about June 1 of each Contract Year at a mutually agreeable time. Any test to determine the Net Dependable Capacity and Net Heat Rate shall include a period of two hours during which the Net Dependable Capacity is generated and the Electric Energy delivered to the Point of Delivery. Once a test period has been initiated, it must last for two hours unless Buyer's and Seller's authorized representatives mutually agree to a shorter duration. Testing procedures to establish the Net Dependable Capacity and Net Heat Rate from and after the Commercial Operations Date are included as Appendix B and are consistent with ASME and OEM guidelines to the extent practicable. No tests will be conducted or continued which, in the opinion of Seller, should not be conducted or continued in accordance with Prudent Industry Practice. Seller shall always have the right to perform a Compressor Wash prior to a test. If Seller prevents or discontinues a test in accordance with Prudent Industry Practice, Buyer shall have the right to require a retest upon prior notice to Seller, if the test was conducted pursuant to Buyer's request.

8.2 *Buyer Right to Request Testing.* Buyer shall have the right, at its expense (except as provided in this Section 8.2), to require Seller to establish or reestablish the Net Dependable Capacity and Net Heat Rate on or about the Commercial Operations Date and annually thereafter pursuant to a performance test conducted at a mutually agreeable time if the Buyer reasonably believes based upon operation of the Facility over the preceding thirty (30) days that the Net Dependable Capacity as adjusted in accordance with Section 8.1 is more than 2% below the then current level of Net Dependable Capacity or the Net Heat Rate exceeds the Guaranteed Heat Rate. The first such test of a Unit (regardless of the number of Units tested in such tests) in each Contract Year shall be performed without a charge to Buyer. For the second test required by Buyer in the same Contract Year, the Buyer shall pay to Seller $5,000, for the third test, $15,000 and for the fourth test and all subsequent tests, $30,000 (regardless, in each case, of the number of Units tested in such tests). If the results of the test indicate the Net Dependable Capacity is below 2% of the current level or that Net Heat Rate exceeds the Guaranteed Heat Rate, Buyer shall not pay for the cost of the test.

8.3 *Seller Right to Retest.* Seller shall have the right to reestablish Net Dependable Capacity and Net Heat Rate pursuant to a capacity test at mutually agreeable time(s). The results of each capacity test under this Section 8.3 shall immediately determine or redetermine the Net Dependable Capacity and Net Heat Rate retroactively to the date Seller can reasonably demonstrate that it took corrective actions to improve the Net Dependable Capacity or Net Heat Rate, adjusted by reference to the curves in Appendix F to Reference Conditions.

8.4 *Conditions for Testing.* During any capacity testing, Seller shall designate a maximum level for Buyer's Dispatch during such capacity testing, which may be above the then current Net Dependable Capacity. All appropriate auxiliary equipment associated with the Facility shall be in service at the time of any test under this Section 8.3. Test data shall be collected with plant instruments, except that Seller shall be allowed to substitute test instrumentation for Facility instrumentation, provided that the test instrumentation is of greater accuracy. Determination of net plant output shall be with the Revenue Meter with appropriate adjustments made for transformer and line losses.

8.5 *Scheduling of Testing.* Any testing requested by Seller after the Commercial Operations Date shall either be performed during times Dispatched by Buyer to generate or at mutually agreeable times. Buyer shall be entitled to witness any such tests.

9. *Ancillary Services*

9.1 *Availability of Ancillary Services.* Buyer shall be entitled, at no additional cost, to all Ancillary Services with respect to the Net Dependable Capacity at the Point of Delivery. Seller does not guarantee the availability of any ancillary services but does warrant that it will not remarket such services to any third party; except in the case of Buyer default under Section 13.2.1. Notwithstanding the above, Seller has the right to use Ancillary Services to meet any requirement of the Interconnected Utility System, the ISO, or their successors.

9.2 *Operational Considerations.* Buyer may Dispatch the Facility with the objective to avoid the need for energy imbalance service from a control area service provider, and to provide reactive power, load following (consistent with the scheduling), voltage control, and frequency response, provided that such services do not cause the Facility to operate outside of the Design Limits, and do not impose any additional costs or liabilities on Seller.

9.3 *Future Enhancements.* Seller shall provide such services, including but not limited to automatic generation control, to the extent that Buyer agrees to be responsible for reasonable incremental costs incurred by Seller to provide such services subject to mutual agreement of the parties working in good faith to arrive at an equitable arrangement.

10. *Limitation of Liability and Exclusive Remedies*

10.1 *CONSEQUENTIAL DAMAGES.* IN NO EVENT OR UNDER ANY CIRCUMSTANCES SHALL EITHER PARTY (INCLUDING SUCH PARTY'S AFFILIATES AND SUCH PARTY'S AND SUCH AFFILIATES' RESPECTIVE DIRECTORS, OFFICERS, EMPLOYEES AND AGENTS) BE LIABLE TO THE OTHER PARTY (INCLUDING SUCH PARTY'S AFFILIATES AND SUCH PARTY'S AND SUCH AFFILIATE'S RESPECTIVE DIRECTORS, OFFICERS, EMPLOYEES AND AGENTS) FOR ANY SPECIAL, INCIDENTAL, EXEMPLARY, INDIRECT, PUNITIVE OR CONSEQUENTIAL DAMAGES OR DAMAGES IN THE NATURE OF LOST PROFITS, WHETHER SUCH LOSS IS BASED ON CONTRACT, WARRANTY OR TORT. A PARTY'S LIABILITY UNDER THIS AGREEMENT SHALL BE LIMITED TO DIRECT, ACTUAL DAMAGES.

10.2 *SOLE REMEDIES FOR FAILURE TO DELIVER OR RELATED BREACHES.* NOTWITHSTANDING ANY OTHER PROVISION OF THIS AGREEMENT, OTHER THAN AS PROVIDED IN SECTION 10.3 BELOW, BUYER'S SOLE REMEDY FOR DAMAGES AND SELLER'S SOLE LIABILITY FOR DAMAGES FOR SELLER'S DEFAULT RELATING

TO, ARISING OUT OF, OR IN ANY WAY CONNECTED WITH ANY FAILURE BY SELLER TO MEET GUARANTEED SUMMER ON PEAK AVAILABILITY OR GUARANTEED NON−SUMMER ON PEAK AVAILABILITY, TO DELIVER (OR CAUSE TO BE DELIVERED) ELECTRIC ENERGY, REPLACEMENT POWER OR SUBSTITUTE POWER AS DISPATCHED BY BUYER, OR FAILURE TO COMPLY WITH ANY FACILITY PERFORMANCE RELATED PROVISIONS INCLUDING SECTIONS 4.1, 4.5.7, 4.5.8 OR 6.1, SHALL BE THE ADJUSTMENT TO CAPACITY CHARGES BASED UPON THE AVAILABILITY ADJUSTMENT SUBJECT TO THE LIMIT ON SELLER'S LIABILITY FOR SUCH ADJUSTMENT SET FORTH IN SECTION 7.1.3.4; AND SUCH AVAILABILITY ADJUSTMENT SHALL BE CONSIDERED LIQUIDATED DAMAGES IN LIEU OF ANY OTHER DAMAGES AT LAW, IN EQUITY OR AS SET FORTH ELSEWHERE IN THIS AGREEMENT.

10.3 *SOLE REMEDY FOR LATE COMMERCIAL OPERATIONS.* BUYER'S SOLE REMEDIES AND SELLER'S SOLE LIABILITY FOR FAILURE OF THE COMMERCIAL OPERATIONS DATE TO OCCUR ON OR BEFORE THE TARGET COD (INCLUDING FAILURE TO COMPLY WITH SECTION 3) SHALL BE (a) THE OFFSET OF DELAY LDs AS SET FORTH IN SECTION 3.3 AGAINST CAPACITY CHARGES AS THEY COME DUE, SUBJECT TO THE LIMITATION ON SELLER'S LIABILITY SET FORTH IN SUCH SECTION 3.3 AND (b) TERMINATION IN ACCORDANCE WITH SECTION 3.3.7, IF THE COMMERCIAL OPERATIONS DATE DOES NOT OCCUR BY THE FINAL COMMERCIAL OPERATIONS DATE.

10.4 *SOLE TERMINATION FOR DEFAULT REMEDIES.* BUYER'S SOLE AND EXCLUSIVE REMEDIES OF TERMINATION FOR DEFAULT SHALL BE AS SET FORTH IN SECTIONS 3.3.7, 13 AND 19, AND SHALL BE, IN LIEU OF ANY OTHER REMEDIES OF TERMINATION AT LAW OR IN EQUITY.

10.5 *DIRECT DAMAGES FOR OTHER BREACHES.* SUBJECT TO THE LIMITATIONS SET FORTH IN SECTIONS 10.1, 10.2, AND 10.3, AND SUBJECT FURTHER TO THE ARBITRATION PROVISION OF SECTIONS 11.1 − 11.6, EACH PARTY SHALL BE ENTITLED WITHOUT DUPLICATION TO RECOVER FROM THE OTHER PARTY ITS DIRECT DAMAGES OR SEEK AN INJUNCTION OR OTHER EQUITABLE RELIEF FOR BREACH BY SUCH PARTY OF ITS OBLIGATIONS UNDER THIS AGREEMENT AND TO ENFORCE ANY PAYMENT OBLIGATIONS OF SELLER HEREUNDER OR TO TAKE ALL LEGAL ACTION NECESSARY TO ENFORCE ANY ORDER, DECISION OR SETTLEMENT OF AN ARBITRATOR RENDERED PURSUANT TO SECTION 11.2.5.

11. *Disagreements*

11.1 *Negotiations.* The Parties shall attempt in good faith to resolve all disputes promptly by negotiation, as follows. Any Party may give the other Party written notice of any dispute not resolved in the normal course of business. Executives of both Parties at levels one level above the personnel who have previously been involved in the dispute shall meet at a mutually acceptable time and place within ten (10) days after delivery of such notice, and thereafter as often as they reasonably deem necessary, to exchange relevant information and to attempt to resolve the dispute. If the matter has not been resolved within thirty (30) days from the referral of the dispute to senior executives, or if no meeting of senior executives has taken place within fifteen (15) days after such referral, either Party may initiate arbitration as provided hereinafter. If a Party intends to be accompanied at a meeting by an attorney, the other Party shall be given at least three (3) Business Days' notice of such intention and may also be accompanied by an attorney. All negotiations pursuant to this clause shall be confidential.

11.2 *Arbitration*

11.2.1 If the negotiation process provided for in Section 11.1 above has not resolved the dispute, the dispute shall be decided solely and exclusively by arbitration in Chicago, Illinois in accordance with the Commercial Arbitration Rules of the American Arbitration Association. The arbitration shall be governed by the United States Arbitration Act (9 U.S.C. ss. 1 et seq.), and judgment entered upon the award rendered by the arbitrator(s) may be entered in any court having jurisdiction thereof. This agreement to arbitrate and any other agreement or consent to arbitrate entered into in accordance herewith will be specifically enforceable under the prevailing arbitration law of any court having jurisdiction. Notice of demand for arbitration must be filed in writing with the other Party to this Agreement. The demand must be made within a reasonable time after the controversy has arisen. In no event may the demand for arbitration be made if the institution of legal or equitable proceedings based on such controversy is barred by the applicable statute of limitations. Any arbitration may be consolidated with any other arbitration proceedings. Either party may join any other interested parties. The award of the arbitrator shall be specifically enforceable in a court of competent jurisdiction.

11.2.2 Either Party shall give to the other written notice in sufficient detail of the existence and nature of any dispute proposed to be arbitrated. The Parties shall attempt to agree on a person with special knowledge and expertise with respect to the matter at issue to serve as arbitrator. If the Parties cannot agree on an arbitrator within ten (10) days, each shall then appoint one individual to serve as an arbitrator and the two (2) thus appointed shall select a third arbitrator with such special knowledge and expertise to serve as chairman of the panel of arbitrators; and such three (3) arbitrators shall determine all matters by majority vote; *provided, however*, if the two (2) arbitrators appointed by the Parties are unable to agree upon the appointment of the third arbitrator within five (5) days after their appointment, both shall give written notice of such failure to agree to the Parties, and, if the Parties fail to agree upon the selection of such third arbitrator within five (5) days thereafter, then either of the Parties upon written notice to the other may require such appointment from, and pursuant to the rules of, the Chicago office of the American Arbitration Association for commercial arbitration. Prior to appointment, each arbitrator shall agree to conduct such arbitration in accordance with the terms of this Agreement. The arbitration panel may choose legal counsel to advise it on the remedies it may grant, procedure, and such other legal issues as the panel deems appropriate but subject to limits on remedies and damages set forth in this Agreement.

11.2.3 The Parties shall have sixty (60) days to perform discovery and present evidence and argument to the arbitrators. During that period, the arbitrators shall be available to receive and consider all such evidence as is relevant and, within reasonable limits due to the restricted time period, to hear as much argument as is feasible, giving a fair allocation of time to each Party to the arbitration. The arbitrators shall use all reasonable means to expedite discovery and to sanction noncompliance with reasonable discovery requests or any discovery order. The arbitrators shall not consider any evidence or argument not presented during such period and shall not extend such period except by the written consent of both Parties. At the conclusion of such period, the arbitrators shall have forty−five (45) days to reach a determination. To the extent not in conflict with the procedures set forth herein, which shall govern, such arbitration shall be held in accordance with the prevailing rules of the Chicago office of the American Arbitration Association for commercial arbitration.

11.2.4 The arbitrators shall have the right only to interpret and apply the terms and conditions of this Agreement and to order any remedy allowed by this Agreement, but may not change any term or condition of this Agreement, deprive either Party of any right or remedy expressly provided hereunder, or provide any right or remedy that has been excluded hereunder.

11.2.5 The arbitrators shall give a written decision to the Parties stating their findings of fact, conclusions of law and order, and shall furnish to each Party a copy thereof signed by them within five (5) days from the date of their determination.

11.3 *Costs.* Each Party shall pay the cost of the arbitrator or arbitrators, and any legal counsel appointed pursuant to subparagraph (a) above, with respect to those issues as to which they do not prevail, as determined by the arbitrator or arbitrators.

11.4 *Settlement Discussions.* The Parties agree that no statements of position or offers of settlement made in the course of the dispute process described in this Section 11 will be offered into evidence for any purpose in any litigation or arbitration between the Parties, nor will any such statements or offers of settlement be used in any manner against either Party in any such litigation or arbitration. Further, no such statements or offers of settlement shall constitute an admission or waiver of rights by either Party in connection with any such litigation or arbitration. At the request of either Party, any such statements and offers of settlement, and all copies thereof, shall be promptly returned to the Party providing the same.

11.5 *Preliminary Injunctive Relief.* Nothing in this Section 11 shall preclude, or be construed to preclude, the resort by either Party to a court of competent jurisdiction solely for the purposes of securing a temporary or preliminary injunction to preserve the status quo or avoid irreparable harm pending arbitration pursuant to this Section 11.

11.6 *Obligations to Pay Charges and Perform.* If a disagreement arises on any matter which is not resolved as provided in Section 11.1 above, then, pending the resolution of the disagreement by arbitration, Seller shall continue to perform its obligations hereunder including its obligations to operate the Units in a manner consistent with the applicable provisions of this Agreement and Buyer shall continue to pay all charges and perform all other obligations required in accordance with the applicable provisions of this Agreement. In addition, notwithstanding the provisions of Section 13.3, neither Party shall be entitled to terminate this Agreement for default (other than defaults pursuant to Sections 13.1.1 or 13.2.1) by the other Party if the alleged default is the subject of an arbitration pursuant to Section 11, pending the outcome of such arbitration.

12. *Assignment; Project Financing; and Transfer of Units*

12.1 *Assignment.* Except as set forth in this Section 12, neither Party may assign its rights or obligations under this Agreement without the prior written consent of the other Party. Either Party may assign this Agreement, without the consent of the other Party, to an Affiliate or the parent company of an Affiliate, but no such assignment shall release such assignor from any obligations hereunder whether arising before or after such assignment.

12.2 *Transfers and Change of Control.* For the Purposes of this Section 12.2, any direct transfer or series of direct transfers (whether voluntary or by operation of law) of a majority of the outstanding voting equity interests of a Party (or any entity or entities directly or indirectly holding a majority of the outstanding voting equity interests of such Party) to any party other than an Affiliate controlled by, or under common control with, such Party shall be deemed an assignment of this Agreement. In such events; (i) prior notice of any such assignment shall be provided to the other Party; (ii) any assignee (other than Lenders or their designees pursuant to Section 12.3 below) shall expressly assume assignor's obligation hereunder, unless otherwise agreed to by the other Party; and (iii) except with respect to an assignment of this Agreement in its entirety permitted hereunder by the Seller's Lender, no assignment, whether or not consented to, shall relieve the assignor of its obligations hereunder in the event the assignee fails to perform, unless the other party agrees in writing in advance to waive the assignor's continuing obligations pursuant to this Agreement, such waiver not to be unreasonably withheld.

12.3 *Consent to Assignment to Lender.* Buyer consents to Seller's assignment of this Agreement to any Lenders or the granting to any Lenders of a lien or security interest in any right, title or interest in part or all of the Facility or any or all of Seller's rights under this Agreement for the purpose of the financing or refinancing of the Facility (or any part thereof) and the Interconnection Facilities; *provided, however*, that such assignment shall recognize Buyer's rights under this Agreement. Buyer further agrees to comply with reasonable requests of Seller in Seller's efforts to obtain project financing for the Facility, including without limitation execution of a consent to assignment by Buyer and delivery by Buyer's counsel of an opinion as described below as reasonably required by Lenders. Buyer recognizes that such financing will likely entail Buyer's execution of a consent to assignment that may grant certain rights to such Lenders, which shall be fully developed and described in the consent documents, including (i) this Agreement shall not be amended in any material respect or terminated (except for termination pursuant to the terms of this Agreement) without the consent of Lenders, which consent is not to be unreasonably withheld or delayed, (ii) Lenders shall be given notice of, and a reasonable opportunity to cure (in addition to the periods designated hereunder), any Seller breach or default of this Agreement, and (iii) if a Lender forecloses, takes a deed in lieu or otherwise exercises its remedies pursuant to any security documents, that Buyer shall, at Lender's request, continue to perform all of its obligations hereunder (subject to Buyer's rights under Section 13), so long as Lender or its nominee is performing all obligations of Seller hereunder in the place of Seller, and Lender may assign this Agreement to a Permitted Assignee so long as such Permitted Assignee assumes all obligations of Seller hereunder and so long as all monetary defaults of Seller are cured prior to such assignment, and may enforce all of Seller's rights to the extent Seller's obligations hereunder are being performed, (iii) that Lender(s) shall have no liability under this Agreement except during the period of such Lender(s)' ownership and/or operation of the Facility, (iv) that Buyer shall accept performance in accordance with this Agreement by Lender(s) or its (their) nominee, (v) if this Agreement is rejected in Seller's bankruptcy, Buyer will enter into a replacement agreement identical to this Agreement with a Permitted Assignee so long as such Permitted Assignee assumes all obligations of Seller hereunder and so long as all monetary defaults of Seller are cured prior to such assignment, and (vi) that Buyer shall make representations and warranties to Lender(s) as Lender(s) may reasonably request with regard to (A) Buyer's corporate existence, (B) Buyer's corporate authority to execute, deliver, and perform this Agreement, (C) the binding nature of (x) the document evidencing Buyer's consent to assignment to Lenders and (y) this Agreement on Buyer, (D) receipt of regulatory approvals by Buyer with respect to its execution and performance under this Agreement, and (E) whether to Buyer's knowledge, any defaults by Seller are known by Buyer then to exist under this Agreement. The documentation that Lenders may require under this Section 12.3 may include an opinion of counsel typical in project finance transactions. Seller agrees to reimburse Buyer for reasonable fees and expenses incurred by Buyer in connection with consent to assignment including without limitation, attorneys' fees and expenses. Such consent to assignment to Lenders shall provide that upon the exercise of trustee's or mortgagee's assignment rights pursuant to such assignment, trustee or mortgagee shall notify Buyer of the date and particulars of any such exercise of assignment rights.

12.4 *Potential Changes in Ownership or Control of Aquila.* Seller acknowledges that Aquila may become the subject of a merger, acquisition, transfer of a majority of the outstanding voting equity of Aquila, or other change in control (the "Aquila Change in Control") in the near future and that such transaction may be deemed an assignment of this Agreement pursuant to Section 12.2. Seller agrees that, if, following the consummation of the Aquila Change in Control, Aquila, or its successor entity resulting from such transaction, provides evidence reasonably satisfactory to Lenders (in accordance with common industry practice) demonstrating that it has a credit rating that is equal to or higher than such rating applicable to UCU as of the date of this Agreement, Seller shall provide its consent pursuant to Section 12.1 to such deemed assignment, and upon consummation thereof shall release UCU from its joint and several liability and from all obligations arising from and after the Aquila Change in Control.

12.5 *Transfers Not in Accordance Herewith.* Any sale, transfer, or assignment of any interest in the Facility or in this Agreement made without fulfilling the requirements of this Section 12 shall be null and void and shall constitute an Event of Default.

13. *Default, Termination and Remedies; Notice of Default.* If Buyer defaults under this Agreement, then Seller shall give Buyer written notice describing such default. If Seller defaults under this Agreement, then Buyer shall give Seller written notice describing such default and concurrently provide any Lender with a copy of such notice.

13.1 *Events of Default of Seller.* The following shall constitute Events of Default of Seller ("Seller Events of Default") upon their occurrence unless cured within seven (7) days after written receipt of Notice from Buyer of such failure requiring its remedy, in the case of defaults under Sections 13.1.1 (and twenty−one (21) days with respect to Section 13.1.2) or within sixty (60) days, in the case of all other defaults, after the date of written notice from Buyer as provided above, provided that, if any such other default cannot be cured within sixty (60) days with exercise of due diligence, and if Seller within such period submits to Buyer a plan reasonably designed to correct the default within a reasonable additional period of time not to exceed six (6) months, then an Event of Default shall not exist unless Seller fails to diligently pursue such cure or fails to cure such default within the additional period of time specified by such plan:

13.1.1 Seller's failure to make payments when due; Seller Guarantor's failure to pay for Substitute Power (if Seller has failed previously to make such payment), a Delay Book Out Charge or an Outage Book Out Charge;

13.1.2 (i) A Seller Guarantee ceases to remain in full force and effect in accordance with its terms (other than as a result of such Seller Guarantee having been fully drawn down by Buyer); (ii) the failure of a Seller Guarantor to make a payment upon a proper drawing by Buyer against a Seller Guarantee; or (iii) Seller fails to deliver a letter of credit as required by Section 18.1 upon a Downgrade Event with respect to a Seller Guarantor.

13.1.3 Seller's dissolution or liquidation;

13.1.4 A Bankruptcy Event occurs with respect to Seller;

13.1.5 Seller's assignment of this Agreement or any of Seller's rights under the Agreement or the sale or transfer of any interest in Seller in each case not in compliance with the provisions of Section 12;

13.1.6 The sale by Seller to a third party of Electric Energy or Capacity committed to Buyer by Seller other than as permitted under this Agreement; and

13.1.7 Any representation made by Seller under Section 14.1 shall be false in any material respect.

13.2 *Buyer Default.* The following shall constitute Events of Default of ("Buyer Events of Default") upon their occurrence unless cured within seven (7) days after written receipt of Notice from Seller of such failure requiring its remedy, in the case of a default under Section 13.2.1 or within sixty (60) days, in the case of all other defaults, after the date of written notice from Buyer as provided above, provided that, if any such other default cannot be cured within sixty (60) days with exercise of due diligence, and if Seller within such period submits to Buyer a plan reasonably designed to correct the default within a reasonable additional period of time not to exceed six

(6) months, then an Event of Default shall not exist unless Seller fails to diligently pursue such cure or fails to cure such default within the additional period of time specified by such plan:

13.2.1 Buyer fails to pay any sum due from it hereunder on the due date thereof;

13.2.2 A Bankruptcy Event occurs with respect to Buyer;

13.2.3 Buyer dissolution or liquidation except in connection with an Aquila Change in Control pursuant to Section 12.4;

13.2.4 Buyer's failure to post or maintain security in the form of a letter of credit as a result of a Downgrade Event with regard to Buyer as described in Section 18.2, to the levels, and upon the timing, specified in such Section 18.2;

13.2.5 Buyer's assignment of this Agreement or any of Buyer's rights under this Agreement or the sale or transfer of any interest in Buyer in each case not in compliance with the provisions of Section 12; or

13.2.6 Any representation made by Buyer under Section 14.1 shall be false in any material respect.

13.3 *Remedies.*

13.3.1 Upon the occurrence and during the continuance of a Buyer Event of Default or a Seller Event of Default, the non−defaulting Party may at its discretion suspend performance hereunder or terminate this Agreement upon thirty (30) days (or five (5) days for defaults under Section 13.1.4 or 13.2.2 above) prior written notice to the Party in default. In addition, if Seller terminates this Agreement pursuant to this section 13.3.1, Seller may draw the amount of its direct damages incurred as a result of Buyer's default from the Buyer letter of credit, if any, posted pursuant to Section 18.2.

13.3.2 If a Buyer Event of Default under Section 13.2.1 has occurred and is continuing, Seller shall have the right to sell Capacity and Electric Energy from the Facility on a daily basis to third parties during the continuance of such Buyer Event of Default.

13.4 *Special Termination for Chronic Poor Availability.* If the Summer Average Availability for the Facility for a Summer Period (the "Initial Poor Availability Period") is less than 80%, then Seller shall promptly engage a mutually acceptable independent engineer to conduct an assessment of Seller's operating and maintenance practices to determine what steps are necessary to restore the Facility to an Equivalent Availability of at least 97% and to recommend a detailed and specific protocol of equipment, operational and maintenance improvements necessary to achieve such Equivalent Availability (collectively, the "IE Protocol"). If Seller fails to fully and timely implement the IE Protocol and either (i) the Facility has a Summer Average Availability of less than 80% for each of the two Summer Periods subsequent to the Initial Poor Availability Period or (ii) if the Summer Average Availability for the Initial Poor Availability Period was less than 70%, and the Facility has a Summer Average Availability less than 70% for the Summer Period subsequent to the Initial Poor Availability Period, then Buyer may terminate this Agreement on September 15th of the year that is two years after the Initial Poor Availability Period (in the case of a termination pursuant to the foregoing clause (i)) or on September 15th of the year after the Initial Poor Availability Period (in the case of a termination pursuant to clause (ii)). In the event of such termination, Seller shall have no liability to Buyer except for liability for obligations (including Availability Adjustments) accrued prior to such termination.

14. *Representations and Warranties*

14.1 *Representations and Warranties of Seller*. Seller hereby makes the following representations and warranties to Buyer:

14.1.1 Seller is a Delaware limited liability company duly organized, validly existing and in good standing under the laws of the State of Delaware, is qualified to do business in the State of Illinois and has the legal power and authority to own its properties, to carry on its business as now being conducted and to enter into this Agreement and, subject to the receipt of the regulatory approvals set forth in Section 20, carry out the transactions contemplated hereby and perform and carry out all covenants and obligations on its part to be performed under and pursuant to this Agreement.

14.1.2 The execution, delivery and performance by Seller of this Agreement have been duly authorized by all necessary corporate action, and do not and will not require any consent or approval of Seller's Management Committee or equity holders other than that which has been obtained.

14.1.3 The execution and delivery of this Agreement, the consummation of the transactions contemplated hereby and the fulfillment of and compliance with the provisions of this Agreement, do not and will not conflict with or constitute a breach of or a default under, any of the terms, conditions or provisions of any legal requirements, or any organizational documents, agreement, deed of trust, mortgage, loan agreement, other evidence of indebtedness or any other agreement or instrument to which Seller is a party or by which it or any of its property is bound, or result in a breach of or a default under any of the foregoing, and Seller has obtained all permits, licenses, approvals and consents of governmental authorities required for the lawful performance of its obligations hereunder.

14.1.4 This Agreement constitutes the legal, valid and binding obligation of Seller enforceable in accordance with its terms, except as such enforceability may be limited by bankruptcy, insolvency, reorganization or similar laws relating to or affecting the enforcement of creditors' rights generally or by general equitable principles, regardless of whether such enforceability is considered in a proceeding in equity or at law.

14.1.5 There is no pending, or to the knowledge of Seller, threatened action or proceeding affecting Seller before any governmental authority which purports to affect the legality, validity or enforceability of this Agreement. 14.2 Representations and Warranties of Buyer. Aquila and UCU, on a joint and several basis, hereby make the following representations and warranties to Seller:

14.2 *Representations and Warranties of Buyer.* Aquila and UCU, on a joint and several basis, hereby make the following representations and warranties to Seller:

14.2.1 Aquila is a corporation duly organized, validly existing and in good standing under the laws of the State of Delaware and UCU is a corporation duly organized, validly existing and in good standing under the laws of the State of Delaware. Each of Aquila and UCU is qualified to do business in the State of Illinois and has the legal power and authority to own its properties, to carry on its business as now being conducted and to enter into this Agreement and carry out the transactions contemplated hereby and perform and carry out all covenants and obligations on its part to be performed under and pursuant to this Agreement.

14.2.2 The execution, delivery and performance by each of Aquila and UCU of this Agreement have been duly authorized by all necessary corporate action, and do not and will not require any consent or approval of its Board of Directors or shareholders other than that which has been obtained.

14.2.3 The execution and delivery of this Agreement, the consummation of the transactions contemplated hereby and the fulfillment of and compliance with the provisions of this Agreement do not and will not conflict with or constitute a breach of or a default under, any of the terms, conditions or provisions of any legal requirements, or its Sections of incorporation or bylaws, or any deed of trust, mortgage, loan agreement, other evidence of indebtedness or any other agreement or instrument to which either Aquila or UCU is a party or by which it or any of its property is bound, or result in a breach of or a default under any of the foregoing.

14.2.4 This Agreement constitutes the legal, valid and binding obligation of Aquila and UCU enforceable in accordance with its terms, except as such enforceability may be limited by bankruptcy, insolvency, reorganization or similar laws relating to or affecting the enforcement of creditors' rights generally or by general equitable principles, regardless of whether such enforceability is considered in a proceeding in equity or at law.

14.2.5 There is no pending, or to the knowledge of Aquila or UtiliCorp, threatened action or proceeding affecting it before any governmental authority which purports to affect the legality, validity or enforceability of this Agreement.

15. *Indemnification*

Each Party shall indemnify and hold harmless the other Party, and its officers, directors, agents and employees from and against any and all claims, demands, actions, losses, liabilities, expenses (including reasonable legal fees and expenses), suits and proceedings of any nature whatsoever for personal injury, death or property damage to each other's property or facilities or personal injury, death or property damage to third parties (collectively "Liabilities") caused by the negligence or willful misconduct of the indemnifying Party that arise out of or are in any manner connected with the performance of this Agreement, except to the extent such injury or damage is attributable to the gross negligence or willful misconduct of, or breach of this Agreement by, the Party seeking indemnification hereunder. Buyer shall indemnify Seller from all Liabilities related to Electric Energy and Replacement Power from and after delivery to the Point of Delivery or Replacement Power Delivery Point as applicable; and Seller shall indemnify Buyer for all Liabilities related to Electric Energy or Replacement Power prior to its delivery to the Point of Delivery or Replacement Power Delivery Point as applicable.

16. *Notices.*

Unless otherwise provided in this Agreement, any notice, consent or other communication required to be made under this Agreement shall be in writing and shall be delivered to the address set forth below or such other address or persons as the receiving Party may from time to time designate by written notice:

If to Buyer, to:

Aquila Energy Marketing Corporation
1100 Walnut—Suite 2900
Kansas City, Missouri 64106
Attention: President
Fax: (816) 527−1006

With a copy to:

Hogan & Hartson, L.L.P.
555 Thirteenth Street, Columbia Square
Washington, D.C. 20004−1109

Attn: John P. Mathis, Esquire
Fax: (202) 637−5910

If to Seller, to:

Elwood Energy II, LLC
c/o Dominion Energy, Inc.
120 Tredegar Street
Richmond, VA 23219
Attention: Christine M. Schwab, Esq.
Fax: (804) 819−2202

with a copy to:

Elwood Energy II, LLC
c/o McGuire, Woods, Battle & Boothe LLP
901 E. Cary Street
Richmond, VA 23219
Attention: Mark J. La Fratta, Esq.
Telephone: (804) 775−1106
Fax: (804) 698−2096

All notices shall be effective when received.

17. *Confidentiality*

Each Party agrees that it will treat in confidence all documents, materials and other information marked "Confidential" or "Proprietary" by the disclosing Party ("Confidential Information") which it shall have obtained during the course of the negotiations leading to, and its performance of, this Agreement (whether obtained before or after the date of this Agreement). Confidential Information shall not be communicated to any third party (other than, in the case of Seller, to its Affiliates, to its counsel, accountants, financial or tax advisors, or insurance consultants, to prospective partners and other investors in Seller and their counsel, accountants, or financial or tax advisors, or in connection with its financing or refinancing; and in the case of Buyer, to its Affiliates, or to its counsel, accountants, financial advisors, tax advisors or insurance consultants). As used herein, the term "Confidential Information" shall not include any information which (i) is or becomes available to a Party from a source other than the other Party, (ii) is or becomes available to the public other than as a result of disclosure by the receiving Party or its agents or (iii) is required to be disclosed in the opinion for a Party's legal counsel under applicable law or judicial, administrative or regulatory process, but only to the extent it must be disclosed. The timing and content of any press releases associated with this Agreement shall be agreed to by the Parties prior to any public disclosure or distribution.

18. *Security*

18.1 *Seller Guarantees.* Seller shall provide guarantees of Dominion Energy, Inc. ("Dominion") and Peoples Energy Corp ("Pecorp") (the "Seller Guarantees") in the form of Appendix H, each with a cumulative maximum liability amount for the Term equal to ten million dollars ($10,000,000). Such guarantees shall be in force beginning June 1, 2001 and shall remain in force until the termination of this Agreement. If and when a Seller Guarantor has paid out an amount equal to the maximum amount of the Seller Guarantee, such Seller Guarantor shall be released from any further liability to Buyer pursuant to this Agreement, and from and after such date Buyer shall be released from any obligation hereunder to obtain Substitute Power. Such Seller Guarantor may, in its sole discretion, reissue additional guarantees beyond such maximum. If a Downgrade Event occurs with respect to a Seller Guarantor, Seller shall post or cause to be posted in lieu of Seller's Guarantee, a letter of credit in favor of and reasonably acceptable to Buyer in an amount equal to its remaining liability under such Seller Guarantees. Neither Dominion nor Pecorp may assign or transfer its guarantee obligations to a third party entity without the consent of Buyer, and any assignee or transferee must have credit standing of Investment Grade or better. Pursuant to such guarantees, each of Dominion and Pecorp shall be severally, but not jointly or jointly and severally, liable for the performance of Seller, and their liabilities shall be limited to the amount stated in the guarantees for the applicable time period. Upon Buyer's request, Seller shall cause Dominion to provide audited financial statements on an annual basis after April 30 of each year for the preceding calendar year.

18.2 *Buyer Security.* Upon request of Seller, Buyer shall be required to post security in the form of a letter of credit in favor of and reasonably acceptable to Seller within ten (10) days of Seller's request if the rating of both Moody's and Standard & Poor's of UCU (or its successor or replacement entity pursuant to the operation of Section 12.4) the co−obligor under this Agreement, falls below Investment Grade. Such letter of credit shall be in an amount equal the next six (6) months Capacity Charges if such rating is one Rating Category below Investment Grade, or twelve (12) months Capacity Charges if such rating is two or more Rating Categories below Investment Grade, upon which Seller may draw any amounts due from Buyer hereunder and not timely paid. Any six month Capacity Charge letter of credit shall have a term of not less than 180 days. Any twelve month Capacity Charge letter of credit shall have a term of not less than 364 days. If such letter of credit is not renewed at least thirty (30) days prior to expiration, Seller may draw the full amount of such letter of credit and hold such amounts to offset against liability (including future liability) of Buyer under this Agreement. If one or both rating agencies restores UCU's (or its successor or replacement entity pursuant to the operation of Section 12.4) long term debt rating to Investment Grade, than Buyer may request that Seller surrender the letter of credit to Buyer, and Seller will do so within three Business Days of such request.

19. *Force Majeure*

19.1 *Definition.* For the purposes of this Agreement, "Force Majeure Event" means an event, condition or circumstance beyond the reasonable control of and without the fault or negligence of the Party affected (the "Affected Party") which, despite all reasonable efforts of the Affected Party to prevent it or mitigate its effects, prevents the performance by such Affected Party of its obligations hereunder. Subject to the foregoing, "Force Majeure Event" as to either Party, shall include:

19.1.1 explosion and fire (in either case to the extent not attributable to the fault or the negligence of the Affected Party);

19.1.2 lightning, flood, earthquake, landslide, tornado, unusually severe storms, or other natural calamity or act of God;

19.1.3 strike or other labor dispute other than any labor dispute or strike by Seller's employees or the employees of any contractor or subcontractor employed at or performing work with respect to the Facility (except to the extent arising out of a strike or labor action by employees or labor organization members not employed at or performing work with respect to the Facility);

19.1.4 war, insurrection, civil disturbance, sabotage or riot;

19.1.5 failure to obtain Governmental Approvals as a result of a Change in Law;

19.1.6 Changes in Law materially adversely affecting operation of the Facility;

19.1.7 lack of fuel caused by a Force Majeure Event (as defined in this Agreement) experienced by the Facility's fuel supplier or transporter (as if for purposes of this Section 19.1.7 such fuel supplier or transporter is the Affected Party) or curtailment of firm gas transportation service to the Facility pursuant governmental order that materially affects the delivery of gas to the Facility;

19.1.8 the failure of performance by any third party having an agreement with Seller, including, without limitation, any vendor, supplier, or customer of Seller that is excused by reason of force majeure (or comparable term), as defined in Seller's agreement with such third party but only if such event would also constitute Force Majeure as defined in this Agreement; and

19.1.9 mechanical equipment breakdown caused by a Force Majeure Event described in Section 19.1.1, 19.1.2 or 19.1.4, and

19.1.10 interruption of acceptance by the Interconnected Utility of delivery of Electric Energy from the Facility into the Interconnected Utility System.

19.2 *Obligations Under Force Majeure.*

19.2.1 If either Party is rendered unable, wholly or in part, by a Force Majeure Event, to carry out some or all of its obligations under this Agreement (other than obligations to pay money) despite all reasonable efforts of such Party to prevent or mitigate its effects, then, during the continuance of such inability, the obligation of such Party to perform the obligations so affected shall be suspended, except as provided in this Section 19. If Seller is the Affected Party, the Target COD shall be extended day for day for the duration of the effects of a Force Majeure Event.

19.2.2 A Party relying on a Force Majeure Event shall give written notice of such Force Majeure Event to the other Party as soon as practicable after such event occurs, which notice shall include information with respect to the nature, cause and date of commencement of the occurrence(s), and the anticipated scope and duration of the delay. Upon the conclusion of the Force Majeure Event, the Party heretofore relying on such Force Majeure Event shall, with all reasonable dispatch, take all steps reasonably necessary to resume the obligation(s) previously suspended.

19.2.3 Notwithstanding the foregoing, a Party shall not be excused under this Section 19, (x) for any non−performance of its obligations under this Agreement having a greater scope or longer period than is justified by the Force Majeure Event, (y) for the performance of obligations that arose prior to the Force Majeure Event, or (z) to the extent absent the Force Majeure Event the Affected Party would nonetheless have been unable to perform its obligations under this Agreement.

19.3 *Force Majeure Not Forced Outage.* Any periods of Forced Outage or Forced Derating caused by Force Majeure Events shall not be included as Forced Outage Hours, or Forced Derating Hours for purposes of calculation of the Availability Adjustment.

19.4 *No Economic Force Majeure.* Force Majeure Events do not include changes in market conditions.

19.5 *Continued Payment Obligation.* Buyer shall have no obligation to pay the monthly Capacity Charge during a Force Majeure period when the Seller is the Affected Party except:

19.5.1 *Prior to Commercial Operations Date.* Buyer shall have noobligation to pay Capacity Charges during a Force Majeure Period unless, and to the extent Seller delivers or causes to be delivered Replacement Power or Substitute Power. However, Seller's provision of Replacement Power, causing Substitute Power to be delivered, or payment of a Delay or Outage Book Out Charge shall not constitute, in any manner, a waiver of a Force Majeure Event.

19.5.2 *After the Commercial Operations Date.* After the Commercial Operations Date, Buyer shall have no obligation to pay Capacity Charges during any Force Majeure Period where Seller is the Affected Party, except that Buyer shall continue to pay for 50% of the Capacity Charges for up to the first 15 days of any Force Majeure Event as if the Unit(s) were meeting the Guaranteed Availability during such period. Beginning on the sixteenth (16th) day Buyer shall have no obligation to pay Capacity Charges unless and to the extent (a) Seller provides Replacement Power or causes to be delivered Substitute Power, or (b) the Facility is Available for Dispatch by Buyer.

19.5.3 *Proration of Effect of Force Majeure Affecting Elwood Station and Expansions Thereto.* If a Force Majeure Event affects both the Units and other units at the Elwood Station (including expansions thereof), Seller shall equitably allocate the burdens of the effects of such Force Majeure Event over all affected units (for example, if a gas curtailment affecting Units 1−6 constitutes a Force Majeure, the gas available shall be ratably allocated over such six units to the extent feasible).

19.6 *Extended Force Majeure Event After Commercial Operations.* If an Affected Party reasonably believes that a Force Majeure Event that is preventing it from performing its obligations hereunder could result in a suspension of such performance for a period of one (1) month or longer, the Affected Party shall submit a plan to the other Party to overcome the Force Majeure Event. Such plan shall be submitted within thirty (30) Business Days of the start of the Force Majeure Event. The plan shall set forth a course of repairs, improvements, changes to operations or other actions which could reasonably be expected to permit the Affected Party to resume performance its obligations under this Agreement within a reasonable time frame projected in the plan. While such a plan is in effect, the Affected Party shall provide weekly status reports to the other Party notifying the other Party of the steps which have been taken to remedy the Force Majeure Event and the expected remaining duration of the Party's inability to perform its obligations. If the Force Majeure Event has not been overcome within five (5) months from its inception, the Parties shall meet to reassess the amount of time that is likely to pass before the Affected Party can reasonably be expected to resume performance under this Agreement, and Seller shall have thirty (30) days to establish a revised plan to overcome the Force Majeure Event within twelve (12) months of its beginning. If at the end of such thirty (30) days one or both of the Parties reasonably concludes that the Force Majeure Event cannot be reasonably be expected to be overcome within twelve months of the beginning of the Force Majeure Event, the Party that is not the Affected Party may terminate this Agreement with five (5) days notice to the Affected Party. If the Affected Party is Seller and the Force Majeure Event only materially impacts the operation of one Unit, then any termination by Buyer will be as to the impacted Unit only. Notwithstanding

Buyer's election not to terminate this Agreement, Buyer shall nonetheless have the right to terminate this Agreement, if Seller has failed to remedy the effects of the Force Majeure Event within twelve months of its inception such that the Facility is capable of delivering the Net Dependable Capacity and meeting other performance criteria hereunder. Upon termination of this Agreement as provided in this Section 19.6, the Parties shall have no further liability or obligation to each other except for any obligation arising prior to the date of such termination and those that survive termination as listed in Section 2.2. In addition to the foregoing, the Party not prevented from performing its obligations due to the Force Majeure Event may terminate this Agreement upon ten (10) Days prior written notice if (a) the Affected Party fails to provide a Force Majeure remedy plan as provided for in this Section 19.6, (b) the Affected Party fails to carry out the Force Majeure remedy plans in a method reasonably designed to cause that Party to be able to perform it obligations hereunder within twelve (12) months of the Force Majeure Event occurring, or (c) within five (5) Business Days after a request therefor fails to provide a weekly status report to the other Party.

20. *Interconnection and Transmission*

20.1 *Facilities.* Seller shall own, operate, maintain and controlduring the Term at its sole cost and expense all interconnection facilities located on the Facility site up to, but not including, the Point of Delivery. Seller shall pay all costs associated with interconnecting the Facility to the Interconnected Utility System, including any facilities upgrades required by ComEd.

20.2 *Transmission.* Buyer shall be responsible for arranging and paying for transmission services from the Point of Delivery, including any applicable transmission costs, system charges or line/system losses from the Point of Delivery, except to the extent of Incremental Transmissions Costs for Replacement Power. Buyer shall also be responsible for obtaining and paying for any ancillary or control area services required by FERC, ComEd or any independent system operator or other transmission utility with respect to the delivery and transmission of ComEd past the Point of Delivery.

21. *Taxes*

21.1 *Applicable Taxes.* Each Party shall be responsible for the payment of all taxes imposed on its income or net worth. Except as provided in this Section 21, Seller shall be responsible for the payment of all present or future federal, state, municipal or other lawful taxes applicable by reason of the operation of the Facility or assessable on Seller's property or operations including taxes on (i) the purchase by Seller or delivery of fuel to the Facility, and (ii) production of electricity. Buyer shall pay all existing and any new sales, use, excise, and any other similar taxes, if any, imposed or levied by a governmental agency on the sale or use of or payments for the Electric Energy, Replacement Power, Substitute Power and Net Dependable Capacity sold and delivered under this Agreement arising at or after the Point of Delivery.

Buyer shall indemnify, defend, and hold Seller harmless from any liability for all such taxes for which Buyer is responsible. Seller shall indemnify, defend, and hold Buyer harmless from any liability from all such taxes for which Seller is responsible. Buyer shall reimburse Seller promptly on demand for the amount of any such tax that is Buyer's responsibility hereunder that Seller remits, plus any penalties and interest incurred and remitted, except such penalties as result from Seller's conduct. Seller shall reimburse Buyer promptly on demand for the amount of any such tax that is Seller's responsibility hereunder that Buyer remits, plus any penalties, interest incurred and remitted, except penalties as result from Buyer's conduct.

21.2 *Contested Taxes.* Neither Party shall be required to pay any such tax, assessment, charge, levy, account payable or claim if the validity, applicability or amount thereof is being contested in good faith by appropriate actions or proceedings (including posting security as may be required) which will prevent the forfeiture or sale of any property utilized under this Agreement or any material interference with the use thereof.

21.3 *Other Charges.* Seller and Buyer will pay and discharge all lawful assessments and governmental charges or levies imposed upon it or in respect to all or any part of its property or business, all trade accounts payable in accordance with usual and customary business terms, and all claims for work, labor, or materials which, if unpaid might become a lien or charge upon any of its property.

22. *Miscellaneous Provisions*

22.1 *Non−Waiver.* The failure of either Party to insist in any one or more instances upon strict performance of any provisions of this Agreement, or to take advantage of any of its rights hereunder, shall not be construed as a waiver of any such provisions or the relinquishment of any such right or any other right hereunder, which shall remain in full force and effect.

22.2 *Relationship of Parties.* This Agreement shall not be interpreted or construed to create an association, joint venture, or partnership between the Parties or to impose any partnership obligation or liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or to act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

22.3 *Successors and Assigns.* This Agreement shall inure to the benefit of and be binding upon the successors and permitted assigns of the Parties.

22.4 *Governing Laws.* This Agreement shall be construed in accordance with and governed by the laws of the State of Illinois without regard to its conflicts of laws provisions.

22.5 *Counterparts.* This Agreement may be executed in more than one counterpart, each of which may be signed by fewer than all Parties, but all of which constitute the same Agreement.

22.6 *Third Party Beneficiaries.* This Agreement is intended solely for the benefit of the Parties hereto. Nothing in this Agreement shall be construed to create a duty to or standard of care with reference to, or any liability to, any Person not a Party to this Agreement.

22.7 *Financial Information.* After Seller closes on any third party financing, then from the date of such financing, for information purposes only, Seller shall, on a quarterly basis, provide to Buyer a statement of its debt coverage ratio if it is below 1.5. If Seller's debt coverage ratio is 1.5 or greater, Seller shall only inform Buyer that its debt cover ratio is 1.5 or greater without further information. Buyer agrees to treat such information as confidential pursuant to Section 17. In no event shall Buyer alter its performance under this Agreement in any manner based upon such information. Under no circumstances shall Seller have any liability to Buyer whatsoever as a result of actions taken by Buyer in reliance upon such information and Buyer hereby releases Seller for any liability whatsoever resulting therefrom.

23. *Appointment of Aquila As UCU's Agent*

23.1 *Appointment*

UCU hereby appoints Aquila as its true and lawful agent and attorney−in−fact, with full power and this Agreement, including without limitation, any notices, consents, elections, waivers, correspondence, agreements, instruments or claims which Aquila deems appropriate; provided, however, that Aquila may not agree to amend this Agreement on behalf of UCU. UCU may terminate this appointment upon written notice to Seller.

23.2 *Presumption of Authority.* Seller may conclusively presume and rely upon the fact that to the extent specified in Section 23.1, any instrument executed by Aquila acting as Buyer or agent or attorney−infact for UCU in authorized, regular, and binding upon UCU, without further need for inquiry.

24. *Entire Agreement and Amendments*

This Agreement supersedes all previous representations, understandings, negotiations and agreements (including the Original Agreement) either written or oral between the Parties hereto or their representatives with respect to the subject matter hereof and constitutes the entire agreement of the Parties with respect to the subject matter hereof. No amendments or changes to this Agreement shall be binding unless made in writing and duly executed by both Parties.

IN WITNESS WHEREOF, the Parties hereto have executed this Agreement as of the date set forth at the beginning of this Agreement.

Buyer: Aquila Energy Marketing Corporation

By /s/ VJ HORGAN

Name: VJ Horgan
Title: Senior VP

Buyer: UtiliCorp United Inc.

By /s/ KEITH STAMM

Name: Keith Stamm
Title: Senior VP

Seller: Elwood Energy II, LLC

By /s/ RONALD D. USHER

Name: Ronald D. Usher
Title: General Manager

APPENDIX A
FACILITY DESIGN LIMITS
AND OTHER DISPATCH RESTRICTIONS

(1) *The Design Limits for the Facility shall be the following*:

(a) The Maximum Load for a Facility shall be equal to the Net Dependable Capacity pursuant to OEM warranties, recommendations, and ambient conditions and the Governmental Approvals relating to the Facility;

(b) The Minimum Load for a Unit shall be equal to sixty percent (60%) of Net Dependable Capacity (but no less than ninety (90) MW) which shall adjust with ambient conditions in accordance with actual capability of the Units as provided in Appendix F.

(c) The minimum time required to Start−Up any one Unit (including the Elwood III Units) is twenty−two (22) minutes. The minimum time required to Start−Up multiple units under simultaneous Dispatch for two or three units is thirty−seven (37) minutes; provided however that the commencement of the Start−Up of second and the third Unit shall follow the commencement of Start−Up of the first Units by fifteen (15) minutes. The minimum time required to Start−Up four units under simultaneous Dispatch is fifty−two (52) minutes, provided however that the commencement of the Start−Up of the fourth Unit shall follow the commencement Start−Up of the second Unit by fifteen (15) minutes.

(d) The ramp rate (load increase rate) from synchronization to Minimum Load is twelve and one−half (12.5) MW per minute per Unit. Minimum time for the load increase from synchronization to Minimum Load is seven (7) minutes.

(e) The ramp rate (load increase rate) from Minimum Load to Maximum Load is thirteen (13) MW per minute per Unit. Minimum time for the load increase from Minimum Load to Maximum Load is four and six−tenths (4.6) minutes.

(f) The ramp down rate (load decrease rate) from all load levels is fifteen (11.5) MW per minute per Unit.

(g) The power factor of Electric Energy from a Unit as measured at the Unit's Revenue Meter shall be in the range from 0.90 lagging to 0.95 leading.

(2) *Dispatch and Start Procedure*

(a) Upon Start Up of Unit(s), Seller will ramp Unit(s) to Minimum Load according to the Design Limits above, and thereafter adjust the load between Minimum Load and Maximum Load of the Unit(s) according with the Dispatch Notification and in compliance with the Design Limits above.

(b) There shall be a minimum run time per Unit of four (4) consecutive hours; *provided, however*, Buyer shall have the option to Dispatch each Unit for a minimum run time of two (2) consecutive hours up to ten (10) times each Contract Year subject to Prudent Industry Practice and within manufacturer's recommendations.

(c) There shall be a minimum idle time of two (2) hours between the time a Unit is taken off−line until the initiation of the next Start Up Sequence for that Unit.

(d) Seller shall have the flexibility to Start Up the Units (along with the Elwood III Units) in a manner that meets Buyer's Dispatch schedule with the least number of Units, consistent with Design Limits and Prudent Industry Practice.

(3) *Generation During Start Up*

(a) During Start Up of one or more Units and while making load changes in response to Dispatch Requests, Seller shall use Prudent Industry Practices and commercially reasonable efforts to conform the Start Up and operation of the Unit(s) to the Dispatch Request and to minimize the amount of inadvertent Electric Energy generated prior to the Requested Load Delivery Time.

(b) Prior to the Requested Load Delivery Time, during the Start Up of one Unit, Seller expects to deliver no more than 26 MWh.

(c) Prior to the Dispatch Load Delivery Time, during the Start Up of two Units, Seller expects to deliver no more than 70 MWh.

(d) Prior to the Dispatch Load Delivery Time, during the Start Up of three Units, Seller expects to deliver no more than 114 MWh.

(e) Prior to the Dispatch Load Delivery Time, during the Start Up of four Units, (a 1Unit then 2 Units then 1 Unit Start Up), Seller expects to deliver no more than 178 MWh.

(f) Seller expects to deliver no more than 18 MWh per unit during ramp down to off line.

(g) If more MWh are delivered during the Start Up(s) than stated in sections (3)(a) to (3)(f) above, Buyer will market such MWh, and Seller will reimburse Buyer if Buyer's resale price is less than the Facility Electric Energy Rate at such time.

(4) *Permitted Runtime Hours*

(a) A maximum permitted runtime per Unit of 2500 hours per Contract Year, except in the first Contract Year, 90% of the maximum permitted runtime and in the final Contract Year, 92% of the maximum permitted runtime.

(b) To the extent that permitted runtime hours are less than 2500 hours per Contract Year, Seller shall be obligated to deliver Replacement Power or comparable consideration between the permitted runtime hours and 2500 hours per Contract Year.

APPENDIX B

HEAT RATE and CAPACITY TEST PROCEDURE
Elwood Units 5−8

1. *Introduction*

This document describes the procedure for determining the Net Dependable Capacities and corrected Net Heat Rates of Elwood Units 5−8. The Net Dependable Capacities determined by this procedure will serve as the baseline establishing the Capacity Payments and the amount of any future Forced Derating a given Unit may experience. The corrected Net Heat Rates determined by this procedure will be used to evaluate the thermal performance of each unit against the expected degradation in thermal performance as predicted by GE Curve 519HA772, "Expected Gas Turbine Plant Performance Loss Following Normal Maintenance and Off−Line Compressor Wash."

The introduction should clarify that there are essentially two performance test procedures considered in this Appendix B. The first will be conducted by the EPC Contractor on or about the Commercial Operations and that the results of that performance testing will serve both to qualify the EPC Contractor's performance commitment to the Seller, and those results will apply in the determination of the Net Dependable Capacity and Initial Net Heat Rate under this Agreement. Thereafter periodic tests will be conducted by the Seller for the purpose of determining ongoing performance of the Units and/or the Facility. The following period tests conducted by the Seller shall be accomplished utilizing permanent meters and instruments installed at the Facility for data acquisition, but otherwise conducted with the intent of yielding results that will be comparable with the first testing series.

There will be a series of pre−test activities to verify that the gas turbine generator being tested is operating properly at full capability and is adequately prepared for the capacity test. The Unit will be operated at 100% capability in the normal (not overfiring) operating mode with evaporative coolers in service.

The evaluation methodologies utilize correction factors to correct the measured Unit capacity and Heat Rate to the Reference Conditions. Thermal performance and capacity will be further adjusted for degradation according to the accumulated fired hours at the time of the test. These correction factors are determined from curves supplied by the turbine OEM.

2. *References*

A. Power Sales Agreement between Seller and Buyer relating to Units 5−8.

B. ASME Performance Test Procedures For General Electric Heavy Duty Gas Turbines, GEI−41067D.

C. Correction Curve set supplied by GE as part of output and thermal performance guarantees and GE Degradation Curve.

D. ASME PTC−22 (1997) Gas Turbine Performance Test Code

3. *Measurement and Instrumentation*

The test set−up consists of the gas turbine generator unit, selected station instruments, precision psychrometer, and weather instruments installed at the Facility.

The ambient air humidity will be measured near the inlet air filter on each Unit using a precision psychrometer.

The ambient temperature will be measured near the inlet air filter on each Unit using a precision thermometer.

The barometric pressure will be determined by averaging the barometric pressure readings from transmitters installed on each Unit.

The gross power output will be measured utilizing the General Electric Mark V control system.

The generator net power output will be measured with the installed Transdata watt−hour meter (Revenue Meter). The measurement will be made by repeatedly timing a fixed increment of elapsed Watt−hours.

The test point duration will be determined by stopwatch.

The gaseous fuel flow rate will be measured with the orifice metering section supplied with the gas turbine and its associated pressure and temperature instrumentation.

4. *Pre−Test Preparation*

4.1 The gas turbine compressor section will be cleaned as described in the GE Turbine Generator Manual immediately prior to testing. The compressor inlet plenum will be inspected before and after the Compressor Wash. If the compressor is judged to be dirty after the initial wash, additional Compressor Wash may be required.

4.2 The gas turbine exhaust thermocouple signal processing system will be confirmed to be operating to control specification. A thermocouple/calibrator will be used to input a 1000EF signal to the unit control system at the terminal strips where the unit thermocouple leads first terminate. At least three thermocouple wire sets for each control system computer will be checked (R, S, and T) for a total of at least nine wire sets. If proper operation cannot be confirmed, the control system must be corrected before testing. This calibration check will be conducted no more than sixty (60) days prior to the test and the calibration data sheets made part of the test record.

4.3 The calibration and proper operation of all pertinent pressure transmitters will be verified not more than sixty (60) days prior to the conduct of the test. Copies of the calibration data sheets shall be made a part of each test record. At a minimum, the following transmitters shall be checked:

- Gas fuel static pressure transmitter(s)
- Gas fuel orifice differential pressure transmitter(s)
- Barometric pressure transmitter(s)

During verification, pressure will be supplied to each transmitter with an NIST traceable device. The input pressure levels shall cover an appropriate estimated range of normal operation. If proper operation cannot be confirmed, the transmitter in question must be re−calibrated before testing.

4.4 The Revenue Meter calibration must have been completed within the interval specified in Section 5.1 of the Agreement and best reasonable efforts shall be used to schedule the Revenue Meter calibration within the sixty (60) day period prior to the test.

4.5 Inlet Guide Vane (IGV) angular position will be measured with a machinist's protractor. The angle will be measured on sixteen vanes around the inlet circumference. The average of these measurements will define the true position of the IGV's. The true angle will be compared to the feedback angle displayed by the unit control system. The control system angle must be in agreement with the measured angle to within plus or minus 0.5 degrees, or the control system must be re−calibrated.

4.6 A fuel sampling location will be identified as close as possible to the gas turbine and upstream of the metering station.

5. *Conducting the Test*

Capacity and thermal performance testing will be conducted by Seller and witnessed by Buyer at its discretion.

5.1 A minimum of three test points will be conducted on each unit. Each test point will be conducted with the gas turbine power equipment and all test instrumentation functioning satisfactorily and in a steady−state condition with evaporative coolers in service and with the Mark V control system indicating that the unit is at base load. Prior to and during each test point, the gas turbine wheel space temperatures will be monitored individually to verify thermal stability. The gas turbine will be considered in a steady state condition when each turbine wheel space temperature changes by no more than 5EF over a fifteen minute period. The unit thermal stability will be documented by print−outs from the unit control system.

5.2 In accordance with ASME PTC−22 (1997), additional parameters will be monitored during each test point to verify that the system is in a steady state condition. These parameters and corresponding limits of variation are listed in the following table:

Table: Steady−State Conditions Summary

Parameter	**Monitored**	**Variation Limit**	**Rule**
Turbine Wheelspace Temperature (each)	Prior to and during test point	n/a	May not change more than 5EF over any 15 minute period
Ambient Temperature	During test point	± 4/o/F	Variation from test point average may not exceed limit
Wet Bulb Temperature	During test point	± 3/o/F	Variation from test point average may not exceed limit
Gross Power Output	During test point	± 2.0%	Variation from test point average may not exceed limit
Barometric Pressure	During test point	± 0.5%	Variation from test point average may not exceed limit

5.3 In accordance with ASME PTC−22 (1997), each test point will be conducted over a thirty minute time period. Data will be recorded at five minute intervals (or more frequently) throughout the duration of the test point for a minimum of seven complete sets of instrument readings. No test point should exceed thirty minutes nor should the data recording interval exceed ten minutes.

5.4. Fuel samples will be taken at the beginning and end of each test point for a total of twelve samples per unit (including duplicates). Fuel samples will be delivered to a reputable third party laboratory for analysis. As a backup, duplicate fuel samples will be retained at the site until all fuel analysis is completed.

5.5 Testing shall be conducted with the inlet bleed heat system off and isolated.

6. *Evaluation*

6.0 Test Boundary

This test procedure and the calculations employed are intended to determine the Net Dependable Capacity and Net Heat Rate as shown on the Heat Rate Boundary Diagram.

6.1 *Net Dependable Capacity Evaluation*

Generator Net Power Output

Generator Net Power Output (GNPO) will be calculated from the measured net power output from the test point divided by the test point duration in hours.

GNPO = measured net power output (kWh) / test point duration (hrs.)

Net Dependable Capacity

Generator Net Power Output (GNPO) will be corrected from the test conditions to the Reference Conditions. The result will be the Net Dependable Capacity (NDC).

NDC = Net Dependable Capacity corrected to Reference Conditions.

NDC = GNPO × CF\\1\\ × CF\\2\\ × CF\\3\\

where:

CF\\1\\ = Factor used to correct power from the measured ambient temperature and humidity to the contract conditions

= CF\\a\\ / CF\\b\\

where:

CF\\a\\ = Ambient temperature and humidity correction factor from GE Curve [insert curve number when received from GE] at the Reference Conditions

CF\\b\\ = Ambient temperature and humidity correction factor from GE Curve [insert curve number when received from GE] at the measured ambient temperature and humidity

CF\\2\\ = Factor used to correct power from the measured barometric pressure to the rated barometric pressure

= P\\R\\ / P\\M\\

where:

P\\R\\ = Rated barometric pressure (14.39 psia)

P\\M\\ = Measured barometric pressure

CF\\3\\ = Factor used to correct for accumulated fired hours prior to the test

= 1 + (% output loss from curve 519HA772)

The NDC's determined from each test point will be summed and divided by the number of test points to determine the NDC for contract purposes.

6.2 *Net Heat Rate*

Net Heat Rate will be calculated from the measured rate of heat consumption and the measured net power output.

NHR = Net Heat Rate, Btu/kWh (uncorrected)

NHR = HC / GNPO, Btu/kWh

where:

HC = Heat consumption rate, BTU/hr

GNPO = Generator net power output from paragraph 6.1, kW

6.3

Heat Consumption Rate

Turbine rate of heat consumption will be calculated from the measured fuel flow rate (from turbine control system and compensated for fuel temperature) and the fuel higher heating value as determined from the average of laboratory analysis of the fuel samples.

HC = Turbine heat consumption rate, Btu/hr

HC = 3600 × W_F × HHV, Btu/hr

where:

3600 = units conversion, 3600 sec/hr
W_F = Fuel flow rate, lb/s (measured by turbine control system and compensated for fuel temperature)
HHV = Fuel higher heating value, Btu/lb

6.4

Corrected Net Heat Rate

Net Heat Rate will be corrected from test conditions to the Reference Conditions accounting for degradation in accordance with Section 1 of this procedure.

CNHR = Corrected Net Heat Rate, Btu/kWh

CNHR = NHR × $CF1_{HR}$ × $CF2_{HR}$

where:

NHR = Net Heat Rate from Section 6.2, Btu/kWh

$CF1_{HR}$ = Correction factor to correct heat rate from the measured ambient temperature and humidity to the Reference Conditions

= $CF1_{HR(a)}$ / $CF1_{HR(b)}$

where:

$CF1_{HR(a)}$ = Ambient temperature and humidity correction factor from GE Curve [insert curve number when received from GE] at the Reference Conditions.

$CF1_{HR(b)}$ = Ambient temperature and humidity correction factor from GE Curve [insert curve number when received from GE] at the measured ambient temperature and humidity

$CF2_{HR}$ = Factor to correct heat rate for the total fired hours accumulated prior to the test. Factor derived from GE Curve 519HA772 at the accumulated fired hours

= 1− (% heat rate degradation from curve 519HA772) B−7

APPENDIX C

COMMUNICATIONS

1. Purpose

The purpose of this Appendix is:

(i) To describe the nature of, and the requirements for the communication link that will be maintained between Seller and Buyer;

(ii) To identify and establish a communications procedure (the "Communications Procedure") that defines the responsibilities for, and the frequency, content, and logistics of communication between personnel responsible for operating the Facility ("Seller's Operator(s)") and Dispatcher concerning the availability and Dispatch of the Units. The Parties desire that such a procedure be established so that only responsible and authorized personnel can issue requests and/or orders that may impact reliability and availability of the Units.

2. Communication Link.

(i) Buyer shall establish and maintain dedicated phone lines for all communications concerning the availability and Dispatch of the Units. These dedicated systems shall be used as the primary communications link between Seller's Operators and Buyer's Dispatcher responsible for Dispatching Buyer's system ("Generation Dispatcher"). In addition to the dedicated phone lines, Seller and Buyer shall establish standard phone line(s) as a back−up system. Seller's dedicated and standard phone lines are to be located at the control facilities of the Units.

(ii) At any time a Unit at the Facility is synchronized to the Interconnected Utility System, Seller must ensure that a Seller's Operator is available at the dedicated phone line (or back−up phone line if the dedicated line is unavailable) to respond to the Dispatch orders from the Generation Dispatcher. Both Seller and Buyer recognize that there may be operational conditions or events that will required Seller's Operator to leave the control room in order to resolve the condition or event. Both Seller and Buyer also recognize that these conditions or events will be infrequent. During such times, Seller's Operator must first notify the Generation Dispatcher, and provide information regarding how the Seller's Operator can be reached (i.e. a standard, back−up phone line and/or a cellular phone).

(iii) Seller shall establish and maintain a paging system for the Seller's Operators. Such paging system shall constitute the secondary communications link between Seller's Operators and the Generation Dispatcher. During those times when no Unit at the Facility is synchronized to the Interconnected Utility, or during power operation when Seller's Operator has left the control room to resolve an operational condition or event, this paging system will become the primary communications link between Seller's Operator and the Generation Dispatcher. Whenever the paging system is the primary communications link, Seller will ensure at least one Seller's Operator will be available at all times, via the paging system. Should the Dispatcher initiate the paging system, Seller's Operator(s) shall immediately contact the Generation Dispatcher via telephone for specific Dispatch orders. Seller will notify Buyer as soon as possible of any disruption or unavailability of the dedicated or standard phone lines, or the pager system, as soon as practicable. Seller shall also provide a list of back−up contracts to the paging system (i.e. the names and home phone numbers for the operators) to be used should the paging system fail, be inadvertently turned off, lost, unavailable due to satellite communication problems, or if the operator fails to respond. This list of back−up contacts shall be incorporated into the Communications Procedure.

3. Communications Procedure

(i) Prior to the Commercial Operations Date, Seller and Buyer shall establish a mutually approved Communication Procedure that defines the responsibilities for, and the frequency, content, and logistics of, all communications between Seller's Operator(s) and the Generation Dispatcher concerning the availability and dispatch of the Units.

Seller and Buyer shall ensure that the most current mutuallyapproved revision of this Communication Procedure is available to the Seller's Operator(s) and the Generation Dispatcher. Both Seller and Buyer shall mutually review and revise the communications procedure, as necessary.

(ii) The Communications Procedure shall provide telephone numbers for all dedicated and standard phone lines of both Seller and Buyer (including telephone numbers for facsimile machines) and pager numbers for all of Seller's Operators.

The Communications Procedure shall also provide back−up contacts to the paging system (i.e. the names and home phone numbers for the operators) to be used should the paging system fail, be inadvertently turned off, lost, unavailable due to satellite communication problems, or if the Seller's Operator fails to respond.

In addition, the Communications Procedure shall provide instructions and requirements to both the Seller's Operator(s) and the Generation Dispatcher describing the process(es) for communicating unit availability and Dispatch orders for the Units. At a minimum, the Communication Procedure shall provide communication instructions for the following items:

a) Routine notifications (by both Seller's Operator(s) and the Generation Dispatcher) of expected hourly capability and demand, as required by Section 4(e)(ii) of this Agreement.

b) Start−up and Dispatch orders for Units;

c) Conditions, issues or events that could affect the output or reliability of the Units;

d) The time of day (based on a twenty−four hour clock) when a Unit is placed on line and taken off line;

e) Unit deratings, including the amount of any derate, the estimated or known start time and date of the derate, the estimated or known ending time and date of the derate, and the cause of the derate;

f) Conditions at the Facility or a Unit that could affect the present or anticipated load following capability of a Unit;

g) Planned and emergency testing requirements, or other operational work that could limit the availability or maneuverability of a Unit; and

h) The use of operational reporting forms that are provided in Appendix D.

4. Revisions

Each Party shall appoint a representative having power and authority to act on its behalf (the "Representative"). Each Party may change its Representative from time−to−time, effective upon notice given to the other Party. A Representative may change addresses, telephone numbers, facsimile numbers and other similar data to be used in directing communications under this Appendix C or Appendix D to the Party represented by that Representative. Each Representative shall be authorized to agree on behalf of the Party that appointed that Representative to any change in the forms or procedures provided under this Appendix C or Appendix D.

APPENDIX D

OPERATIONS REPORTING FORM

DATA APPLICABLE FOR ELWOOD AVAILABILITY DECLARATION

Availability Declaration Period Commencing
PM/AM, / / TO PM/AM, / /

TO: FAX No.
Telephone No.

This FAX is a submission of

Generator's Offer Data

A *revision* to the previously submitted offer of / /

This document is a hardcopy back−up to the offer of / /

Unit	Available to Meet Net Dependable Capacity	☐	Yes	☐	No
Unit	Available to Meet Net Dependable Capacity	☐	Yes	☐	No

Deratings: Time Time

Unit	Cause Code:	MW	Start	Date	/ /	Stop	Date	/ /
Unit	Cause Code:	MW	Start	Date	/ /	Stop	Date	/ /

Minimum: Time Time

Unit	Cause Code:	MW	Start	Date	/ /	Stop	Date	/ /
Unit	Cause Code:	MW	Start	Date	/ /	Stop	Date	/ /

Submitted By:

Date:

If you do not receive all the pages or if clarification or retransmission is required call

Return acknowledgment FAX to the attention of:

FAX Number:

Acknowledgment by (Signature)

(Title)

Acknowledgment date and time

APPENDIX E

EQUIVALENT AVAILABILITY CALCULATIONS ("EA")

Seller shall calculate for each month, an Equivalent Availability ("EA") for calculation of the Availability Adjustment Credit described in Section 7.1.3. The EA will be calculated (a) for the Summer Super Peak Hours; (b) for the Summer Partial−Peak Hours and (c) for the total of all Non−Summer On−Peak Hours in accordance with the following formula:

$$EA = \left\{1 - \frac{[FOH + EFDH]}{PH}\right\}$$

Where:

Equivalent Forced Derated Hours ("EFDH") are the product of Forced Derated Hours (FDH) and Size of Reduction (as defined below), divided by the Net Dependable Capacity (NDC). Equivalent hours are computed for each Forced Derating and then summed for the applicable period.

Forced Derated Hours ("FDH") and Forced Outage Hours ("FOH") are calculated over On Peak Hours, during the applicable period, during which a Unit experiences a Forced Derating or Forced Outage, as applicable. They are calculated monthly in the Summer Period across all Summer Super Peak Hours and Summer Partial Peak Hours and annually for Non−Summer On Peak Hours (as applicable).

Period Hours ("PH") means the total number of Summer Super Peak, Summer Partial Peak or Non−Summer On Peak Hours (as applicable) in each period.

A Forced Outage or Forced Derating event shall only be included in the calculation of the Equivalent Availability when Seller fails to meet, in whole or part, Buyer's Dispatch and fails (a) to deliver or cause to be delivered Replacement Power or Substitute Power, (b) to pay to Buyer Third Party Damages pursuant to Section 4.7.4, or (c) to pay the Outage Book Out Charge due to an unplanned component failure or other condition that requires the load on the Unit or Facility to be reduced below the level Dispatched.

The Size of Reduction for a Forced Derating shall be determined by Seller and shall be based upon observed output of a typical unit having the same equipment problems under similar operating and environmental conditions. Buyer may request Seller to justify the size of the reduction through provision of reasonably available historical operating records in support of Seller's selection of the Size of Reduction.

In the event of a continuing Forced Outage or Forced Derating, Buyer may submit Dispatch requests as if the Unit were available for full operation, provided such requests are submitted in good faith and support Buyer's need to Dispatch a Unit absent the Forced Outage or Forced Derating. If other units at the Elwood Station are operating, Buyer's request shall be deemed to be in good faith. If no other units are running at the Elwood Station, Buyer shall, if requested by Seller, provide written explanation of the reasons that would demonstrate the economic justification for such Dispatch request.

The following shall not be deemed a Forced Outage or Forced Derating for purposes of calculating the Equivalent Availability (a) a Unit is shut down for Scheduled Maintenance Outages or Compressor Washes as provided in Section 6.4 and 6.5 respectively, (b) A Unit is down or derated, but Seller meets Buyer's Dispatch order through (i) Replacement Power, (ii) Substitute Power, (iii) payment of Third Party Damages pursuant to Section 4.7.4, or (iv) payment of an Outage Book Out Charge, (c) a Unit is curtailed, interrupted, reduced or increased by the Interconnected Utility pursuant to Sections 4.8 or 6.6.2, (d) to the extent a Unit is not Available as a result of a Force Majeure Event, or (e) Seller pays imbalance charges to compensate for any under−delivery.

APPENDIX F

Output Adjustment Curve

Degradation Curves

Curve	**Number**
GE Expected Degradation	719HA722

Turbine Performance Curves

Curve	**Number**
Estimated Single Unit Performance, Base	522HA851
Compressor Inlet Temperature Corrections, Base	522HA852
Modulated Inlet Guide Vanes Effect	522HA853
Altitude Correction for Turbine	416HA622B
Humidity Effects Curve	498HA697B

APPENDIX G

Non Billable Generation

To establish the kilowatt−hours of electricity provided by a Unit and consumed by other units for a billing period, the total for each billing period of electricity consumed by each of units 5, 6, 7 and 8 to be determined from the individual unit electric meter readings using the Revenue Meter which will then be summed for all four units. From this sum, the total monthly electricity purchased from the Interconnected Utility (as determined from the Interconnected Utility's revenue meter in the ComEd/Elwood Switchyard) will be subtracted, yielding an aggregate total of the electricity consumed by all four units that had been generated by one or more other units. This amount will then be multiplied by the ratio of the total operating hours of a given unit to the total operating hours of all four units. This product will represent the electricity generated by a given unit and consumed by other units. This value will be subtracted from the reading of the Revenue Meter for a particular Committed Unit for billing purposes for the billing period. The following example demonstrates the calculation methodology:

Total electricity generated Unit 5—30,000 MWh

Total electricity generated Unit 6—22,500 MWh

Total electricity generated Unit 7—15,000 MWh

Total electricity generated Unit 8—0 MWh

Total electricity consumed Unit 5—20,000 kWh

Total electricity consumed Unit 6—30,000 kWh

Total electricity consumed Unit 7—15,000 kWh

Total electricity consumed Unit 8—2,000 kWh

Total electricity consumed All Units = 20,000 + 30,000 + 15,000 + 2,000 = 67,000 kWh

Total electricity purchased from the Interconnected Utility—30,000 kWh

Total electricity consumed by all four units and generated by all four units = 67,000 − 30,000 = 37,000 kWh

Unit 5 monthly operating hours—200

Unit 6 monthly operating hours—150

Unit 7 monthly operating hours—100

Unit 8 monthly operating hours—0

Total operating hours = 200 + 150 + 100 + 0 = 450 hours

CALCULATION:

Electricity furnished by Unit 5 and consumed by the other units = (200/450) (37,000) = 16,444 kWh (16.444 MWh)

Electricity furnished by Unit 6 and consumed by the other units = (150/450) (37,000) = 12,333 kWh (12.333 MWh)

Electricity furnished by Unit 7 and consumed by the other units = (100/450) (37,000) = 8,222 kWh (8.222 MWh)

Electricity furnished by Unit 8 and consumed by the other units = (0/450) (37,000) = 0 kWh

Billable Generation Unit 5 = 30,000 − 16.444 = 29,983 MWh

Billable Generation Unit 6 = 22,500 − 12.333 = 22,488 MWh

Billable Generation Unit 7 = 15,000 − 8.222 = 14,992 MWh

Billable Generation Unit 8 = 0−0 = 0 MWh"

APPENDIX H−1

GUARANTY

THIS GUARANTY dated as of , is made by Peoples Energy Corporation, an Illinois corporation ("Guarantor"), in favor of UtiliCorp United Inc. and Aquila Energy Marketing Corporation, Delaware corporations (referring to collectively hereafter as "Creditor").

WHEREAS, Creditor and Elwood Energy, II LLC, a Delaware limited liability company ("Debtor"), have entered into that certain Power Sales Agreement dated , (the "Contract") and capitalized items used and not otherwise defined herein shall have the meanings assigned to them in the Contract;

WHEREAS, Guarantor, through one or more subsidiaries, owns a 50 percent membership interest in Debtor and the remaining 50 percent membership interest is indirectly owned by Dominion Energy, Inc. ("Dominion"); and

WHEREAS, to induce Creditor to extend credit to Debtor pursuant to the Contract, Guarantor has agreed to provide to Creditor this Guaranty;

NOW, THEREFORE, in consideration of the premises, Creditor's execution of the Contract and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, Guarantor hereby agrees as follows:

1. *Guaranty.* Subject to the provisions hereof, Guarantor hereby irrevocably, absolutely and unconditionally guarantees the timely payment of all financial obligations which become due and payable by Debtor to Creditor under or in connection with the Contract (collectively, "Obligations" and individually, an "Obligation") such that, if Debtor fails, neglects or refuses to perform any Obligation, Guarantor shall make such payment within ten business days after Guarantor receives written notice thereof. Notwithstanding the foregoing, as to any Obligation which Guarantor is called upon to pay or cause payment to be made, Guarantor reserves to itself the right to assert any and all defenses under the Contract which Debtor could assert against Creditor with respect to such Obligation; provided, however, that such reservation shall not include any legal or equitable discharge or defense of a guarantor or surety arising out of any of the events described in Section 2 or Section 3 hereof. The guarantee of Guarantor pursuant to this Section 1 is limited to 50 percent of the Obligations; provided, however, that in no event shall the maximum aggregate liability of Guarantor under this Guaranty exceed $10,000,000 (the "Guaranty Cap Amount") plus any amounts owed for collecting or enforcing this Guaranty pursuant to the next sentence hereof; provided further, that Guarantor's obligations hereunder are separate and independent obligations from those of Dominion under Dominion's Guaranty of even date herewith and neither Guarantor nor Dominion shall be liable for the obligations of the other under their respective guaranties by reason of joint and several liability or otherwise. In addition to Guarantor's liability for the Obligations set forth herein, Guarantor agrees to pay to Creditor such further amounts as shall be sufficient to cover the costs of collecting or enforcing this Guaranty (including reasonable fees, expenses and disbursements of counsel). This Guaranty is a guaranty of payment and not of collection.

2. *Guaranty Absolute.* Except as otherwise expressly provided in Section 3(b) hereof, Creditormay, at any time and from time to time, without the consent of or notice to Guarantor, and without impairing or releasing the obligations of Guarantor hereunder:

(a) change the manner, place or terms of payment of, or (if applicable) interest rate on, or renew, extend or alter, any or all of the Obligations;

(b) amend, waive, terminate or otherwise modify the Contract or any other document, instrument or agreement relating to any Obligation;

(c) release (in whole or in part) or compromise or settle with Debtor or any other person liable in any manner for payment of any or all of the Obligations;

(d) exercise or refrain from exercising any rights against Debtor or any other person or otherwise act or refrain from acting or otherwise fail to be diligent; and

(e) take, substitute, surrender, exchange or release any collateral or other security for any or all of the Obligations.

3. *Effect of Certain Events.* Guarantor agrees that, except as otherwise expressly provided in Section 3(b) hereof, Guarantor's liability hereunder will not be released, reduced or impaired by the occurrence of any of the following events:

(a) the liquidation, dissolution, receivership, insolvency, bankruptcy, assignment for the benefit of creditors, reorganization, arrangement, composition or readjustment or other similar proceeding affecting the status, composition, identity, existence, assets or obligations of Debtor, or the disaffirmance or termination of any of the Obligations or the Contract in or as a result of any such proceeding;

(b) the renewal, consolidation, extension, modification or amendment from time to time of the Contract or any document, instrument or agreement relating to any Obligation, provided, however, that notwithstanding anything contained in this Guaranty or the Contract to the contrary, Creditor and Debtor may not, without the prior written consent of Guarantor, (i) extend or lengthen the Term of the Contract (as defined in the Contract as of the date hereof) beyond or (ii) change, modify or amend the definition of the term "Capacity Charges" (as defined in the Contract as of the date hereof) in any manner that would increase Guarantor's liability under this Guaranty;

(c) the failure, delay, waiver or refusal by Creditor to exercise, in whole or in part, any right or remedy held by Creditor with respect to the Contract or the Obligations thereunder; or

(d) the sale, encumbrance, transfer or other modification of the ownership of Debtor or Creditor or any change in the name, identity, business, structure, composition, financial condition or management (including, without limitation, by reason of a merger, dissolution, consolidation or reorganization) of Debtor or Creditor;

(e) future changes in conditions, including change of law, or any invalidity, unenforceability or irregularity with respect to the execution and delivery of the Contract or this Guaranty; and

(f) any other circumstance which might otherwise constitute a legal or equitable discharge or defense of a guarantor or surety, subject to clause (ii) of Section 1 hereof.

4. *Waivers.* Except as expressly provided in Section 1 hereof, Guarantor waives:

(a) notice of acceptance of this Guaranty, of the creation or existence of the Contract or any Obligation thereunder, and of any action by Creditor in reliance hereon or in connection herewith;

(b) promptness, diligence, presentment, demand for payment, notice of dishonor or nonpayment, protest and notice of protest with respect to any Obligation;

(c) any requirement that suit be brought against, or any other action by Creditor be taken against, Debtor or any other person as a condition to Guarantor's obligations under this Guaranty or as a condition to enforcement of this Guaranty against Guarantor.

(d) notice of adverse change in the financial condition of Debtor or any other fact which might increase Creditor's risk; and

(e) any other notices or demands to which guarantors or sureties may be entitled.

5. *Continuing Guaranty.* This Guaranty is an absolute and continuing guaranty. This Guaranty shall terminate when all of the Obligations have been indefeasibly paid in full to Creditor. Notwithstanding anything in this Guaranty to the contrary, this Guaranty shall continue to be effective or shall be reinstated, as the case may be, if at any time, either before or after the termination hereof, payment of the Obligations guaranteed pursuant to this Guaranty, or any part thereof, is rescinded or must be returned by Creditor upon the insolvency, bankruptcy or reorganization of Debtor or Guarantor, all as though such payment had not been made.

6. *Representations and Warranties.* Guarantor represents and warrants to Creditor as follows:

(a) Guarantor is a corporation duly organized, validly existing and in good standing under the laws of Illinois and has full corporate power and authority to execute, deliver and perform this Guaranty.

(b) The execution, delivery and performance of this Guaranty by Guarantor have been and remain duly authorized by all necessary corporate action on the part of by Guarantor and do not contravene any provision of law or of Guarantor's certificate of incorporation or bylaws or any contractual restriction binding on Guarantor or any of its assets.

(c) All consents, authorizations and approvals of, and registrations and declarations with, any governmental authority necessary for the due execution, delivery and performance of this Guaranty by Guarantor have been obtained and remain in full force and effect and all conditions thereof have been duly complied with, and no other action by, and no notice to or filing with, any governmental authority is required in connection with the execution, delivery or performance by Guarantor of this Guaranty.

(d) This Guaranty constitutes the legal, valid and binding obligation of Guarantor enforceable against Guarantor in accordance with its terms, subject, as to enforcement, to bankruptcy, insolvency, reorganization and other laws of general applicability relating to or affecting creditors' rights and to general equity principles.

(e) Debtor is indirectly partially owned by Guarantor, and this Guaranty reasonably may be expected to benefit, directly or indirectly, Guarantor.

7. *Covenants.* Guarantor agrees that, so long as this Guaranty remains in effect, Guarantor will promptly furnish to Creditor, upon request at any time and from time to time, a copy of Guarantor's most recent annual report on Form 10−K or quarterly report on Form 10−Q, in each case as filed with the Securities and Exchange Commission (the "SEC"); provided however, if Guarantor is not required to file such reports with the SEC, Guarantor agrees to furnish to Creditor such comparable financial information respecting Guarantor as Creditor may from time to time reasonably request.

8. *Miscellaneous.*

(a) *Notice.* Any notice or other communication given hereunder by either Guarantor or Creditor to the other party ("Notice") shall be in writing and delivered personally, mailed by registered or certified mail, postage prepaid and return receipt requested, by telecopier, or by courier guaranteeing overnight delivery, as follows:

(i) if to Guarantor:

Peoples Energy Corporation
130 East Randolph Drive
Chicago, Illinois
Attention: William W. Reynolds, Treasurer
Telecopy No.: (312) 240−4348

(ii) if to Creditor:

Notice given by personal delivery or mail shall be effective upon actual receipt or refusal of receipt. Notice given by telecopier shall be deemed effective upon transmission and electronic confirmation by the transmitting telecopier. All Notices by telecopier shall be confirmed promptly after transmission in writing by certified mail or personal delivery. Any party may change any address to which Notice is to be given to it by giving Notice as provided above of such change of address. All amounts becoming payable by Guarantor to Creditor under this Guaranty shall be payable at Creditor's offices located at its address for purposes of Notice, or such other place as Creditor may from time to time designate (including wire transfer instructions).

(b) *Amendments; Waivers; Remedies.* All amendments, waivers, consents or approvals arising pursuant to this Guaranty must be in writing signed by Guarantor and Creditor. No failure on the part of Creditor to exercise, and no delay in exercising, and no course of dealing with respect to, any right, power or privilege hereunder shall operate as a waiver thereof; nor shall any single or partial exercise thereof or the exercise of any other right, power or privilege operate as such a waiver. No right, power or remedy of Creditor under this Guaranty or the Contract shall be exclusive of any other right, power or remedy, but shall be cumulative and in addition to any other right, power or remedy thereunder or now or hereafter existing by law or in equity.

(c) *Severability.* If any provision of this Guaranty or the application thereof to any party or circumstance shall be invalid or unenforceable, then the remaining provisions or the application of such provision to parties or circumstances other than those as to which it is invalid or unenforceable, shall continue to be valid and enforceable.

(d) *Assignment.* Neither Guarantor nor Creditor may assign its rights or obligations under this Guaranty without the other party's prior written consent, which consent may not be unreasonably withheld; provided, however, Creditor may assign its rights hereunder without consent of Guarantor (but with prior notice thereof to Guarantor) to any party to whom the Contract has been properly assigned in accordance with the terms thereof. Subject to the foregoing, this Guaranty shall be binding on, and shall inure to the benefit of, Guarantor and Creditor and their respective successors and assigns.

(e) *GOVERNING LAW.* THIS GUARANTY SHALL BE GOVERNED BY, AND INTERPRETED IN ACCORDANCE WITH, THE LAWS OF THE STATE OF ILLINOIS, WITHOUT REGARD TO PRINCIPLES OF CONFLICT OF LAWS. GUARANTOR AND CREDITOR EACH HEREBY IRREVOCABLY SUBMITS FOR ITSELF AND IN RESPECT OF ITS PROPERTY TO THE ORIGINAL JURISDICTION OF THE STATE AND FEDERAL COURTS SITTING IN CHICAGO, ILLINOIS WITH REGARD TO ANY SUIT, CLAIM OR ACTION IN ANY WAY RELATED TO THE EXECUTION, DELIVERY OR PERFORMANCE OF THIS GUARANTY, AND GUARANTOR HEREBY IRREVOCABLY WAIVES ANY AND ALL OBJECTIONS TO WHICH IT MAY NOW OR

HEREAFTER HAVE TO THE BRINGING OF ANY SUCH SUITS, CLAIMS OR ACTIONS IN SUCH JURISDICTIONS, INCLUDING, WITHOUT LIMITATION, ANY OBJECTION TO THE LAYING OF VENUE OR BASED ON THE GROUNDS OF FORUM NON CONVENIENS. THE PARTIES HERETO FURTHER AGREE THAT ANY AND ALL SUCH SUITS, CLAIMS OR ACTIONS SHALL BE BROUGHT OR FILED EXCLUSIVELY IN SUCH COURTS AND NOWHERE ELSE.

(f) *Headings.* The headings of the sections and subsections of this Guaranty are for convenience only, and shall not limit or otherwise affect the meaning hereof.

(g) *Counterparts.* Guarantor may sign this Guaranty in any number of counterparts, each of which shall be an original but all of which when taken together shall constitute one and the same instrument.

(h) *Construction of Agreement.* Unless the context of this Agreement clearly requires otherwise, (i) pronouns, wherever used herein and of whatever gender, shall include natural persons, corporations, and associations of every kind and character, (ii) the gender of all words used in this Guaranty shall include the masculine, feminine and neuter, (iii) the words "includes" or "including" shall mean "including without limitation", and (iv) the words "hereof", "herein", "hereunder" and similar terms in this Guaranty shall refer to this Guaranty as a whole and not any particular section or subsection in which such words appear.

(i) *Interpretation and Reliance.* No presumption will apply in favor of any party hereto in the interpretation of this Guaranty or in the resolution of any ambiguity of any provision hereof.

IN WITNESS WHEREOF, Guarantor has caused this Guaranty to be executed effective as of the date first above written.

PEOPLES ENERGY CORPORATION

By: ______________________________

Name: ______________________________

Title: ______________________________

APPENDIX H − 2

GUARANTY

THIS GUARANTY dated as of , is made by Dominion Energy, Inc., a Virginia corporation ("Guarantor"), in favor of UtiliCorp United Inc. and Aquila Energy Marketing Corporation, Delaware corporations (referred to collectively hereafter as "Creditor").

WHEREAS, Creditor and Elwood Energy II, LLC, a Delaware limited liability company ("Debtor"), have entered into that certain Power Sales Agreement dated , (the "Contract") and capitalized terms used and not otherwise defined herein shall have the meanings assigned to them in the Contract;

WHEREAS, Guarantor, through one or more subsidiaries, owns a 50 percent membership interest in Debtor and the remaining 50 percent membership interest is indirectly owned by Peoples Energy Corporation ("Peoples"); and

WHEREAS, to induce Creditor to extend credit to Debtor pursuant to the Contract, Guarantor has agreed to provide to Creditor this Guaranty;

NOW, THEREFORE, in consideration of the premises, Creditor's execution of the Contract and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, Guarantor hereby agrees as follows:

1. *Guaranty.* Subject to the provisions hereof, Guarantor hereby irrevocably, absolutely and unconditionally guarantees the timely payment of all financial obligations which become due and payable by Debtor to Creditor under or in connection with the Contract (collectively, "Obligations" and individually, an "Obligation") such that, if Debtor fails, neglects or refuses to perform any Obligation, Guarantor shall make such payment within ten business days after Guarantor receives written notice thereof. Notwithstanding the foregoing, as to any Obligation which Guarantor is called upon to pay or cause payment to be made, Guarantor reserves to itself the right to assert any and all defenses under the Contract which Debtor could assert against Creditor with respect to such Obligation; provided, however, that such reservation shall not include any legal or equitable discharge or defense of a guarantor or surety arising out of any of the events described in Section 2 or Section 3 hereof. The guarantee of Guarantor pursuant to this Section 1 is limited to 50 percent of the Obligations; provided, however, that in no event shall the maximum aggregate liability of Guarantor under this Guaranty exceed $10,000,000 (the "Guaranty Cap Amount") plus any amounts owed for collecting or enforcing this Guaranty pursuant to the next sentence hereof; provided further, that Guarantor's obligations hereunder are separate and independent obligations from those of Peoples under Peoples' Guaranty of even date herewith and neither Guarantor nor Peoples shall be liable for the obligations of the other under their respective guaranties by reason of joint and several liability or otherwise. In addition to Guarantor's liability for the Obligations set forth herein, Guarantor agrees to pay to Creditor such further amounts as shall be sufficient to cover the costs of collecting or enforcing this Guaranty (including reasonable fees, expenses and disbursements of counsel). This Guaranty is a guaranty of payment and not of collection.

2. *Guaranty Absolute.* Except as otherwise expressly provided in Section 3(b) hereof, Creditor may, at any time and from time to time, without the consent of or notice to Guarantor, and without impairing or releasing the obligations of Guarantor hereunder:

(a) change the manner, place or terms of payment of, or (if applicable) interest rate on, or renew, extend or alter, any or all of the Obligations;

(b) amend, waive, terminate or otherwise modify the Contract or any other document, instrument or agreement relating to any Obligation;

(c) release (in whole or in part) or compromise or settle with Debtor or any other person liable in any manner for payment of any or all of the Obligations;

(d) exercise or refrain from exercising any rights against Debtor or any other person or otherwise act or refrain from acting or otherwise fail to be diligent; and

(e) take, substitute, surrender, exchange or release any collateral or other security for any or all of the Obligations.

3. *Effect of Certain Events.* Guarantor agrees that, except as otherwise expressly provided in Section 3(b) hereof, Guarantor's liability hereunder will not be released, reduced or impaired by the occurrence of any of the following events:

(a) the liquidation, dissolution, receivership, insolvency, bankruptcy, assignment for the benefit of creditors, reorganization, arrangement, composition or readjustment or other similar proceeding affecting the status, composition, identity, existence, assets or obligations of Debtor, or the disaffirmance or termination of any of the Obligations or the Contract in or as a result of any such proceeding;

(b) the renewal, consolidation, extension, modification or amendment from time to time of the Contract or any document, instrument or agreement relating to any Obligation, provided, however, that notwithstanding anything contained in this Guaranty or the Contract to the contrary, Creditor and Debtor may not, without the prior written consent of Guarantor, (i) extend or lengthen the Term of the Contract (as defined in the Contract as of the date hereof) beyond or . (ii) change, modify or amend the definition of the term "Capacity Charges" (as defined in the Contract as of the date hereof) in any manner that would increase Guarantor's liability under this Guaranty;

(c) the failure, delay, waiver or refusal by Creditor to exercise, in whole or in part, any right or remedy held by Creditor with respect to the Contract or the Obligations thereunder; or

(d) the sale, encumbrance, transfer or other modification of the ownership of Debtor or Creditor or any change in the name, identity, business, structure, composition, financial condition or management (including, without limitation, by reason of a merger, dissolution, consolidation or reorganization) of Debtor or Creditor;

(e) future changes in conditions, including change of law, or any invalidity, unenforceability or irregularity with respect to the execution and delivery of the Contract or this Guaranty; and

(f) any other circumstance which might otherwise constitute a legal or equitable discharge or defense of a guarantor or surety, subject to clause (ii) of Section 1 hereof.

4. *Waivers.* Except as expressly provided in Section 1 hereof, Guarantor waives:

(a) notice of acceptance of this Guaranty, of the creation or existence of the Contract or any Obligation thereunder, and of any action by Creditor in reliance hereon or in connection herewith;

(b) promptness, diligence, presentment, demand for payment, notice of dishonor or nonpayment, protest and notice of protest with respect to any Obligation;

(c) any requirement that suit be brought against, or any other action by Creditor be taken against, Debtor or any other person as a condition to Guarantor's obligations under this Guaranty or as a condition to enforcement of this Guaranty against Guarantor.

(d) notice of adverse change in the financial condition of Debtor or any other fact which might increase Creditor's risk; and

(e) any other notices or demands to which guarantors or sureties may be entitled.

5. *Continuing Guaranty.* This Guaranty is an absolute and continuing guaranty. This Guaranty shall terminate when all of the Obligations have been indefeasibly paid in full to Creditor. Notwithstanding anything in this Guaranty to the contrary, this Guaranty shall continue to be effective or shall be reinstated, as the case may be, if at any time, either before or after the termination hereof, payment of the Obligations guaranteed pursuant to this Guaranty, or any part thereof, is rescinded or must be returned by Creditor upon the insolvency, bankruptcy or reorganization of Debtor or Guarantor, all as though such payment had not been made.

6. *Representations and Warranties.* Guarantor represents and warrants to Creditor as follows:

(a) Guarantor is a corporation duly organized, validly existing and in good standing under the laws of Illinois and has full corporate power and authority to execute, deliver and perform this Guaranty.

(b) The execution, delivery and performance of this Guaranty by Guarantor have been and remain duly authorized by all necessary corporate action on the part of by Guarantor and do not contravene any provision of law or of Guarantor's certificate of incorporation or bylaws or any contractual restriction binding on Guarantor or any of its assets.

(c) All consents, authorizations and approvals of, and registrations and declarations with, any governmental authority necessary for the due execution, delivery and performance of this Guaranty by Guarantor have been obtained and remain in full force and effect and all conditions thereof have been duly complied with, and no other action by, and no notice to or filing with, any governmental authority is required in connection with the execution, delivery or performance by Guarantor of this Guaranty.

(d) This Guaranty constitutes the legal, valid and binding obligation of Guarantor enforceable against Guarantor in accordance with its terms, subject, as to enforcement, to bankruptcy, insolvency, reorganization and other laws of general applicability relating to or affecting creditors' rights and to general equity principles.

(e) Debtor is indirectly partially owned by Guarantor, and this Guaranty reasonably may be expected to benefit, directly or indirectly, Guarantor.

7. *Covenants.* Guarantor agrees that, so long as this Guaranty remains in effect, Guarantor will promptly furnish to Creditor, upon request at any time and from time to time, a copy of Guarantor's most recent annual report on Form 10−K or quarterly report on Form 10−Q, in each case as filed with the Securities and Exchange Commission (the "SEC"); provided however, if Guarantor is not required to file such reports with the SEC, Guarantor agrees to furnish to Creditor such comparable financial information respecting Guarantor as Creditor may from time to time reasonably request.

8. *Miscellaneous.*

(a) *Notice.* Any notice or other communication given hereunder by either Guarantor or Creditor to the other party ("Notice") shall be in writing and delivered personally, mailed by registered or certified mail, postage prepaid and return receipt requested, by telecopier, or by courier guaranteeing overnight delivery, as follows:

(i) if to Guarantor:

Dominion Energy, Inc.
120 Tredegar Street
Richmond, Virginia 23218
Attention: Diane Leopold/Christine M. Schwab, Esq.
Telecopy No.: (804) 819−2202

(ii) if to Creditor:

Notice given by personal delivery or mail shall be effective upon actual receipt or refusal of receipt. Notice given by telecopier shall be deemed effective upon transmission and electronic confirmation by the transmitting telecopier. All Notices by telecopier shall be confirmed promptly after transmission in writing by certified mail or personal delivery. Any party may change any address to which Notice is to be given to it by giving Notice as provided above of such change of address. All amounts becoming payable by Guarantor to Creditor under this Guaranty shall be payable at Creditor's offices located at its address for purposes of Notice, or such other place as Creditor may from time to time designate (including wire transfer instructions).

(b) *Amendments; Waivers; Remedies.* All amendments, waivers, consents or approvals arising pursuant to this Guaranty must be in writing signed by Guarantor and Creditor. No failure on the part of Creditor to exercise, and no delay in exercising, and no course of dealing with respect to, any right, power or privilege hereunder shall operate as a waiver thereof; nor shall any single or partial exercise thereof or the exercise of any other right, power or privilege operate as such a waiver. No right, power or remedy of Creditor under this Guaranty or the Contract shall be exclusive of any other right, power or remedy, but shall be cumulative and in addition to any other right, power or remedy thereunder or now or hereafter existing by law or in equity.

(c) *Severability.* If any provision of this Guaranty or the application thereof to any party or circumstance shall be invalid or unenforceable, then the remaining provisions or the application of such provision to parties or circumstances other than those as to which it is invalid or unenforceable, shall continue to be valid and enforceable.

(d) *Assignment.* Neither Guarantor nor Creditor may assign its rights or obligations under this Guaranty without the other party's prior written consent, which consent may not be unreasonably withheld; provided, however, Creditor may assign its rights hereunder without consent of Guarantor (but with prior notice thereof to Guarantor) to any party to whom the Contract has been properly assigned in accordance with the terms thereof. Subject to the foregoing, this Guaranty shall be binding on, and shall inure to the benefit of, Guarantor and Creditor and their respective successors and assigns.

(e) *GOVERNING LAW.* THIS GUARANTY SHALL BE GOVERNED BY, AND INTERPRETED IN ACCORDANCE WITH, THE LAWS OF THE STATE OF ILLINOIS, WITHOUT REGARD TO PRINCIPLES OF CONFLICT OF LAWS. GUARANTOR AND CREDITOR EACH HEREBY IRREVOCABLY SUBMITS FOR ITSELF AND IN RESPECT OF ITS PROPERTY TO THE ORIGINAL JURISDICTION OF THE STATE AND FEDERAL COURTS SITTING IN CHICAGO, ILLINOIS WITH REGARD TO ANY SUIT, CLAIM OR ACTION IN ANY WAY RELATED TO THE EXECUTION, DELIVERY OR PERFORMANCE OF THIS GUARANTY, AND GUARANTOR HEREBY IRREVOCABLY WAIVES ANY AND ALL OBJECTIONS TO WHICH IT MAY NOW OR HEREAFTER HAVE TO THE BRINGING OF ANY SUCH SUITS, CLAIMS OR ACTIONS IN SUCH JURISDICTIONS, INCLUDING, WITHOUT LIMITATION, ANY OBJECTION TO THE LAYING OF VENUE OR BASED ON THE GROUNDS OF FORUM NON CONVENIENS. THE PARTIES HERETO FURTHER AGREE THAT ANY AND ALL SUCH SUITS, CLAIMS OR ACTIONS SHALL BE BROUGHT OR FILED EXCLUSIVELY IN SUCH COURTS AND NOWHERE ELSE.

(f) *Headings.* The headings of the sections and subsections of this Guaranty are for convenience only, and shall not limit or otherwise affect the meaning hereof.

(g) *Counterparts.* Guarantor may sign this Guaranty in any number of counterparts, each of which shall be an original but all of which when taken together shall constitute one and the same instrument.

(h) *Construction of Agreement.* Unless the context of this Agreement clearly requires otherwise, (i) pronouns, wherever used herein and of whatever gender, shall include natural persons, corporations, and associations of every kind and character, (ii) the gender of all words used in this Guaranty shall include the masculine, feminine and neuter, (iii) the words "includes" or "including" shall mean "including without limitation", and (iv) the words "hereof", "herein", "hereunder" and similar terms in this Guaranty shall refer to this Guaranty as a whole and not any particular section or subsection in which such words appear.

(i) *Interpretation and Reliance.* No presumption will apply in favor of any party hereto in the interpretation of this Guaranty or in the resolution of any ambiguity of any provision hereof.

IN WITNESS WHEREOF, Guarantor has caused this Guaranty to be executed effective as of the date first above written.

DOMINION ENERGY, INC.

By: ______________________

Name: ______________________

Title: ______________________

APPENDIX I

Scheduled Maintenance Outages

Type	Scheduled Maintenance	Frequency of Inspection	Duration of Inspection
Major	Combustion Inspection	Every 400 starts or 8,000 equivalent hours	4−5 days
Major	Hot Gas Path Inspection	Every 800 starts or 24,000 equivalent hours	10−12 days
Major	Major CT Overhaul	Every 1,600 starts or 48,000 equivalent hours	20 days
Routine*	BOP Inspections	Each Spring and Fall	4 days

*

Note: Routine Balance of Plant inspections will be scheduled during a Major Inspection outage.

APPENDIX K

Remote Monitoring Data Points

Pursuant to Section 4.3.2.7, Seller shall use commercially reasonable efforts to make available to Buyer the Station Fuel Meter outputs listed below:

Station Fuel Meter, including:

(a) instantaneous and integrated natural gas fuel flow;

(b) instantaneous and integrated natural gas fuel energy flow;

(c) instantaneous fuel quality raw data (fuel heat content, delivery pressure, delivery temperature).

Pursuant to Section 4.3.2.7, Seller shall make available to Buyer the Facility and Unit outputs listed below:

1. Revenue Meter Per Unit, including:

   (a) instantaneous and integrated Electric Energy output (corrected to the Point of Delivery);

   (b) instantaneous reactive power (volt−amperes−reactive, leading or lagging), or power factor (leading or lagging) as available;

   (c) integrated electric power inflow (backfeed)

   (d) station voltage (as measured at the Revenue Meter potential transformers;

   (e) system frequency (as measured on the interconnected Utility system bus, or if not available, at the Revenue Meter).

2. Individual Fuel Meter instantaneous natural gas fuel flow to the individual Units (including Elwood III Units).

3. Station service instantaneous and integrated electric energy consumption.

4. Ambient dry−bulb temperature at or near to the combustion turbine air inlet.

5. Relative humidity or ambient wet−bulb temperature at or near to the combustion turbine air inlet.

6. Ambient atmospheric pressure at or near to the combustion turbine air inlet.

QuickLinks

EXHIBIT 10(a)(31)

Execution Copy

POWER SALES AGREEMENT

Dated as of June 30, 2000

Between

Aquila Energy Marketing Corporation,

UtiliCorp United Inc.
(Buyer)
and

Elwood Energy III, LLC
(Seller)

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APPENDICES

POWER SALES AGREEMENT

THIS POWER SALES AGREEMENT (including Appendices, this "Agreement") dated as of June 30, 2000, is entered into between Aquila Energy Marketing Corporation ("Aquila"), and UtiliCorp United Inc. ("UCU") (Aquila and UCU referred to herein collectively as "Buyer"), and Elwood Energy III, LLC, a Delaware limited liability company ("Seller"); Buyer and Seller are sometimes referred to herein individually as a "Party" and collectively as the "Parties");

W I T N E S S E T H:

WHEREAS, Seller owns and operates an electric generating facility in Elwood, Illinois and is engaged in the generation and sale of Electric Energy, Capacity and associated Ancillary Services; and

WHEREAS, Seller is building the Facility which will be located at the Elwood Station; and

WHEREAS, Seller anticipates the Commercial Operations Date of Units 7 and 8 of the Facility will occur on or prior to July 1, 2001; and

WHEREAS, Buyer desires to receive and purchase, and Seller desires to deliver and sell the Electric Energy, Capacity and associated Ancillary Services from Units 7 and 8 of the Facility and Replacement Power, pursuant to this Agreement; and

NOW, THEREFORE, in consideration of the mutual covenants and agreements herein set forth, the Parties hereto agree as follows:

1. *Definitions and Interpretation.*

1.1 *Definitions.* As used in this Agreement, the terms set forth below in this Section 1 shall have the respective meanings so set forth.

"ASME" means the American Society of Mechanical Engineers.

"Actual Heat Rate" for any period shall be the Heat Rate which is determined based upon actual performance of the Facility and the Elwood II Units during such period and calculated by the quotient of the aggregate gas energy consumption in Btus for Units 7 and 8 (not including gas consumed to generate Test Energy, incremental gas consumed (at a Heat Rate above the Net Heat Rate) to generate Incremental Energy to the extent used to offset what would otherwise be a Forced Derating, or gas consumed during Failed Starts), and the Elwood II Units as measured by the Station Fuel Meter divided by the Electric Energy output (in kWh) produced by the same Units and the Elwood II Units during the identical period as measured by the Revenue Meter.

"Affected Party" has the meaning set forth in Section 19.1.

"Affiliate" means, when used with respect to any Person, any Person controlling, controlled by or under common control with such Person. For the purposes of this definition, the term "controlling" (and, with correlative meanings, the terms "controlled by" and "under common control with") shall mean the possession of the power to direct or cause the direction of the management and policies of such Person, whether through the ownership of voting securities or by contract or agency or otherwise.

"Aggregate Delay LD Cap" means $21,215,800, less any Delay Book Out Charges paid by Seller.

"Ancillary Services" has the meaning set forth in Section 9.

"Availability Adjustment" has the meaning set forth in Section 7.1.3.

"Available" means a state in which the Facility is capable of providing full service, whether or not it is actually in operation or in service.

"Average Summer Partial Peak Availability" means the Equivalent Availability during Partial Peak Hours averaged over all months of a given Summer Period, calculated as:

1 − [(sum total of FOH + EFDH)/(sum total of Partial Peak period hours)].

"Average Summer Super Peak Availability" means the Equivalent Availability during Super Peak Hours averaged over all months of a given Summer Period, calculated as:

1 − [(sum total of FOH + EFDH)/(sum total of Super Peak period hours)].

"Bankruptcy" means any case, action or proceeding under any bankruptcy, reorganization, debt arrangement, insolvency or receivership law or any dissolution or liquidation proceeding commenced by or against a Person and, if such case, action or proceeding is not commenced by such Person, such case or proceeding shall be consented to or acquiesced in by such Person or shall result in an order for relief or shall remain undismissed for 90 days.

"Bankruptcy Event" means with respect to a Party, an assignment by such Party for the benefit of creditors or the filing of a case in Bankruptcy or any proceeding under any other insolvency law under which such Party is debtor in bankruptcy.

"Base Fuel Charge" means the Fuel Index plus either 10 cents/MMBTU or 15 cents/MMBTU, as applicable under Section 7.2.5.1 or Section 7.2.5.2.

"Btu" means British thermal unit.

"Business Day" means each weekday (Monday through Friday) excluding NERC Holidays.

"Buyer Event of Default" has the meaning specified in Section 13.2.

"Cap Date" has the meaning specified in Section 3.3.5.

"Capacity" means the capability measured in kW of Seller to produce Electric Energy at the Facility or deliver Replacement Power to the Point of Delivery or the Replacement Power Delivery Point, as applicable.

"Capacity Bonus" has the meaning set forth in Section 7.1.4.

"Capacity Charge" has the meaning set forth in Section 7.1.

"Capacity Rate" has the meaning set forth in Section 7.1.2

"Capacity Rate Reduction Amount" has the meaning set forth in Section 3.3.6.

"Cap Date" has the meaning set forth in Section 3.3.5.

"Change in Law" means, after the Effective Date, the enactment, adoption, promulgation, modification or repeal or a material modification or change in the administrative or judicial application by any Governmental Agency of any applicable Requirement of Law.

"ComEd" means Commonwealth Edison Company or its successors and assigns.

"ComEd/Elwood Switchyard" means that switchyard that provides interconnection services to the Facility as identified Appendix J.

"Commercial Operations" means that a Unit or the Facility shall have achieved all of the conditions specified in Section 3.2.

"Commercial Operations Date" means the day on which a Unit or the Facility achieves Commercial Operations.

"Commercial Operations Delay Period" is the period of time, if any, between the Target COD and the Commercial Operations Date.

"Commission" or "Commissioning" as applicable, means the test and start up process leading up to Commercial Operations.

"Compressor Wash" has the meaning set forth in Section 6.5.

"Confidential Information" has the meaning specified in Section 17.

"Contract Year" means (i) for the first Contract Year, the period commencing on July 1, 2001 and ending on the December 31 occurring immediately thereafter, and (ii) for all other Contract Years (other than the final Contract Year), the calendar year, except that the final Contract Year shall be the period from the first day of the calendar year (during which the Term will expire) through the expiration of the Term.

"Cover Period" means a period during which the Seller is permitted pursuant to this Agreement to deliver or cause to be delivered Replacement Power or Substitute Power to Buyer. Such periods shall include only the following: (i) any time during Commercial Operations Delay Period; (ii) a Forced Outage or a Forced Derating; (iii) a period that could reasonably be likely to result in a Forced Outage or Forced Derating, as a result of which Seller determines, in accordance with Prudent Industry Practices, that safety concerns, potential equipment breakdowns or Unit vibration alarms require the Units to be made unavailable for a period of time necessary to diagnose and remedy such operational problems; or (iv) a Force Majeure Period.

"Day Ahead Schedule" means Buyer's hour by hour Dispatch schedule for the next calendar day or days, as applicable, as provided to Seller pursuant to Section 4.3.2.1.

"Default Rate" means (a) the one−month "LIBOR" as published from time to time in the "Money Rates" section of The Wall Street Journal, plus (b) 4.5% (450 basis points) per annum.

"Degradation Curves" means the combustion turbine degradation curve(s) as represented by General Electric Bulletin No. 519HA772, Rev. A, dated February 9, 1995.

"Delay Book Out Charge" has the meaning specified in Section 3.3.2

"Delay Election" has the meaning specified in Section 3.3.1

"Delay LDs" has the meaning specified in Section 3.3.3.

"Design Limits" means the operating specifications listed in *Appendix A*.

"Diagnostic Period" has the meaning specified in Section 4.5.3.

"Differential Transmission Adjustment" means the difference between the cost to Buyer to have Replacement Power delivered from the Replacement Power Delivery Point to Buyer's ultimate customer and the cost Buyer would have incurred to transmit such power from the Point of Delivery to such customer. Such amount may be a negative or positive number and shall be determined in accordance with Section 7.2.4.3.

"Dispatch" means Buyer's rights to schedule the designated Electric Energy output of the Facility pursuant to Section 4.3 or to schedule the delivery of Replacement Power pursuant to Section 4.7.

"Dispatch Notification" means that Buyer has notified Seller by telephone conversation of Buyer's Dispatch order in accordance with Appendix C.

"Dispatcher" means Buyer's authorized representative for Dispatch under this Agreement.

"DLD Escrow" has the meaning set forth in Section 3.3.5.

"Dominion" means Dominion Energy, Inc., a Virginia corporation.

"Downgrade Event" means (i) with respect to a Buyer or Seller Guarantor whose long term unsecured indebtedness is rated by one or both of Standard & Poor's or Moody's, a downgrade in such ratings such that both fall below Investment Grade, and (ii) with respect to a Seller Guarantor that is not rated, a value below $600,000,000 in owner's equity or a ratio of total liabilities to total assets for Dominion that exceeds 72%.

"EPC Contractor" means the party under contract to Seller to design, engineer, procure, and construct the Facility.

"Effective Date" means the date of this Agreement.

"Electric Energy" means all electric energy output from the Facility (net of Facility station service and auxiliaries for the Units and the Elwood II Units) delivered to Buyer by Seller from and after the Commercial Operations Date in accordance with the terms of this Agreement.

"Elwood Station" means the multi−unit power generation station that includes the Facility and other units, located in Elwood, Illinois owned by Seller and its Affiliates.

"Elwood II Units" means Units 5 and 6 at Elwood Station.

"Emergency Condition" means a condition or situation which (i) in the sole judgment of the Interconnected Utility presents an imminent physical threat of danger to life, or significant threat to health or property (including in the ComEd/Elwood Switchyard), (ii) in the sole judgment of the Interconnected Utility could cause a significant disruption on or significant damage to the Interconnected Utility's System (or any material portion thereof) or the transmission system of a third party (or any material portion thereof), (iii) in the reasonable judgment of Seller presents an imminent physical threat of danger to life, or significant threat to health or property (including in the ComEd/Elwood Switchyard) or (iv) in the reasonable judgment of Seller could cause significant damage to the Facility (or any material portion thereof).

"Energy Charge" has the meaning set forth in Section 7.2.

"Energy Rate" means, individually or collectively, as the context requires, the Replacement Power Energy Rate, the Incremental Energy Rate, the Facility Electric Energy Rate, or the Test Energy Rate.

"Equivalent Availability" has the meaning set forth in *Appendix E*.

"Equivalent Forced Derated Hours" or "EFDH" has the meaning set forth in Appendix E.

"Escrow Agreement" has the meaning specified in Section 3.3.5.

"Extension Term" has the meaning set forth in Section 2.1.

"Facility" means the natural gas fueled electric generation plant consisting of two GE Frame 7 FA combustion turbines designated as Units 7 and 8, together with appurtenant facilities, and having a total net output estimated to be approximately 303,560 kWs located at the Elwood Station.

"Facility Electric Energy Rate" has the meaning set forth in Section 7.2.

"Failed Start" means an attempted start up of a Unit whereby Seller initiates the Start Up Sequence but does not achieve a Start Up.

"FERC" means the Federal Energy Regulatory Commission.

"Final Commercial Operations Date" means June 1, 2002, as such date may be extended pursuant to Section 19, in which case such date shall be extended by the period during which a Force Majeure Event impairs or precludes the performance by a Party of its obligations hereunder, but in no event beyond June 1, 2003.

"First Outage Notice" has the meaning set forth in Section 4.5.1.

"Force Majeure Event" has the meaning set forth in Section 19.1.

"Force Majeure Period" means any period during which a Force Majeure Event affecting Seller occurs that precludes wholly or in part the capability of the Facility to deliver Electric Energy and Capacity as required hereunder.

"Forced Derating" has the meaning set forth in *Appendix E*.

"Forced Outage" has the meaning set forth in *Appendix E*.

"Forced Outage Hours" or "FOH" has the meaning set forth in *Appendix E*.

"Four Month Date" has the meaning set forth in Section 3.3.6.

"Fuel Charge" means the Base Fuel Charge plus the applicable surcharge, if any, imposed pursuant to Section 7.2.5.3.

"Fuel Index" means the index as published in *Gas Daily*—"Midpoint, Chicago−LDCs, Large e−us"—for the day of Energy delivery to Buyer. If this index ceases to be published the Parties shall select a mutually agreeable substitute index designed to track the market price of gas in the Chicago area for large end users for next day service.

"Fuel Metering Point 'means the Station Fuel Meter identified in *Appendix J*.

"GDP−IPD" means the Gross Domestic Product—Implicit Price Deflator as published in the National Income and Product Account by the U.S. Department of Commerce.

"Government Agency" means any federal, state, local, territorial or municipal government, governmental department, commission, board, bureau, agency, instrumentality, judicial or administrative body (or any agency, instrumentality or political subdivision thereof) having jurisdiction over the Buyer, Seller, the Facility, or the Interconnected Utility.

"Governmental Approval" means any authorization, consent, approval, license, ruling, permit, exemption, filing, variance, order, judgment, decree, publication, notice to, declarations of or with or regulation by or with any Government Agency relating to the acquisition, ownership, occupation, construction, Commissioning , operation or maintenance of the Units and the Facility or to the execution, delivery or performance of this Agreement.

"Gross Margin" shall mean the reasonable documented actual sales proceeds at Prevailing Market Prices for energy and/or capacity, less Transaction Costs, less (i) the Facility Electric Energy Rate or (ii) in the case of Incremental Energy, $100/MWh.

"Guaranteed Availability" means the Guaranteed Non−Summer On Peak Availability, the Guaranteed Summer Partial Peak Availability or the Guaranteed Summer Super Peak Availability for the applicable period.

"Guaranteed Heat Rate" means 10,787 Btu/kWh (HHV), new and clean at Reference Conditions.

"Guaranteed Non−Summer On Peak Availability" shall be equal to 97%.

"Guaranteed Ramp Rate" has the meaning set forth in *Appendix A*.

"Guaranteed Start−Up Time" has the meaning set forth in *Appendix A*.

"Guaranteed Summer Partial Peak Availability" shall be equal to 97%.

"Guaranteed Summer Super Peak Availability" shall be equal to 97%.

"Heat Rate" means the efficiency expressed as the amount of Btus of natural gas consumed to generate a kwh of electric energy.

"Heat Rate Credits" has the meaning set forth in Section 7.3.2.

"ISO" or "Independent System Operator" means any Person, other than ComEd, that becomes responsible as system operator for the Interconnected Utility System.

"Imbalance Charge" means a charge for oversupply or undersupply of Electric Energy incurred pursuant to Schedule 4 of ComEd's Open Access Transmission Tariff or the Interconnection Agreement.

"Incremental Energy" has the meaning set forth in Section 4.4.

"Incremental Energy Rate" has the meaning set forth in Section 7.2.

"Individual Fuel Meter" means the meter located as indicated in Appendix J, measuring gas consumption of an individual Unit or similar meters on the Elwood II Units.

"Initial Net Heat Rate" means the Net Heat Rate as tested in the final performance testing for each Unit under the contract with the EPC Contractor averaged over the Units and the Elwood II Units with evaporative coolers in service as corrected to Reference Conditions in accordance with Appendix B.

"Initial Term" has the meaning set forth in Section 2.1.

"Interconnection Facilities" means the interconnection facilities that will connect the Facility with the Interconnected Utility System, as more fully described in the Interconnection Agreement.

"Interconnected Utility" means ComEd or its successors and assigns; such assigns may include an ISO or any other entity operating a control area that includes the Interconnected Utility System.

"Interconnected Utility System" means the electric transmission and distribution system owned by ComEd and its Affiliates, or their successors and assigns; such assigns may include assignment of operations to an ISO which shall then mean that Interconnected Utility System operated by such ISO.

"Interconnection Agreement" means the Interconnection Agreement to be agreed to and executed between the Interconnected Utility and Seller with respect to the Facility.

"Interconnection Facilities" means the interconnection facilities that will connect the Facility with the Interconnected Utility System, as more fully described in the Interconnection Agreement.

"Investment Grade" means a rating on the long term unsecured indebtedness of an entity of at least Baa3 from Moody's or at least BBB− from Standard & Poor's.

"kW" means kiloWatt

"KWh" means kiloWatthour.

"Lenders" means with respect to the Seller (i) any person or entity that, from time to time, has made loans to the Seller, its permitted successors or permitted assigns for the financing or refinancing of the Facility or the marketing of the Electric Energy, Capacity or Ancillary Services of the Facility or which are secured by the Facility, (ii) any holder of indebtedness of the Seller, (iii) any person or entity acting on behalf of such holder(s) to which any holders' rights under financing documents have been transferred, any trustee or agent on behalf of any such holders, or (iv) any Person who purchases the Facility in connection with a sale−leaseback or other lease arrangement in which the Seller is the lessee of the Facility pursuant to a net lease.

"Liabilities" has the meaning set forth in Section 15.

"MMBtu" means million Btus.

"MW" means megaWatt.

"MWh" means megaWatthour.

"MAIN" means the Mid−America Interconnected Network, or its successors.

"Monthly Adjustment Factor" means, with respect to the calculation of the Availability Adjustment, 18% for the month of June, 32% for the month of July and 32% for the month of August, except that for the first Contract Year only, the Monthly Adjustment Factor shall be 0% for the month of June, and 41% for each of the months of July and August.

"Moody's" means Moody's Investors Service, or its successor.

"NERC" means the North American Electric Reliability Council, or its successor.

"NERC Holidays" means New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day, and other holidays observed by NERC.

"Net Dependable Capacity" means the net aggregate generating capacity measured in kWs of both Units of the Facility, based upon demonstrated output (net of station service and auxiliaries for the Units and the Elwood II Units) achieved during capacity testing of the Facility pursuant to Section 8.1 and *Appendix B*, adjusted by the Degradation Curves and to Reference Conditions; provided, however, that prior to the Commercial Operations Date, the Net Dependable Capacity of the Facility shall be deemed to be 303,560 kW, at Reference Conditions. If one Unit achieves Commercial Operations prior to the other Unit, then for the period when only one Unit is in Commercial Operations, Net Dependable Capacity for all purposes other than calculation of Capacity Charges shall mean the net dependable capacity of such Unit.

"Net Heat Rate" means the Heat Rate established by periodic testing of the Units and the Elwood II Units as corrected with the Degradation Curve to Reference Conditions pursuant to Appendix B.

"Nicor" means Northern Illinois Gas Company, or its successors.

"Non−Billable Generation" has the meaning specified in Section 5.1 and shall be calculated in accordance with Appendix O.

"Non−Summer On Peak Hours" means during the Non−Summer Period, the hour ending 0700 Central Time through the hour ending 2200 Central Time, Monday through Friday, excluding NERC holidays.

"Non−Summer Period" means September 1 through May 31.

"OEM" means the original equipment supplier.

"On Peak Hours" means (i) during the Summer Period, the hour ending 0700 Central Time through the hour ending 2200 Central Time, Monday through Saturday, excluding NERC Holidays and (ii) during the Non−Summer Period, the hour ending 0700 Central Time through the hour ending 2200 Central Time, Monday through Friday, excluding NERC Holidays.

"Outage Book Out Charge" has the meaning set forth in Section 4.5.1.

"Outage Election" means Seller's election during any Cover Period either to provide Replacement Power or cause to be provided Substitute Power in accordance with Section 4.7.3.

"Partial Peak Hours" means, during the Summer Period, the hour ending 0700 through the hour ending 1100 and the hour ending 2000 through the hour ending 2200, Central Time, Monday through Saturday, excluding NERC holidays.

"Pecorp" means Peoples Energy Corporation, an Illinois corporation.

"Period Hours" or "PH" has the meaning set forth in Appendix E.

"Permitted Assignee" means a Person having at least five (5) years experience in the operations and maintenance of electrical generation facilities similar to the Facility and having a level of creditworthiness equivalent to Seller and Seller Guarantors, which Person shall be reasonably acceptable to Buyer.

"Person" means any individual, corporation, partnership, joint venture, limited liability company, association, joint stock company, trust, unincorporated organization, entity, government or other political subdivision.

"Per Unit Delay LD Cap" means $10,607,900, less any Delay Book Out Charges paid by Seller in respect of the applicable Unit.

"Point of Delivery" means, for Electric Energy delivered from a Unit, the point of interconnection between the Facility and the Interconnected Utility System in the ComEd/Elwood Switchyard, as identified in Appendix J.

"Post COD Test Energy" means Test Energy generated on and after the Commercial Operations Date.

"Pre COD Test Energy" means Test Energy generated before the Commercial Operations Date.

"Prevailing Market Price" means the best price available to Buyer (i.e., highest price when Buyer markets Test Energy and Incremental Energy and lowest price when Buyer procures Substitute Power) actually obtained for energy or capacity (taking into account the type, reliability, and duration and other relevant attributes of such energy or capacity), which shall be obtained through commercially reasonable efforts, as evidenced, upon request of Seller, by documentation of such price, unless and until an index or other mechanism mutually acceptable to the Parties is created and agreed upon by the Parties to serve as the Prevailing Market Price.

"Prudent Industry Practice" means any of the practices, methods, standards and acts required or approved by any ISO or engaged in or approved by a significant portion of the electric generation industry in the geographic region covered by MAIN during the relevant time period, or any of the practices, methods, standards and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. "Prudent Industry Practice" is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be acceptable practices, methods or acts generally accepted in the geographic region covered by MAIN and which generally conform to operation and maintenance standards recommended by the OEM, the Design Limits, and Government Approvals.

"Rating Category" means a letter category rating for long term unsecured indebtedness of an entity (e.g. Aaa, Aa, A, Baa, Ba, and so on in the case of Moody's and AAA, AA, A, BBB and so on in the case of Standard & Poor's), disregarding in each case any numerals or other modifiers appended to such rating.

"Reference Conditions" means ambient atmospheric temperature of 95 degrees Fahrenheit (dry−bulb), 60% relative humidity, adjusted for elevation above mean sea level.

"Reference Heat Rate" shall be determined for each hour using the turbine OEM's heat rate performance curves adjusted to site elevation, ambient conditions, load factor and Degradation Curves and as provided in Appendix F.

"Replacement Power" (i) prior to the Commercial Operations Date, means electric Capacity and electric energy provided by Seller from time to time to Buyer from sources (including from other units at the Elwood Station) other than the Facility and (ii) after the Commercial Operations Date, means electric energy provided by Seller from time to time to Buyer from sources (including other units at the Elwood Station) other than the Facility.

"Replacement Power Delivery Point" means the point where Replacement Power is delivered to Buyer, at a point or points that are acceptable to Buyer, such acceptance not to be unreasonably withheld or delayed, unless the Replacement Power Delivery Point shall be the same as the Point of Delivery, in which case it shall be deemed to be acceptable to Buyer.

"Replacement Power Energy Rate" has the meaning set forth in Section 7.2.2

"Requested Load Delivery Time" means the designated time in Buyer's Dispatch schedule for a Unit to be generating at a specified level.

"Requirement of Law" means any applicable federal, state and local laws, statutes, regulations, rules, codes or ordinances enacted, adopted, issued or promulgated by any federal, state, local or other Governmental Agency (including those pertaining to electrical, building, zoning, environmental and occupational safety and health requirements).

"Revenue Meter" means the meter which measures power flow into the main step up transformer of each Unit and similar meters on the Elwood II Units at a point after auxiliary loads are withdrawn from the bus.

"Scheduled Maintenance Outage" means the time period during which a Unit or any portion of the Facility is removed from service to perform work on specific components based upon manufacturer's recommended schedules in accordance with Section 6.4.

"Scheduling Fees" means the charge of Buyer to Seller for scheduling Test Energy and Incremental Energy, which shall equal $1.00 per MWh.

"Second Outage Notice" has the meaning set forth in Section 4.5.3.

"Seller Event of Default" has the meaning specified in Section 13.1.

"Seller Guarantees" has the meaning specified in Section 18.1.

"Seller Guarantor" means Dominion or Pecorp.

"Site" means the real property on which the Units are located.

"Size of Reduction" has the meaning set forth in Appendix E.

"Standard & Poor's" means Standard & Poor's Rating Group a division of McGraw−Hill, Inc. or its successor.

"Start Up" means the initiation of the Start Up Sequence followed by the applicable Unit's generating at least 60% of the Net Dependable Capacity.

"Start Up Charge" has the meaning set forth in Section 7.4.

"Start Up Sequence" means the normal sequence of events, beginning with the cranking process, in order to achieve Start Up.

"Station Fuel Meter" means the Nicor fuel meter common to Units 7 and 8 and to the Elwood II Units.

"Substitute Power" (i) prior to the Commercial Operations Date means electric energy and capacity (ii) after the Commercial Operations Date, electric energy, in each case obtained by Buyer at the direction of Seller in accordance with Section 4.7.3.

"Substitute Power Cost Credit" is a credit adjustment to Buyer for its reasonable costs to acquire Substitute Power at the direction of Seller and as calculated in accordance with Section 7.2.4.3.

"Summer Average Availability" means the Equivalent Availability for all Summer On Peak Hours in each month during the Summer Period of any given Contract Year, averaged over such three months.

"Summer Period" means the period from June 1 through August 31 of each Contract Year.

"Summer Off Peak Hours" means all hours in the Summer Period other than On Peak Hours.

"Summer On Peak Hours" means all Super Peak Hours and Partial Peak Hours.

"Super Peak Hours" means, during the Summer Period, the hour ending at 1200 Central Time and through the hour ending 1900 Central Time, Monday through Saturday, excluding NERC holidays.

"Target COD" means July 1, 2001, as such date may be extended day−for−day due to Force Majeure Events as and to the extent permitted by Section 19 or for days covered by a Delay Book Out Charge pursuant to Section 3.3.3.

"Term" has the meaning specified in Section 2.1.

"Test Energy" means electricity generated during a test at a time when the tested Unit would not be Dispatched by Buyer to generate but for the running of the test.

"Third Party Damages" has the meaning set forth in Section 4.7.4.

"Threshold Heat Rate" is 10,759 Btu/KWh, new and clean at Reference Conditions.

"Transaction Costs" means reasonable documented transaction costs associated with the sale and marketing of Electric Energy or Test Energy, as applicable, including and limited to transmission costs (or fees or charges imposed by a third party in lieu of or in addition to such transmission costs in accordance with common industry practice), transmission line losses, Scheduling Fees and ancillary service charges.

"Unit" means either of the GE frame 7FA gas−fired turbine generator units of the Facility subject to Dispatch by Buyer under this Agreement, i.e., numbers seven (7) and eight (8).

"Variable O&M Rate" means $1.00/MWh (as of June 1, 1999), and as adjusted on the anniversary of the first and each subsequent Contract Year by the annual change in the GDP−IPD.

1.2 *Interpretation.* In this Agreement, unless a clear contrary intention appears:

1.2.1 the singular number includes the plural number and vice versa;

1.2.2 reference to any Person includes such Person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this Agreement, and reference to a Person in a particular capacity excludes such Person in any other capacity or individually;

1.2.3 reference to any gender includes each other gender;

1.2.4 reference to any agreement (including this Agreement), document, instrument or tariff means such agreement, document, instrument or tariff as amended or modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof;

1.2.5 reference to any Requirement of Law means such Requirement of Law as amended, modified, codified or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder;

1.2.6 reference to any Section or Appendix means such Section of this Agreement or such Appendix to this Agreement, as the case may be, and references in any Section or definition to any clause means such clause of such Section or definition;

1.2.7 "hereunder", "hereof", "hereto" and words of similar import shall be deemed references to this Agreement as a whole and not to any particular Section or other provision hereof or thereof;

1.2.8 "including" (and with correlative meaning "include") means including without limiting the generality of any description preceding such term;

1.2.9 relative to the determination of any period of time, "from" means "from and including", "to" means "to but excluding" and "through" means "through and including"; and

1.2.10 reference to time shall always refer to prevailing Central Time, i.e., standard time or daylight time as applicable in Elwood, Illinois.

1.2.11 wherever this Agreement speaks in terms of both Units (or the Facility), and the context of a provision requires application to only one Unit, then such provision and operative terms or amounts relating thereto shall be appropriately construed or prorated, as appropriate.

1.3 *Legal Representation of Parties.* This Agreement was negotiated by the Parties with the benefit of legal representation and any rule of construction or interpretation otherwise requiring this Agreement to be construed or interpreted against any Party shall not apply to any construction or interpretation hereof or thereof.

1.4 *Titles and Headings.* Section and Appendix titles and headings in this Agreement are inserted for convenience of reference only and are not intended to be a part of, or to affect the meaning or interpretation of, this Agreement.

1.5 *Order of Precedence.* In the event of a conflict between any of the terms of this Agreement, the conflict shall be resolved by giving priority to the terms in the following order of precedence: (1) Sections 1−23, (2) Appendix E, (3) Appendix A, and (4) the remaining Appendices in the order in which they appear in this Agreement.

2. *Term and Survival*

2.1 *Term.* This Agreement shall have a term (the "Term") commencing on the Effective Date and ending on August 31, 2017 (the "Initial Term") unless otherwise extended or terminated in accordance with the provisions of this Agreement. The Buyer shall have the unilateral right to extend the Initial Term for a five (5) year period (or such other period as the Parties mutually agree) (the "Extension Term") provided the Buyer notifies Seller in writing by September 1, 2015 of its desire to so extend.

2.2 *Survival.* The provisions of Section 1 (Definitions and Interpretation), Section 6.7 (Records), Section 10 (Limitation of Liability and Exclusivity of Remedies), Section 11 (Disagreements), Section 13 (Default, Termination and Remedies), Section 15 (Indemnification), Section 17 (Confidentiality), Section 18 (Security), Section 22 (Miscellaneous), and Section 24 (Entire Agreement and Amendments) shall survive the termination of this Agreement.

3. *Project Implementation and Achievement of Commercial Operations.*

3.1 *Development and Construction Development.* Seller shall (i) use all commercially reasonable efforts to develop, engineer, procure, construct, and Commission the Facility, (ii) achieve the Commercial Operations Date on or prior to the Target COD, and (iii) apply for and obtain all Governmental Approvals and all renewals thereof as are required for Seller to perform its obligations under this Agreement, including air emissions permits.

3.1.2 *Construction.* Seller shall complete, or cause the completion of, the design, construction, installation, and Commissioning of the Facility in a manner consistent with Prudent Industry Practices.

3.1.3 *Status Report.* Starting thirty (30) days after the Effective Date, Seller shall report to Buyer, each month, on the construction status, fuel supply and transportation status, and shall provide a report on Seller's progress toward achieving the milestone schedule included in Appendix M. Such report shall, at a minimum, provide a schedule showing Facility permit status, items completed and to be completed, the expected Commercial Operations Date, and the estimated percentage of completion for the Facility.

3.2 *Conditions to Commercial Operations.* The occurrence of Commercial Operations of a single Unit or the Facility is contingent upon Seller providing evidence reasonably acceptable to Buyer of the satisfaction or occurrence of all of the following conditions:

3.2.1 *Communications.* The Facility (or single Unit as applicable) has demonstrated the reliability of any communications systems and equipment for communications with the Interconnected Utility's system control center required to be provided by Seller pursuant to this Agreement prior to the Commercial Operations Date.

3.2.2 *Tests.* Seller shall perform a heat rate and capacity test in accordance with Appendix B of a Unit or Units. In conjunction with such test each tested Unit shall operate continuously for a minimum of four (4) consecutive hours synchronized to the Interconnected Utility System at a level equal to at least 288 MW if for both Units and 144 MW if for one Unit, and each Unit has successfully completed five (5) consecutive Start Ups and shutdowns.

3.2.3. *Security.* Seller security arrangements meeting the requirements of Section 18.1 shall have been established.

3.2.4 *Fuel Supply and Transportation.* Seller shall have entered into fuel supply and transportation arrangements of a sufficient level of firmness so as to permit Buyer to Dispatch the Unit or Units in accordance with the terms of this Agreement.

Seller shall be deemed to satisfy this condition if Seller has in place an agreement for balancing services similar in all material respects to the NICOR Transportation and Balancing Agreement for units 1−4 at the Elwood Station. Construction of pipeline facilities and improvements necessary for operation of the Facility has been completed.

3.2.5 *Seller Certification.* Seller has delivered a certificate stating that (1) the Unit has been completed in all material respects (excepting, e.g., punch list items that do not materially adversely affect the ability of the Unit or Units to operate in accordance with Prudent Industry Practice), (2) the Unit or Units has been designed and constructed and all conditions have been satisfied so as to permit Buyer to Dispatch the Unit or Units pursuant to the terms of the Agreement, and (3) that adequate levels of insurance coverage of the types and with the limits for electrical generation facilities similar to the Facility have been purchased by Seller that are usual and customary in accordance with Prudent Industry Practice.

3.2.6 *Opinion of Counsel.* An opinion of Seller's counsel has been rendered that all permits, licenses, approvals, and other Governmental Approvals required for the construction and operation of the Facility in accordance with this Agreement have been obtained.

3.2.7 *Interconnection.* The electrical interconnection of the Facility to the Interconnected Utility System has been completed in accordance with Prudent Industry Practice sufficient to permit Buyer to Dispatch the Unit or Units in accordance with this Agreement.

3.3 *Late Commercial Operations Date.* Seller anticipates that the Commercial Operations Date for each Unit will occur no later than the Target COD.

3.3.1 *COD Delays.* If the Commercial Operations Date for a Unit does not occur prior to 1000 Central Time on the Target COD and if Seller fails to deliver or cause to be delivered Replacement Power or Substitute Power in accordance with Section 4.7.3 or to agree to Buyer's Delay Book Out Charge as described in Section 3.3.2, Seller shall be liable to Buyer for Delay LDs per Unit per day for the period of the delay.

3.3.2 *Delay Book Out Charge.* Seller may request that Buyer provide Seller a Delay Book Out Charge, which request shall be made by Seller no later than noon sixteen (16) Business Days prior to the Target COD, and by noon every seventh (7th) day thereafter, if necessary. Within twenty four (24) hours of Seller's request, Buyer shall provide Seller a quote in dollars at a mutually agreeable time for the first seven (7) days of the Commercial Operations Delay Period (a "Delay Book Out Charge"). Immediately upon Seller's receipt of the quoted Delay Book Out Charge, Seller shall notify Buyer as to whether Seller elects to pay Delay LDs, provide Replacement Power, request Buyer to procure Substitute Power or accept the Delay Book Out Charge (the "Delay Election"). Upon acceptance and payment of the Delay Book Out Charge by Seller, Seller shall be released from any liability for Delay LDs for the first seven (7) days of the Commercial Operations Delay Period and the Target COD shall be delayed by seven (7) days for all purposes other than initiation of Capacity Charges. Seller shall pay Buyer the Delay Book Out Charge within ten (10) days thereafter and may offset such amount against the Capacity Charges due for the period to which the Delay Book Out Charge applies, with such offset discharging Buyer's obligation to pay Capacity Charges to the extent so offset. Subsequent to the Delay Election, if Seller anticipates that the Commercial Operations Date will not occur by the Target COD, Seller may repeat the process for the Delay Election set forth above. If Seller rejects the Delay Book Out Charge, then Seller shall be liable for Delay LDs until the earlier to occur of (a) the time at which Seller begins to deliver or causes to be delivered Replacement Power, (b) the Commercial Operations Date, or (c) the first day of the seven (7) day period to which a subsequent Delay Book Out Charge applies. Any amounts paid by Seller for Delay Book Out Charges shall be deducted from both the Aggregate LD Cap and pro rata from the Per Unit LD Cap for the applicable Unit(s). To the extent that a Unit is capable of delivering and delivers any Electric Energy during a period covered by a Delay Book Out Charge, such Electric Energy shall be purchased by Buyer at a price equal to the Facility Electric Energy Rate plus 80% of the Gross Margin, if the Prevailing Market Price less Transaction Costs exceeds the Facility Electric Energy Rate.

3.3.3 *Amounts of Delay LDs.* Liquidated damages ("Delay LDs") shall accrue at the rate of $100,000 per Unit per day during June, $225,000 per Unit per day during July, $200,000 per Unit per day during August; and for all other months, the prorated daily portion of the applicable month's Capacity Charges per Unit per day, provided however, in no event shall Delay LDs (x) be assessed for the day on which the Commercial Operations Date occurs if it occurs prior to 10:00 a.m. on such day or (y) exceed Per Unit LD Cap, or the Aggregate LD Cap as applicable. Delay LDs shall be offset against Capacity Charges as they come due.

3.3.4 *Interest on Deferred Amounts and Offsets.* To the extent that accrued Delay LDs exceed the Capacity Charges that would have been paid currently if the Facility or a Unit had achieved Commercial Operations on the Target COD, such amounts shall accrue interest at the Default Rate until recovered by Buyer through offsets against Capacity Charges as they come due.

3.3.5 *DLD Escrow.* Notwithstanding the foregoing, if the Commercial Operations Date for one or both Units has not occurred on or before the date (the "Cap Date") that Seller has incurred an aggregate amount of Delay LDs equal to the Per Unit Delay LD Cap (in the case of one Unit) or the Aggregate Delay LD Cap (in the case of both Units), then Seller shall, within seven (7) Business Days after the Cap Date, establish and fund (in cash) an escrow with an A−rated bank (the "DLD Escrow") in an initial amount equal to the gross amount of accrued Delay LDs, plus interest accrued at the Default Rate less offsets of Capacity Charges accrued as of the date the DLD Escrow is funded. If and to the extent Seller fails to establish and/or fully fund the DLD Escrow, the Buyer may draw on the Seller Guarantees for the amount of Delay LDs (plus interest accrued thereon at the Default Rate) not paid or placed in escrow as required by this Section 3.3.5. Upon the Commercial Operations Date, Seller shall be entitled to withdraw from the DLD Escrow an amount equal to the Capacity Charges that accrued from and after the date the DLD Escrow was funded up to and including the Commercial Operations Date. Seller may make subsequent withdrawals each month in an amount equal to such month's Capacity Charges that would be due from Buyer but for offsets pursuant to Section 3.3 until the principal balance in the DLD Escrow is zero. Upon the closing of the account by Seller, Seller shall pay to Buyer an amount equal to the interest that would have been earned on such account at the Default Rate of interest and any funds remaining in the account shall exclusively belong to Seller. At no time shall Buyer be entitled to receive the funds in the account.

3.3.6 *Extended COD Delays.* If the Commercial Operations Date for a Unit has not occurred on or before the date that is 120 days after the Target COD (as extended day−for−day for a Force Majeure Event) (the "Four Month Date"), then the applicable Capacity Rate shall be reduced (the "Capacity Rate Reduction") by an amount equal to $.01 KW−month multiplied by a fraction, the numerator of which is the number of days from the Four Month Date to the Commercial Operations Date and the denominator of which is thirty (30) days. The Capacity Rate Reduction shall take effect beginning with the later to occur of (i) June 1 of the second Contract Year and (ii) the Commercial Operations Date, and continue for the remainder of the Term.

3.3.7 *Termination for Extended Delay.* Buyer may terminate this Agreement with regard to a Unit if the Commercial Operations Date for such Unit is not achieved by June 1, 2002, except to the extent such delay is caused by a Force Majeure Event, in which case such termination date shall be extended by the Force Majeure Period, but in no event beyond June 1, 2003 (*provided, however*, that Buyer may terminate this Agreement following a Force Majeure Period lasting twelve months or more, unless Seller closes on financing for the Facility by May 31, 2002). If this Agreement is terminated with regard to a Unit(s) pursuant to this Section 3.3.7 for failure to achieve the Commercial Operations Date by June 1, 2002, (i) Buyer's sole remedy for damages and Seller's sole liability for damages shall be for Buyer to offset Delay LDs against Capacity Charges accrued and not paid to Seller prior to termination and to receive the Default Rate of interest on Delay LDs accrued in excess of Capacity Charges due at any given time until such Delay LDs are received by Buyer through offsets against Capacity Charges and (ii) Seller shall have no obligation to pay Delay LDs accrued during any Commercial Operations Delay Period except as an offset against Capacity Charges due from Buyer. If this Agreement is terminated pursuant to this Section 3.3.7, neither Party shall have any liability to the other Party whatsoever (including liability for previously accrued Delay LDs or Capacity Charges, but excluding liability in respect of Delay Book Out Charges and interest accrued on the DLD Escrow at the Default Rate).

3.4 *Commissioning and Test Power.* Seller anticipates that prior to its Commercial Operations Date each Unit will require between 50−100 hours for Commissioning purposes during which Seller will generate Pre COD Test Energy. Buyer shall purchase all Pre COD Test Energy at Pre COD Test Energy Rates as provided in Section 7.2.4. Seller will provide a test schedule prior to each test, and Buyer will advise Seller its estimate of Prevailing Market Prices for Pre COD Test Energy prior to the scheduled start of the testing. Seller shall have no right to sell the Pre COD Test Energy to third parties.

4. *Electric Energy Delivery, Dispatch and Forced Outages, Delivery of Electric Energy.* Subject to the terms and conditions of this Agreement, Seller shall sell, make available and deliver at the Point of Delivery and Buyer shall receive and purchase from Seller at the Point of Delivery, Electric Energy as Dispatched by Buyer. Consistent with the terms of this Agreement, Electric Energy shall be generated and delivered from the Facility and may include Incremental Energy.

4.1.1 *Operation in Accordance with Buyer Dispatch.* Buyer shall not be obligated to receive or purchase any Electric Energy from Seller except (a) such Electric Energy as is Dispatched by Buyer and (b) Test Energy. Seller shall not operate either Unit except in response to a Dispatch order from Buyer other than (i) for testing purposes prior to the Commercial Operations Date pursuant to Section 3.4, (ii) for testing purposes after the Commercial Operations Date scheduled in accordance with Section 8.1, or in connection with a Scheduled Maintenance Outage, Forced Derating or Forced Outage or to analyze performance of a Unit or its components; (iii) for Seller's rights to sell to third parties pursuant to Section 13.3.2 or (iv) pursuant to instructions from the Interconnected Utility in accordance with Section 6.6.2 and the Interconnection Agreement. Notwithstanding the above, when a Unit is operating, Seller or its Affiliates may consume electric energy from that Unit for Start−Up of the other Unit of the Facility or other units at the Elwood Station, subject to a credit for the value of such electric energy as set forth in Section 5.1. Seller shall not sell Electric Energy or Capacity to any Person other than (a) Buyer, (b) Interconnected Utility pursuant to the requirements of the Interconnection Agreement, or (c) third parties as permitted under Section 13.3.2.

4.1.2 *Quality of Electric Energy.* All Electric Energy shall be measured by the Revenue Meter and shall meet the specifications of the Interconnected Utility. In the event that electricity delivered by Seller hereunder fails to conform to the specifications of the

Interconnected Utility, Seller shall (as soon as reasonably practicable after becoming aware thereof) notify Buyer of the same and of its best good faith estimate of the duration and extent of such failure to conform, and Seller shall attempt to cure such failure as soon as reasonably practicable thereafter. If Seller is unable to deliver electricity to Buyer in accordance with the terms of this Agreement due to such failure to conform to such specifications, such inability to deliver shall be considered a Forced Outage.

4.2 *Point of Sale.* The point where sale of Electric Energy and Replacement Power will take place and title to and risk of loss with respect to, such Electric Energy and Replacement Power shall transfer is at the Point of Delivery for Electric Energy and the Replacement Power Delivery Point for Replacement Power. Buyer shall be responsible for any transmission beyond the Point of Delivery or the Replacement Power Delivery Point, as applicable.

4.3 *Dispatch Rights of Buyer.*

4.3.1 *Buyer Dispatch.* Beginning on the earlier of the Commercial Operations Date and the Target COD and provided that Buyer complies with the mandatory notification obligations in Section 4.3.2, Buyer may Dispatch the delivery of Electric Energy and Replacement Power (if applicable) in accordance with the provisions set forth in this Agreement up to the total Net Dependable Capacity of the Units and may Dispatch Incremental Energy as provided in Section 4.4; *provided, however*, Buyer agrees that Seller may, at its sole discretion but also subject to Prudent Industry Practices, operate any combination of Units 7 and 8 (including overfiring of a Unit to compensate for what would otherwise be a Forced Derating on another Unit), or, during a Cover Period may deliver Replacement Power through other sources (including the Elwood II Units as permitted by the agreement between the owner of the Elwood II Units and the Buyer thereunder) or cause to be delivered Substitute Power to meet Buyer's Dispatch under this Agreement. Notwithstanding the above, except to the extent Seller has notified Buyer that Seller has arranged for delivery of Replacement Power consistent with the terms of this Agreement, Seller shall be obligated to comply with any Dispatch order issued by Buyer except: (1) during any Scheduled Maintenance Outage or Compressor Wash or (2) to the extent that a Force Majeure Event causes a reduction in the level of the Facility's Available Capacity. Failures by Seller to comply with Buyer's Dispatch orders shall be subject to the provisions of Appendix E for calculation of the Equivalent Availability.

4.3.2 *Dispatch Notifications*

4.3.2.1 *Day Ahead Schedule Notification.* Buyer shall provide to Seller, by no later than 0900 Central Time each day, Buyer's schedule for Dispatch for each hour of the following day (such schedule, the "Day Ahead Schedule"). Buyer may subsequently alter its Dispatch schedule set forth in the Day Ahead Schedule in accordance with Section 4.3.2.3 during Summer Period On−Peak Hours and Section 4.3.2.4 for all other hours.

4.3.2.2 *Facility Availability Notification.* Seller shall, by noon Central Time each day, inform Buyer of the estimated Capacity (taking into account the effect of any expected deratings) that will be available to Buyer for the following three (3) days. These estimates shall not be binding upon Seller and Seller may subsequently alter its estimates. Seller shall advise Buyer of any changes in its estimated Capacity as soon as practicable.

4.3.2.3 *Mandatory Notification Obligation—Summer On Peak Hours.* Buyer must provide Seller its Dispatch request and such request must be confirmed by Seller's operator, for any Summer On Peak Hours a minimum of one hour and twenty five (25) minutes prior to the Requested Load Delivery Time of one or both Units, and if Buyer is also dispatching one or both of the Elwood II Units, one hour and thirty five (35) minutes prior to the Requested Load Delivery Time for all Units Dispatched (including Elwood II Units). Units will be started in accordance with the procedure described in Appendix A. Units will ramp to the requested Dispatch level in accordance with the provisions of Appendix A. Seller shall use reasonable commercial efforts to change Dispatch levels at the request of Buyer while a Unit is running. Buyer must provide one hour's notice, confirmed by Seller's operator, to stop Dispatch (reduce Electric Energy to zero) or to change a Dispatch order during the Summer On Peak Hours. Seller shall not be obligated to comply with any Dispatch order issued for generation during Summer On Peak Hours unless issued with the minimum notice required by this Section, but shall use commercially reasonable efforts to do so. Notwithstanding the above, however, any failure to comply with a non−complying Dispatch order between the time of issuance of Buyer's Dispatch order and the expiration of the applicable mandatory notification period for such Dispatch order shall not be taken into account for calculation of the Availability Adjustment. For example, if Buyer's Dispatch order for one Unit was given 75 minutes prior to the Requested Load Delivery Time of 1200 and Seller delivers Electric Energy at the requested load by 1210 such delay beyond the Requested Load Delivery Time shall not be taken into account in calculation of an Availability Adjustment; however, deliveries after 1210 shall be taken into account for calculation of the Availability Adjustment.

4.3.2.4 *Mandatory Notification Obligation—Non−Summer Period and Summer Off Peak Hours.* Buyer must provide Seller its Day Ahead Schedule request for Dispatch for any Non−Summer Period and for all Summer Off Peak Hours in accordance with Section 4.3.2.1 above; *provided, however,* that (a) during the month of September, such Day Ahead Schedule shall not become binding until five (5) hours prior to the scheduled time for a Dispatched Start Up. If Buyer requests to change the Day Ahead Schedule after 0900 on the day covered by such schedule (i.e. the day after the day of its issuance), and if the Unit is on turning gear, Buyer may provide as little as three hours notice prior to its changed Requested Load Delivery Time, with details of the changes to the schedule. Within thirty minutes of Seller's receipt of such notice, Seller shall quote the fee pursuant to Section 7.2.5 in which Seller shall provide Buyer with an expected time at which Seller can achieve the .generation level requested by Buyer in its Dispatch order. For the Electric Energy to be delivered between the time of issuance of Buyer's Dispatch order and the expiration of the applicable mandatory notification period for such Dispatch order, Seller shall not be obligated to comply with any Dispatch order issued for generation during the Non−Summer Period or during Summer Off Peak Hours unless either (a) such notice was issued with the minimum notice required by this Section, or (b) Buyer accepts the surcharge above the Base Fuel Charge or a fixed change fee as applicable quoted by Seller pursuant to Section 7.2.5. Immediately upon receipt of Seller's quoted surcharge, Buyer shall either accept such surcharge or the Day Ahead Schedule will remain unchanged. If Buyer accepts such surcharge, Seller shall comply with the revised Dispatch schedule. Notwithstanding the above, however, Buyer must provide one hour's notice to stop Dispatch (reduce Electric Energy to zero).

4.3.2.5 *Cancellation of Start Up.* If Buyer requests Seller to cancel a scheduled Start Up with less than the applicable mandatory notification period (required pursuant to Section 4.3.2 remaining prior to the scheduled Start Up, Seller shall use reasonable commercial efforts to stop or modify its Start Up of the applicable Units and Buyer shall be obligated to pay all of Seller 's reasonable documented out of pocket costs incurred, if any (other than fuel related costs covered in Section 7.2.5) as a result of such cancellation. In addition, if Seller has begun the Start Up Sequence during Summer On Peak Hours or has put the Unit on turning gear during any other hours prior to receipt of Buyer's cancellation request, Buyer shall pay to Seller the Start Up Charge for such Unit.

4.3.2.6 *Communications.* The Parties have developed mutually acceptable procedures for communications between Seller's control room and Buyer's Dispatcher included herewith as Appendix C−Dispatch Communications Guidelines to this Agreement and the Parties shall develop mutually acceptable associated reporting forms for such communications to be appended to this Agreement as Appendix D−Reporting Forms.

4.3.2.7 *Remote Monitoring.* Seller shall furnish data communication ports on its control system(s), the Revenue Meters, and the Station Fuel Meter such that Buyer may remotely monitor (read only) selected meter and operating data for the Facility and the Elwood II Units. Buyer shall be responsible for all data communication equipment from the data communications port interface to the point of remote monitoring, including the cost of equipment purchase, installation, operations, maintenance and upkeep. Seller shall furnish or shall cause to be furnished in a timely fashion the necessary interface protocol requirements and specifications of its control system and metering equipment such that Buyer may specify its compatible equipment. Seller shall have the right and opportunity to review and approve the specification of the first interface and protective devices of the Buyer to assure that such devices are compatible with and shall not interfere with Seller's control system(s) and metering equipment, and such approval shall not be unreasonably withheld. The data to be sampled, transmitted, and monitored shall include everything that is essential to Buyer's Dispatch. Such data shall include, but may not be necessarily limited to, the meter outputs and process control system data points set forth in Appendix K, which Seller shall use commercially reasonable efforts to make available to Buyer at Seller's data communications ports on its control system(s), the Revenue Meters, and the Station Fuel Meter.

4.4 *Incremental Energy.* The Facility may through limited over−firing of the Units, have a generation capability that is higher than Net Dependable Capacity of up to approximately five (5) MW per Unit higher than its Net Dependable Capacity. "Incremental Energy" means Electric Energy generated through limited over−firing of the Units (as installed as of the Commercial Operations Date). Buyer may Dispatch Incremental Energy if and to the extent available in an amount of up to 250 hours per Contract Year in accordance with this Section 4.4, if and to the extent that Seller is not generating Incremental Energy to offset a Forced Derating. Buyer shall not be obligated to purchase Incremental Energy at the Incremental Energy Rate to the extent generated by Seller to offset a Forced Derating.

4.5 *Forced Outages*

4.5.1 *First Outage Notice.* Seller must notify Buyer within fifteen (15) minutes (the "First Outage Notice") after discovering that a Unit(s) is (a) unable to deliver all or part of the Electric Energy required during a Dispatch schedule or (b) unavailable for future Dispatch schedules. In such notice Seller shall provide its best estimate of the duration of the Forced Outage or Forced Derating. Within fifteen (15) minutes (but not less than ten (10) minutes) of receipt of such notice, Buyer shall provide to Seller a quote, (such price, the "Outage Book Out Charge") for the remainder of the day of such notice.

4.5.2 *Seller Election.* Immediately upon receipt of Buyer's Outage Book Out Charge, Seller must elect at its sole option, to either:

4.5.2.1 provide Replacement Power on its own behalf as soon as commercially practicable but not later than beginning at the top of the next hour (unless commercial practices permit earlier delivery); or

4.5.2.2 accept Buyer's quoted Outage Book Out Charge; if Seller elects this option then Seller shall pay the quoted and accepted Outage Book Out Charge and upon such payment, Seller shall be released from any further obligation or liability (including Availability Adjustment) associated with the applicable Dispatch order for the remainder of the day covered by such Outage Book Out Charge.

4.5.2.3 Seller's election pursuant to Section 4.5.2 will remain in effect until the earliest to occur of: (a) the expiration of Buyer's anticipated Dispatch schedule in effect for that day, (b) the end of the Forced Outage or Forced Derating, or (c) the end of the day of such notice.

4.5.3 *Second Outage Notice.* As soon as practicable, but by no later than two (2) hours after the start of the Forced Outage or Forced Derating (the "Second Outage Notice"), Seller must notify Buyer of (a) the cause of the Forced Outage or Forced Derating, if known, (b) the proposed corrective action, and (c) Seller's best estimate of the expected duration of the Forced Outage or Forced Derating period. Seller shall in such Second Outage Notice elect to either:

4.5.3.1 provide Replacement Power on its own behalf; or

4.5.3.2 request Buyer to procure Substitute Power in accordance with Section 4.7.3.

4.5.3.3 Seller's election under this Section 4.5.3 will become effective beginning at 0001 on the next day, and will remain in effect until the earlier to occur of: (a) the end of the Forced Outage or Forced Derating or (b) 2300 on the third Business Day after the day on which the Forced Outage or Forced Derating began (the "Diagnostic Period").

4.5.4 *Consequences for Availability Adjustment.* If Seller fails to timely notify Buyer if its election under Section 4.5.2, or its Outage Election or fails to deliver or cause to be delivered either Replacement Power or Substitute Power, such incident shall be included as a Forced Outage or Forced Derating (as applicable) for purposes of the calculation of the Availability Adjustment.

4.5.5 *Incidents Longer than Diagnostic Period.* If Seller determines that the incident is expected to extend beyond the Diagnostic Period, then, Seller shall (as soon as practicable but no later than the expiration of the Diagnostic Period) make an Outage Election applicable to the remainder of the incident.

4.5.6 *Resumption of Delivery.*

4.5.6.1 *From the Facility.* Seller may resume delivery of Electric Energy from the Unit(s) as soon as the Units can produce Electric Energy (if it can be scheduled by Buyer on such short notice). Otherwise, Seller's election under Sections 4.5.2, as applicable above shall take effect no sooner than the top of the next hour provided Seller notifies Buyer 45 minutes in advance of such delivery (for example, if the incident occurs at 0810, Seller's provision of Replacement Power may begin at 0900, avoiding Availability Adjustments as of 0900 but subject to an Availability Adjustment for the period between 0810 and 0900). Seller shall incur an Availability Adjustment only in the event that the incident meets the definition of Forced Outage or Forced Derating and Seller fails to deliver or cause to be delivered Replacement Power or Substitute Power. If Seller is able to resume delivery of Electric Energy before any Outage Election is made, Seller may do so immediately without waiting until the top of the next hour, if it can be scheduled by Buyer on such short notice.

4.5.6.2 *When Substitute Power is Procured.* If Seller is able to resume delivery of Electric Energy from the Unit(s) prior to the expiration of any arrangements (entered into based on Seller's instructions) where Buyer is procuring Substitute Power at Seller's direction in accordance with Section 4.7.3 then, at Seller's direction, Buyer shall use commercially reasonable efforts to liquidate or unwind the Substitute Power arrangements at Prevailing Market Prices and any gain or loss realized by Buyer will be for the Seller's own account.

4.5.6.3 *During an Outage Book Out.* If Seller is able to resume delivery of Electric Energy during a period for which Seller has paid or agreed to pay an Outage Book Out Charge, Seller may resume operation of the applicable Unit(s) or portions thereof and Buyer will market the Electric Energy and pay to Seller 50% of the Gross Margin associated with such transaction plus the Facility Electric Energy Rate, if the Prevailing Market Price less Transaction Costs exceeds the Facility Electric Energy Rate.

4.5.7 *Minimization of Outages.* Consistent with Prudent Industry Practices, Seller shall use reasonable efforts to avoid Forced Outages and Forced Deratings and to minimize the length of any Forced Outages and Forced Deratings.

4.5.8 *Information Related to Outages.* In addition to the foregoing, Seller shall provide to Buyer information relating to outages of Capacity at the Units which could affect Seller's ability to deliver Electric Energy from such Units.

4.6 *Access to Facility.* Seller authorizes Buyer and its authorized agents, employees and inspectors to have access to the Facility, upon reasonable prior notice (in light of the circumstances) and subject to the safety rules and regulations of Seller, solely for the purpose of reading, testing, and maintaining metering equipment, or examining, repairing or removing any of Buyer's property.

4.7 *Delivery of Replacement Power and Substitute Power*

4.7.1 *Replacement Power.* All Replacement Power must be delivered in accordance with the following:

4.7.1.1 Buyer shall issue Dispatch instructions to schedule Replacement Power not in excess of the Net Dependable Capacity for delivery at each hour, and Seller shall, at its expense, deliver or cause to be delivered, all scheduled Replacement Power to the Replacement Power Delivery Point.

4.7.1.2 Buyer shall pay Capacity Charges for all such scheduled and delivered Replacement Power in accordance with Section 7.

4.7.2 *Pre−Commercial Operations Failure to Deliver.* If Seller fails to deliver or fails to cause to be delivered all or any part of any Replacement Power or Substitute Power scheduled for delivery prior to the Commercial Operations Date, Seller shall pay to Buyer within ten (10) days of receipt of an invoice therefor an amount equal to Buyer's actual, reasonable documented direct damages incurred for the cost of cover as a result of such failure to deliver Replacement Power or Substitute Power. At the end of each month during the Commercial Operations Delay Period, Buyer shall invoice Seller for such cost of cover if any incurred during such month, and Seller shall pay such amount within ten (10) days of Buyer's invoice therefor, and if Seller fails to timely pay such amount, Buyer may draw on the Seller Guarantees for such amount.

4.7.3 *Substitute Power.* Any request by Seller that Buyer procure Substitute Power shall be in accordance with the following:

4.7.3.1 Seller shall request Buyer to obtain quotes for Substitute Power on Seller's behalf at Prevailing Market Prices, which instructions shall include information as to whether such Substitute Power shall be obtained on a block or hourly basis.

4.7.3.2 Buyer shall use commercially reasonable efforts to obtain such Substitute Power at Prevailing Market Prices.

4.7.3.3 Subject to Section 4.7.4 at the end of each month, in conjunction with regular billings, if Substitute Power arranged by Buyer is not delivered, Buyer shall pay or credit to Seller any cost of cover damages Buyer receives from the entity that is the source of such Substitute Power.

4.7.4 *Post Commercial Operations Failure to Deliver.* If there is a failure to deliver energy to Buyer under any Substitute Power or Replacement Power arrangement by the entity that is the source of such Replacement Power or Substitute Power, then for the period of the failure until the applicable Unit(s) are able to resume operation in accordance with Buyer's Dispatch Seller shall pay to Buyer the greater of (i) the cost of cover damages ("or market LDs") Seller actually receives from such entity under the Replacement Power arrangement (or the amounts received by Buyer for Substitute Power pursuant to Section 4.7.3.3, (in either case "Third Party Damages") or (ii) the amount of any Availability Adjustment due as a result of such failure, if any.

4.7.5 *Characteristics of Replacement and Substitute Power.* When Seller is delivering Replacement Power to Buyer, Seller shall be obligated to deliver the amount of energy (at no cost to Seller, except to the extent required to deliver Replacement Power to the Replacement Power Delivery Point) scheduled by Buyer, up to the level necessary to comply with Buyer's Dispatch order (taking into account Electric Energy still being delivered by Seller during a Forced Derating) along with associated Ancillary Services in accordance with Section 9. Seller shall make appropriate power purchase and transmission arrangements to the Replacement Power Delivery Point to *provide* energy to Buyer which is of the same level of firmness (e.g. if unit contingent, an availability comparable to that of the Facility) or higher level of firmness (e.g., system firm, firm with liquidated damages, or as firm as utility native load) as the Net Dependable Capacity hereunder. Substitute Power procured by Buyer may be of a lower level of firmness.

4.8 *Emergency Conditions.* During an Emergency condition, Seller may increase, reduce, curtail or interrupt electrical generation at the Facility in accordance with Prudent Industry Practice or take other appropriate action in accordance with the applicable provisions of the Interconnection Agreement which in the reasonable judgment of the Interconnected Utility may be necessary to operate, maintain and protect the Interconnected Utility System or the transmission system of another Person during an Emergency Condition or in the reasonable judgment of Seller may be necessary to operate, maintain and protect the Facility during an Emergency Condition.

5. *Metering; Billing; Payment*

5.1 *Metering Electricity.* All Electric Energy delivered by Seller to Buyer from the Facility under this Agreement shall be metered by the Revenue Meters and the readings therefrom, including calculated transformer and transmission line losses between the Revenue Meters and the Point of Delivery, shall be made in accordance with Prudent Industry Practice consistently applied. All Replacement Power and Substitute Power delivered to Buyer from facilities inside the Interconnected Utility System, shall be metered by the Interconnected Utility. For all Replacement Power and Substitute Power from sources outside the Interconnected Utility System, the delivered amount shall be the amount scheduled as delivered to the Interconnected Utility System by the system delivering such Replacement Power or Substitute Power into the Interconnected Utility

System. The Energy Charge for which Buyer will be billed for Electric Energy also will be net of an adjustment for the value of the amount of electricity consumed by other non−operating Units at the Facility (or the Elwood II Units) during the billing period ("Non−Billable Generation") to yield the "billable generation" for the billing period. To establish the value of kilowatt hours of electricity provided by the Facility and consumed by the Elwood II Units for a billing period, the total for each billing period of electricity consumed by each Unit or unit will be determined from the individual Unit or unit meter readings using the Facility's Revenue Meter(s) (for the Units) and similar meters for the Elwood II Units which will then be summed for (both) Units and the Elwood II Units. Samples of such calculations are set forth in Appendix G.

5.1.1 *Fuel.* Billings for the fuel component of the Energy Rate shall be based on the Actual Heat Rate and the total consumption of gas as measured by the total Station Fuel Meter as prorated to Units 7 and 8 and the Elwood II Units based upon the Individual Fuel Meters, except where Replacement Power and Substitute Power is applicable, in which case the fuel component of the Energy Rate shall be derived in accordance with Section 7.2. Billings for the Variable O&M Rate component of the Energy Charge shall be derived from Revenue Meter information or, in the event Section 5.1.4 below is applicable, the best available data.

5.1.2 *Meter Testing.* The Revenue Meters shall be tested by the Parties at least once each year at Seller's expense and at any other reasonable time upon request by either Party, at the requesting Party's expense; provided, however, Buyer shall have no obligation to pay for any such test if such test results in a recalibration of meters. Seller shall give Buyer at least fourteen (14) days notice of any testing of the Revenue Meters, Station Fuel Meters, and Individual Fuel Meters and Buyer shall have the right to be present during all testing and shall be furnished all testing results on a timely basis.

5.1.3 *Inaccurate Meters.* If testing of the Revenue Meters indicates that an inaccuracy of more than +/−.5% in measurement of Electric Energy has occurred, the affected Revenue Meter shall be recalibrated promptly to register accurately within the Revenue Meter manufacturer stated tolerances. Each Party shall comply with any reasonable request of the other concerning the sealing of meters, the presence of a representative of the other Party when the seals are broken and the tests are made, and other matters affecting the accuracy of the measurement of Electric Energy. If either Party believes that there has been a meter failure or stoppage, it shall immediately notify the other Party.

5.1.4 *Failed Meters.* If, for any reason, any Revenue Meter is out of service or out of repair so that the amount of Electric Energy delivered cannot be ascertained or computed from the readings thereof, the Electric Energy delivered during the period of such outage shall be estimated and agreed upon by the Parties hereto upon the basis of the best data available, and any failure to agree shall be subject to resolution in accordance with Section 11.

5.1.5 *Examination of Records.* Each Party (and its representative(s)) has the right, at its sole expense, upon reasonable notice and during normal working hours, to have an independent third party examine the records of the other Party to the extent reasonably necessary to verify the accuracy of any statement, charge or computation relating to the output of Electric Energy. If requested, a Party shall provide to the other Party statements evidencing the amounts of Electric Energy delivered at the Point of Delivery.

5.2 *Adjustment for Inaccurate Meters.* If a Revenue Meter fails to register, or if the measurement made by a Revenue Meter is found upon testing to be inaccurate by more than or less than one half of one percent (.5%), an adjustment shall be made correcting all measurements by the inaccurate or defective Revenue Meter for both the amount of the inaccuracy and the period of inaccuracy, in the following manner:

5.2.1 As may be agreed upon by the Parties, or

5.2.2 In the event that the Parties cannot agree on the amount of the adjustment necessary to correct the measurements made by any inaccurate or defective Revenue Meter, the Parties shall use Seller's backup metering, if installed, to determine the amount of such inaccuracy; *provided, however*, that Seller's backup metering has been tested andmaintained in accordance with the provisions of this Section 5.2.2. In the event that Seller's backup metering also is found to be inaccurate by more than the allowable limits set forth in this Section 5.2.2, the Parties shall mutually agree to estimate the amount of the necessary adjustment on the basis of deliveries of Capacity and Electric Energy during periods of similar operating conditions when the Revenue Meter was registering accurately.

5.2.3 In the event that the Parties cannot agree on the actual period during which the Revenue Meter(s) made inaccurate measurements, the period during which the measurements are to be adjusted shall be the shorter of (i) the last one−half of the period from the last previous test of the Revenue Meter to the test that found the Revenue Meter to be defective or inaccurate, or (ii) the one hundred eighty (180) days immediately preceding the test that found the Revenue Meter to be defective or inaccurate.

5.2.4 To the extent that the adjustment period covers a period of deliveries for which payment has already been made by Buyer, Seller shall use the corrected measurements as determined in accordance with Sections 5.2.1, 5.2.2, or 5.2.3 hereof to recompute the amount due for the period of inaccuracy and shall subtract the previous payments by Buyer for this period from such recomputed amount. If the difference is a positive number, the difference shall be paid by Buyer to Seller; if the difference is a negative number, that difference shall be paid by Seller to Buyer in the form of an offset to payments due Seller by Buyer hereunder. Adjustment of such difference by the owing Party shall be made not later than thirty (30) days after the owing Party receives notice of the amount due, unless Buyer elects payment via an offset.

5.3 *Billing.* Within ten (10) days after the last day of each month during the Term, Seller shall render a statement to Buyer for the amounts due in respect of such month under Section 7, which statement shall contain reasonable detail showing the manner in which the applicable charges were determined.

5.4 *Payments.* The amount due to Seller as shown on any monthly statement rendered by Seller pursuant to Section 5.3 shall be paid by Buyer by electronic wire transfer to an account specified by Seller within ten (10) days after the date such statement is received by Buyer. Any amount not paid by Buyer when due shall bear interest at the Default Rate from the date that the payment was due until the date payment by Buyer is made.

5.5 *Offsets.* Amounts due to Buyer as a result of late Commercial Operations Date pursuant to Section 3.3 or amounts due to Buyer pursuant to Section 7 shall be offset against current and future payments due from Buyer with interest accrued daily at the Default Rate until fully offset or paid.

5.6 *Billing Disputes.*

5.6.1 If a Party questions or contests any amount claimed by the other Party to be due under Section 7, the Party obligated to pay shall pay the entire invoiced amount including the disputed portion (except obvious typographical or administrative errors).

5.6.2 In the event that either Party, by timely notice to the invoicing Party, questions or contests the correctness of any charge or payment claimed to be due by the invoicing Party, the invoicing Party shall promptly review the questioned charge or payment and shall notify the invoiced Party, within fifteen (15) Business Days following receipt by the invoicing Party of such notice , of the amount of any error and the amount of any reimbursement that the invoiced Party is entitled to receive in respect of such alleged error. Any disputes not resolved within fifteen (15) Business Days after the invoicing Party's receipt of notice from the invoiced Party shall be resolved in accordance with Section 11. Upon determination of the correct amount of any reimbursement, such amount shall be promptly paid by the invoicing Party to the invoiced Party.

5.6.3 Reimbursements made under this Section 5.6 shall include interest at the Default Rate from the date the original payment was made until the date of such reimbursement.

6. *Operation and Maintenance of the Facility*

6.1 *Standard of Operation*

6.1.1 *Operation and Maintenance.* Seller shall manage, control, operate and maintain the Facility in a manner consistent with Prudent Industry Practice, in accordance with (a) the practices, methods, acts, guidelines, standards and criteria of MAIN, NERC, the ISO and any successors to the functions thereof; (b) the requirements of the Interconnection Agreement; and (c) all applicable Requirements of Law and (d) permits taking into account Buyer's Dispatch rights under this Agreement.

6.1.2 *Fuel Arrangements.* Seller shall obtain and maintain fuel supply and transportation arrangements in a manner consistent with Prudent Industry Practice, taking into account Buyer's Dispatch rights under this Agreement.

6.1.3 *Insurance.* Seller shall obtain and maintain appropriate insurance coverages typical for plants similar to the Facility, in accordance with Prudent Industry Practice.

6.2 *Permits and Licenses.* Seller will obtain and maintain all certifications, permits, licenses and approvals necessary to operate and maintain the Facility and to perform its obligations under this Agreement during the Term.

6.3 *Sole Remedy.* Buyer's sole and exclusive remedy (other than specific performance) and Seller's sole and exclusive liability for breach of Section 6.1 shall be the Availability Adjustment and the termination rights provided in Section 13.4.

6.4 *Scheduled Maintenance.* No later than March 1, 2001, Seller shall submit to Buyer a proposed schedule of Scheduled Maintenance Outages scheduled by Seller for the following Contract Year for the Units, which schedule shall be updated by Seller by each March 31 and September 30 thereafter to cover the twelve month period following each such update; provided, however, that no Scheduled Maintenance Outage may be scheduled to cover the period from May 15 to September 15. Parameters within which Scheduled Maintenance Outages must be planned are included as Appendix I. If the OEM issues recommendations for changes to the parameters in Appendix I, the parties shall negotiate in good faith to revise Appendix I accordingly. Such schedule, and each supplement thereto, shall indicate the planned start and completion dates for each Scheduled Maintenance Outage during the period covered thereby and the amount of the Net Dependable Capacity of a Unit that will be affected. Within thirty (30) days of receipt of such schedule or any supplement thereto, Buyer may request reasonable modifications in the Scheduled Maintenance Outage schedule contained therein. Both parties agree to use reasonable efforts to develop a mutually acceptable final schedule for such Scheduled Maintenance Outages. If within six months prior to the scheduled start of a Scheduled Maintenance Outage, Buyer desires to change the scheduled start or duration of such Scheduled Maintenance Outage, Buyer shall notify Seller of Buyer's requested change and Seller shall use reasonable efforts to accommodate Buyer's requested change. Seller may propose compensation from Buyer to Seller for such change. Buyer shall then have the right to either direct such change and pay Seller such compensation, or withdraw the request for such change. At least one week prior to any Scheduled Maintenance Outage, Seller shall orally notify Buyer of the expected start date of such Scheduled Maintenance Outage, the amount of Capacity at the Units that will not be available to Buyer during such Scheduled Maintenance Outage, and the expected completion date of such Scheduled Maintenance Outage. Seller shall orally notify Buyer of any subsequent changes in such Capacity not available or any subsequent changes in the Scheduled Maintenance Outage completion date. As soon as practicable, all such oral notifications shall be confirmed in writing. Scheduled Maintenance Outages may be taken in any number of non−contiguous periods, subject to Buyer's approval, which shall not be unreasonably withheld or delayed. Subject to the foregoing, the duration, frequency and timing of Scheduled Maintenance Outages shall be based on OEM recommendations and the age and operation of the Units generally plus up to five (5) days per Unit on a semi−annual basis for Non−Summer Period balance of plant maintenance.

6.5 *Compressor Wash.* Buyer shall permit Seller to shut down each Unit (either at the same time or at different times) for a compressor wash, (the "Compressor Wash") at a mutually agreeable time that is not during On−Peak Hours, approximately once per month in the Summer Period. Such Compressor Wash requires that the Unit be off−line for an eighteen (18) hour cool down period prior to the start of such Compressor Wash. Seller agrees that at any time during such cool down period, Buyer may interrupt such cool down, Dispatch the Unit on−line and cause Seller to reschedule the cool down and Compressor Wash for the next mutually agreeable time. Buyer agrees that once the actual Compressor Wash begins, the Compressor Wash must be completed without interruption and that Buyer cannot Dispatch the Unit on−line until such Compressor Wash is completed.

6.6 *Operating Characteristics*

6.6.1 *Design Limits.* The operating characteristics of the Facility shall be consistent with the Design Limits set forth in Appendix A unless otherwise mutually agreed by the Parties. Any such agreed upon change must be in writing, signed by both Parties. If the OEM provides written direction for operations that requires a change to the Design Limits, the Parties will negotiate in good faith to modify the Design Limits accordingly.

6.6.2 *Interaction with Interconnected Utility System.* Buyer understands that Seller may be required to increase, reduce, curtail or interrupt electrical generation at the Facility in accordance with Prudent Industry Practice or to take other appropriate action in accordance with the applicable provisions of the Interconnection Agreement which in the reasonable judgment of the Interconnected Utility may be necessary to operate, maintain and protect the Interconnected Utility System or the transmission system of another Person during an Emergency Condition or in the reasonable judgment of Seller may be necessary to operate, maintain and protect the Facility during an Emergency Condition. Any such curtailment shall be applied by Seller prorata across all units at the Elwood Station to the extent allowed by existing contracts (for electrical output from the Elwood Station) which terminate December 31, 2004 and in all cases shall be prorata for future power contracts. For purposes of calculating the Availability Adjustment, the Facility shall be considered Available during any such increase, reduction, curtailment, interruption or action, unless the order to increase, reduce, curtail, interrupt, or take other action with respect to generation at the Facility or the Emergency Condition is caused by a condition on Seller's side of the interconnection point between the Facility and the Interconnected Utility System. Buyer acknowledges that other conditions on the Interconnected Utility System (for example, transmission outages or interruptions) may impact Seller's ability to deliver Electric Energy into the Interconnected Utility System at the Point of Delivery. For purposes of calculating the Availability Adjustment, the Facility shall be considered Available during any time that the Facility would have been actually Available but for conditions (including, for example, transmission outages or interruptions) on the Interconnected Utility System.

6.7 *Records.* Each Party shall keep and maintain all records as may be necessary or useful in performing or verifying any calculations made pursuant to this Agreement, or in verifying such Party's performance hereunder. All such records shall be retained by each Party for at least six (6) calendar years following the calendar year in which such records were created. Each Party shall make such records available to the other Party for inspection and copying at the other Party's expense, upon reasonable notice during such Party's regular business hours. Each Party shall have the right, upon thirty days written notice prior to the end of an applicable six (6) calendar year period to request copies of such records. Each Party shall provide such copies, at the other Party's expense, within thirty (30) days of receipt of such notice or shall make such records available to the other Party in accordance with the foregoing provisions of this Section 6.7.

7. *Compensation*

7.1 *Capacity Charge.* For each month, commencing July 1, 2001 (as such date is extended for Force Majeure Events pursuant to Section 19) and each month thereafter during the Term, Buyer shall owe Capacity Charges calculated pursuant to Section 7.1.1 (subject to offsets pursuant to Section 5.5).

7.1.1 *Computation.* The Capacity Charge for each month shall be equal to the product of (a) the applicable Capacity Rate for such month times (b) the Net Dependable Capacity for such month, minus the Availability Adjustment, when applicable.

7.1.2 *Capacity Rates.* The Capacity Rate during the Term shall be: (a) $7.39 per kW per month from July 1, 2001 to December 31, 2001, and (b) $5.11 per kW per month for the remainder of the Initial Term subject in each case to a Capacity Rate Reduction. The Capacity Rate for the Extension Term shall be $4.90 per kW per month, subject to a Capacity Rate Reduction.

7.1.3 *Availability Adjustment to Capacity Charge.* From and after the Commercial Operations Date, if the Facility does not achieve the Guaranteed Summer Super Peak Availability, Guaranteed Summer Partial Peak Availability or the Guaranteed Non−Summer On Peak Availability, as measured by Equivalent Availability in accordance with *Appendix E*, Seller shall be subject to the application of an Availability Adjustment as liquidated damages as provided in this Section 7.1.3.

7.1.3.1 *Summer Period.* For each month in the Summer Period, the Availability Adjustment shall equal the sum of (a) the Availability Adjustment for the Super Peak Hours plus (b) the greater of zero and the Availability Adjustment for the Partial Peak Hours where:

(i) the Availability Adjustment for Super Peak Hours is the product of (a) the sum of the monthly Capacity Charges (before application of the Availability Adjustment) for the applicable Contract Year and (b) the applicable Monthly Adjustment Factor and (c) 75% and (d) the Guaranteed Summer Super Peak Availability less the actual Equivalent Availability for Super Peak Hours during such month; and

(ii) the Availability Adjustment for Partial Peak Hours is the product of (a) the sum of the monthly Capacity Charges (before application of the Availability Adjustment) for the applicable Contract Year and (b) the applicable Monthly Adjustment Factor and (c) 25% and (d) the Guaranteed Summer Partial Peak Availability less the actual Equivalent Availability for Partial Peak Hours during such month.

(iii) for purposes of the calculations in subsections (i) and (ii) above and Section 7.1.3.4 only, in the first Contract Year, the first Contract Year shall be deemed to be from July 1, 2001 through May 31, 2002.

7.1.3.2 *Non−Summer Period* For the Non−Summer Period the Availability Adjustment shall equal the Availability Adjustment for Non−Summer On Peak Hours, where:

The Availability Adjustment for Non−Summer On Peak Hours is the product of (a) the sum of the monthly Capacity Charges (before application of the Availability Adjustment) for the applicable Contract Year and (b) 18% and (c) the Guaranteed Non−Summer On Peak Availability less the actual Non−Summer On Peak Availability for such Non−Summer Period. This will be calculated once per Contract Year.

7.1.3.3 *Super Peak 80% or below*. If the Equivalent Availability during Super Peak Hours in any month is less than or equal to 80%, then for purposes of calculating the Availability Adjustment during the Partial Peak Hours in the same month, the Equivalent Availability during Partial Peak Hours shall be deemed to be equal to the Equivalent Availability during Super Peak Hours for such month.

7.1.3.4 *Availability Adjustment Limit.* In no event shall the cumulative Availability Adjustment exceed (i) in the first Contract Year, $21,215,800, (ii) in all other Contract Years, other than the final Contract Year, $18,000,000 per year and (iii) in the final Contract Year $12,000,000.

7.1.4 *Capacity Bonus.*

7.1.4.1 *Applicability of Bonus.* Buyer shall pay Seller a Capacity Bonus if both (a) the Average Summer Super Peak Availability exceeds the Guaranteed Summer Super Peak Availability and (b) the Average Summer Partial Peak Availability exceeds the Guaranteed Partial Peak Availability; provided, however, if the Summer Super Peak Availability during any Summer Period month is less than or equal to 80%, then Seller shall not be entitled to a Capacity Bonus.

7.1.4.2 *Calculation of Bonus.* The Capacity Bonus for each Unit shall be equal to: [(Average Summer Super Peak Availability minus Guaranteed Summer Super Peak Availability)/.03 * maximum Capacity Bonus * .75] + [(Average Summer Partial Peak Availability minus Guaranteed Summer Partial Peak Availability)/.03 * maximum Capacity Bonus * .25] . If the Commercial Operations Date occurs during the first Contract Year, then for such first Contract Year, the maximum Capacity Bonus per Unit shall be equal to the sum of (a) (number of days of Commercial Operations in July / 31 days) * $62,500 and (b) (number of days of Commercial Operations in August / 31 days) * $62,500. If the Commercial Operations Date occurs in the second Contract Year, then for such second Contract Year the maximum Capacity Bonus per Unit shall be equal to the sum of (a) (number of days of Commercial Operations in June / 30 days) * $27,500 and (b) (number of days of Commercial Operations in July / 31 days) * $48,750 and (c) (number of days of Commercial Operations in August / 31 days) * $48,750. For all other Contract Years, the maximum Capacity Bonus shall be equal to $125,000 per Unit.

7.1.4.3 *Payable Monthly.* The Capacity Bonus shall be divided by 12 and shall be paid over a 12 month term beginning with September of each Contract Year.

7.2 *Energy Charge.* Each month beginning on the earlier of the Commercial Operations Date or the Target COD and continuing for the Term, Buyer shall pay Seller an Energy Charge to the extent Seller delivers Electric Energy, Incremental Energy, Replacement Power or Test Energy.

The Energy Charge for a billing month shall equal to the difference between (A) the sum of (a) the product of the total Electric Energy (in MWh) delivered to Buyer at the Point of Delivery from the Facility pursuant to Buyer's Dispatch orders, multiplied by the Facility Electric Energy Rate for each hour of such month plus (b) the product of the total Replacement Power (in MWh) provided by Seller to Buyer at the Replacement Power Delivery Point pursuant to Buyer's Dispatch orders, multiplied by the Replacement Power Energy Rate for each hour of such month adjusted for any Differential Transmission Adjustments incurred by Buyer plus (c) the product of the total Incremental Energy delivered to Buyer at the Point of Delivery pursuant to Section 4.3 multiplied by the Incremental Energy Rate for each hour of such month, plus (d) the product of the Test Energy (either Pre COD Test Energy or Post COD Test Energy, as applicable) multiplied by the applicable Test Energy Rate, minus (B) any Substitute Power Cost Credit.

7.2.1 *Facility Electric Energy Rate.* The Facility Electric Energy Rate is calculated as (the Actual Heat Rate x Fuel Charge)/1000+ Variable O&M Rate.

7.2.2 *Replacement Power Energy Rate.* The Replacement Power Energy Rate is calculated as (Reference Heat Rate x Fuel Charge)/1000+Variable O&M Rate.

7.2.3 *Incremental Energy Rate.* The Incremental Energy Rate is the sum of $100/MWh of Incremental Energy delivered to the Point of Delivery plus (a) with respect to the first 100 hours per Unit of Incremental Energy Dispatched by Buyer during any Contract Year, twenty percent (20%) of the Gross Margin resulting from such transaction, and (b) with respect to the next 150 hours per Unit of Incremental Energy Dispatched by Buyer in any Contract Year, thirty five (35%) of the Gross Margin resulting from such transaction.

7.2.4 *Test Energy Rates*

7.2.4.1 *Pre COD Test Energy.* The Pre COD Test Energy Rate shall be one of the following. If the Prevailing Market Price (less Transaction Costs) (expressed as $/MWh) is greater than the Facility Electric Energy Rate, the Pre COD Test Energy Rate shall be the sum of the Facility Electric Energy Rate, plus 95% of the difference between the Facility Electric Energy Rate and the Prevailing Market Price (less Transaction Costs). If the Prevailing Market Price (less Transaction Costs) is less than the Facility Electric Energy Rate, the Pre COD Test Energy Rate shall be 100% of such Prevailing Market Price less Transaction Costs, (but not including Scheduling Fees).

7.2.4.2 *Post COD Test Energy.* The Test Energy Rate for Post COD Test Energy shall be equal to either (a) the Facility Electric Energy Rate with respect to a test requested by Buyer the results of which do not require any corrections or adjustments, or (b) the lesser of the Facility Electric Energy Rate or the Prevailing Market Price (less Transaction Costs) in all other circumstances.

7.2.4.3 *Substitute Power Cost Credit.* Substitute Power Cost Credit shall be the Buyer's documented cost per MWh of Substitute Power (adjusted for any documented Differential Transmission Adjustments incurred by Buyer, if incrementally higher, or less any amounts of Differential Transmission Adjustments saved by Buyer if incrementally lower, less the Replacement Power Energy Rate multiplied by the Substitute Power (expressed in MWh) purchased by Buyer for each hour of such month.

7.2.5 *Fuel Charge*

7.2.5.1 *Base Fuel Charge.* If Buyer does not alter its Day Ahead Schedule, the Fuel Charge for all Electric Energy delivered in accordance with such schedule shall be the Fuel Index value plus 10 cents/MMBtu.

7.2.5.2 *Changes to Day Ahead Schedule for the Summer On Peak Hours and in September for On Peak Hours.* If Buyer makes a change(s) to the Day Ahead Schedule for operation in Summer On Peak Hours or in the On Peak Hours in September as provided in Section 4.3.2.4, the Fuel Charge for such Electric Energy generated pursuant to such Dispatch order shall be the Fuel Index value plus 15 cents/MMBtu.

7.2.5.3 *Changes to Day Ahead Schedule for Non−Summer Period and Summer Off Peak Hours.* If Buyer makes changes to the Day Ahead Schedule for operation in the Non−Summer Period or Summer Off Peak Hours and such change requires Seller to purchase more gas than would have been purchased but for such change in the schedule, then Seller shall provide Buyer with a quoted surcharge to be added to the Base Fuel Charge, the sum of which shall be the Fuel Charge for all Electric Energy generated pursuant to such changed schedule. If such change requires Seller to liquidate any excess gas, then Seller shall provide Buyer with a quoted fixed change fee pursuant to such changed schedule. If Buyer does not accept the quoted fixed change fee, Seller will proceed with operation of the Facility in accordance with the Dispatch schedule in effect prior to the requested change.

7.2.6 *Early Commercial Operations Date.* If the Commercial Operations Date occurs prior to July 1, 2001 for one or both Units, Buyer shall market and sell such Electric Energy delivered to Buyer from such Unit(s) at the Prevailing Market Price therefor if the Prevailing Market Price less Transaction Costs exceeds the Facility Electric Energy Rate, and Buyer shall remit to Seller 90% of the Gross Margin on any such transaction.

7.3 *Adjustment to Actual Heat Rate for Failure to Meet Guaranteed Heat Rate.*

7.3.1 *Established by Testing.* For purposes of calculating the Facility Electric Energy Rate, the Actual Heat Rate shall be reduced if the results of periodic tests indicate the combined Net Heat Rate of Units 7 and 8 and the Elwood II Units is greater than the Guaranteed Heat Rate under test conditions as set forth in Appendix B. The adjustment to the Actual Heat Rate shall be equal to the ratio of the Guaranteed Heat Rate divided by the Net Heat Rate, times the Actual Heat Rate. If any adjustment is necessary, the Actual Heat Rate Adjustment shall be effective retroactive to the date on which it was mutually determined that the Actual Heat Rate exceeded the Guaranteed Heat Rate and shall remain in effect until it is demonstrated by testing that the Net Heat Rate is less than the Guaranteed Heat Rate. In the event that Seller makes repairs to reduce the Net Heat Rate, the improvement shall be demonstrated by testing conducted at the expense of the Seller and the resulting adjustment to the Actual Heat Rate shall be retroactive to the date that repairs were effected.

7.3.2 *Accrual of Heat Rate Credits.* To the extent Net Heat Rate (including the Initial Net Heat Rate) is below the Threshold Heat Rate, Seller shall accrue half of such difference as credits to be applied in the future when the Net Heat Rate exceeds the Guaranteed Heat Rate ("Heat Rate Credits"). To the extent that the Net Heat Rate (beginning with the first test of the Net Heat Rate after the determination of the Initial Net Heat Rate) is less than the Initial Net Heat Rate (after application of the Degradation Curve) all of the difference will be accrued as Heat Rate Credits. For the purposes of tracking and accrual tabulation, the Heat Rate Credits that are established by testing shall be multiplied by the Electric Energy (kWh) delivered over the same period as the test results application period, and shall effectively be accrued in units of heat energy (Btus). If there is retroactive adjustment as provided for in Section 7.3.1, then the accrual tabulation of heat energy units shall be adjusted for the same period.

7.3.3 *Application of Heat Rate Credits.* If the Net Heat Rate (including the Initial Heat Rate) exceeds the Guaranteed Heat Rate, Seller may reduce the Net Heat Rate for purposes of calculating the Actual Heat Rate Adjustment (for the period during which such Net Heat Rate is in effect) by up to 50 Btus/kWh so long as Heat Rate Credits exist. The Seller's accumulated quantity of Heat Rate Credits shall be reduced to the extent utilized to reduce the Net Heat Rate. For the purposes of tracking and application tabulation, the negative Heat Rate Credits that are established by testing shall be multiplied by the Electric Energy (kWh) delivered over the same period as the test results application period, and shall effectively become a withdrawal of heat energy units (Btus) from the accumulated units of energy per Section 7.3.2. If there is retroactive adjustment as provided for in Section 7.3.1, then the withdrawal tabulation of heat energy units shall be adjusted for the same period.

7.3.4 *Cost of Heat Rate Tests.* The costs (and allocation of the costs) of any test pursuant to this Section 7.3 are set forth in Section 8.2.

7.4 *Start Up Charge.* For each Start Up of a Unit pursuant to the Dispatch of such Unit by Buyer, Seller shall be entitled to a payment of $2500.00 (the "Start Up Charge") in June 1, 1999 dollars. At the beginning of each Contract Year (i.e., January 1), thereafter, the Start Up Charge shall be adjusted by the change in the GDP−IPD from the GDP−IPD value on the previous January 1 (or June 1 in the case of the first Contract Year). Seller shall pay for the gas consumed during any Failed Starts.

7.5 *Imbalance Charges.* Buyer shall hold Seller harmless from any Imbalance Charges (i) that result from Buyer's Dispatch orders or other scheduling of generation under this Agreement, (ii) that are assessed against Buyer or Seller at any time when the Facility is generating Electric Energy within 1.5% of the Dispatch level directed by Buyer after achieving Start Up and has achieved the desired Dispatched load level for a period of ten (10) minutes, (iii) that are assessed for deliveries of Electric Energy during startup and shutdown, so long as Seller operates, Starts Up and shuts down the Units in accordance with this Agreement or (iv) that result from Unit trips. Buyer and Seller recognize that the Units may produce more or less energy than scheduled by Buyer.

7.6 *Rates Not Subject to Review.* The rates for service specified herein (i.e., delivery of Electric Energy, Replacement Power and Capacity) shall remain in effect for the Term, and shall not be subject to change through application to the FERC pursuant to provisions of Section 205 et seq. of the Federal Power Act, absent agreement of the Parties.

8. *Performance Tests.*

8.1 *Test Procedures.* Seller must conduct a test to determine the Initial Net Heat Rate in conjunction with the final performance testing for each Unit under the contract with the EPC Contractor. Seller must conduct a test on or prior to the Commercial Operations Date to determine Net Dependable Capacity. Thereafter at least once per Contract Year, Seller must conduct a test to determine the Net Dependable Capacity and Net Heat Rate. After the Commercial Operations Date, such annual testing shall be conducted on or about June 1 of each Contract Year at a mutually agreeable time. Any test to determine the Net Dependable Capacity and Net Heat Rate shall include a period of two hours during which the Net Dependable Capacity is generated and the Electric Energy delivered to the Point of Delivery. Once a test period has been initiated, it must last for two hours unless Buyer's and Seller's authorized representatives mutually agree to a shorter duration. Testing procedures to establish the Net Dependable Capacity and Net Heat Rate from and after the Commercial Operations Date are included as Appendix B and are consistent with ASME and OEM guidelines to the extent practicable. No tests will be conducted or continued which, in the opinion of Seller, should not be conducted or continued in accordance with Prudent Industry Practice. Seller shall always have the right to perform a Compressor Wash prior to a test. If Seller prevents or discontinues a test in accordance with Prudent Industry Practice, Buyer shall have the right to require a retest upon prior notice to Seller, if the test was conducted pursuant to Buyer's request.

8.2 *Buyer's Right to Retest.* Buyer shall have the right, at its expense (except as provided in this Section 8.2), to require Seller to establish or reestablish the Net Dependable Capacity and Net Heat Rate on or about the Commercial Operations Date and annually thereafter pursuant to a performance test conducted at a mutually agreeable time if the Buyer reasonably believes based upon operation of the Facility over the preceding thirty (30) days that the Net Dependable Capacity as adjusted in accordance with Section 8.1 is more than 2% below the then current level of Net Dependable Capacity or the Net Heat Rate exceeds the Guaranteed Heat Rate. The first such test of a Unit (regardless of the number of Units tested in such tests) in each Contract Year shall be performed without a charge to Buyer. For the second test required by Buyer in the same Contract Year, the Buyer shall pay to Seller $5,000, for the third test, $15,000 and for the fourth test and all subsequent tests, $30,000 (regardless, in each case, of the number of Units tested in such tests). If the results of the test indicate the Net Dependable Capacity is below 2% of the current level or that Net Heat Rate exceeds the Guaranteed Heat Rate, Buyer shall not pay for the cost of the test.

8.3 *Seller Right to Retest.* Seller shall have the right to reestablish Net Dependable Capacity and Net Heat Rate pursuant to a capacity test at mutually agreeable time(s). The results of each capacity test under this Section 8.3 shall immediately determine or redetermine the Net Dependable Capacity and Net Heat Rate retroactively to the date Seller can reasonably demonstrate that it took corrective actions to improve the Net Dependable Capacity or Net Heat Rate, adjusted by reference to the curves in Appendix F to Reference Conditions.

8.4 *Conditions for Testing.* During any capacity testing, Seller shall designate a maximum level for Buyer's Dispatch during such capacity testing, which may be above the then current Net Dependable Capacity. All appropriate auxiliary equipment associated with the Facility shall be in service at the time of any test under this Section 8.3. Test data shall be collected with plant instruments, except that Seller shall be allowed to substitute test instrumentation for Facility instrumentation, provided that the test instrumentation is of greater accuracy. Determination of net plant output shall be with the Revenue Meter with appropriate adjustments made for transformer and line losses.

8.5 *Scheduling of Testing.* Any testing requested by Seller after the Commercial Operations Date shall either be performed during times Dispatched by Buyer to generate or at mutually agreeable times. Buyer shall be entitled to witness any such tests.

9. *Ancillary Services*

9.1 *Availability of Ancillary Services.* Buyer shall be entitled, at no additional cost, to all Ancillary Services with respect to the Net Dependable Capacity at the Point of Delivery. Seller does not guarantee the availability of any ancillary services but does warrant that it will not remarket such services to any third party; except in the case of Buyer default under Section 13.2.1. Notwithstanding the above, Seller has the right to use Ancillary Services to meet any requirement of the Interconnected Utility System, the ISO, or their successors.

9.2 *Operational Considerations.* Buyer may Dispatch the Facility with the objective to avoid the need for energy imbalance service from a control area service provider, and to provide reactive power, load following (consistent with the scheduling), voltage control, and frequency response, provided that such services do not cause the Facility to operate outside of the Design Limits, and do not impose any additional costs or liabilities on Seller.

9.3 *Future Enhancements.* Seller shall provide such services, including but not limited to automatic generation control, to the extent that Buyer agrees to be responsible for reasonable incremental costs incurred by Seller to provide such services subject to mutual agreement of the parties working in good faith to arrive at an equitable arrangement.

10. *Limitation of Liability and Exclusive Remedies*

10.1 *CONSEQUENTIAL DAMAGES.* IN NO EVENT OR UNDER ANY CIRCUMSTANCES SHALL EITHER PARTY (INCLUDING SUCH PARTY'S AFFILIATES AND SUCH PARTY'S AND SUCH AFFILIATES' RESPECTIVE DIRECTORS, OFFICERS, EMPLOYEES AND AGENTS) BE LIABLE TO THE OTHER PARTY (INCLUDING SUCH PARTY'S AFFILIATES AND SUCH PARTY'S AND SUCH AFFILIATE'S RESPECTIVE DIRECTORS, OFFICERS, EMPLOYEES AND AGENTS) FOR ANY SPECIAL, INCIDENTAL, EXEMPLARY, INDIRECT, PUNITIVE OR CONSEQUENTIAL DAMAGES OR DAMAGES IN THE NATURE OF LOST PROFITS, WHETHER SUCH LOSS IS BASED ON CONTRACT, WARRANTY OR TORT. A PARTY'S LIABILITY UNDER THIS AGREEMENT SHALL BE LIMITED TO DIRECT, ACTUAL DAMAGES.

10.2 *SOLE REMEDIES FOR FAILURE TO DELIVER OR RELATED BREACHES.* NOTWITHSTANDING ANY OTHER PROVISION OF THIS AGREEMENT, OTHER THAN AS PROVIDED IN SECTION 10.3 BELOW, BUYER'S SOLE REMEDY FOR DAMAGES AND SELLER'S SOLE LIABILITY FOR DAMAGES FOR SELLER'S DEFAULT RELATING TO, ARISING OUT OF, OR IN ANY WAY CONNECTED WITH ANY FAILURE BY SELLER TO MEET GUARANTEED SUMMER ON PEAK AVAILABILITY OR GUARANTEED NON−SUMMER ON PEAK AVAILABILITY, TO DELIVER (OR CAUSE TO BE DELIVERED) ELECTRIC ENERGY, REPLACEMENT POWER OR SUBSTITUTE POWER AS DISPATCHED BY BUYER, OR FAILURE TO COMPLY WITH ANY FACILITY PERFORMANCE RELATED PROVISIONS INCLUDING SECTIONS 4.1, 4.5.7, 4.5.8 OR 6.1, SHALL BE THE ADJUSTMENT TO CAPACITY CHARGES BASED UPON THE AVAILABILITY ADJUSTMENT SUBJECT TO THE LIMIT ON SELLER'S LIABILITY FOR SUCH ADJUSTMENT SET FORTH IN SECTION 7.1.3.4; AND SUCH AVAILABILITY ADJUSTMENT SHALL BE CONSIDERED LIQUIDATED DAMAGES IN LIEU OF ANY OTHER DAMAGES AT LAW, IN EQUITY OR AS SET FORTH ELSEWHERE IN THIS AGREEMENT.

10.3 *SOLE REMEDY FOR LATE COMMERCIAL OPERATIONS.* BUYER'S SOLE REMEDIES AND SELLER'S SOLE LIABILITY FOR FAILURE OF THE COMMERCIAL OPERATIONS DATE TO OCCUR ON OR BEFORE THE TARGET COD (INCLUDING FAILURE TO COMPLY WITH SECTION 3) SHALL BE (a) THE OFFSET OF DELAY LDs AS SET FORTH IN SECTION 3.3 AGAINST CAPACITY CHARGES AS THEY COME DUE, SUBJECT TO THE LIMITATION ON SELLER'S LIABILITY SET FORTH IN SUCH SECTION 3.3 AND (b) TERMINATION IN ACCORDANCE WITH SECTION 3.3.7, IF THE COMMERCIAL OPERATIONS DATE DOES NOT OCCUR BY THE FINAL COMMERCIAL OPERATIONS DATE.

10.4 *SOLE TERMINATION FOR DEFAULT REMEDIES.* BUYER'S SOLE AND EXCLUSIVE REMEDIES OF TERMINATION FOR DEFAULT SHALL BE AS SET FORTH IN SECTIONS 3.3.7, 13 AND 19, AND SHALL BE, IN LIEU OF ANY OTHER REMEDIES OF TERMINATION AT LAW OR IN EQUITY.

10.5 *DIRECT DAMAGES FOR OTHER BREACHES.* SUBJECT TO THE LIMITATIONS SET FORTH IN SECTIONS 10.1, 10.2, AND 10.3, AND SUBJECT FURTHER TO THE ARBITRATION PROVISION OF SECTIONS 11.1 − 11.6, EACH PARTY SHALL BE ENTITLED WITHOUT DUPLICATION TO RECOVER FROM THE OTHER PARTY ITS DIRECT DAMAGES OR SEEK AN INJUNCTION OR OTHER EQUITABLE RELIEF FOR BREACH BY SUCH PARTY OF ITS OBLIGATIONS UNDER THIS AGREEMENT AND TO ENFORCE ANY PAYMENT OBLIGATIONS OF SELLER HEREUNDER OR TO TAKE ALL

LEGAL ACTION NECESSARY TO ENFORCE ANY ORDER, DECISION OR SETTLEMENT OF AN ARBITRATOR RENDERED PURSUANT TO SECTION 11.2.5.

11. *Disagreements*

11.1 *Negotiations.* The Parties shall attempt in good faith to resolve all disputes promptly by negotiation, as follows. Any Party may give the other Party written notice of any dispute not resolved in the normal course of business. Executives of both Parties at levels one level above the personnel who have previously been involved in the dispute shall meet at a mutually acceptable time and place within ten (10) days after delivery of such notice, and thereafter as often as they reasonably deem necessary, to exchange relevant information and to attempt to resolve the dispute. If the matter has not been resolved within thirty (30) days from the referral of the dispute to senior executives, or if no meeting of senior executives has taken place within fifteen (15) days after such referral, either Party may initiate arbitration as provided hereinafter. If a Party intends to be accompanied at a meeting by an attorney, the other Party shall be given at least three (3) Business Days' notice of such intention and may also be accompanied by an attorney. All negotiations pursuant to this clause shall be confidential.

11.2 *Arbitration*

11.2.1. If the negotiation process provided for in Section 11.1 above has not resolved the dispute, the dispute shall be decided solely and exclusively by arbitration in Chicago, Illinois in accordance with the Commercial Arbitration Rules of the American Arbitration Association. The arbitration shall be governed by the United States Arbitration Act (9 U.S.C. ss. 1 et seq.), and judgment entered upon the award rendered by the arbitrator(s) may be entered in any court having jurisdiction thereof. This agreement to arbitrate and any other agreement or consent to arbitrate entered into in accordance herewith will be specifically enforceable under the prevailing arbitration law of any court having jurisdiction. Notice of demand for arbitration must be filed in writing with the other Party to this Agreement. The demand must be made within a reasonable time after the controversy has arisen. In no event may the demand for arbitration be made if the institution of legal or equitable proceedings based on such controversy is barred by the applicable statute of limitations. Any arbitration may be consolidated with any other arbitration proceedings. Either party may join any other interested parties. The award of the arbitrator shall be specifically enforceable in a court of competent jurisdiction.

11.2.2 Either Party shall give to the other written notice in sufficient detail of the existence and nature of any dispute proposed to be arbitrated. The Parties shall attempt to agree on a person with special knowledge and expertise with respect to the matter at issue to serve as arbitrator. If the Parties cannot agree on an arbitrator within ten (10) days, each shall then appoint one individual to serve as an arbitrator and the two (2) thus appointed shall select a third arbitrator with such special knowledge and expertise to serve as chairman of the panel of arbitrators; and such three (3) arbitrators shall determine all matters by majority vote; *provided, however*, if the two (2) arbitrators appointed by the Parties are unable to agree upon the appointment of the third arbitrator within five (5) days after their appointment, both shall give written notice of such failure to agree to the Parties, and, if the Parties fail to agree upon the selection of such third arbitrator within five (5) days thereafter, then either of the Parties upon written notice to the other may require such appointment from, and pursuant to the rules of, the Chicago office of the American Arbitration Association for commercial arbitration. Prior to appointment, each arbitrator shall agree to conduct such arbitration in accordance with the terms of this Agreement. The arbitration panel may choose legal counsel to advise it on the remedies it may grant, procedure, and such other legal issues as the panel deems appropriate but subject to limits on remedies and damages set forth in this Agreement.

11.2.3 The Parties shall have sixty (60) days to perform discovery and present evidence and argument to the arbitrators. During that period, the arbitrators shall be available to receive and consider all such evidence as is relevant and, within reasonable limits due to the restricted time period, to hear as much argument as is feasible, giving a fair allocation of time to each Party to the arbitration. The arbitrators shall use all reasonable means to expedite discovery and to sanction noncompliance with reasonable discovery requests or any discovery order. The arbitrators shall not consider any evidence or argument not presented during such period and shall not extend such period except by the written consent of both Parties. At the conclusion of such period, the arbitrators shall have forty−five (45) days to reach a determination. To the extent not in conflict with the procedures set forth herein, which shall govern, such arbitration shall be held in accordance with the prevailing rules of the Chicago office of the American Arbitration Association for commercial arbitration.

11.2.4 The arbitrators shall have the right only to interpret and apply the terms and conditions of this Agreement and to order any remedy allowed by this Agreement, but may not change any term or condition of this Agreement, deprive either Party of any right or remedy expressly provided hereunder, or provide any right or remedy that has been excluded hereunder.

11.2.5 The arbitrators shall give a written decision to the Parties stating their findings of fact, conclusions of law and order, and shall furnish to each Party a copy thereof signed by them within five (5) days from the date of their determination.

11.3 *Costs.* Each Party shall pay the cost of the arbitrator or arbitrators, and any legal counsel appointed pursuant to subparagraph (a) above, with respect to those issues as to which they do not prevail, as determined by the arbitrator or arbitrators.

11.4 *Settlement Discussions.* The Parties agree that no statements of position or offers of settlement made in the course of the dispute process described in this Section 11 will be offered into evidence for any purpose in any litigation or arbitration between the Parties, nor will any such statements or offers of settlement be used in any manner against either Party in any such litigation or arbitration. Further, no such statements or offers of settlement shall constitute an admission or waiver of rights by either Party in connection with any such litigation or arbitration. At the request of either Party, any such statements and offers of settlement, and all copies thereof, shall be promptly returned to the Party providing the same.

11.5 *Preliminary Injunctive Relief.* Nothing in this Section 11 shall preclude, or be construed to preclude, the resort by either Party to a court of competent jurisdiction solely for the purposes of securing a temporary or preliminary injunction to preserve the status quo or avoid irreparable harm pending arbitration pursuant to this Section 11.

11.6 *Obligations to Pay Charges and Perform.* If a disagreement arises on any matter which is not resolved as provided in Section 11.1 above, then, pending the resolution of the disagreement by arbitration, Seller shall continue to perform its obligations hereunder including its obligations to operate the Units in a manner consistent with the applicable provisions of this Agreement and Buyer shall continue to pay all charges and perform all other obligations required in accordance with the applicable provisions of this Agreement. In addition, notwithstanding the provisions of Section 13.3, neither Party shall be entitled to terminate this Agreement for default (other than defaults pursuant to Sections 13.1.1 or 13.2.1) by the other Party if the alleged default is the subject of an arbitration pursuant to Section 11, pending the outcome of such arbitration.

12. *Assignment; Project Financing; and Transfer of Units*

12.1 *Assignment.* Except as set forth in this Section 12, neither Party may assign its rights or obligations under this Agreement without the prior written consent of the other Party. Either Party may assign this Agreement, without the consent of the other Party, to an Affiliate or the parent company of an Affiliate, but no such assignment shall release such assignor from any obligations hereunder whether arising before or after such assignment.

12.2 *Transfers and Change of Control.* For the Purposes of this Section 12.2, any direct transfer or series of direct transfers (whether voluntary or by operation of law) of a majority of the outstanding voting equity interests of a Party (or any entity or entities directly or indirectly holding a majority of the outstanding voting equity interests of such Party) to any party other than an Affiliate controlled by, or under common control with, such Party shall be deemed an assignment of this Agreement. In such events; (i) prior notice of any such assignment shall be provided to the other Party; (ii) any assignee (other than Lenders or their designees pursuant to Section 12.3 below) shall expressly assume assignor's obligation hereunder, unless otherwise agreed to by the other Party; and (iii) except with respect to an assignment of this Agreement in its entirety permitted hereunder by the Seller's Lender, no assignment, whether or not consented to, shall relieve the assignor of its obligations hereunder in the event the assignee fails to perform, unless the other party agrees in writing in advance to waive the assignor's continuing obligations pursuant to this Agreement, such waiver not to be unreasonably withheld.

12.3 *Consent to Assignment to Lender.* Buyer consents to Seller's assignment of this Agreement to any Lenders or the granting to any Lenders of a lien or security interest in any right, title or interest in part or all of the Facility or any or all of Seller's rights under this Agreement for the purpose of the financing or refinancing of the Facility (or any part thereof) and the Interconnection Facilities; *provided, however*, that such assignment shall recognize Buyer's rights under this Agreement. Buyer further agrees to comply with reasonable requests of Seller in Seller's efforts to obtain project financing for the Facility, including without limitation execution of a consent to assignment by Buyer and delivery by Buyer's counsel of an opinion as described below as reasonably required by Lenders. Buyer recognizes that such financing will likely entail Buyer's execution of a consent to assignment that may grant certain rights to such Lenders, which shall be fully developed and described in the consent documents, including (i) this Agreement shall not be amended in any material respect or terminated (except for termination pursuant to the terms of this Agreement) without the consent of Lenders, which consent is not to be unreasonably withheld or delayed, (ii) Lenders shall be given notice of, and a reasonable opportunity to cure (in addition to the periods designated hereunder), any Seller breach or default of this Agreement, and (iii) if a Lender forecloses, takes a deed in lieu or otherwise exercises its remedies pursuant to any security documents, that Buyer shall, at Lender's request, continue to perform all of its obligations hereunder (subject to Buyer's rights under Section 13), so long as Lender or its nominee is performing all obligations of Seller hereunder in the place of Seller, and Lender may assign this Agreement to a Permitted Assignee so long as such Permitted Assignee assumes all obligations of Seller hereunder and so long as all monetary defaults of Seller are cured prior to such assignment, and may enforce all of Seller's rights to the extent Seller's obligations hereunder are being performed, (iii) that Lender(s) shall have no liability under this Agreement except during the period of such Lender(s)' ownership and/or operation of the Facility, (iv) that Buyer shall accept performance in accordance with this Agreement by Lender(s) or its (their) nominee, (v) if this Agreement is rejected in Seller's bankruptcy, Buyer will enter into a replacement agreement identical to this Agreement with a Permitted Assignee so long as such Permitted Assignee assumes all obligations of Seller hereunder and so long as all monetary defaults of Seller are cured prior to such assignment, and (vi) that Buyer shall make representations and warranties to Lender(s) as Lender(s) may reasonably request with regard to (A) Buyer's corporate existence, (B) Buyer's corporate authority to execute, deliver, and perform this Agreement, (C) the binding nature of (x) the document evidencing Buyer's consent to assignment to Lenders and (y) this Agreement on Buyer, (D) receipt of regulatory approvals by Buyer with respect to its execution and performance under this Agreement, and (E) whether to Buyer's knowledge, any defaults by Seller are known by

Buyer then to exist under this Agreement. The documentation that Lenders may require under this Section 12.3 may include an opinion of counsel typical in project finance transactions. Seller agrees to reimburse Buyer for reasonable fees and expenses incurred by Buyer in connection with consent to assignment including without limitation, attorneys' fees and expenses. Such consent to assignment to Lenders shall provide that upon the exercise of trustee's or mortgagee's assignment rights pursuant to such assignment, trustee or mortgagee shall notify Buyer of the date and particulars of any such exercise of assignment rights.

12.4 *Potential Changes in Ownership or Control of Aquila.* Seller acknowledges that Aquila may become the subject of a merger, acquisition, transfer of a majority of the outstanding voting equity of Aquila, or other change in control (the "Aquila Change in Control") in the near future and that such transaction may be deemed an assignment of this Agreement pursuant to Section 12.2. Seller agrees that, if, following the consummation of the Aquila Change in Control, Aquila, or its successor entity resulting from such transaction, provides evidence reasonably satisfactory to Lenders (in accordance with common industry practice) demonstrating that it has a credit rating that is equal to or higher than such rating applicable to UCU as of the date of this Agreement, Seller shall provide its consent pursuant to Section 12.1 to such deemed assignment, and upon consummation thereof shall release UCU from its joint and several liability and from all obligations arising from and after the Aquila Change in Control.

12.5 *Transfers Not in Accordance Herewith.* Any sale, transfer, or assignment of any interest in the Facility or in this Agreement made without fulfilling the requirements of this Section 12 shall be null and void and shall constitute an Event of Default.

13. *Default, Termination and Remedies; Notice of Default.* If Buyer defaults under this Agreement, then Seller shall give Buyer written notice describing such default. If Seller defaults under this Agreement, then Buyer shall give Seller written notice describing such default and concurrently provide any Lender with a copy of such notice.

13.1 *Events of Default of Seller.* The following shall constitute Events of Default of Seller ("Seller Events of Default") upon their occurrence unless cured within seven (7) days after written receipt of Notice from Buyer of such failure requiring its remedy, in the case of defaults under Sections 13.1.1 (and twenty−one (21) days with respect to Section 13.1.2) or within sixty (60) days, in the case of all other defaults, after the date of written notice from Buyer as provided above, provided that, if any such other default cannot be cured within sixty (60) days with exercise of due diligence, and if Seller within such period submits to Buyer a plan reasonably designed to correct the default within a reasonable additional period of time not to exceed six (6) months, then an Event of Default shall not exist unless Seller fails to diligently pursue such cure or fails to cure such default within the additional period of time specified by such plan:

13.1.1 Seller's failure to make payments when due; Seller Guarantor's failure to pay for Substitute Power (if Seller has failed previously to make such payment), a Delay Book Out Charge or an Outage Book Out Charge;

13.1.2 (i) A Seller Guarantee ceases to remain in full force and effect in accordance with its terms (other than as a result of such Seller Guarantee having been fully drawn down by Buyer); (ii) the failure of a Seller Guarantor to make a payment upon a proper drawing by Buyer against a Seller Guarantee; or (iii) Seller fails to deliver a letter of credit as required by Section 18.1 upon a Downgrade Event with respect to a Seller Guarantor.

13.1.3 Seller's dissolution or liquidation;

13.1.4 A Bankruptcy Event occurs with respect to Seller;

13.1.5 Seller's assignment of this Agreement or any of Seller's rights under the Agreement or the sale or transfer of any interest in Seller in each case not in compliance with the provisions of Section 12;

13.1.6 The sale by Seller to a third party of Electric Energy or Capacity committed to Buyer by Seller other than as permitted under this Agreement; and

13.1.7 Any representation made by Seller under Section 14.1 shall be false in any material respect.

13.2 *Buyer Default.* The following shall constitute Events of Default of ("Buyer Events of Default") upon their occurrence unless cured within seven (7) days after written receipt of Notice from Seller of such failure requiring its remedy, in the case of a default under Section 13.2.1 or within sixty (60) days, in the case of all other defaults, after the date of written notice from Buyer as provided above, provided that, if any such other default cannot be cured within sixty (60) days with exercise of due diligence, and if Seller within such period submits to Buyer a plan reasonably designed to correct the default within a reasonable additional period of time not to exceed six (6) months, then an Event of Default shall not exist unless Seller fails to diligently pursue such cure or fails to cure such default within the additional period of time specified by such plan:

13.2.1 Buyer fails to pay any sum due from it hereunder on the due date thereof;

13.2.2 A Bankruptcy Event occurs with respect to Buyer;

13.2.3 Buyer dissolution or liquidation except in connection with an Aquila Change in Control pursuant to Section 12.4;

13.2.4 Buyer's failure to post or maintain security in the form of a letter of credit as a result of a Downgrade Event with regard to Buyer as described in Section 18.2, to the levels, and upon the timing, specified in such Section 18.2;

13.2.5 Buyer's assignment of this Agreement or any of Buyer's rights under this Agreement or the sale or transfer of any interest in Buyer in each case not in compliance with the provisions of Section 12; or

13.2.6 Any representation made by Buyer under Section 14.1 shall be false in any material respect.

13.3 *Remedies.*

13.3.1 Upon the occurrence and during the continuance of a Buyer Event of Default or a Seller Event of Default, the non−defaulting Party may at its discretion suspend performance hereunder or terminate this Agreement upon thirty (30) days (or five (5) days for defaults under Section 13.1.4 or 13.2.2 above) prior written notice to the Party in default. In addition, if Seller terminates this Agreement pursuant to this section 13.3.1, Seller may draw the amount of its direct damages incurred as a result of Buyer's default from the Buyer letter of credit, if any, posted pursuant to Section 18.2.

13.3.2 If a Buyer Event of Default under Section 13.2.1 has occurred and is continuing, Seller shall have the right to sell Capacity and Electric Energy from the Facility on a daily basis to third parties during the continuance of such Buyer Event of Default.

13.4 *Special Termination for Chronic Poor Availability.* If the Summer Average Availability for the Facility for a Summer Period (the "Initial Poor Availability Period") is less than 80%, then Seller shall promptly engage a mutually acceptable independent engineer to conduct an assessment of Seller's operating and maintenance practices to determine what steps are necessary to restore the Facility to an Equivalent Availability of at least 97% and to recommend a detailed and specific protocol of equipment, operational and maintenance improvements necessary to achieve such Equivalent Availability (collectively, the "IE Protocol"). If Seller fails to fully and timely implement the IE Protocol and either (i) the Facility has a Summer Average Availability of less than 80% for each of the two Summer Periods subsequent to the Initial Poor Availability Period or (ii) if the Summer Average Availability for the Initial Poor Availability Period was less than 70%, and the Facility has a Summer Average Availability less than 70% for the Summer Period subsequent to the Initial Poor Availability Period, then Buyer may terminate this Agreement on September 15/th/ of the year that is two years after the Initial Poor Availability Period (in the case of a termination pursuant to the foregoing clause (i)) or on September 15/th/ of the year after the Initial Poor Availability Period (in the case of a termination pursuant to clause (ii)). In the event of such termination, Seller shall have no liability to Buyer except for liability for obligations (including Availability Adjustments) accrued prior to such termination.

14. *Representations and Warranties*

14.1 *Representations and Warranties of Seller.* Seller hereby makes the following representations and warranties to Buyer:

14.1.1 Seller is a Delaware limited liability company duly organized, validly existing and in good standing under the laws of the State of Delaware, is qualified to do business in the State of Illinois and has the legal power and authority to own its properties, to carry on its business as now being conducted and to enter into this Agreement and, subject to the receipt of the regulatory approvals set forth in Section 20, carry out the transactions contemplated hereby and perform and carry out all covenants and obligations on its part to be performed under and pursuant to this Agreement.

14.1.2 The execution, delivery and performance by Seller of this Agreement have been duly authorized by all necessary corporate action, and do not and will not require any consent or approval of Seller's Management Committee or equity holders other than that which has been obtained.

14.1.3 The execution and delivery of this Agreement, the consummation of the transactions contemplated hereby and the fulfillment of and compliance with the provisions of this Agreement, do not and will not conflict with or constitute a breach of or a default under, any of the terms, conditions or provisions of any legal requirements, or any organizational documents, agreement, deed of trust, mortgage, loan agreement, other evidence of indebtedness or any other agreement or instrument to which Seller is a party or by which it or any of its property is bound, or result in a breach of or a default under any of the foregoing, and Seller has obtained all permits, licenses, approvals and consents of governmental authorities required for the lawful performance of its obligations hereunder.

14.1.4 This Agreement constitutes the legal, valid and binding obligation of Seller enforceable in accordance with its terms, except as such enforceability may be limited by bankruptcy, insolvency, reorganization or similar laws relating to or affecting the enforcement of creditors' rights generally or by general equitable principles, regardless of whether such enforceability is considered in a proceeding in equity or at law.

14.1.5 There is no pending, or to the knowledge of Seller, threatened action or proceeding affecting Seller before any governmental authority which purports to affect the legality, validity or enforceability of this Agreement.

14.2 *Representations and Warranties of Buyer.* Aquila and UCU, on a joint and several basis, hereby make the following representation and warranties to Seller:

14.2.1 Aquila is a corporation duly organized, validly existing and in good standing under the laws of the State of Delaware and UCU is a corporation duly organized, validly existing and in good standing under the laws of the State of Delaware. Each of Aquila and UCU is qualified to do business in the State of Illinois and has the legal power and authority to own its properties, to carry on its business as now being conducted and to enter into this Agreement and carry out the transactions contemplated hereby and perform and carry out all covenants and obligations on its part to be performed under and pursuant to this Agreement.

14.2.2 The execution, delivery and performance by each of Aquila and UCU of this Agreement have been duly authorized by all necessary corporate action, and do not and will not require any consent or approval of its Board of Directors or shareholders other than that which has been obtained.

14.2.3 The execution and delivery of this Agreement, the consummation of the transactions contemplated hereby and the fulfillment of and compliance with the provisions of this Agreement do not and will not conflict with or constitute a breach of or a default under, any of the terms, conditions or provisions of any legal requirements, or its Sections of incorporation or bylaws, or any deed of trust, mortgage, loan agreement, other evidence of indebtedness or any other agreement or instrument to which either Aquila or UCU is a party or by which it or any of its property is bound, or result in a breach of or a default under any of the foregoing.

14.2.4 This Agreement constitutes the legal, valid and binding obligation of Aquila and UCU enforceable in accordance with its terms, except as such enforceability may be limited by bankruptcy, insolvency, reorganization or similar laws relating to or affecting the enforcement of creditors' rights generally or by general equitable principles, regardless of whether such enforceability is considered in a proceeding in equity or at law.

14.2.5 There is no pending, or to the knowledge of Aquila or UtiliCorp, threatened action or proceeding affecting it before any governmental authority which purports to affect the legality, validity or enforceability of this Agreement.

15. *Indemnification*

Each Party shall indemnify and hold harmless the other Party, and its officers, directors, agents and employees from and against any and all claims, demands, actions, losses, liabilities, expenses (including reasonable legal fees and expenses), suits and proceedings of any nature whatsoever for personal injury, death or property damage to each other's property or facilities or personal injury, death or property damage to third parties (collectively "Liabilities") caused by the negligence or willful misconduct of the indemnifying Party that arise out of or are in any manner connected with the performance of this Agreement, except to the extent such injury or damage is attributable to the gross negligence or willful misconduct of, or breach of this Agreement by, the Party seeking indemnification hereunder. Buyer shall indemnify Seller from all Liabilities related to Electric Energy and Replacement Power from and after delivery to the Point of Delivery or Replacement Power Delivery Point as applicable; and Seller shall indemnify Buyer for all Liabilities related to Electric Energy or Replacement Power prior to its delivery to the Point of Delivery or Replacement Power Delivery Point as applicable.

16. *Notices.*

Unless otherwise provided in this Agreement, any notice, consent or other communication required to be made under this Agreement shall be in writing and shall be delivered to the address set forth below or such other address or persons as the receiving Party may from time to time designate by written notice:

If to Buyer, to:

Aquila Energy Marketing Corporation
1100 Walnut − Suite 2900
Kansas City, Missouri 64106
Attention: President
Fax: (816) 527−1006

With a copy to:

Hogan & Hartson, L.L.P.
555 Thirteenth Street, Columbia Square
Washington, D.C. 20004−1109
Attn: John P. Mathis, Esquire
Fax: (202) 637−5910

If to Seller, to:

Elwood Energy III, LLC
c/o Dominion Energy, Inc.
120 Tredegar Street
Richmond, VA 23219
Attention: Christine M. Schwab, Esq.
Fax: (804) 819−2202

with a copy to:

Elwood Energy III, LLC
c/o McGuire, Woods, Battle & Boothe LLP
901 E. Cary Street
Richmond, VA 23219
Attention: Mark J. La Fratta, Esq.
Telephone: (804) 775−1106
Fax: (804) 698−2096

All notices shall be effective when received.

17. *Confidentiality*

Each Party agrees that it will treat in confidence all documents, materials and other information marked "Confidential" or "Proprietary" by the disclosing Party ("Confidential Information") which it shall have obtained during the course of the negotiations leading to, and its performance of, this Agreement (whether obtained before or after the date of this Agreement). Confidential Information shall not be communicated to any third party (other than, in the case of Seller, to its Affiliates, to its counsel, accountants, financial or tax advisors, or insurance consultants, to prospective partners and other investors in Seller and their counsel, accountants, or financial or tax advisors, or in connection with its financing or refinancing; and in the case of Buyer, to its Affiliates, or to its counsel, accountants, financial advisors, tax advisors or insurance consultants). As used herein, the term "Confidential Information" shall not include any information which (i) is or becomes available to a Party from a source other than the other Party, (ii) is or becomes available to the public other than as a result of disclosure by the receiving Party or its agents or (iii) is required to be disclosed in the opinion for a Party's legal counsel under applicable law or judicial, administrative or regulatory process, but only to the extent it must be disclosed. The timing and content of any press releases associated with this Agreement shall be agreed to by the Parties prior to any public disclosure or distribution.

18. *Security*

18.1 *Seller Guarantees.* Seller shall provide guarantees of Dominion Energy, Inc. ("Dominion") and Peoples Energy Corp ("Pecorp") (the "Seller Guarantees") in the form of Appendix H, each with a cumulative maximum liability amount for the Term equal to ten million dollars ($10,000,000). Such guarantees shall be in force beginning July 1, 2001 and shall remain in force until the termination of this Agreement. If and when a Seller Guarantor has paid out an amount equal to the maximum amount of the Seller Guarantee, such Seller Guarantor shall be released from any further liability to Buyer pursuant to this Agreement, and from and after such date Buyer shall be released from any obligation hereunder to obtain Substitute Power. Such Seller Guarantor may, in its sole discretion, reissue additional guarantees beyond such maximum. If a Downgrade Event occurs with respect to a Seller Guarantor, Seller shall post or cause to be posted in lieu of Seller's Guarantee, a letter of credit in favor of and reasonably acceptable to Buyer in an amount equal to its remaining liability under such Seller Guarantees. Neither Dominion nor Pecorp may assign or transfer its guarantee obligations to a third party entity without the consent of Buyer, and any assignee or transferee must have credit standing of Investment Grade or better . Pursuant to such guarantees, each of Dominion and Pecorp shall be severally, but not jointly or jointly and severally, liable for the performance of Seller, and their liabilities shall be limited to the amount stated in the guarantees for the applicable time period. Upon Buyer's request, Seller shall cause Dominion to provide audited financial statements on an annual basis after April 30 of each year for the preceding calendar year.

18.2 *Buyer Security.* Upon request of Seller, Buyer shall be required to post security in the form of a letter of credit in favor of and reasonably acceptable to Seller within ten (10) days of Seller's request if the rating of both Moody's and Standard & Poor's of UCU (or its successor or replacement entity pursuant to the operation of Section 12.4) the co−obligor under this Agreement, falls below Investment Grade. Such letter of credit shall be in an amount equal the next six (6) months Capacity Charges if such rating is one Rating Category below Investment Grade, or twelve (12) months Capacity Charges if such rating is two or more Rating Categories below Investment Grade, upon which Seller may draw any amounts due from Buyer hereunder and not timely paid. Any six month Capacity Charge letter of credit shall have a term of not less than 180 days. Any twelve month Capacity Charge letter of credit shall have a term of not less than 364 days. If such letter of credit is not renewed at least thirty (30) days prior to expiration, Seller may draw the full amount of such letter of credit and hold such amounts to offset against liability (including future liability) of Buyer under this Agreement. If one or both rating agencies restores UCU's (or its successor or replacement entity pursuant to the operation of Section 12.4) long term debt rating to Investment Grade, than Buyer may request that Seller surrender the letter of credit to Buyer, and Seller will do so within three Business Days of such request.

19. *Force Majeure*

19.1 *Definition.* For the purposes of this Agreement, "Force Majeure Event" means an event, condition or circumstance beyond the reasonable control of and without the fault or negligence of the Party affected (the "Affected Party") which, despite all reasonable efforts of the Affected Party to prevent it or mitigate its effects, prevents the performance by such Affected Party of its obligations hereunder. Subject to the foregoing, "Force Majeure Event" as to either Party, shall include:

19.1.1 explosion and fire (in either case to the extent not attributable to the fault or the negligence of the Affected Party);

19.1.2 lightning, flood, earthquake, landslide, tornado, unusually severe storms, or other natural calamity or act of God;

19.1.3 strike or other labor dispute other than any labor dispute or strike by Seller's employees or the employees of any contractor or subcontractor employed at or performing work with respect to the Facility (except to the extent arising out of a strike or labor action by employees or labor organization members not employed at or performing work with respect to the Facility);

19.1.4 war, insurrection, civil disturbance, sabotage or riot;

19.1.5 failure to obtain Governmental Approvals as a result of a Change in Law;

19.1.6 Changes in Law materially adversely affecting operation of the Facility;

19.1.7 lack of fuel caused by a Force Majeure Event (as defined in this Agreement) experienced by the Facility's fuel supplier or transporter (as if for purposes of this Section 19.1.7 such fuel supplier or transporter is the Affected Party) or curtailment of firm gas transportation service to the Facility pursuant governmental order that materially affects the delivery of gas to the Facility;

19.1.8 the failure of performance by any third party having an agreement with Seller, including, without limitation, any vendor, supplier, or customer of Seller that is excused by reason of force majeure (or comparable term), as defined in Seller's agreement with such third party but only if such event would also constitute Force Majeure as defined in this Agreement; and

19.1.9 mechanical equipment breakdown caused by a Force Majeure Event described in Section 19.1.1, 19.1.2, or 19.1.4, and

19.1.10 interruption of acceptance by the Interconnected Utility of delivery of Electric Energy from the Facility into the Interconnected Utility System.

19.2 *Obligations Under Force Majeure.*

19.2.1 If either Party is rendered unable, wholly or in part, by a Force Majeure Event, to carry out some or all of its obligations under this Agreement (other than obligations to pay money) despite all reasonable efforts of such Party to prevent or mitigate its effects, then, during the continuance of such inability, the obligation of such Party to perform the obligations so affected shall be suspended, except as provided in this Section 19. If Seller is the Affected Party, the Target COD shall be extended day for day for the duration of the effects of a Force Majeure Event.

19.2.2 A Party relying on a Force Majeure Event shall give written notice of such Force Majeure Event to the other Party as soon as practicable after such event occurs, which notice shall include information with respect to the nature, cause and date of commencement of the occurrence(s), and the anticipated scope and duration of the delay. Upon the conclusion of the Force Majeure Event, the Party heretofore relying on such Force Majeure Event shall, with all reasonable dispatch, take all steps reasonably necessary to resume the obligation(s) previously suspended.

19.2.3 Notwithstanding the foregoing, a Party shall not be excused under this Section 19, (x) for any non−performance of its obligations under this Agreement having a greater scope or longer period than is justified by the Force Majeure Event, (y) for the performance of obligations that arose prior to the Force Majeure Event, or (z) to the extent absent the Force Majeure Event the Affected Party would nonetheless have been unable to perform its obligations under this Agreement.

19.3 *Force Majeure Not Forced Outage.* Any periods of Forced Outage or Forced Derating caused by Force Majeure Events shall not be included as Forced Outage Hours, or Forced Derating Hours for purposes of calculation of the Availability Adjustment.

19.4 *No Economic Force Majeure.* Force Majeure Events do not include changes in market conditions.

19.5 *Continued Payment Obligation.* Buyer shall have no obligation to pay the monthly Capacity Charge during a Force Majeure period when the Seller is the Affected Party except:

19.5.1 *Prior to Commercial Operations Date.* Buyer shall have no obligation to pay Capacity Charges during a Force Majeure Period unless, and to the extent Seller delivers or causes to be delivered Replacement Power or Substitute Power. However, Seller's provision of Replacement Power, causing Substitute Power to be delivered, or payment of a Delay or Outage Book Out Charge shall not constitute, in any manner, a waiver of a Force Majeure Event.

19.5.2 *After the Commercial Operations Date.* After the Commercial Operations Date, Buyer shall have no obligation to pay Capacity Charges during any Force Majeure Period where Seller is the Affected Party, except that Buyer shall continue to pay for 50% of the Capacity Charges for up to the first 15 days of any Force Majeure Event as if the Unit(s) were meeting the Guaranteed Availability during such period. Beginning on the sixteenth (16/th/) day Buyer shall have no obligation to pay Capacity Charges unless and to the extent (a) Seller provides Replacement Power or causes to be delivered Substitute Power, or (b) the Facility is Available for Dispatch by Buyer.

19.5.3 *Proration of Effect of Force Majeure Affecting Elwood Station and Expansions Thereto.* If a Force Majeure Event affects both the Units and other units at the Elwood Station (including expansions thereof), Seller shall equitably allocate the burdens of the effects of such Force Majeure Event over all affected units (for example, if a gas curtailment affecting Units 1−6 constitutes a Force Majeure, the gas available shall be ratably allocated over such six units to the extent feasible).

19.6 *Extended Force Majeure Event After Commercial Operations.* If an Affected Party reasonably believes that a Force Majeure Event that is preventing it from performing its obligations hereunder could result in a suspension of such performance for a period of one (1) month or longer, the Affected Party shall submit a plan to the other Party to overcome the Force Majeure Event. Such plan shall be submitted within thirty (30) Business Days of the start of the Force Majeure Event. The plan shall set forth a course of repairs, improvements, changes to operations or other actions which could reasonably be expected to permit the Affected Party to resume performance its obligations under this Agreement within a reasonable time frame projected in the plan. While such a plan is in effect, the Affected Party shall provide weekly status reports to the other Party notifying the other Party of the steps which have been taken to remedy the Force Majeure Event and the expected remaining duration of the Party's inability to perform its obligations. If the Force Majeure Event has not been overcome within five (5) months from its inception, the Parties shall meet to reassess the amount of time that is likely to pass before the Affected Party can reasonably be expected to resume performance under this Agreement, and Seller shall have thirty (30) days to establish a revised plan to overcome the Force Majeure Event within twelve (12) months of its beginning. If at the end of such thirty (30) days one or both of the Parties reasonably concludes that the Force Majeure Event cannot be reasonably be expected to be overcome within twelve months of the beginning of the Force Majeure Event, the Party that is not the Affected Party may terminate this Agreement with five (5) days notice to the Affected Party. If the Affected Party is Seller and the Force Majeure Event only materially impacts the operation of one Unit, then any termination by Buyer will be as to the impacted Unit only. Notwithstanding Buyer's election not to terminate this Agreement, Buyer shall nonetheless have the right to terminate this Agreement, if Seller has failed to remedy the effects of the Force Majeure Event within twelve months of its inception such that the Facility is capable of delivering the Net Dependable Capacity and meeting other performance criteria hereunder. Upon termination of this Agreement as provided in this Section 19.6, the Parties shall have no further liability or obligation to each other except for any obligation arising prior to the date of such termination and those that survive termination as listed in Section 2.2. In addition to the foregoing, the Party not prevented from performing its obligations due to the Force Majeure Event may terminate this Agreement upon ten (10) Days prior written notice if (a) the Affected Party fails to provide a Force Majeure remedy plan as provided for in this Section 19.6, (b) the Affected Party fails to carry out the Force Majeure remedy plans in a method reasonably designed to cause that Party to be able to perform it obligations hereunder within twelve (12) months of the Force Majeure Event occurring, or (c) within five (5) Business Days after a request therefor fails to provide a weekly status report to the other Party.

20. *Interconnection and Transmission*

20.1 *Facilities.* Seller shall own, operate, maintain and control during the Term at its sole cost and expense all interconnection facilities located on the Facility site up to, but not including, the Point of Delivery. Seller shall pay all costs associated with interconnecting the Facility to the Interconnected Utility System, including any facilities upgrades required by ComEd.

20.2 *Transmission.* Buyer shall be responsible for arranging and paying for transmission services from the Point of Delivery, including any applicable transmission costs, system charges or line/system losses from the Point of Delivery, except to the extent of Incremental Transmissions Costs for Replacement Power. Buyer shall also be responsible for obtaining and paying for any ancillary or control area services required by FERC, ComEd or any independent system operator or other transmission utility with respect to the delivery and transmission of ComEd past the Point of Delivery.

21. *Taxes*

21.1 *Applicable Taxes.* Each Party shall be responsible for the payment of all taxes imposed on its income or net worth. Except as provided in this Section 21, Seller shall be responsible for the payment of all present or future federal, state, municipal or other lawful taxes applicable by reason of the operation of the Facility or assessable on Seller's property or operations including taxes on (i) the purchase by Seller or delivery of fuel to the Facility, and (ii) production of electricity. Buyer shall pay all existing and any new sales, use, excise, and any other similar taxes, if any, imposed or levied by a governmental agency on the sale or use of or payments for the Electric Energy, Replacement Power, Substitute Power and Net Dependable Capacity sold and delivered under this Agreement arising at or after the Point of Delivery.

Buyer shall indemnify, defend, and hold Seller harmless from any liability for all such taxes for which Buyer is responsible. Seller shall indemnify, defend, and hold Buyer harmless from any liability from all such taxes for which Seller is responsible. Buyer shall reimburse Seller promptly on demand for the amount of any such tax that is Buyer's responsibility hereunder that Seller remits, plus any penalties and interest incurred and remitted, except such penalties as result from Seller's conduct. Seller shall reimburse Buyer promptly on demand for the amount of any such tax that is Seller's responsibility hereunder that Buyer remits, plus any penalties, interest incurred and remitted, except penalties as result from Buyer's conduct.

21.2 *Contested Taxes.* Neither Party shall be required to pay any such tax, assessment, charge, levy, account payable or claim if the validity, applicability or amount thereof is being contested in good faith by appropriate actions or proceedings (including posting security as may be required) which will prevent the forfeiture or sale of any property utilized under this Agreement or any material interference with the use thereof.

21.3 *Other Charges.* Seller and Buyer will pay and discharge all lawful assessments and governmental charges or levies imposed upon it or in respect to all or any part of its property or business, all trade accounts payable in accordance with usual and customary business terms, and all claims for work, labor, or materials which, if unpaid might become a lien or charge upon any of its property.

22. *Miscellaneous Provisions*

22.1 *Non−Waiver.* The failure of either Party to insist in any one or more instances upon strict performance of any provisions of this Agreement, or to take advantage of any of its rights hereunder, shall not be construed as a waiver of any such provisions or the relinquishment of any such right or any other right hereunder, which shall remain in full force and effect.

22.2 *Relationship of Parties.* This Agreement shall not be interpreted or construed to create an association, joint venture, or partnership between the Parties or to impose any partnership obligation or liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or to act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

22.3 *Successors and Assigns.* This Agreement shall inure to the benefit of and be binding upon the successors and permitted assigns of the Parties.

22.4 *Governing Laws.* This Agreement shall be construed in accordance with and governed by the laws of the State of Illinois without regard to its conflicts of laws provisions.

22.5 *Counterparts.* This Agreement may be executed in more than one counterpart, each of which may be signed by fewer than all Parties, but all of which constitute the same Agreement.

22.6 *Third Party Beneficiaries.* This Agreement is intended solely for the benefit of the Parties hereto. Nothing in this Agreement shall be construed to create a duty to or standard of care with reference to, or any liability to, any Person not a Party to this Agreement.

22.7 *Financial Information.* After Seller closes on any third party financing, then from the date of such financing, for information purposes only, Seller shall, on a quarterly basis, provide to Buyer a statement of its debt coverage ratio if it is below 1.5. If Seller's debt coverage ratio is 1.5 or greater, Seller shall only inform Buyer that its debt cover ratio is 1.5 or greater without further information. Buyer agrees to treat such information as confidential pursuant to Section 17. In no event shall Buyer alter its performance under this Agreement in any manner based upon such information. Under no circumstances shall Seller have any liability to Buyer whatsoever as a result of actions taken by Buyer in reliance upon such information and Buyer hereby releases Seller for any liability whatsoever resulting therefrom.

23. *Appointment of Aquila As UCU's Agent*

23.1 *Appointment.* UCU hereby appoints Aquila as its true and lawful agent and attorney−in−fact, with full power and this Agreement, including without limitation, any notices, consents, elections, waivers, correspondence, agreements, instruments or claims which Aquila deems appropriate; provided, however, that Aquila may not agree to amend this Agreement on behalf of UCU. UCU may terminate this appointment upon written notice to Seller.

23.2 *Presumption of Authority.* Seller may conclusively presume and rely upon the fact that to the extent specified in Section 23.1, any instrument executed by Aquila acting as Buyer or agent or attorney−in−fact for UCU in authorized, regular, and binding upon UCU, without further need for inquiry.

24. *Entire Agreement and Amendments*

This Agreement supersedes all previous representations, understandings, negotiations and agreements either written or oral between the Parties hereto or their representatives with respect to the subject matter hereof and constitutes the entire agreement of the Parties with respect to the subject matter hereof. No amendments or changes to this Agreement shall be binding unless made in writing and duly executed by both Parties.

IN WITNESS WHEREOF, the Parties hereto have executed this Agreement as of the date set forth at the beginning of this Agreement.

Buyer: Aquila Energy Marketing Corporation

By /s/ VJ HORGAN

Name: VJ Horgan
Title: Senior VP

Buyer: UtiliCorp United Inc.

By /s/ KEITH STAMM

Name: Keith Stamm
Title: Senior VP

Seller: Elwood Energy III, LLC

By /s/ RONALD D. USHER

Name: Ronald D. Usher
Title: General Manager

APPENDIX A
FACILITY DESIGN LIMITS
AND OTHER DISPATCH RESTRICTIONS

(1)

The Design Limits for the Facility shall be the following:

(a)

The Maximum Load for a Facility shall be equal to the Net Dependable Capacity pursuant to OEM warranties, recommendations, and ambient conditions and the Governmental Approvals relating to the Facility;

(b)

The Minimum Load for a Unit shall be equal to sixty percent (60%) of Net Dependable Capacity (but no less than ninety (90) MW) which shall adjust with ambient conditions in accordance with actual capability of the Units as provided in Appendix F.

(c)

The minimum time required to Start−Up any one Unit (including the Elwood II Units) is twenty−two (22) minutes. The minimum time required to Start−Up multiple units under simultaneous Dispatch for two or three units is thirty−seven (37) minutes; provided however that the commencement of the Start−Up of second and the third Unit shall follow the commencement of Start−Up of the first Units by fifteen (15) minutes. The minimum time required to Start−Up four units under simultaneous Dispatch is fifty−two (52) minutes, provided however that the commencement of the Start−Up of the fourth Unit shall follow the commencement Start−Up of the second Unit by fifteen (15) minutes.

(d)

The ramp rate (load increase rate) from synchronization to Minimum Load is twelve and one−half (12.5) MW per minute per Unit. Minimum time for the load increase from synchronization to Minimum Load is seven (7) minutes.

(e)

The ramp rate (load increase rate) from Minimum Load to Maximum Load is thirteen (13) MW per minute per Unit. Minimum time for the load increase from Minimum Load to Maximum Load is four and six−tenths (4.6) minutes.

(f)

The ramp down rate (load decrease rate) from all load levels is fifteen (11.5) MW per minute per Unit.

(g)

The power factor of Electric Energy from a Unit as measured at the Unit's Revenue Meter shall be in the range from 0.90 lagging to 0.95 leading.

(2)

Dispatch and Start Procedure

(a)

Upon Start Up of Unit(s), Seller will ramp Unit(s) to Minimum Load according to the Design Limits above, and thereafter adjust the load between Minimum Load and Maximum Load of the Unit(s) according with the Dispatch Notification and in compliance with the Design Limits above.

(b)

There shall be a minimum run time per Unit of four (4) consecutive hours; *provided, however*, Buyer shall have the option to Dispatch each Unit for a minimum run time of two (2) consecutive hours up to ten (10) times each Contract Year subject to Prudent Industry Practice and within manufacturer's recommendations.

(c)

There shall be a minimum idle time of two (2) hours between the time a Unit is taken off−line until the initiation of the next Start Up Sequence for that Unit.

(d)

Seller shall have the flexibility to Start Up the Units (along with the Elwood II Units) in a manner that meets Buyer's Dispatch schedule with the least number of Units, consistent with Design Limits and Prudent Industry Practice.

(3)

Generation During Start Up

(a)

During Start Up of one or more Units and while making load changes in response to Dispatch Requests, Seller shall use Prudent Industry Practices and commercially reasonable efforts to conform the Start Up and operation of the Unit(s) to the Dispatch Request and to minimize the amount of inadvertent Electric Energy generated prior to the Requested Load Delivery Time.

(b)

Prior to the Requested Load Delivery Time, during the Start Up of one Unit, Seller expects to deliver no more than 26 MWh.

(c)

Prior to the Dispatch Load Delivery Time, during the Start Up of two Units, Seller expects to deliver no more than 70 MWh.

(d)

Prior to the Dispatch Load Delivery Time, during the Start Up of three Units, Seller expects to deliver no more than 114 MWh.

(e)

Prior to the Dispatch Load Delivery Time, during the Start Up of four Units, (a 1Unit then 2 Units then 1 Unit Start Up), Seller expects to deliver no more than 178 MWh.

(f)

Seller expects to deliver no more than 18 MWh per unit during ramp down to off line.

(g)

If more MWh are delivered during the Start Up(s) than stated in sections (3)(a) to (3)(f) above, Buyer will market such MWh, and Seller will reimburse Buyer if Buyer's resale price is less than the Facility Electric Energy Rate at such time.

(4)

Permitted Runtime Hours

(a)

A maximum permitted runtime per Unit of 2500 hours per Contract Year, except in the first Contract Year, 90% of the maximum permitted runtime and in the final Contract Year, 92% of the maximum permitted runtime.

(b)

To the extent that permitted runtime hours are less than 2500 hours per Contract Year, Seller shall be obligated to deliver Replacement Power or comparable consideration between the permitted runtime hours and 2500 hours per Contract Year.

APPENDIX B

HEAT RATE and CAPACITY TEST PROCEDURE
Elwood Units 5 −8

1.
Introduction

This document describes the procedure for determining the Net Dependable Capacities and corrected Net Heat Rates of Elwood Units 5−8. The Net Dependable Capacities determined by this procedure will serve as the baseline establishing the Capacity Payments and the amount of any future Forced Derating a given Unit may experience. The corrected Net Heat Rates determined by this procedure will be used to evaluate the thermal performance of each unit against the expected degradation in thermal performance as predicted by GE Curve 519HA772, "Expected Gas Turbine Plant Performance Loss Following Normal Maintenance and Off−Line Compressor Wash."

The introduction should clarify that there are essentially two performance test procedures considered in this Appendix B. The first will be conducted by the EPC Contractor on or about the Commercial Operations and that the results of that performance testing will serve both to qualify the EPC Contractor's performance commitment to the Seller, and those results will apply in the determination of the Net Dependable Capacity and Initial Net Heat Rate under this Agreement. Thereafter periodic tests will be conducted by the Seller for the purpose of determining ongoing performance of the Units and/or the Facility. The following period tests conducted by the Seller shall be accomplished utilizing permanent meters and instruments installed at the Facility for data acquisition, but otherwise conducted with the intent of yielding results that will be comparable with the first testing series.

There will be a series of pre−test activities to verify that the gas turbine generator being tested is operating properly at full capability and is adequately prepared for the capacity test. The Unit will be operated at 100% capability in the normal (not overfiring) operating mode with evaporative coolers in service.

The evaluation methodologies utilize correction factors to correct the measured Unit capacity and Heat Rate to the Reference Conditions. Thermal performance and capacity will be further adjusted for degradation according to the accumulated fired hours at the time of the test. These correction factors are determined from curves supplied by the turbine OEM.

2.
References

A.
Power Sales Agreement between Seller and Buyer relating to Units 5−8.

B.
ASME Performance Test Procedures For General Electric Heavy Duty Gas Turbines, GEI−41067D.

C.
Correction Curve set supplied by GE as part of output and thermal performance guarantees and GE Degradation Curve.

D.
ASME PTC−22 (1997) Gas Turbine Performance Test Code

3.
Measurement and Instrumentation

The test set−up consists of the gas turbine generator unit, selected station instruments, precision psychrometer, and weather instruments installed at the Facility.

The ambient air humidity will be measured near the inlet air filter on each Unit using a precision psychrometer.

The ambient temperature will be measured near the inlet air filter on each Unit using a precision thermometer.

The barometric pressure will be determined by averaging the barometric pressure readings from transmitters installed on each Unit.

The gross power output will be measured utilizing the General Electric Mark V control system.

The generator net power output will be measured with the installed Transdata watt−hour meter (Revenue Meter). The measurement will be made by repeatedly timing a fixed increment of elapsed Watt−hours.

The test point duration will be determined by stopwatch.

The gaseous fuel flow rate will be measured with the orifice metering section supplied with the gas turbine and its associated pressure and temperature instrumentation.

4.

Pre−Test Preparation

4.1 The gas turbine compressor section will be cleaned as described in the GE Turbine Generator Manual immediately prior to testing. The compressor inlet plenum will be inspected before and after the Compressor Wash. If the compressor is judged to be dirty after the initial wash, additional Compressor Wash may be required.

4.2 The gas turbine exhaust thermocouple signal processing system will be confirmed to be operating to control specification. A thermocouple/calibrator will be used to input a 1000EF signal to the unit control system at the terminal strips where the unit thermocouple leads first terminate. At least three thermocouple wire sets for each control system computer will be checked (R, S, and T) for a total of at least nine wire sets. If proper operation cannot be confirmed, the control system must be corrected before testing. This calibration check will be conducted no more than sixty (60) days prior to the test and the calibration data sheets made part of the test record.

4.3 The calibration and proper operation of all pertinent pressure transmitters will be verified not more than sixty (60) days prior to the conduct of the test. Copies of the calibration data sheets shall be made a part of each test record. At a minimum, the following transmitters shall be checked:

- Gas fuel static pressure transmitter(s)
- Gas fuel orifice differential pressure transmitter(s)
- Barometric pressure transmitter(s)

During verification, pressure will be supplied to each transmitter with an NIST traceable device. The input pressure levels shall cover an appropriate estimated range of normal operation. If proper operation cannot be confirmed, the transmitter in question must be re−calibrated before testing.

4.4 The Revenue Meter calibration must have been completed within the interval specified in Section 5.1 of the Agreement and best reasonable efforts shall be used to schedule the Revenue Meter calibration within the sixty (60) day period prior to the test.

4.5 Inlet Guide Vane (IGV) angular position will be measured with a machinist's protractor. The angle will be measured on sixteen vanes around the inlet circumference. The average of these measurements will define the true position of the IGV's. The true angle will be compared to the feedback angle displayed by the unit control system. The control system angle must be in agreement with the measured angle to within plus or minus 0.5 degrees, or the control system must be re−calibrated.

4.6 A fuel sampling location will be identified as close as possible to the gas turbine and upstream of the metering station.

5.

Conducting the Test

Capacity and thermal performance testing will be conducted by Seller and witnessed by Buyer at its discretion.

5.1 A minimum of three test points will be conducted on each unit. Each test point will be conducted with the gas turbine power equipment and all test instrumentation functioning satisfactorily and in a steady−state condition with evaporative coolers in service and with the Mark V control system indicating that the unit is at base load. Prior to and during each test point, the gas turbine wheel space temperatures will be monitored individually to verify thermal stability. The gas turbine will be considered in a steady state condition when each turbine wheel space temperature changes by no more than 5EF over a fifteen minute period. The unit thermal stability will be documented by print−outs from the unit control system.

5.2 In accordance with ASME PTC−22 (1997), additional parameters will be monitored during each test point to verify that the system is in a steady state condition. These parameters and corresponding limits of variation are listed in the following table:

Table: Steady−State Conditions Summary

Parameter	**Monitored**	**Variation Limit**	**Rule**
Turbine Wheelspace Temperature (each) period	Prior to and during test point	n/a	May not change more than 5EF over any 15 minute
Ambient Temperature	During test point	± 4/o/F	Variation from test point average may not exceed limit
Wet Bulb Temperature	During test point	± 3/o/F	Variation from test point average may not exceed limit
Gross Power Output	During test point	± 2.0%	Variation from test point average may not exceed limit
Barometric Pressure	During test point	± 0.5%	Variation from test point average may not exceed limit

5.3 In accordance with ASME PTC−22 (1997), each test point will be conducted over a thirty minute time period. Data will be recorded at five minute intervals (or more frequently) throughout the duration of the test point for a minimum of seven complete sets of instrument readings. No test point should exceed thirty minutes nor should the data recording interval exceed ten minutes.

5.4 Fuel samples will be taken at the beginning and end of each test point for a total of twelve samples per unit (including duplicates). Fuel samples will be delivered to a reputable third party laboratory for analysis. As a backup, duplicate fuel samples will be retained at the site until all fuel analysis is completed.

5.5 Testing shall be conducted with the inlet bleed heat system off and isolated.

6.

Evaluation

6.0

Test Boundary

This test procedure and the calculations employed are intended to determine the Net Dependable Capacity and Net Heat Rate as shown on the Heat Rate Boundary Diagram.

6.1 *Net Dependable Capacity Evaluation*

Generator Net Power Output

Generator Net Power Output (GNPO) will be calculated from the measured net power output from the test point divided by the test point duration in hours.

GNPO = measured net power output (kWh) / test point duration (hrs.)

Net Dependable Capacity

Generator Net Power Output (GNPO) will be corrected from the test conditions to the Reference Conditions. The result will be the Net Dependable Capacity (NDC).

NDC = Net Dependable Capacity corrected to Reference Conditions.

NDC = GNPO x CF\\1\\ x CF\\2\\ x CF\\3\\

where:

CF\\1\\ = Factor used to correct power from the measured ambient temperature and humidity to the contract conditions

= CF\\a\\ / CF\\b\\

where:

CF\\a\\ = Ambient temperature and humidity correction factor from GE Curve [insert curve number when received from GE] at the Reference Conditions

CF\\b\\ = Ambient temperature and humidity correction factor from GE Curve [insert curve number when received from GE] at the measured ambient temperature and humidity

CF\\2\\ = Factor used to correct power from the measured barometric pressure to the rated barometric pressure

= P\\R\\ / P\\M\\

where:

P\\R\\ = Rated barometric pressure (14.39 psia)
P\\M \\= Measured barometric pressure

CF\\3\\ = Factor used to correct for accumulated fired hours prior to the test

= 1 + (% output loss from curve 519HA772)

The NDC's determined from each test point will be summed and divided by the number of test points to determine the NDC for contract purposes.

6.2

Net Heat Rate

Net Heat Rate will be calculated from the measured rate of heat consumption and the measured net power output.

NHR = Net Heat Rate, Btu/kWh (uncorrected)

NHR = HC / GNPO, Btu/kWh

where:

HC = Heat consumption rate, BTU/hr

GNPO = Generator net power output from paragraph 6.1, kW

6.3
Heat Consumption Rate

Turbine rate of heat consumption will be calculated from the measured fuel flow rate (from turbine control system and compensated for fuel temperature) and the fuel higher heating value as determined from the average of laboratory analysis of the fuel samples.

HC = Turbine heat consumption rate, Btu/hr

HC = 3600 x W_F x HHV, Btu/hr

where:

3600 = units conversion, 3600 sec/hr
W_F = Fuel flow rate, lb/s (measured by turbine control system and compensated for fuel temperature)
HHV = Fuel higher heating value, Btu/lb

6.4
Corrected Net Heat Rate

Net Heat Rate will be corrected from test conditions to the Reference Conditions accounting for degradation in accordance with Section 1 of this procedure.

CNHR = Corrected Net Heat Rate, Btu/kWh

CNHR = NHR x $CF1_{HR}$ x $CF2_{HR}$

where:

NHR = Net Heat Rate from Section 6.2, Btu/kWh

$CF1_{HR}$ = Correction factor to correct heat rate from the measured ambient temperature and humidity to the Reference Conditions

= $CF1_{HR(a)}$ / $CF1_{HR(b)}$

where:

$CF1_{HR(a)}$ = Ambient temperature and humidity correction factor from GE Curve [insert curve number when received from GE] at the Reference Conditions.

$CF1_{HR(b)}$ = Ambient temperature and humidity correction factor from GE Curve [insert curve number when received from GE] at the measured ambient temperature and humidity

$CF2_{HR}$ = Factor to correct heat rate for the total fired hours accumulated prior to the test. Factor derived from GE Curve 519HA772 at the accumulated fired hours

= 1− (% heat rate degradation from curve 519HA772)

APPENDIX C

COMMUNICATIONS

1. Purpose

The purpose of this Appendix is:

(i) To describe the nature of, and the requirements for the communication link that will be maintained between Seller and Buyer;

(ii) To identify and establish a communications procedure (the "Communications Procedure") that defines the responsibilities for, and the frequency, content, and logistics of communication between personnel responsible for operating the Facility ("Seller's Operator(s)") and Dispatcher concerning the availability and Dispatch of the Units. The Parties desire that such a procedure be established so that only responsible and authorized personnel can issue requests and/or orders that may impact reliability and availability of the Units.

2. Communication Link.

(i) Buyer shall establish and maintain dedicated phone lines for all communications concerning the availability and Dispatch of the Units. These dedicated systems shall be used as the primary communications link between Seller's Operators and Buyer's Dispatcher responsible for Dispatching Buyer's system ("Generation Dispatcher"). In addition to the dedicated phone lines, Seller and Buyer shall establish standard phone line(s) as a back−up system. Seller's dedicated and standard phone lines are to be located at the control facilities of the Units.

(ii) At any time a Unit at the Facility is synchronized to the Interconnected Utility System, Seller must ensure that a Seller's Operator is available at the dedicated phone line (or back−up phone line if the dedicated line is unavailable) to respond to the Dispatch orders from the Generation Dispatcher. Both Seller and Buyer recognize that there may be operational conditions or events that will required Seller's Operator to leave the control room in order to resolve the condition or event. Both Seller and Buyer also recognize that these conditions or events will be infrequent. During such times, Seller's Operator must first notify the Generation Dispatcher, and provide information regarding how the Seller's Operator can be reached (i.e. a standard, back−up phone line and/or a cellular phone).

(iii) Seller shall establish and maintain a paging system for the Seller's Operators. Such paging system shall constitute the secondary communications link between Seller's Operators and the Generation Dispatcher. During those times when no Unit at the Facility is synchronized to the Interconnected Utility, or during power operation when Seller's Operator has left the control room to resolve an operational condition or event, this paging system will become the primary communications link between Seller's Operator and the Generation Dispatcher. Whenever the paging system is the primary communications link, Seller will ensure at least one Seller's Operator will be available at all times, via the paging system. Should the Dispatcher initiate the paging system, Seller's Operator(s) shall immediately contact the Generation Dispatcher via telephone for specific Dispatch orders. Seller will notify Buyer as soon as possible of any disruption or unavailability of the dedicated or standard phone lines, or the pager system, as soon as practicable. Seller shall also provide a list of back−up contracts to the paging system (i.e. the names and home phone numbers for the operators) to be used should the paging system fail, be inadvertently turned off, lost, unavailable due to satellite communication problems, or if the operator fails to respond. This list of back−up contacts shall be incorporated into the Communications Procedure.

3. Communications Procedure

(i) Prior to the Commercial Operations Date, Seller and Buyer shall establish a mutually approved Communication Procedure that defines the responsibilities for, and the frequency, content, and logistics of, all communications between Seller's Operator(s) and the Generation Dispatcher concerning the availability and dispatch of the Units.

Seller and Buyer shall ensure that the most current mutually−approved revision of this Communication Procedure is available to the Seller's Operator(s) and the Generation Dispatcher. Both Seller and Buyer shall mutually review and revise the communications procedure, as necessary.

(ii) The Communications Procedure shall provide telephone numbers for all dedicated and standard phone lines of both Seller and Buyer (including telephone numbers for facsimile machines) and pager numbers for all of Seller's Operators.

The Communications Procedure shall also provide back−up contacts to the paging system (i.e. the names and home phone numbers for the operators) to be used should the paging system fail, be inadvertently turned off, lost, unavailable due to satellite communication problems, or if the Seller's Operator fails to respond.

In addition, the Communications Procedure shall provide instructions and requirements to both the Seller's Operator(s) and the Generation Dispatcher describing the process(es) for communicating unit availability and Dispatch orders for the Units.

At a minimum, the Communication Procedure shall provide communication instructions for the following items:

a) Routine notifications (by both Seller's Operator(s) and the Generation Dispatcher) of expected hourly capability and demand, as required by Section 4(e)(ii) of this Agreement.

b) Start−up and Dispatch orders for Units;

c) Conditions, issues or events that could affect the output or reliability of the Units;

d) The time of day (based on a twenty−four hour clock) when a Unit is placed on line and taken off line;

e) Unit deratings, including the amount of any derate, the estimated or known start time and date of the derate, the estimated or known ending time and date of the derate, and the cause of the derate;

f) Conditions at the Facility or a Unit that could affect the present or anticipated load following capability of a Unit;

g) Planned and emergency testing requirements, or other operational work that could limit the availability or maneuverability of a Unit; and

h) The use of operational reporting forms that are provided in Appendix D.

4. Revisions

Each Party shall appoint a representative having power and authority to act on its behalf (the "Representative"). Each Party may change its Representative from time−to−time, effective upon notice given to the other Party. A Representative may change addresses, telephone numbers, facsimile numbers and other similar data to be used in directing communications under this Appendix C or Appendix D to the Party represented by that Representative. Each Representative shall be authorized to agree on behalf of the Party that appointed that Representative to any change in the forms or procedures provided under this Appendix C or Appendix D.

APPENDIX D

OPERATIONS REPORTING FORM

DATA APPLICABLE FOR ELWOOD AVAILABILITY DECLARATION

Availability Declaration Period Commencing
PM/AM, / / TO PM/AM, / /

TO: FAX No.
Telephone No.

This FAX is a submission of

Generator's Offer Data

A *revision* to the previously submitted offer of / /

This document is a hardcopy back−up to the offer of / /

Unit	Available to Meet Net Dependable Capacity	☐	Yes	☐	No
Unit	Available to Meet Net Dependable Capacity	☐	Yes	☐	No

Deratings:		Time				Time		
Unit	Cause Code:	MW	Start	Date	/ /	Stop	Date	/ /
Unit	Cause Code:	MW	Start	Date	/ /	Stop	Date	/ /
Minimum:		Time				Time		
Unit	Cause Code:	MW	Start	Date	/ /	Stop	Date	/ /
Unit	Cause Code:	MW	Start	Date	/ /	Stop	Date	/ /

Submitted By:

Date:

If you do not receive all the pages or if clarification or retransmission is required call

Return acknowledgment FAX to the attention of:

FAX Number:

Acknowledgment by (Signature)

(Title)

Acknowledgment date and time

APPENDIX E
EQUIVALENT AVAILABILITY CALCULATIONS ("EA")

Seller shall calculate for each month, an Equivalent Availability ("EA") for calculation of the Availability Adjustment Credit described in Section 7.1.3. The EA will be calculated (a) for the Summer Super Peak Hours; (b) for the Summer Partial−Peak Hours and (c) for the total of all Non−Summer On−Peak Hours in accordance with the following formula:

$$EA = \left\{1 - \frac{[FOH + EFDH]}{PH}\right\}$$

Where:

Equivalent Forced Derated Hours ("EFDH") are the product of Forced Derated Hours (FDH) and Size of Reduction (as defined below), divided by the Net Dependable Capacity (NDC). Equivalent hours are computed for each Forced Derating and then summed for the applicable period.

Forced Derated Hours ("FDH") and Forced Outage Hours ("FOH") are calculated over On Peak Hours, during the applicable period, during which a Unit experiences a Forced Derating or Forced Outage, as applicable. They are calculated monthly in the Summer Period across all Summer Super Peak Hours and Summer Partial Peak Hours and annually for Non−Summer On Peak Hours (as applicable).

Period Hours ("PH") means the total number of Summer Super Peak, Summer Partial Peak or Non−Summer On Peak Hours (as applicable) in each period.

A Forced Outage or Forced Derating event shall only be included in the calculation of the Equivalent Availability when Seller fails to meet, in whole or part, Buyer's Dispatch and fails (a) to deliver or cause to be delivered Replacement Power or Substitute Power, (b) to pay to Buyer Third Party Damages pursuant to Section 4.7.4, or (c) to pay the Outage Book Out Charge due to an unplanned component failure or other condition that requires the load on the Unit or Facility to be reduced below the level Dispatched.

The Size of Reduction for a Forced Derating shall be determined by Seller and shall be based upon observed output of a typical unit having the same equipment problems under similar operating and environmental conditions. Buyer may request Seller to justify the size of the reduction through provision of reasonably available historical operating records in support of Seller's selection of the Size of Reduction.

In the event of a continuing Forced Outage or Forced Derating, Buyer may submit Dispatch requests as if the Unit were available for full operation, provided such requests are submitted in good faith and support Buyer's need to Dispatch a Unit absent the Forced Outage or Forced Derating. If other units at the Elwood Station are operating, Buyer's request shall be deemed to be in good faith. If no other units are running at the Elwood Station, Buyer shall, if requested by Seller, provide written explanation of the reasons that would demonstrate the economic justification for such Dispatch request.

The following shall not be deemed a Forced Outage or Forced Derating for purposes of calculating the Equivalent Availability (a) a Unit is shut down for Scheduled Maintenance Outages or Compressor Washes as provided in Section 6.4 and 6.5 respectively, (b) A Unit is down or derated, but Seller meets Buyer's Dispatch order through (i) Replacement Power, (ii) Substitute Power, (iii) payment of Third Party Damages pursuant to Section 4.7.4, or (iv) payment of an Outage Book Out Charge, (c) a Unit is curtailed, interrupted, reduced or increased by the Interconnected Utility pursuant to Sections 4.8 or 6.6.2, (d) to the extent a Unit is not Available as a result of a Force Majeure Event, or (e) Seller pays imbalance charges to compensate for any under−delivery.

APPENDIX F

Output Adjustment Curve

Degradation Curves

CURVE	NUMBER
GE Expected Degradation	719HA722

Turbine Performance Curves

CURVE	NUMBER
Estimated Single Unit Performance, Base	522HA851
Compressor Inlet Temperature Corrections, Base	522HA852
Modulated Inlet Guide Vanes Effect	522HA853
Altitude Correction for Turbine	416HA622B
Humidity Effects Curve	498HA697B

APPENDIX G

Non Billable Generation

To establish the kilowatt−hours of electricity provided by a Unit and consumed by other units for a billing period, the total for each billing period of electricity consumed by each of units 5, 6, 7 and 8to be determined from the individual unit electric meter readings using the Revenue Meter which will then be summed for all four units. From this sum, the total monthly electricity purchased from the Interconnected Utility (as determined from the Interconnected Utility's revenue meter in the ComEd/Elwood Switchyard) will be subtracted, yielding an aggregate total of the electricity consumed by all four units that had been generated by one or more other units. This amount will then be multiplied by the ratio of the total operating hours of a given unit to the total operating hours of all four units. This product will represent the electricity generated by a given unit and consumed by other units. This value will be subtracted from the reading of the Revenue Meter for a particular Committed Unit for billing purposes for the billing period. The following example demonstrates the calculation methodology:

Total electricity generated Unit 5—30,000 MWh

Total electricity generated Unit 6—22,500 MWh

Total electricity generated Unit 7—15,000 MWh

Total electricity generated Unit 8—0 MWh

Total electricity consumed Unit 5—20,000 kWh

Total electricity consumed Unit 6—30,000 kWh

Total electricity consumed Unit 7—15,000 kWh

Total electricity consumed Unit 8—2,000 kWh

Total electricity consumed All Units = 20,000 + 30,000 + 15,000 + 2,000 = 67,000 kWh

Total electricity purchased from the Interconnected Utility—30,000 kWh

Total electricity consumed by all four units and generated by all four units = 67,000 − 30,000 = 37,000 kWh

Unit 5 monthly operating hours—200

Unit 6 monthly operating hours—150

Unit 7 monthly operating hours—100

Unit 8 monthly operating hours—0

Total operating hours = 200 + 150 + 100 + 0 = 450 hours

CALCULATION:

Electricity furnished by Unit 5 and consumed by the other units = (200/450) (37,000) = 16,444 kWh (16.444 MWh)

Electricity furnished by Unit 6 and consumed by the other units = (150/450) (37,000) = 12,333 kWh (12.333 MWh)

Electricity furnished by Unit 7 and consumed by the other units = (100/450) (37,000) = 8,222 kWh (8.222 MWh)

Electricity furnished by Unit 8 and consumed by the other units = (0/450) (37,000) = 0 kWh

Billable Generation Unit 5 = 30,000 − 16.444 = 29,983 MWh

Billable Generation Unit 6= 22,500 − 12.333 = 22,488 MWh

Billable Generation Unit 7 = 15,000 − 8.222 = 14,992 MWh

Billable Generation Unit 8 = 0−0 = 0 MWh"

APPENDIX H−1

GUARANTY

THIS GUARANTY dated as of , is made by Peoples Energy Corporation, an Illinois corporation ("Guarantor"), in favor of UtiliCorp United Inc. and Aquila Energy Marketing Corporation, Delaware corporations (referring to collectively hereafter as "Creditor").

WHEREAS, Creditor and Elwood Energy, III LLC, a Delaware limited liability company ("Debtor"), have entered into that certain Power Sales Agreement dated , (the "Contract") and capitalized items used and not otherwise defined herein shall have the meanings assigned to them in the Contract;

WHEREAS, Guarantor, through one or more subsidiaries, owns a 50 percent membership interest in Debtor and the remaining 50 percent membership interest is indirectly owned by Dominion Energy, Inc. ("Dominion"); and

WHEREAS, to induce Creditor to extend credit to Debtor pursuant to the Contract, Guarantor has agreed to provide to Creditor this Guaranty;

NOW, THEREFORE, in consideration of the premises, Creditor's execution of the Contract and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, Guarantor hereby agrees as follows:

1. *Guaranty.* Subject to the provisions hereof, Guarantor hereby irrevocably, absolutely and unconditionally guarantees the timely payment of all financial obligations which become due and payable by Debtor to Creditor under or in connection with the Contract (collectively, "Obligations" and individually, an "Obligation") such that, if Debtor fails, neglects or refuses to perform any Obligation, Guarantor shall make such payment within ten business days after Guarantor receives written notice thereof. Notwithstanding the foregoing, as to any Obligation which Guarantor is called upon to pay or cause payment to be made, Guarantor reserves to itself the right to assert any and all defenses under the Contract which Debtor could assert against Creditor with respect to such Obligation; provided, however, that such reservation shall not include any legal or equitable discharge or defense of a guarantor or surety arising out of any of the events described in Section 2 or Section 3 hereof. The guarantee of Guarantor pursuant to this Section 1 is limited to 50 percent of the Obligations ; provided, however, that in no event shall the maximum aggregate liability of Guarantor under this Guaranty exceed $10,000,000 (the "Guaranty Cap Amount") plus any amounts owed for collecting or enforcing this Guaranty pursuant to the next sentence hereof; provided further, that Guarantor's obligations hereunder are separate and independent obligations from those of Dominion under Dominion's Guaranty of even date herewith and neither Guarantor nor Dominion shall be liable for the obligations of the other under their respective guaranties by reason of joint and several liability or otherwise. In addition to Guarantor's liability for the Obligations set forth herein, Guarantor agrees to pay to Creditor such further amounts as shall be sufficient to cover the costs of collecting or enforcing this Guaranty (including reasonable fees, expenses and disbursements of counsel). This Guaranty is a guaranty of payment and not of collection.

2. *Guaranty Absolute.* Except as otherwise expressly provided in Section 3(b) hereof, Creditor may, at any time and from time to time, without the consent of or notice to Guarantor, and without impairing or releasing the obligations of Guarantor hereunder:

(a) change the manner, place or terms of payment of, or (if applicable) interest rate on, or renew, extend or alter, any or all of the Obligations;

(b) amend, waive, terminate or otherwise modify the Contract or any other document, instrument or agreement relating to any Obligation;

(c) release (in whole or in part) or compromise or settle with Debtor or any other person liable in any manner for payment of any or all of the Obligations;

(d) exercise or refrain from exercising any rights against Debtor or any other person or otherwise act or refrain from acting or otherwise fail to be diligent; and

(e) take, substitute, surrender, exchange or release any collateral or other security for any or all of the Obligations.

3. *Effect of Certain Events.* Guarantor agrees that, except as otherwise expressly provided in Section 3(b) hereof, Guarantor's liability hereunder will not be released, reduced or impaired by the occurrence of any of the following events:

(a) the liquidation, dissolution, receivership, insolvency, bankruptcy, assignment for the benefit of creditors, reorganization, arrangement, composition or readjustment or other similar proceeding affecting the status, composition, identity, existence, assets or obligations of Debtor, or the disaffirmance or termination of any of the Obligations or the Contract in or as a result of any such proceeding;

(b) the renewal, consolidation, extension, modification or amendment from time to time of the Contract or any document, instrument or agreement relating to any Obligation, provided, however, that notwithstanding anything contained in this Guaranty or the Contract to the contrary, Creditor and Debtor may not, without the prior written consent of Guarantor, (i) extend or lengthen the Term of the Contract (as defined in the Contract as of the date hereof) beyond or (ii) change, modify or amend the definition of the term "Capacity Charges" (as defined in the Contract as of the date hereof) in any manner that would increase Guarantor's liability under this Guaranty;

(c) the failure, delay, waiver or refusal by Creditor to exercise, in whole or in part, any right or remedy held by Creditor with respect to the Contract or the Obligations thereunder; or

(d) the sale, encumbrance, transfer or other modification of the ownership of Debtor or Creditor or any change in the name, identity, business, structure, composition, financial condition or management (including, without limitation, by reason of a merger, dissolution, consolidation or reorganization) of Debtor or Creditor;

(e) future changes in conditions, including change of law, or any invalidity, unenforceability or irregularity with respect to the execution and delivery of the Contract or this Guaranty; and

(f) any other circumstance which might otherwise constitute a legal or equitable discharge or defense of a guarantor or surety, subject to clause (ii) of Section 1 hereof.

4. *Waivers.* Except as expressly provided in Section 1 hereof, Guarantor waives:

(a) notice of acceptance of this Guaranty, of the creation or existence of the Contract or any Obligation thereunder, and of any action by Creditor in reliance hereon or in connection herewith;

(b) promptness, diligence, presentment, demand for payment, notice of dishonor or nonpayment, protest and notice of protest with respect to any Obligation;

(c) any requirement that suit be brought against, or any other action by Creditor be taken against, Debtor or any other person as a condition to Guarantor's obligations under this Guaranty or as a condition to enforcement of this Guaranty against Guarantor.

(d) notice of adverse change in the financial condition of Debtor or any other fact which might increase Creditor's risk; and

(e) any other notices or demands to which guarantors or sureties may be entitled.

5. *Continuing Guaranty.* This Guaranty is an absolute and continuing guaranty. This Guaranty shall terminate when all of the Obligations have been indefeasibly paid in full to Creditor. Notwithstanding anything in this Guaranty to the contrary, this Guaranty shall continue to be effective or shall be reinstated, as the case may be, if at any time, either before or after the termination hereof, payment of the Obligations guaranteed pursuant to this Guaranty, or any part thereof, is rescinded or must be returned by Creditor upon the insolvency, bankruptcy or reorganization of Debtor or Guarantor, all as though such payment had not been made.

6. *Representations and Warranties.* Guarantor represents and warrants to Creditor as follows:

(a) Guarantor is a corporation duly organized, validly existing and in good standing under the laws of Illinois and has full corporate power and authority to execute, deliver and perform this Guaranty.

(b) The execution, delivery and performance of this Guaranty by Guarantor have been and remain duly authorized by all necessary corporate action on the part of by Guarantor and do not contravene any provision of law or of Guarantor's certificate of incorporation or bylaws or any contractual restriction binding on Guarantor or any of its assets.

(c) All consents, authorizations and approvals of, and registrations and declarations with, any governmental authority necessary for the due execution, delivery and performance of this Guaranty by Guarantor have been obtained and remain in full force and effect and all conditions thereof have been duly complied with, and no other action by, and no notice to or filing with, any governmental authority is required in connection with the execution, delivery or performance by Guarantor of this Guaranty.

(d) This Guaranty constitutes the legal, valid and binding obligation of Guarantor enforceable against Guarantor in accordance with its terms, subject, as to enforcement, to bankruptcy, insolvency, reorganization and other laws of general applicability relating to or affecting creditors' rights and to general equity principles.

(e) Debtor is indirectly partially owned by Guarantor, and this Guaranty reasonably may be expected to benefit, directly or indirectly, Guarantor.

7. *Covenants.* Guarantor agrees that, so long as this Guaranty remains in effect, Guarantor will promptly furnish to Creditor, upon request at any time and from time to time, a copy of Guarantor's most recent annual report on Form 10−K or quarterly report on Form 10−Q, in each case as filed with the Securities and Exchange Commission (the "SEC"); provided however, if Guarantor is not required to file such reports with the SEC, Guarantor agrees to furnish to Creditor such comparable financial information respecting Guarantor as Creditor may from time to time reasonably request.

8. *Miscellaneous.*

(a) *Notice.* Any notice or other communication given hereunder by either Guarantor or Creditor to the other party ("Notice") shall be in writing and delivered personally, mailed by registered or certified mail, postage prepaid and return receipt requested, by telecopier, or by courier guaranteeing overnight delivery, as follows:

(i) if to Guarantor:

Peoples Energy Corporation
130 East Randolph Drive
Chicago, Illinois
Attention: William W. Reynolds, Treasurer
Telecopy No.: (312) 240−4348

(ii) if to Creditor:

Notice given by personal delivery or mail shall be effective upon actual receipt or refusal of receipt. Notice given by telecopier shall be deemed effective upon transmission and electronic confirmation by the transmitting telecopier. All Notices by telecopier shall be confirmed promptly after transmission in writing by certified mail or personal delivery. Any party may change any address to which Notice is to be given to it by giving Notice as provided above of such change of address. All amounts becoming payable by Guarantor to Creditor under this Guaranty shall be payable at Creditor's offices located at its address for purposes of Notice, or such other place as Creditor may from time to time designate (including wire transfer instructions).

(b) *Amendments; Waivers; Remedies.* All amendments, waivers, consents or approvals arising pursuant to this Guaranty must be in writing signed by Guarantor and Creditor. No failure on the part of Creditor to exercise, and no delay in exercising, and no course of dealing with respect to, any right, power or privilege hereunder shall operate as a waiver thereof; nor shall any single or partial exercise thereof or the exercise of any other right, power or privilege operate as such a waiver. No right, power or remedy of Creditor under this Guaranty or the Contract shall be exclusive of any other right, power or remedy, but shall be cumulative and in addition to any other right, power or remedy thereunder or now or hereafter existing by law or in equity.

(c) *Severability.* If any provision of this Guaranty or the application thereof to any party or circumstance shall be invalid or unenforceable, then the remaining provisions or the application of such provision to parties or circumstances other than those as to which it is invalid or unenforceable, shall continue to be valid and enforceable.

(d) *Assignment.* Neither Guarantor nor Creditor may assign its rights or obligations under this Guaranty without the other party's prior written consent, which consent may not be unreasonably withheld; provided, however, Creditor may assign its rights hereunder without consent of Guarantor (but with prior notice thereof to Guarantor) to any party to whom the Contract has been properly assigned in accordance with the terms thereof. Subject to the foregoing, this Guaranty shall be binding on, and shall inure to the benefit of, Guarantor and Creditor and their respective successors and assigns.

(e) *GOVERNING LAW.* THIS GUARANTY SHALL BE GOVERNED BY, AND INTERPRETED IN ACCORDANCE WITH, THE LAWS OF THE STATE OF ILLINOIS, WITHOUT REGARD TO PRINCIPLES OF CONFLICT OF LAWS. GUARANTOR AND CREDITOR EACH HEREBY IRREVOCABLY SUBMITS FOR ITSELF AND IN RESPECT OF ITS PROPERTY TO THE ORIGINAL JURISDICTION OF THE STATE AND FEDERAL COURTS SITTING IN CHICAGO, ILLINOIS WITH REGARD TO ANY SUIT, CLAIM OR ACTION IN ANY WAY RELATED TO THE EXECUTION, DELIVERY OR PERFORMANCE OF THIS GUARANTY, AND GUARANTOR HEREBY IRREVOCABLY WAIVES ANY AND ALL OBJECTIONS TO WHICH IT MAY NOW OR HEREAFTER HAVE TO THE BRINGING OF ANY SUCH SUITS, CLAIMS OR ACTIONS IN SUCH JURISDICTIONS, INCLUDING, WITHOUT LIMITATION, ANY OBJECTION TO THE LAYING OF VENUE OR BASED ON THE GROUNDS OF FORUM NON CONVENIENS. THE PARTIES HERETO FURTHER AGREE THAT ANY AND ALL SUCH SUITS, CLAIMS OR ACTIONS SHALL BE BROUGHT OR FILED EXCLUSIVELY IN SUCH COURTS AND NOWHERE ELSE.

(f) *Headings.* The headings of the sections and subsections of this Guaranty are for convenience only, and shall not limit or otherwise affect the meaning hereof.

(g) *Counterparts.* Guarantor may sign this Guaranty in any number of counterparts, each of which shall be an original but all of which when taken together shall constitute one and the same instrument.

(h) *Construction of Agreement.* Unless the context of this Agreement clearly requires otherwise, (i) pronouns, wherever used herein and of whatever gender, shall include natural persons, corporations, and associations of every kind and character, (ii) the gender of all words used in this Guaranty shall include the masculine, feminine and neuter, (iii) the words "includes" or "including" shall mean "including without limitation", and (iv) the words "hereof", "herein", "hereunder" and similar terms in this Guaranty shall refer to this Guaranty as a whole and not any particular section or subsection in which such words appear.

(i) *Interpretation and Reliance.* No presumption will apply in favor of any party hereto in the interpretation of this Guaranty or in the resolution of any ambiguity of any provision hereof.

IN WITNESS WHEREOF, Guarantor has caused this Guaranty to be executed effective as of the date first above written.

PEOPLES ENERGY CORPORATION

By: ______________________________

Name: ______________________________

Title: ______________________________

APPENDIX H−2

GUARANTY

THIS GUARANTY dated as of , is made by Dominion Energy, Inc., a Virginia corporation ("Guarantor"), in favor of UtiliCorp United Inc. and Aquila Energy Marketing Corporation, Delaware corporations (referred to collectively hereafter as "Creditor").

WHEREAS, Creditor and Elwood Energy III, LLC, a Delaware limited liability company ("Debtor"), have entered into that certain Power Sales Agreement dated , (the "Contract") and capitalized terms used and not otherwise defined herein shall have the meanings assigned to them in the Contract;

WHEREAS, Guarantor, through one or more subsidiaries, owns a 50 percent membership interest in Debtor and the remaining 50 percent membership interest is indirectly owned by Peoples Energy Corporation ("Peoples"); and

WHEREAS, to induce Creditor to extend credit to Debtor pursuant to the Contract, Guarantor has agreed to provide to Creditor this Guaranty;

NOW, THEREFORE, in consideration of the premises, Creditor's execution of the Contract and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, Guarantor hereby agrees as follows:

1. *Guaranty.* Subject to the provisions hereof, Guarantor hereby irrevocably, absolutely and unconditionally guarantees the timely payment of all financial obligations which become due and payable by Debtor to Creditor under or in connection with the Contract (collectively, "Obligations" and individually, an "Obligation") such that, if Debtor fails, neglects or refuses to perform any Obligation, Guarantor shall make such payment within ten business days after Guarantor receives written notice thereof. Notwithstanding the foregoing, as to any Obligation which Guarantor is called upon to pay or cause payment to be made, Guarantor reserves to itself the right to assert any and all defenses under the Contract which Debtor could assert against Creditor with respect to such Obligation; provided, however, that such reservation shall not include any legal or equitable discharge or defense of a guarantor or surety arising out of any of the events described in Section 2 or Section 3 hereof. The guarantee of Guarantor pursuant to this Section 1 is limited to 50 percent of the Obligations; provided, however, that in no event shall the maximum aggregate liability of Guarantor under this Guaranty exceed $10,000,000 (the "Guaranty Cap Amount") plus any amounts owed for collecting or enforcing this Guaranty pursuant to the next sentence hereof; provided further, that Guarantor's obligations hereunder are separate and independent obligations from those of Peoples under Peoples' Guaranty of even date herewith and neither Guarantor nor Peoples shall be liable for the obligations of the other under their respective guaranties by reason of joint and several liability or otherwise. In addition to Guarantor's liability for the Obligations set forth herein, Guarantor agrees to pay to Creditor such further amounts as shall be sufficient to cover the costs of collecting or enforcing this Guaranty (including reasonable fees, expenses and disbursements of counsel). This Guaranty is a guaranty of payment and not of collection.

2. *Guaranty Absolute.* Except as otherwise expressly provided in Section 3(b) hereof, Creditor may, at any time and from time to time, without the consent of or notice to Guarantor, and without impairing or releasing the obligations of Guarantor hereunder:

(a) change the manner, place or terms of payment of, or (if applicable) interest rate on, or renew, extend or alter, any or all of the Obligations;

(b) amend, waive, terminate or otherwise modify the Contract or any other document, instrument or agreement relating to any Obligation;

(c) release (in whole or in part) or compromise or settle with Debtor or any other person liable in any manner for payment of any or all of the Obligations;

(d) exercise or refrain from exercising any rights against Debtor or any other person or otherwise act or refrain from acting or otherwise fail to be diligent; and

(e) take, substitute, surrender, exchange or release any collateral or other security for any or all of the Obligations.

3. *Effect of Certain Events.* Guarantor agrees that, except as otherwise expressly provided in Section 3(b) hereof, Guarantor's liability hereunder will not be released, reduced or impaired by the occurrence of any of the following events:

(a) the liquidation, dissolution, receivership, insolvency, bankruptcy, assignment for the benefit of creditors, reorganization, arrangement, composition or readjustment or other similar proceeding affecting the status, composition, identity, existence, assets or obligations of Debtor, or the disaffirmance or termination of any of the Obligations or the Contract in or as a result of any such proceeding;

(b) the renewal, consolidation, extension, modification or amendment from time to time of the Contract or any document, instrument or agreement relating to any Obligation, provided, however, that notwithstanding anything contained in this Guaranty or the Contract to the contrary, Creditor and Debtor may not, without the prior written consent of Guarantor, (i) extend or lengthen the Term of the Contract (as defined in the Contract as of the date hereof) beyond , or (ii) change, modify or amend the definition of the term "Capacity Charges" (as defined in the Contract as of the date hereof) in any manner that would increase Guarantor's liability under this Guaranty;

(c) the failure, delay, waiver or refusal by Creditor to exercise, in whole or in part, any right or remedy held by Creditor with respect to the Contract or the Obligations thereunder; or

(d) the sale, encumbrance, transfer or other modification of the ownership of Debtor or Creditor or any change in the name, identity, business, structure, composition, financial condition or management (including, without limitation, by reason of a merger, dissolution, consolidation or reorganization) of Debtor or Creditor;

(e) future changes in conditions, including change of law, or any invalidity, unenforceability or irregularity with respect to the execution and delivery of the Contract or this Guaranty; and

(f) any other circumstance which might otherwise constitute a legal or equitable discharge or defense of a guarantor or surety, subject to clause (ii) of Section 1 hereof.

4. *Waivers.* Except as expressly provided in Section 1 hereof, Guarantor waives:

(a) notice of acceptance of this Guaranty, of the creation or existence of the Contract or any Obligation thereunder, and of any action by Creditor in reliance hereon or in connection herewith;

(b) promptness, diligence, presentment, demand for payment, notice of dishonor or nonpayment, protest and notice of protest with respect to any Obligation;

(c) any requirement that suit be brought against, or any other action by Creditor be taken against, Debtor or any other person as a condition to Guarantor's obligations under this Guaranty or as a condition to enforcement of this Guaranty against Guarantor.

(d) notice of adverse change in the financial condition of Debtor or any other fact which might increase Creditor's risk; and

(e) any other notices or demands to which guarantors or sureties may be entitled.

5. *Continuing Guaranty.* This Guaranty is an absolute and continuing guaranty. This Guaranty shall terminate when all of the Obligations have been indefeasibly paid in full to Creditor. Notwithstanding anything in this Guaranty to the contrary, this Guaranty shall continue to be effective or shall be reinstated, as the case may be, if at any time, either before or after the termination hereof, payment of the Obligations guaranteed pursuant to this Guaranty, or any part thereof, is rescinded or must be returned by Creditor upon the insolvency, bankruptcy or reorganization of Debtor or Guarantor, all as though such payment had not been made.

6. *Representations and Warranties.* Guarantor represents and warrants to Creditor as follows:

(a) Guarantor is a corporation duly organized, validly existing and in good standing under the laws of Virginia and has full corporate power and authority to execute, deliver and perform this Guaranty.

(b) The execution, delivery and performance of this Guaranty by Guarantor have been and remain duly authorized by all necessary corporate action on the part of by Guarantor and do not contravene any provision of law or of Guarantor's certificate of incorporation or bylaws or any contractual restriction binding on Guarantor or any of its assets.

(c) All consents, authorizations and approvals of, and registrations and declarations with, any governmental authority necessary for the due execution, delivery and performance of this Guaranty by Guarantor have been obtained and remain in full force and effect and all conditions thereof have been duly complied with, and no other action by, and no notice to or filing with, any governmental authority is required in connection with the execution, delivery or performance by Guarantor of this Guaranty.

(d) This Guaranty constitutes the legal, valid and binding obligation of Guarantor enforceable against Guarantor in accordance with its terms, subject, as to enforcement, to bankruptcy, insolvency, reorganization and other laws of general applicability relating to or affecting creditors' rights and to general equity principles.

(e) Debtor is indirectly partially owned by Guarantor, and this Guaranty reasonably may be expected to benefit, directly or indirectly, Guarantor.

7. *Covenants.* Guarantor agrees that, so long as this Guaranty remains in effect, Guarantor will promptly furnish to Creditor, upon request at any time and from time to time, a copy of Guarantor's most recent annual report on Form 10−K or quarterly report on Form 10−Q, in each case as filed with the Securities and Exchange Commission (the "SEC"); provided however, if Guarantor is not required to file such reports with the SEC, Guarantor agrees to furnish to Creditor such comparable financial information respecting Guarantor as Creditor may from time to time reasonably request.

8. *Miscellaneous.*

(a) *Notice.* Any notice or other communication given hereunder by either Guarantor or Creditor to the other party ("Notice") shall be in writing and delivered personally, mailed by registered or certified mail, postage prepaid and return receipt requested, by telecopier, or by courier guaranteeing overnight delivery, as follows:

(i) if to Guarantor:

Dominion Energy, Inc.
120 Tredegar Street
Richmond, Virginia 23219
Attention: Diane Leopold /
Christine M. Schwab, Esq.
Telecopy No.: (804) 819−2202

(ii)

if to Creditor:

Notice given by personal delivery or mail shall be effective upon actual receipt or refusal of receipt. Notice given by telecopier shall be deemed effective upon transmission and electronic confirmation by the transmitting telecopier. All Notices by telecopier shall be confirmed promptly after transmission in writing by certified mail or personal delivery. Any party may change any address to which Notice is to be given to it by giving Notice as provided above of such change of address. All amounts becoming payable by Guarantor to Creditor under this Guaranty shall be payable at Creditor's offices located at its address for purposes of Notice, or such other place as Creditor may from time to time designate (including wire transfer instructions).

(b) *Amendments; Waivers; Remedies.* All amendments, waivers, consents or approvals arising pursuant to this Guaranty must be in writing signed by Guarantor and Creditor. No failure on the part of Creditor to exercise, and no delay in exercising, and no course of dealing with respect to, any right, power or privilege hereunder shall operate as a waiver thereof; nor shall any single or partial exercise thereof or the exercise of any other right, power or privilege operate as such a waiver. No right, power or remedy of Creditor under this Guaranty or the Contract shall be exclusive of any other right, power or remedy, but shall be cumulative and in addition to any other right, power or remedy thereunder or now or hereafter existing by law or in equity.

(c) *Severability.* If any provision of this Guaranty or the application thereof to any party or circumstance shall be invalid or unenforceable, then the remaining provisions or the application of such provision to parties or circumstances other than those as to which it is invalid or unenforceable, shall continue to be valid and enforceable.

(d) *Assignment.* Neither Guarantor nor Creditor may assign its rights or obligations under this Guaranty without the other party's prior written consent, which consent may not be unreasonably withheld; provided, however, Creditor may assign its rights hereunder without consent of Guarantor (but with prior notice thereof to Guarantor) to any party to whom the Contract has been properly assigned in accordance with the terms thereof. Subject to the foregoing, this Guaranty shall be binding on, and shall inure to the benefit of, Guarantor and Creditor and their respective successors and assigns.

(e) *GOVERNING LAW.* THIS GUARANTY SHALL BE GOVERNED BY, AND INTERPRETED IN ACCORDANCE WITH, THE LAWS OF THE STATE OF ILLINOIS, WITHOUT REGARD TO PRINCIPLES OF CONFLICT OF LAWS. GUARANTOR AND CREDITOR EACH HEREBY IRREVOCABLY SUBMITS FOR ITSELF AND IN RESPECT OF ITS PROPERTY TO THE ORIGINAL JURISDICTION OF THE STATE AND FEDERAL COURTS SITTING IN CHICAGO, ILLINOIS WITH REGARD TO ANY SUIT, CLAIM OR ACTION IN ANY WAY RELATED TO THE EXECUTION, DELIVERY OR PERFORMANCE OF THIS GUARANTY, AND GUARANTOR HEREBY IRREVOCABLY WAIVES ANY AND ALL OBJECTIONS TO WHICH IT MAY NOW OR HEREAFTER HAVE TO THE BRINGING OF ANY SUCH SUITS, CLAIMS OR ACTIONS IN SUCH JURISDICTIONS, INCLUDING, WITHOUT LIMITATION, ANY OBJECTION TO THE LAYING OF VENUE OR BASED ON THE GROUNDS OF FORUM NON CONVENIENS. THE PARTIES HERETO FURTHER AGREE THAT ANY AND ALL SUCH SUITS, CLAIMS OR ACTIONS SHALL BE BROUGHT OR FILED EXCLUSIVELY IN SUCH COURTS AND NOWHERE ELSE.

(f) *Headings.* The headings of the sections and subsections of this Guaranty are for convenience only, and shall not limit or otherwise affect the meaning hereof.

(g) *Counterparts.* Guarantor may sign this Guaranty in any number of counterparts, each of which shall be an original but all of which when taken together shall constitute one and the same instrument.

(h) *Construction of Agreement.* Unless the context of this Agreement clearly requires otherwise, (i) pronouns, wherever used herein and of whatever gender, shall include natural persons, corporations, and associations of every kind and character, (ii) the gender of all words used in this Guaranty shall include the masculine, feminine and neuter, (iii) the words "includes" or "including" shall mean "including without limitation", and (iv) the words "hereof", "herein", "hereunder" and similar terms in this Guaranty shall refer to this Guaranty as a whole and not any particular section or subsection in which such words appear.

(i) *Interpretation and Reliance.* No presumption will apply in favor of any party hereto in the interpretation of this Guaranty or in the resolution of any ambiguity of any provision hereof.

IN WITNESS WHEREOF, Guarantor has caused this Guaranty to be executed effective as of the date first above written.

DOMINION ENERGY, INC.

By: ______________________

Name: ______________________

Title: ______________________

APPENDIX I

Scheduled Maintenance Outages

Type	Scheduled Maintenance	Frequency of Inspection	Duration of Inspection
Major	Combustion Inspection	Every 400 starts or 8,000 equivalent hours	4−5 days
Major	Hot Gas Path Inspection	Every 800 starts or 24,000 equivalent hours	10−12 days
Major	Major CT Overhaul	Every 1,600 starts or 48,000 equivalent hours	20 days
Routine*	BOP Inspections	Each Spring and Fall	4 days

* Note: Routine Balance of Plant inspections will be scheduled during a Major Inspection outage.

APPENDIX K

Remote Monitoring Data Points

Pursuant to Section 4.3.2.7, Seller shall use commercially reasonable efforts to make available to Buyer the Station Fuel Meter outputs listed below:

Station Fuel Meter, including:

(a) instantaneous and integrated natural gas fuel flow;

(b) instantaneous and integrated natural gas fuel energy flow;

(c) instantaneous fuel quality raw data (fuel heat content, delivery pressure, delivery temperature).

Pursuant to Section 4.3.2.7, Seller shall make available to Buyer the Facility and Unit outputs listed below:

1. Revenue Meter Per Unit, including:

   (a) instantaneous and integrated Electric Energy output (corrected to the Point of Delivery);

   (b) instantaneous reactive power (volt−amperes−reactive, leading or lagging), or power factor (leading or lagging) as available;

   (c) integrated electric power inflow (backfeed)

   (d) station voltage (as measured at the Revenue Meter potential transformers;

   (e) system frequency (as measured on the interconnected Utility system bus, or if not available, at the Revenue Meter)

2. Individual Fuel Meter instantaneous natural gas fuel flow to the individual Units (including Elwood II Units).

3. Station service instantaneous and integrated electric energy consumption.

4. Ambient dry−bulb temperature at or near to the combustion turbine air inlet.

5. Relative humidity or ambient wet−bulb temperature at or near to the combustion turbine air inlet.

6. Ambient atmospheric pressure at or near to the combustion turbine air inlet.

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Exhibit 12

Aquila, Inc.
Ratio of Earnings to Fixed Charges

Dollars in millions	**Year Ended December 31, 2005**	**2004**	**2003**	**2002**	**2001**
Income (loss) from continuing operations before income taxes	$ (201.1)	$ (562.6)	$ (503.5)	$ (1,712.1)	$ 320.3
Add (Subtract):					
Equity in earnings of investments	—	(2.1)	(69.6)	(166.9)	(119.3)
Dividends and fees from investments	.5	1.5	48.6	87.9	55.5
Minority interest in income (loss) of subsidiaries	—	—	—	(7.8)	20.1
Total interest expense	221.3	273.1	296.9	255.2	223.1
Interest capitalized	—	—	—	(1.3)	(1.9)
Portion of rents representative of an interest factor	11.8	13.6	20.5	22.3	16.5
Income (loss), as adjusted	$ 32.5	$ (276.5)	$ (207.1)	$ (1,522.7)	$ 514.3
Fixed Charges:					
Interest on long−term debt	$ 219.3	$ 264.6	$ 278.0	$ 238.9	$ 210.9
Interest on short−term debt	2.1	8.5	18.9	16.3	12.2
Portion of rents representative of an interest factor	11.8	13.6	20.5	22.3	16.5
Fixed Charges	$ 233.2	$ 286.7	$ 317.4	$ 277.5	$ 239.6
Ratio of Earnings to Fixed Charges	.14	—(a)	—(a)	—(a)	2.15

(a) *Ratio amount not shown due to a coverage deficiency in the amount of $563.2 million, $524.5 million and $1,800.2 million for the years ended December 31, 2004, 2003 and 2002, respectively.*

Exhibit 21

Aquila, Inc.
Subsidiaries
2005 Annual Report on Form 10−K

Subsidiary	Jurisdiction of Incorporation
Aquila Merchant Services, Inc.	Delaware

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Aquila, Inc. Subsidiaries 2005 Annual Report on Form 10−K

Exhibit 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of Aquila, Inc.:

We consent to the incorporation by reference into the company's previously filed registration statements on Form S−3 (Nos. 333−88280 and 333−67822) and on Form S−8 (Nos. 333−92294, 333−68042, 333−68040, 333−68044, 333−67820, 333−66233, 033−45525, 033−50260, 333−19671, 333−91305, 333−94955, 333−30742 and 333−77703) of our reports dated March 3, 2006 with respect to the consolidated balance sheets of Aquila, Inc. as of December 31, 2005 and 2004, and the related consolidated statements of income, common shareholders' equity, comprehensive income, and cash flows for each of the years in the three−year period ended December 31, 2005, and all related financial statement schedules, management's assessment of the effectiveness of internal control over financial reporting as of December 31, 2005 and the effectiveness of internal control over financial reporting as of December 31, 2005, which reports appear in the December 31, 2005, Annual Report on Form 10−K of Aquila, Inc.

/s/ KPMG LLP

Kansas City, Missouri
March 3, 2006

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[CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM](#)

Exhibit 31.1

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

I, Richard C. Green, certify that:

1. I have reviewed the annual report of Aquila, Inc. for the annual period ending December 31, 2005;

2. Based on my knowledge, the report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by the report;

3. Based on my knowledge, the financial statements, and other financial information included in the report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a−15(e) and 15d−15(e)) and internal controls over financial reporting (as defined in Exchange Act Rules 13a−15(f) and 15d−15(f)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this periodic report is being prepared;

b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the board of directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weakness in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

March 6, 2006	/s/ RICHARD C. GREEN
	Richard C. Green Chairman, President and Chief Executive Officer, Aquila, Inc.

Exhibit 31.2

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

I, Rick J. Dobson, certify that:

1. I have reviewed the annual report of Aquila, Inc. for the annual period ending December 31, 2005;

2. Based on my knowledge, the report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by the report;

3. Based on my knowledge, the financial statements, and other financial information included in the report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a−15(e) and 15d−15(e)) and internal controls over financial reporting (as defined in Exchange Act Rules 13a−15(f) and 15d−15(f)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this periodic report is being prepared;

b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the board of directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weakness in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

March 6, 2006

/s/ RICK J. DOBSON

Rick J. Dobson
Senior Vice President and Chief Financial Officer,
Aquila, Inc.

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Exhibit 32.1

Aquila, Inc.
Chief Executive Officer
Certification Pursuant to Section 906 of the Sarbanes−Oxley Act of 2002

I, Richard C. Green, certify that:

1. Aquila, Inc.'s annual report on Form 10−K for the annual period ending December 31, 2005 accompanying this Certification, in the form filed with the Securities and Exchange Commission (the "Report") fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934; and

2. The information in the Report fairly presents, in all material respects, the financial condition and results of operations of Aquila, Inc.

Dated: March 6, 2006

/s/ RICHARD C. GREEN

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

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Aquila, Inc. Chief Executive Officer Certification Pursuant to Section 906 of the Sarbanes−Oxley Act of 2002

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Exhibit 32.2

Aquila, Inc.
Chief Financial Officer
Certification Pursuant to Section 906 of the Sarbanes−Oxley Act of 2002

I, Rick J. Dobson, certify that:

1. Aquila, Inc.'s annual report on Form 10−K for the annual period ending December 31, 2005 accompanying this Certification, in the form filed with the Securities and Exchange Commission (the "Report") fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934; and

2. The information in the Report fairly presents, in all material respects, the financial condition and results of operations of Aquila, Inc.

Dated: March 6, 2006

/s/ RICK J. DOBSON

Rick J. Dobson
Senior Vice President and Chief Financial Officer
Aquila, Inc.

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